MAINTENANCE OPTIMISATION FOR WIND TURBINES

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DEDICATION

This thesis is dedicated to my late parents

Andrawus Agwandas

and

Damaris A. Agwandas

ABSTRACT

Wind is becoming an increasingly important source of energy for countries that ratify to reduce the emission of greenhouse gases and mitigate the effects of global warming. Investments in wind farms are affected by inter-related assets and stakeholders' requirements. These requirements demand a well-founded Asset Management (AM) frame-work which is currently lacking in the wind industry. Drawing from processes, tools and techniques of AM in other industries, a structured model for AM in the wind industry is developed. The model divulges that maintenance is indispensable to the core business objectives of the wind industry. However, the common maintenance strategies applied to wind turbines are inadequate to support the current commercial drivers of the wind industry. Consequently, a hybrid approach to the selection of a suitable maintenance strategy is developed. The approach is used in a case study to demonstrate its practical application. Suitable Condition-Based Maintenance activities for wind turbines are determined.

Maintenance optimisation is a means to determine the most cost-effective maintenance strategy. Field failure and maintenance data of wind turbines are collected and analysed using two quantitative maintenance optimisation techniques; Modelling System Failures (MSF) and Delay-Time Maintenance Model (DTMM). The MSF permits the evaluation of life-data samples and enables the design and simulation of a system's model to determine optimum maintenance activities. Maximum Likelihood Estimation is used to estimate the shape (β) and scale (η) parameters of the Weibull distribution for critical components and subsystems of the wind turbines. Reliability Block Diagrams are designed using the estimated β and η to model the failures of the wind turbines and of a selected wind farm. The models are simulated to assess and optimise the reliability, availability and maintainability of the wind turbine and the farm. The DTMM examines equipment failure patterns by taking into account failure consequences, inspection time and cost in order to determine optimum inspection intervals. Defects rate (α) and mean delay-time ($1/\gamma$) of components and subsystems within the wind turbine are estimated. Optimal inspection intervals for critical subsystems of the wind turbine are then determined.

CHAPTER 1

INTRODUCTION

1.1 BACKGROUND

Global warming is increasingly becoming a crucial issue in the contemporary world. The seriousness of the issue is reflected through the recent commitment of corporate organisations and individuals to combat the effects of global warming. In 1997 the *United Nations* adopted the *Kyoto Protocol* as an amendment to the *Framework Convention on Climate Change* (*FCCC*). The Protocol is a legally binding agreement under which industrialised countries are obliged to reduce collective emissions of greenhouse gases (Kyoto Protocol to the United Nations Framework Convention on Climate Change, 1997). Countries which ratify the protocol commit to reduce their emissions of carbon dioxide and five other greenhouse gases, or engage in emissions trading if they maintain or increase emissions of these gases. However, many countries including the United State of America (USA) who contribute a significant percentage of the total global pollution are yet to ratify the Kyoto protocol.

There has been rising concern about the finiteness of the earth's fossil fuel reserves (Manwell et al. 2002). The global demand for energy is increasing with population growth. The normal human daily life such as communication, transportation, health-care, etc is becoming more and more dependent on energy. Nations are currently challenged to find proactive measures to comply with the global policies on climatic change and respond effectively to the finiteness of the earth's fossil fuel reserves.

Accordingly, the UK government in 2002 introduced the *Renewable Obligation Order* (*RO*). The RO requires electricity suppliers to prove that they are generating a specified proportion of their power from renewable energy sources. A target was set to increase the current level of 2% to 10% by 2010 (Department of Trade and Industry, 2002). Electricity suppliers that meet the terms of the RO are issued a *Renewable Obligation Certificate* (*ROC*). This has compelled the electricity suppliers in the UK to generate energy from alternative sources which are naturally replenished, and do not release carbon dioxide as a by-product into the atmosphere. These alternative sources of energy are referred to as *Renewable Energy*.

1.2 RENEWABLE ENERGY

Renewable energy is obtained from natural sources that are essentially inexhaustible (Energy Information Administration, 2005). Basically, there are seven (7) common types of renewable energy; wind, solar, hydroelectric, tidal, wave, geothermal and bio-fuels (Cresswell et al. 2002). Each of these energy sources can be converted from their original form to produce electricity without depleting or distorting the natural characteristics of the resources. Energy generated from wind is fast becoming one of the most utilised renewable energy sources in the world **(**Pellerin, 2005). Improvements in the design of wind turbines (Marsh, 2005) and the ready availability of wind resources in most parts of the world are contributing to the rapid development of the industry.

1.3 WIND ENERGY GENERATION

Wind energy generation refers to the conversion of air movement into electrical energy by using a wind turbine. Wind moves around the earth as a result of temperature and pressure differences. The wind movement is harnessed by the blades of a wind turbine to generate electricity. The blades are connected to a shaft and often times a gearbox to convert the rotational speed of the blades into mechanical energy. This is converted into electrical energy by an electrical generator connected to the gearbox or shaft as required. Wind turbines are often installed onshore but in recent years, the wind industry has experienced a significant shift in the development of wind farms from onshore to offshore locations **(**Gaudiosi, 1999**)**. It is worth noting that the availability of wind resources in a specific location depends on the nature of the landscape, altitude. Indeed, the *European Wind Energy Association* (2003) claims that the North Sea area allocated to offshore wind energy generation could provide enough power to satisfy all of Europe's electricity demand. These factors have increased significantly the potential for investment in the wind energy industry as well as the range of possible stakeholders. However, caution must be exercised in evaluating the business climate of the wind energy industry to ensure the return on investments in wind farms is maximised.

1.4 CHALLENGES OF INVESTMENT IN THE WIND ENERGY INDUSTRY

The UK government's target to generate 10% of the national electricity from renewable sources by 2010 would require an investment of about £10 billion; given that the current level of renewable energy generation is only 2% (Department of Trade and Industry, 2002). The current priority of the wind energy industry is to expand by developing more wind farms using turbines of high capacity ratings. Globally, very significant financial investments have been made in developing wind farms with a wide range of stakeholders. Indeed, the wind energy industry in 2005 spent more than US$14 billion on installing new generating equipment (Environment News Service, 2006). Progressively, the world generated wind energy has now increased to about 59,322 MW (Environment News Service, 2006) from 2,000 MW in 1990 (Marafia and Ashour, 2003) with an annual average growth rate of about 26 percent (Junginger et al. 2005). However, with this huge investment potential and significant increase in generation capacity comes an additional and often overlooked responsibility; the management of wind farms to ensure the lowest total Life Cycle Cost (LCC).

Learney et al. (1999) states that the "*...net revenue from a wind farm is the revenue from sale of electricity less operation and maintenance (O&M) expenditure*". Thus, to increase the productivity and profitability of the existing wind farms, and to ensure the lowest total LCC for successful future developments will require maintenance strategies that are appropriate (technically feasible and economically viable) over the life-cycle of wind turbines.

1.5 COMMON MAINTENANCE STRATEGIES APPLIED TO WIND TURBINES

The term *maintenance* is sometimes referred to as *asset care* or *asset preservation*. It involves activities like inspection, repair, overhaul and/or replacement of parts of the asset. British Standard (BS) 3811 defines maintenance as "…*the combination of all technical and associated administrative actions intended to retain an item or system in, or restore it to, a state in which it can perform its required function*". Dunn (2005) defines maintenance as "…*any activity carried out on an asset in order to ensure that the asset continues to perform its intended functions*". Where as Moubray (1997) defines maintenance as "…*ensuring that physical assets continue to do what their users want them to do*".

Wind turbines are often purchased with a 2-5 years all-in-service contract, which includes warranties, and corrective and preventative maintenance strategies (Verbruggen 2003; Conover et al. 2000; Rademakers & Verbruggen 2002). These maintenance strategies (corrective and preventative) are usually adopted by wind farm operators at the expiration of the contract period to continue the maintenance of wind turbines (Rademakers & Verbruggen 2002).

1.5.1 Preventative Maintenance

The preventative tasks are planned to include routine checks, testing and maintenance. The tasks are aimed to determine whether any major maintenance work is required so that corrective maintenance is reduced to a minimal level. Full servicing of wind turbines is often carried out twice a year (Verbruggen, 2003; Conover et al. 2000; Rademakers & Verbruggen, 2002). This bi-annual servicing is carried out with the aid of a checklist to verify the current status, and update the maintenance record, of each turbine.

The checklists are turbine specific and activities include a check of the gearbox and the hydraulic system oil levels, inspection of oil leaks, inspection of the cables running down the tower and their supporting systems, observation of the machine while running to check for any unusual drive train vibrations, inspection of the brake disc, and inspection of the emergency escape equipment. Other activities include checking the security of fixings (e.g. blade attachment, gearbox hold down, jaw bearing attachment, tower base-bolt), the high speed shaft alignment, the brake adjustment and brake pad wear, the performance of yaw drive and brake, bearing greasing, the security of cable terminations, pitch calibration (for pitch regulated machines), oil filters, etc.

1.5.2 Corrective Maintenance

Corrective maintenance of wind turbines include tasks carried out in response to components' wear and tear, human errors, design faults and operational factors such as over speeding, excessive vibration, low gearbox oil pressure, yaw error, pitch error, premature activation of brakes, synchronisation failure, loss of grid connection, etc. The operators become aware of corrective tasks either during routine inspection or when the protection system shuts down the turbines in response to an incipient fault.

In the final report of the *Concerted Action on offshore Wind Energy in Europe* (Garrad Hassan & Partners, et al. 2001), four maintenance strategies are proposed for European offshore wind farms. These include: (i) *No maintenance*; where neither preventive nor corrective maintenance are executed but major overhauls are to be performed every five years. (ii) *Corrective maintenance only*; where a certain number of wind turbines are allowed to fail before repairs are carried out, and no permanent maintenance crew is required. (iii) *Opportunity maintenance*; where maintenance activities are executed on demand and taking the opportunity to perform preventive maintenance at the same time. Maintenance crew is not required. (iv) *Periodic maintenance*; this includes schedule visits to perform preventative maintenance and corrective actions using permanently dedicated maintenance crew.

1.6 PROBLEMS ASSOCIATED WITH THE CURRENT MAINTENANCE PRACTICES OF WIND TURBINES

The *no-maintenance* and *corrective maintenance-only* strategies commonly known as *Failure-Based Maintenance* (FBM) strategy involve using a wind turbine or any of its components until it fails. This strategy is usually implemented where failure consequences will not result in revenue losses, customer dissatisfaction or health and safety impact. However, critical component failures within a wind turbine can be catastrophic with severe operational and Health, Safety and Environmental (HSE) consequences. Thus, the viability of FBM strategy is averted by the consequences of failures on electricity network and revenue generation.

The preventative maintenance strategy commonly referred to as *Time-Based Maintenance* (TBM) involves carrying out maintenance tasks at predetermined regular-intervals. This strategy is often implemented to avoid invalidating the Original Equipment Manufacturers' (OEM) warranty and to maintain sub-critical machines where patterns of failure are well known. However, the choice of the correct interval poses a problem as too frequent an interval increases operational costs, wastes production time and unnecessary replacements of components in good condition, whereas, unexpected failures frequently occur between TBM intervals which are too long (Thorpe, 2005). Thus, time and resources are usually wasted on maintenance with little knowledge of the current condition of the equipment. This thwarts the adequacy of the periodic and opportunity maintenance strategies to support the current commercial drivers of wind farms.

A detailed assessment of failure characteristics of 15,500 grid-connected wind turbines were carried out in Germany. The aim was to identify all possible causes of failures of horizontal axis wind turbines. It was found that forty two (42) percent of the total failures were caused by components breakdown while twenty one (21) percent were caused by control system failures (Windstats Newsletter, 2004). Similar studies were undertaken at the *Centre for Renewable Energy Systems Technology* (*CREST*) and the *Energy Centre Netherlands* (ECN). The results show components' breakdown was responsible for most of the wind turbines' failure. Rademakers & Verbruggen (2002) observed that the *failure rate* of an onshore wind turbine was about 1.5 to 4 times per year while an offshore wind turbine was said to require about 5 service visits per year (Garrad Hassan & Partners et al, 2001). This implies that huge amount of money and effort are required annually to fix failed wind turbines' components in addition to the severe economic, operational, health, safety and environmental consequences.

Thus, owing to the current maintenance practises and failure characteristics of wind turbines, there exists a need to determine an appropriate maintenance strategy that will effectively reduce the total LCC of wind turbines and maximise the return on capital investment in wind farms. Such a strategy must comprise maintenance activities that are technically feasible and economically viable over the life-cycle of wind turbines.

1.7 ASSET MANAGEMENT

The *Chambers Dictionary* defines asset as "…*any thing of value to the owner*". Eyre-Jackson and Winstone (1999) classified assets into 5 major groups; *physical, human, financial, intellectual* and *intangible*. As a result, the term '*Asset Management*' has been used widely across several industrial sectors. For example, the financial services and banking sectors have applied the term to the management of investment funds, financial assets, credit and equity (Woodhouse, 2002). The Oil and Gas industry uses the phrase to describe a more comprehensive approach to getting the best value out of hydrocarbon reserves and production infrastructure (PAS 55- Asset management view, 2004). In spite of the numerous areas of application, *Asset Management* (AM) has evolved from many industrial sectors as a means to describe a holistic application of business best practices in order to satisfy all stakeholders' requirements.

The *Institute of Asset Management* (*IAM*) defines Asset Management as "…*the systematic and coordinated activities and practises through which an organisation optimally manages its physical assets, and their associated performance, risks and expenditure over their lifecycle for the purpose of achieving its organisational strategic plan*".

The processes, tools and techniques of Asset Management have historically been developed by industries to improve their overall business performance. Nowadays, AM is becoming a major issue in many organisations wishing to redefine business performance and get the best value for money.

1.7.1 Asset Management in other Industrial Sectors

A brief overview of the experiences of some industries that adopted AM methodologies to manage day-to-day business activities give insight into the potential benefits of AM.

1.7.1.1 The Oil and Gas Sector

The first UK's oil was produced from the Argyll field in 1975 (Institute of Petroleum, 2005). A huge financial investment was made in the sector due to the government's commitment to make UK self sufficient in oil production. As a result, the sector experienced rapid infrastructural developments. Moreover, there was a steady increase in the profit margins to a climax of US$20 per barrel (operating expenditure was approximately $15 with a crude oil market value at about $35 per barrel). Subsequently, the oil market price crashed in 1986 to about $9 per barrel (Woodhouse, 2002) resulting in a loss of about $6 per barrel. Production became unprofitable and ownership of physical infrastructure such as production platforms, underwater pipelines, etc became uneconomical. Also in 1988, the sector suffered another business dilemma; the destruction of the Piper Alpha platform killing 167 persons (The History of the oil industry in UK). These economic and safety factors necessitated the development and application of some AM processes, tools and techniques to maximise the return on investment in hydrocarbon reserves and production infrastructure while ensuring a safe working environment.

1.7.1.2 The Electricity Supply Industry

In 1980 the UK started restructuring its Electricity Supply Industry **(**ESI) through privatisation. A substantial part of the privatisation took place between 1990 and 1993. It concluded with the sale of the newer nuclear power stations in 1996 (Pollitt, 1999). The privatisation brought to the sector new and crucial challenges such as improving the efficiency and quality of services to meet the increasing public demand, lower prices to gain a larger market share, reducing operating expenditure to increase overall profitability of the sector, etc. The ESI adopted AM processes, tools and techniques to improve equipment reliability, plant integrity and overall network performance to eliminate intermittent supplies. Regulatory requirements were reviewed. Measures for proactive and total compliance were initiated.

1.7.1.3 The Water Supply Industry

The privatisation of the Water Supply Industry **(**WSI) in the UK had three key objectives; increase efficiency, lower prices and increase quality of services. However, as Hall (2001) pointed out, a constant tension exists between public service objectives and profit-seeking behaviour of a privatised sector. The sector was faced with incompatible objectives of lower prices and profit maximisation. Consequently, WSI prioritised the maintenance of pump stations and the control of leakages in pipes and storage facilities by adopting AM methodologies to ensure the reliability of water supply.

1.7.1.4 Transport Services

AM is gaining popularity in the UK transport services due to the privatisation of the sector. The overall business objectives as well as methods of getting the best value for money are re-defined through the application of AM methodologies.

1.7.2 Processes of Asset Management

A generic business model outlining the fundamental issues involved in the management of any physical asset is presented in figure 1.1. A high level of performance is required in terms of compliance with health, safety and environmental requirements as well as improving the quality of products and services while ensuring cost effectiveness. Equipment reliability needs to be assessed and optimised through the application of appropriate asset management tools and techniques. People and operational requirements for effective and efficient performance should be identified and aligned with equipment reliability requirements. Performance measurement frame-works need to be designed to ensure periodic evaluation of actual performance against intended targets and goals. Where deviations are identified, corrective measures are initiated to ensure continuous performance improvements. Therefore, it is absolutely necessary to review the various tools and techniques used in AM with a view to understand their area of application.

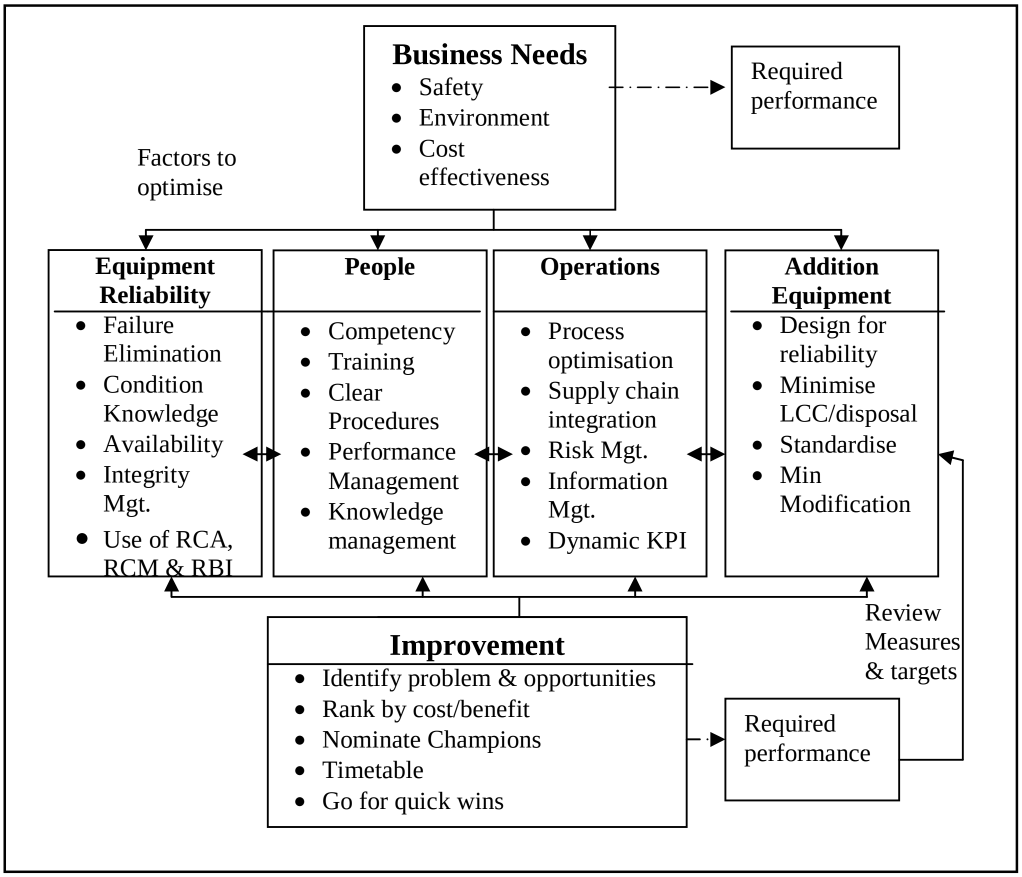

Figure 1.1 Generic Model showing key Business Issues

1.8 ASSET MANAGEMENT AND THE WIND ENERGY INDUSTRY

The offshore Oil and Gas (O & G) sector in the UK reactively adopted AM methodologies to maximise the return on investment in hydrocarbon reserves and production infrastructures when production became unprofitable and ownership of physical infrastructures such as production platforms became uneconomical. There is a clear corollary of the current status of the wind energy industry with that of the O & G industry of 30 years ago; the O & G in the UK increased in size dramatically over one to two decades, with little consideration of the impact that appropriate maintenance might have in terms of reducing total life-cycle costs (LCC). Subsequently, the O& G industry has historically suffered from ineffective and inefficient maintenance practices and the impact on productivity has been significant. It is estimated that an optimal maintenance regime reduces direct maintenance cost by 40-70% and can improve availability by up to 7% (Arthur, 2005). The O& G industry has perpetually been reactively attempting to address these issues by re-engineering design, installation, etc for effective maintenance.

The wind energy industry has a clear opportunity to consider the strategic importance of maintenance now, and to proactively realise the benefits that are available over the life of wind farm installations. This is especially important when it is considered that planning regulations for wind farms currently do not relate to maintenance and no regulations pertinent to maintenance exist (Melford 2004). The processes, tools and techniques of AM are currently well-established in the mature industries most especially in the area of maintenance optimisation but the application to the wind energy sector has historically been poor.

1.9 TOOLS AND TECHNIQUES OF ASSET MANAGEMENT

A number of quality tools and techniques exist in the field of asset management to effectively and efficiently manage the ownership of physical assets; taking into account economic, health, safety and environmental issues. These tools and techniques include the *Reliability-Centred Maintenance* (RCM), *Failure Mode and Effect Analysis* (FMEA), *Hazard and Operatibility studies* (HAZOP), *Hazard Analysis (HAZAN), Fault Tree Analysis* (FTA), *Event Tree Analysis* (ETA), *Critical Task Analysis* (CTA), *Quantified Risk Analysis* (QRA), *Total Productive Maintenance* (TPM), *Risk Based Inspection* (RBI), *Root Cause Analysis* (RCA), *Structured What-if Technique* (SWIFT), etc.

Reliability-Centred Maintenance, Risk Based Inspection and Total Productive Maintenance are techniques commonly used to determine appropriate maintenance strategies for physical assets. Moubray (2000) explains that no comparable technique exists for identifying the true, safe minimum of what must be done to preserve the functions of physical assets in the way that RCM does. RCM was introduced in the air craft industry by Nowlan and Heap (1978). Since its inception, the approach has been applied in several industrial sectors with considerable success (Rausand, 1998) for example, the railway (Rasmussen et al. 2004), offshore Oil & Gas (Arthur & Dunn 2001; Hokstad et al. 1998), manufacturing (Deshpande & Modak 2003).

1.9.1 Reliability-Centred Maintenance

RCM is a technique used to determine what must be done to ensure that any physical asset or system continues to do whatever its users want it to do (Moubray 1991). The process predicts how a system's failures can occur and the potential consequences on the system operation. The technique further assesses failure consequences and the probability of occurrence to provide a basis upon which to decide an appropriate maintenance action for each failure mode (Latino 1997). Fundamentally, there are three (3) factors that must be considered to select an appropriate maintenance strategy for any physical asset. These factors include failure consequences, predictability of reasonable asset life, and the possibility of installing condition monitoring systems on the asset. A suitable maintenance strategy could include one or a combination of the following; failure-based, time-based and/or condition-based maintenance activities.

1.10 CONDITION-BASED MAINTENANCE STRATEGY

Condition-Based Maintenance (CBM) is one of the possible strategies that can be determined through the application of an RCM technique. CBM constitutes maintenance tasks carried out in response to deterioration in the condition or performance of an asset or component as indicated by condition monitoring processes (Moubray 1991). Saranga & Knezevic (2001), Arthur & Dunn (2001) stated that CBM is the "…*most cost-effective means of maintaining critical equipment*". The broad research area of CBM applied to wind energy conversion has largely been ignored, although limited work has been undertaken in the areas of monitoring the structural integrity of turbine blades using thermal imaging and acoustic emission (Clayton et al. 1990; Dutton et al. 1991), the use of performance monitoring (Learney et al. 1999), lubricant analysis, temperature monitoring and on-line analysis systems (Philippidis & Vassilopoulos 2004). Generally, as reported, these works exist in isolation, and are not considered with the wider context of a maintenance, integrity and asset management strategy. For example, the intervals at which these activities should be carried out (if at all) have not been assessed in terms of cost-benefit. Determining an appropriate maintenance strategy for a piece of equipment is not in itself a means to an end, but the maintenance activities ought to be optimised on a continuous basis.

1.11 MAINTENANCE OPTIMISATION

Maintenance optimisation is *"…a process that attempts to balance the maintenance requirements (legislative, economic, technical, etc.) and the resources used to carry out the maintenance program (people, spares, consumables, equipment, facilities, etc.)"* (Systems Reliability Centre, 2003). A maintenance strategy that is appropriate and optimal now may not be optimal in the very near future due the erratic nature of the input variables such as interest rate, components cost, failure behaviour, etc. Thus, maintenance optimisation is not a one-off procedure but a continuous process which requires periodic evaluation of performance and improving on the successes of the past.

Essentially, there are 2 approaches to maintenance optimisation; *qualitative and quantitative*. Arthur (2005) and Scarf (1997) observed that *qualitative* maintenance optimisation is often clouded with subjective opinion and experience, and further suggest the utilisation of *quantitative* methods to optimise the maintenance activities of physical assets. Quantitative maintenance optimisation (QMO) techniques employ a mathematical model in which both the cost and benefits of maintenance are quantified and an optimum balance between both is obtained (Dekker, 1996).

There are a number of QMO techniques in the field of *Applied Mathematics and Operational Research* (AMOR), for example, *Markov Chains and Analytical hierarchy processes* (Chiang et al. 2001); *Genetic Algorithms* (Tsai et al. 2001), etc. However, most of the approaches are criticised for being developed for mathematical purposes only and are seldom used in practical asset management to solve real-life maintenance problems (Dekker, 1996). *Modelling System Failures*

(MSF) has been recommended as the best approach to assess the reliability and optimise the maintenance of mechanical systems (Davidson and Hunsley 1994). The *Delay-Time Maintenance Model* (DTMM) (Scarf, 1997) is well-known for its simplistic mathematical modelling and has been applied practically to optimise the inspection intervals of some physical assets with considerable success. Andrawus et al (2007a) discussed the concept and relevance of the two *quantitative* maintenance optimisation techniques and highlighted their applicability to the wind energy industry.

1.11.1 Benefits of maintenance optimisation for wind turbines

Maintenance is based on observed conditions which reduces components' damage and prevents catastrophic failures of wind turbines. Thus, costs associated with longer downtimes are reduced by ensuring minor failures are resolved before they escalate to major ones. Replacements or overhauls of components in good operating conditions are avoided completely.

The overall availability of wind turbines is increased by maximising the time interval between repairs and overhauls. Furthermore, suitable maintenance intervals, logistics, spare parts and associated man-hours are planned ahead, adding up to greater turbine availability. Consequently, the number of access and logistic costs are reduced significantly.

The conditions of turbines can be monitored remotely in real-time without personnel having to travel to sites which pose serious safety treats. The lead time given by monitoring systems will enable stoppage of a turbine before it reaches a critical condition. Extreme external conditions such as wave-induced oscillation of towers in remote locations can be detected. This prevents damage to components of turbines. The overall result is improved reliability/availability of wind turbines, and significant reduction in downtimes and net maintenance costs.

1.12 RESEARCH AIM AND OBJECTIVES

This section elaborates the aim and objectives of the undertaken research work reported in this thesis.

1.12.1 Research Aim

The overall aim of the research work was to determine and optimise appropriate maintenance tasks for wind turbines.

1.12.2 Research Objectives

Specifically, seven research objectives were logically outlined and addressed:-

1. *Assess the current maintenance of wind turbine equipment.*
2. *Develop a structured model for asset management in the wind energy industry.*
3. *Critically evaluate wind turbines to determine likely failure characteristics.*
4. *Assess the technical and commercial feasibility of maintenance strategies taking into account commercial drivers such as warranty issues, geographical location, intermittent operation and the value of generation.*
5. *Optimise maintenance activities using Modelling System Failures based on Monte Carlo Simulation Techniques.*
6. *Optimise maintenance activities using Delay-time mathematical maintenance model.*
7. *Compare the results of the Modelling System Failures and the Delay-time mathematical maintenance model.*

1.13 THESIS OVERVIEW

The thesis determines and optimises appropriate maintenance tasks for wind turbines. Field failure and maintenance data of wind turbines are collected and analysed using the Modelling System Failures and Delay-Time Maintenance Model optimisation techniques. Failures of the wind turbines are modelled and simulated to assess and optimise the reliability, availability and maintainability of a selected wind farm. Defects rate and mean delay-time of components and subsystems within the wind turbine are estimated to determine optimal inspection intervals for critical subsystems of the wind turbine.

Chapter 2 reviews the renewable energy sector with a particular focus on the wind energy industry. It discusses the failure characteristics and cost significant items of horizontal axis wind turbines. The subject of Asset management is reviewed to understand its concept and processes applied in other industries. Existing asset management tools and techniques which can be deployed to improve assets' performance are identified and discussed.

Chapter 3 presents the approaches and methodologies adopted to achieve the stated objectives of the research work reported in this thesis. Field failure data of wind turbines were collected from 27 wind farms (comprising turbines of different capacity ratings) located within the same geographical region. Failure data pertinent to the critical components and subsystems of wind turbines were extracted from the Supervisory Control and Data Acquisition (SCADA) system of wind farms. The SCADA system records failures and the date and time of occurrence; these were used in conjunction with maintenance Work Orders (WOs) of the same period to ascertain the specific type of failure and the components involved. The collected data were organised in accordance with the type, design and capacity of the wind turbines. A total of seventy seven 600 kW wind turbines of a particular type have been used to carry out the objectives of the research work reported in this thesis. The 600 kW wind turbines rating were of particular interest to the collaborating wind farm operator in regard to optimising maintenance on their wind farm. Therefore maintenance optimisation of 600 kW wind turbine is the focus of this thesis.

The methodology presented in the thesis can be applied to offshore wind farms. However, additional models are required to include the cost of various possible access systems to carry out maintenance works on offshore wind turbines. Hostile weather conditions that can delay the maintenance activities on offshore wind turbines are other factors to be considered

In Chapter 4 we design a structured model for asset management in the wind energy industry. Chapter 5 critically evaluates a generic horizontal axis wind turbine to determine its likely failure characteristics and suitable maintenance activities. The technical and commercial feasibility of the maintenance activities on a 26 x 600 kW wind farm are assessed. In Chapter 6 we analyse collected field failure data of wind turbines to estimate shape (β) and scale (η) parameters of critical components and subsystems. Chapter 7 models the failures of the 600 kW wind turbine and the 26 x 600 kW wind farm. The models are simulated to assess and optimise the reliability, availability and maintainability of the wind turbine and the farm. In Chapter 8 we determine optimal inspection intervals for critical subsystems of the 600 kW wind turbine. Chapter 9 compares the results of the modelling system failures and the delay-time mathematical maintenance model. In Chapter 10 we summarise the study, then presents conclusions drawn from the research work and recommendations for further study.

CHAPTER 2

LITERATURE REVIEW

2.1 INTRODUCTION

This chapter critically reviews literature pertinent to Wind Energy Industry and the field of Asset Management. The wind energy industry is discussed in section 2.2 where we expound on the potentials of onshore and offshore wind energy generation. In section 2.3, the common types of wind turbine design as well as component functionalities and design materials were discussed. The section reviews failure characteristics of horizontal axis wind turbines and, identifies some common causes of failure in wind turbines. A review of the cost significant items within a wind turbine is presented in section 2.4.

Asset management tools and techniques existing in other industries are identified and their applicability, strengths and weaknesses are discussed in section 2.5. Condition monitoring techniques that are applicable to wind turbines are discussed in section 2.6.

2.2 THE WIND ENERGY INDUSTRY

Wind turbines are stand-alone machines which are often installed and net-worked in a place referred to as a *Wind Farm* or *Wind Park*. Wind farms can be located either onshore or offshore.

2.2.1 Onshore and Offshore Wind Energy Generation

Onshore and offshore wind energy generation differs not only in the geographical location but also in some vital technical and economic issues as discussed in the following:

- **Wind resources**

The offshore wind resources are often significantly higher than onshore, even though wind resources at a specific site depend on the nature of the landscape, altitudes, shapes of hills, etc (Department of Trade and Industry, 2005). The temperature difference between the sea surface and the air above it is far smaller than the corresponding difference onshore. This means turbulence tends to be lower offshore than onshore (World Energy Council, 2005). Consequently, offshore wind turbines suffer less dynamic operating stress.

- **Capital cost**

Another significant difference between onshore and offshore wind energy generation is the installed cost. The foundation structures of an onshore wind farm cost about 6% of the total project cost while grid connection facilities cost about 3% (World Energy Council, 2005). On the other hand, the foundation structures of an offshore wind farm need to ensure the turbines are connected to the seabed and are able to cope with additional factors such as loading from waves, currents and ice. Thus, the cost is about 23% of the total project cost while the cost of grid connection facilities is about 14% (World Energy Council, 2005). These costs are significantly higher than onshore wind farm costs.

- **Technology**

The technology of the wind turbines used in onshore and offshore wind farms is very similar. The main difference is in the size and the power rating of the turbines. Onshore farms often utilise turbines with capacities of up to 2 MW while offshore farms use multi-mega watt turbines (Department of Trade and Industry, 2005). Offshore wind farms are usually connected to a sub-station located onshore by using submarine cables. The substation is connected to an electricity grid using overhead cables in similar manner to onshore wind farms. Offshore wind farms usually require higher voltage transmission systems and technical equipment such as transformers and switch-gear. The significant wind resources offshore and the possibility to install multi-mega watt turbines are some of the major drivers of the recent shift in development of wind farms from onshore to offshore locations.

2.3 WIND TURBINES

This section discusses some common design types of wind turbines. It reviews components' functionalities, design materials as well as their failure characteristics.

2.3.1 Design Types

The design of a wind turbine is usually specified according to the following six basic criteria; *hub height*, *rotor diameter or swept area*, *blade solidity*[1], *tip speed ratio*[2], *rated power* and *rated wind speed* (Walker & Jenkins 1997). These criteria are designed to suit a specific orientation or topology (Manwell et al. 2002). Table 2.1 summarises some common design topology of wind turbines. Note there are designs that are not commercially available are not included in the table. HAWT have been popularised by designers because they offer the possibility of using towers to raise the blades to a position of maximum wind resources.

Table 2.1 Common Design Orientation of Wind Turbines

	Sub-system	Design options
1	Rotor axis orientation	a. Horizontal axis wind turbine (HAWT) b. Vertical axis wind turbine (VAWT)
2	Rotor power control	a. Stall control b. Variable pitch control c. Aerodynamic control d. Yaw control
3	Rotor position	a. Down wind rotor b. Up wind rotor
4	Yaw control	a. Free control b. Active control
5	Rotational speed	a. Constant speed b. Variable speed
6	Tip speed ratios	a. High speed b. Low speed
7	Hub	a. Rigid b. Teetering c. Hinged or gimballed
8	Rigidity	a. Stiff b. Flexible
9	Number of blades	a. Three blades b. Two blades
10	Tower structure	a. Tubular b. Pipe-type c. Trusses
11	Foundations	a. Concrete caissons foundation b. Steel gravitational foundation c. Tripod foundation d. Mono piles foundation

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[1] *The ratio of the area of blades to the swept area.*

[2] *Ratio of the speed of the blade tip to the wind speed.*

A horizontal axis wind turbine comprise 3-blades, up-wind, pitch control, a 3-stage planetary gearbox, 4-pole asynchronous generator, and a tubular tower, is chosen to pursue the objectives of the research work reported in this thesis. The subsystems and components of a typical horizontal axis wind turbine are shown in figure 2.1.

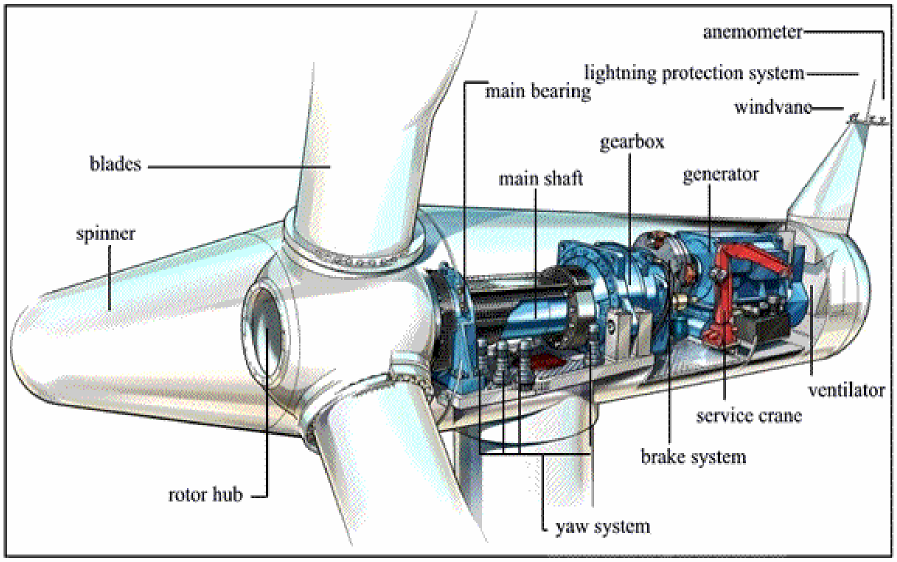

Figure 2.1 Components and Subsystems of a typical HAWT wind turbine

2.3.2 Components Functionality, Design Materials and Failure characteristics

This subsection discusses the functions as well as the design materials of the various subsystems and components of a horizontal axis wind turbine. It further identify from the literature, the possible causes of a wind turbine's components and subsystems failure.

Basically, there are 4 main causes of failure of equipment or physical assets; *human error*[3], *Acts-of-God*[4], *design faults* and *components related failure*[5]. The *International Electro-technical Commission* on *Wind Turbine Standards* [*IEC 61400-22*] and, the *European Wind Turbine Certification Guidelines* [*EWTC, 2001*] 212

[3] The gap between what is done and what should have been done such as wrong installation of components, etc.

[4] Refers to natural events which the occurrence can not be reasonably foreseen or avoided e.g. lightening, etc.

[5] Deterioration of equipment in its normal operating context such as fatigue, wear-out, etc.

require comprehensive design tests for the various components of a wind turbine. However, these design tests cannot accurately predict all the actual environmental factors which vary from site to site (Dutton A.G., et al 1999) or all possible causes of failure that may occur during the operating life of the wind turbine. Thus assessing field failure characteristics of wind turbines is essential to understanding the likely failure behaviour of the turbines when they are exposed to the natural environment.

In Germany, field failure behaviour of 15,500 grid connected wind turbines were assessed to determine all causes of failure. The result presented in figure 2.2 shows that 42% of the total failure was caused by component breakdown while 21% was caused by control system failure (Windstats Newsletter, 2004).

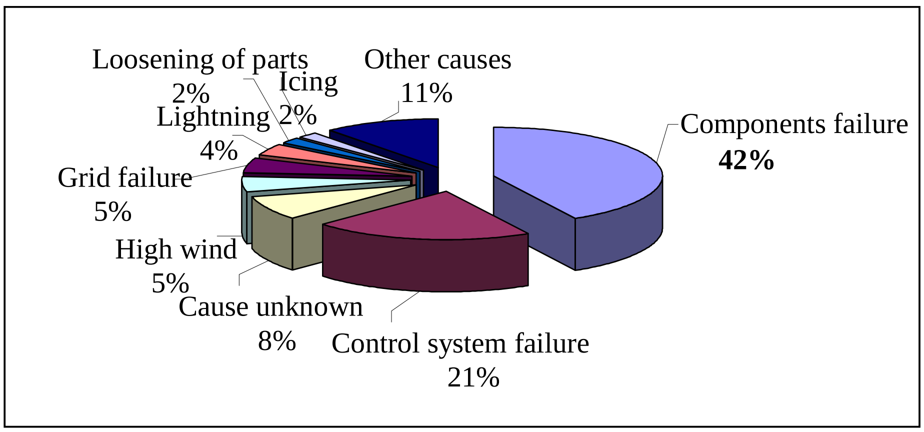

Figure 2.2 Causes of wind turbines failure- The German experience
(Source: Windstats Newsletter, 2004)

Similar studies on failure behaviour of wind turbines in the UK and the Netherlands were undertaken at the *Centre for Renewable Energy Systems Technology* (*CREST*) and the *Energy Centre Netherlands* (*ECN*) respectively. The results are presented in figures 2.3 and 2.4 respectively.

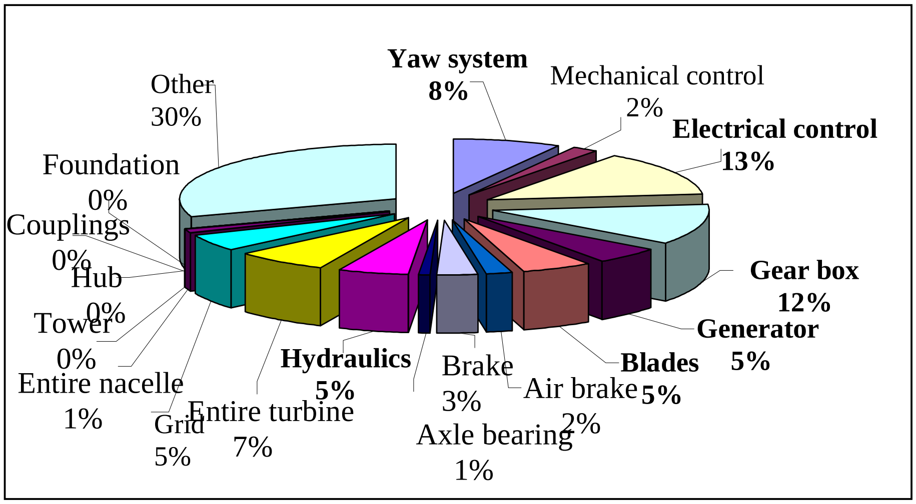

Figure 2.3 Wind turbine component failures in the UK
(Source: CREST Loughborough University- http://www.hie.co.uk/Renewables-seminar-04-presentations/crest-david-infield.pdf)

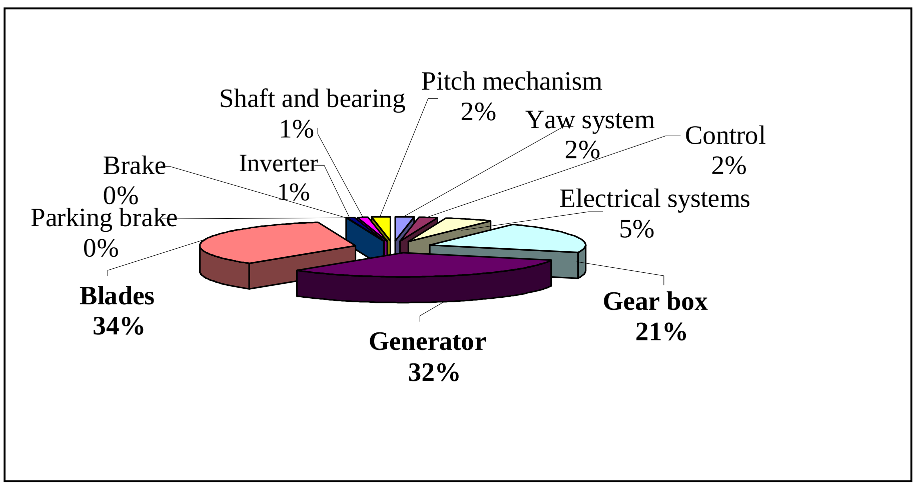

Figure 2.4 causes of offshore wind turbines failure in the Netherlands
(Source: ECN- http://www.ecn.nl/docs/dowec/2003-EWEC-O_M.pdf **)**

2.3.2.1 Blades

Wind turbine blades are designed to harness wind movement and then transmit the rotational energy to the gearbox via the hub and main shaft. The blades of a wind turbine are usually made from composite[6] materials. Composite materials are often preferred because of the possibility of achieving high strength and stiffness-to-weight ratio (Manwell et al. 2002). They are also corrosion resistant and good

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[6] Items made from combining at least two completely different materials

electrical insulators. These properties are advantageous in an offshore environment where corrosion is a critical factor to be considered. Table 2.2 shows some composite materials and their corresponding binders commonly used in the production of wind turbine blades.

Table 2.2 Composites and binders used in manufacturing wind turbine blades

Composites	Binders or Resins
Fibreglass	Polyester (unsaturated)
Carbon fibre	Vinyl ester
Wood	Epoxy

Wind turbine composite blades can be described as *Carbon fibre reinforcing* or *Wood-epoxy laminates* or *fibreglass reinforced plastic* (*GRP*). GRP is the most commonly used blade because it is cheaper than other composite materials (Burton et al. 2001). Furthermore, fibre glass has good tensile strength while the binder (polyester resins) has a short cure time and low cost.

A wind turbine blade consists of two main parts; the *spar* which gives the structural stiffness and the *skin* which provides the air foil shape as required by a specific design. Basically, there are three common shapes of a wind turbine's blade. The shapes are determined by the overall topology of a wind turbine and the aerodynamic considerations. These common shapes are; *near optimum*, *linear taper* and *constant chord* (Manwell et al. 2002). Table 2.3 shows an example of a specification for a wind turbine blade.

Table 2.3 Technical specification of a typical blade of a wind turbine

Type	Self supporting – constant chord
Material	Fibre glass reinforced plastic (GRP)
Length	30 metres

- **Connecting blades to the hub**

The blade is connected to the turbine's hub through the blade's root. The root is usually made thicker to cope with the high dynamic loading it will experience in its operating life. The blades, hubs and the fasteners are made from different materials. Thus, interactions between these 3 components in terms of stiffness during variable loading constitute huge operating problems. Modern wind turbine blades have threaded bushes glued into their roots, and are connected to the hub by using bolts.

2.3.2.2 Causes of Fibreglass reinforced plastic (GRP) blades Failure

Interaction between wind turbine blades' centrifugal and gravitational force as well as varying wind thrust and turbulence induce the blades to a cyclic and flap-wise loading. As a result, the IEC TS 61400-23 requires full-scale blade test for strength, static and dynamic fatigue, stability and critical deflection to validate design certification. GRP blades in normal operating conditions are known to fail as a result of cracks arising from fatigue (Philippidis T.P and Vassilopoulos A.P. 2004; Infield D. 2003; Dutton A.G., et al. 1990), defects in materials accumulating to critical cracks (Jorgensen E.R., et al 2004) (Anastassopoulos A.A., et al 2002) and lightening strikes (Conover K., et al. 2000). Ice build-up is also known to cause failure of GRP blades.

2.3.2.3 Hub

The hub of a wind turbine connects the blades to the main-shaft, and transmits rotational force generated by the blades. Hubs are generally made from steel which can be welded or cast (Manwell et al. 2002). Essentially, there are three common designs of wind turbine hubs; *rigid*, *teetering* and *hinged*. The topology of a wind turbine determines the specific type of hub design to be used on the wind turbine. Table 2.4 shows an example of a wind turbine hub specification.

Table 2.4 Technical specification of a typical hub of a wind turbine

Design	Rigid
Material	SG cast iron
Others	Contains the equipment to alter pitch of blades

2.3.2.4 Main Shaft

The main or low-speed shaft of a wind turbine connects and transmits rotational force from the hub to the gearbox. Wind turbines' main shafts are usually of forged alloy steel (Burton et al. 2001).

2.3.2.5 Main Bearing

The main bearing of a wind turbine reduces the frictional resistance between the blades, the main-shaft and the gearbox while undergoing relative motion. The main bearings of a wind turbine are usually of the *self-aligning spherical roller* type designed specifically for wind turbines. The spherical bearing has two sets of rollers which allow the absorption of *radial loads* (across the shaft) and *axial forces* (along the shaft). The uniqueness of these bearings is associated with the spherical shape which allows the bearing's inner and outer rings to be slightly slanted and out-of-track in relation to each other. The out-of-track can be up to a maximum of a *half degree* without damaging the bearing while it is operating (Manwell et al. 2002).

- **Main bearing installation**

The main bearing is mounted in the bearing housing and bolted to the main frame of the turbine while the pitching bearing uses the hub as housing.

2.3.2.6 Causes of Main Bearings Failure

The main bearings are usually designed to specifically ensure that wind turbines withstand high loads during gusts and braking. However, poor lubrication (Molinas M. 2004), wear, pitting, deformation of outer race and rolling elements (Caselitz P., et al. 2004) are known to cause main bearing failures. Other causes of failure of a generic bearing are identified by Smith and Mobley (2003).

2.3.2.7 Gearbox

The gearbox of a wind turbine increases the rotational speed of the main shaft from very low revolutions per minute (rpm) to a higher rpm required to drive a generator of the wind turbine. The gearbox often has a constant speed increasing ratio, that is, it does not change speed by changing gears like conventional gearboxes. It is worth noting that it is not uncommon to have a wind turbine operating at different operational speeds. This is possible by having two different sized generators in a wind turbine; each generator unit with a distinctive speed of rotation or alternatively having one generator with two different stator windings (Burton et al. 2001).

The gearbox is one of the heaviest and most expensive components of a wind turbine. A three-stage planetary gearbox is usually utilised in wind turbines (Manwell, 2002). The three-stage planetary gearbox consists of a *planetary gear* and a *three-stage gear* as shown conceptually in figure 2.5. The planetary gear comprises an interior toothed gear-wheel known as a *ring wheel* (see 'a' in figure 2.5), three smaller toothed gear wheels known as *planet wheels* (b_1, b_2 and b_3) which are carried on a common carrier arm known as the *planet carrier* 'c', and a centrally placed toothed gear wheel known as the *sun gear wheel 'd'*.

The ring wheel is usually stationary while the planet carrier is mounted on the hollow shaft. The planet carrier rotates with the same rotational speed as the rotor blades. The three planet wheels (b_1, b_2 and b_3) revolve around the inner circumference of the ring wheel 'a' thereby increasing the speed of the sun-gear wheel 'd'. The sun-gear wheel is fixed to a shaft driving the three-stage gear.

The three-stage gear has three sets of toothed gear wheels i.e. *slow speed stage (5&6)*, *intermediate stage (7&8)* and the *high speed stage (9&10)*. In the low speed stage, the larger gear wheel (5) is mounted directly on the hollow-shaft (1) driven by the sun gear wheel. The smaller gear (6) is machined directly onto the intermediate shaft (2). This drives the larger gear wheel (7) in the intermediate stage. The small intermediate gear wheel (8) is mounted on the intermediate shaft (3). This drives the larger gear wheel (9) in the high speed stage. The small gear wheel (10) in the high speed stage is attached to the high speed shaft (4) which is connected to a generator.

- **Connecting the gearbox to the generator**

The high speed shaft from the gearbox is connected to the generator by means of a coupling. The coupling is a flexible unit made from pieces of rubber which allow some slight difference in alignment between the gearbox and the generator during normal operation.

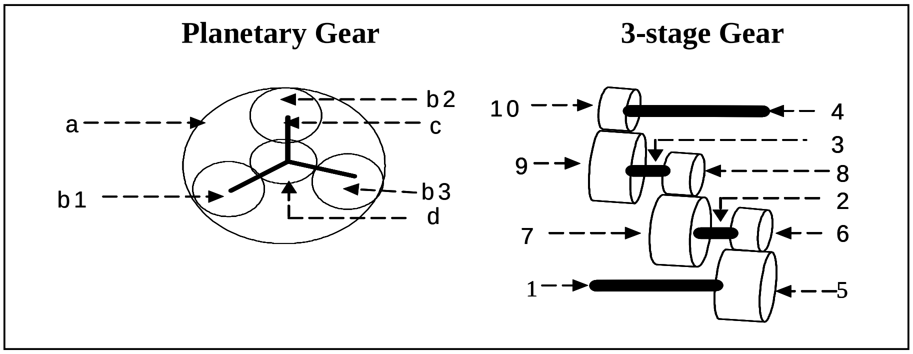

Figure 2.5 components of a 3-stage planetary gearbox

2.3.2.8 Causes of Planetary Gearbox Failure

Some major causes of failure in a wind turbine planetary gearbox include poor lubrication, bearings and gear teeth failures (Rasmussen F., et al. 2004) (Molinas M. 2004), (Caselitz P., et al. 2004) (Niederstucke B., et al. 2000). Polak (1999) carried out a detailed research on gearbox problems, and enumerated some generic causes of their failure. Also, Smith and Mobley (2003) listed some common failure modes of gearbox and gear-sets.

2.3.2.9 Generator

The generator within a wind turbine converts the mechanical rotational energy from the gearbox into electrical energy. The generator is slightly different from other generating units connected to the electric grid because it works with a power source (the wind turbine rotor) that supplies fluctuating mechanical power (torque). Essentially, there are two types of generators commonly used in wind turbines; *synchronous* and *asynchronous*.

- **Synchronous generator**

A generator is *synchronous* when its rotor rotates at a constant speed which is synchronous[7] with the rotation of the magnetic field (stator). Wind turbines which use this type of generator normally use electromagnets in the rotor which are fed by

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[7] Running exactly like the cycle.

direct current from the electric grid. Note that the grid supplies alternating current; this is converted to direct current before sending it into the coil-winding around the electromagnets in the rotor. The rotor electromagnets are connected to the current by using brushes and slip rings on the shaft of the generator.

- **Asynchronous generator**

This is also known as an *induction* generator. It is referred to as asynchronous because the rotor has no torque (power) at the precise synchronous rotational speed. The generator consists of two main parts, the stator and the rotor. The stator contains a series of coils placed in slots forming a cylindrical assembly of thin iron plates. The rotor is also assembled of thin iron plates forming rows of thick aluminium bars joined at each end with an aluminium ring. These are fitted in key ways on the outer surface of the rotor which looks like a squirrel cage. The rotor sits on a shaft placed inside the stator.

2.3.2.10 Causes of Squirrel Cage Induction Generator failure

Bearings are known to be the major cause of failure of a squirrel cage induction generator (Hansen L.H, 2001). Thus, maintenance of a SCIG is mainly restricted to bearing lubrication. Muljadi et al. (1999) observed that at power frequencies, SCIG is inherently stable, but when connected to a weak grid with an unbalanced three-phase load, overheating and torque pulsations may occur. Machelor (1998 & 1999) listed some generic causes of failure in an AC induction motor.

2.3.2.11 Blade Pitching System

Wind turbines are generally designed to operate within specified wind speed limits; *cut-in* and *cut-out* limits. To maximise energy conversion and avoid components' stress or damage due to strong wind, some form of power control are installed in wind turbines. One of these power control systems is the blade pitching system. The pitching system serves a dual purpose; *aerodynamic power control* and *aerodynamic braking*. The electronic controller of a wind turbine supervises wind-speed in relation to power out put by measuring the wind-speed and the power out put as analogue signals. The controller decides which operations are to be carried out while the hydraulic system operates the pitching mechanism.

2.3.2.12 Causes of Pitch System Failure

Each blade has a separate pitching activator which comprises a hydraulic cylinder, piston rod etc. The pitch bearings are generally four-point bearings. Some causes of pitch system failure are listed in the European Wind Turbine Certification Guidelines (2001).

2.3.2.13 Mechanical Brake

The mechanical braking system in a wind turbine serves a dual purpose. First as a back-up system to prevent the rotational speed of the drive train from escalating to an unacceptable level in the event the aerodynamic braking system (pitching system) fails to operate. Secondly as a packing brake when wind turbine is not in operation. The mechanical braking system is usually located on the high speed shaft (HSS) between the gearbox and the generator. The brake system consists of a *brake disc*, *brake pads* and *callipers*.

- **Mechanical Brake Activation**

In the event that the aerodynamic braking system fails to operate, the electronic controller of a wind turbine sends an action message to the hydraulic system to operate the mechanical braking system. During braking, pressure is released by the hydraulic system which actuates the brake callipers. These push the brake pads against the brake disc which is fixed on the rotating high speed shaft. The braking is a result of friction between the brake pads and the disc. Similar operation takes place during parking of the wind turbine. The hydraulic system of the mechanical brake is fail safe i.e. the required hydraulic pressure must be reached before the wind turbine can start operating.

2.3.2.14 Causes of Mechanical Brake Failure

Excessive wear on brake linings may cause brake failure or even fire EWTCG (2001) pp22.

Rademakers et al (2002) listed some common failure modes and causes of a typical wind turbine mechanical brake.

2.3.2.15 Hydraulic System

The hydraulic system operates the mechanical braking system, the pitching system and the yaw control system. It also operates the on-board cranes and locking systems for canopies and spinners in larger wind turbines. Main components of the hydraulic system include *pumps*, *drives*, *oil tanks*, *filters* and *pressure valves*. The hydraulic system contains hydraulic oil which is put under pressure to move pistons in hydraulic cylinders. This system ensures that pressure is established when the wind turbine starts and also releases the pressure when the turbine stops. The pump builds up the pressure which is controlled by a pressure sensitive valve to ensure safe attainment of the required pressure level. For effective operation, a reserve pressure steel tank is often included in the system. The tank contains a rubber membrane which separates the hydraulic oil from the enclosed body of air. When the hydraulic oil is under pressure, it pushes the rubber membrane against the enclosed body of air, this in turn act as a cushion to give a counter pressure that enable the pressure in the system to be maintained.

2.3.2.16 Causes of Hydraulic System Failure

Hydraulic pump failures are often caused by contamination of hydraulic fluid, wrong oil viscosity, premature failure of cylinders as a result of high hydraulic fluid temperature, hydraulic valve failure caused by cavitations, faulty circuit protection devices (Casey B. 2005), and seal failure (Whitlock J. 2003).

2.3.2.17 Yaw Drive

The yaw system is used to continuously align the rotor of a horizontal axis wind turbine with the changing wind directions for maximum energy extraction. Basically, there are two types of yawing systems; *active* and *free*. The topology of the rotor determines the specific type of yaw system to be incorporated. Upwind turbines use active yaw which consists of a motor to actively align the turbine with wind direction. Downwind turbines usually use the free yaw which depends on the aerodynamics of the rotor to align the turbine with the wind direction.

- **Operation of the active yaw system**

The active yaw system comprises a *four-geared drive motor*, *yaw bearing* and a *bull-gear* attached to its circumference, *drive pinion gear*, *pinion shaft and housing*, *gear reducer, brake disc*, *brake callipers, etc*. When wind changes direction, the meteorological sensors of the wind turbine send a message to the electronic controller. This in turn sends a control message to the yaw system which operates by using power supply from slip rings to the electric drive motor. The motor converts the electrical energy into mechanical energy required to drive the pinion gear. The pinion gear engages the bull gear mounted on the yaw bearing there-by turning the whole nacelle to align with wind direction. As soon as yawing is completed, the electronic controller sends a control message to activate the yaw braking system to stop the turbine from turning further. Conversely, brakes are released just before yawing begins.

2.3.2.18 Causes of Yaw System Failure

The major causes of failure of a yaw system include bearing failures, pinion and bull gear teeth pitting, yaw brake failure (Verbruggen T.W. 2003; Manwell J.F., et al. 2002), pinion and bull gear teeth wear-out (Burton T., et al. 2001).

2.3.2.19 Electronic Controller

The electronic controller of a wind turbine basically serves two purposes. First it oversees the normal operation of the turbine by measuring and storing statistical data such that faults are registered and retrieved as required. Secondly, it is responsible for most decision-making processes in the safety system of a wind turbine. The controller uses a micro-computer designed for industrial use. It has a large storage capacity and the control program is stored in a microchip. The microchip, electro-technical equipment, contactors, switches, fuses are placed in the control cabinet of the nacelle. To prevent internal errors by the electronic controller, an internal automatic self-supervision is built-in to allow the controller to check and control its own systems. Usually a back-up system is installed having the same function as the controller but assembled with different types of components.

- **The Control System**

The *IEC 612400-2* defines the control system as "…*a sub-system of wind turbine that receives information about the condition of the wind turbine and/or its environment and adjusts the turbine in order to maintain it within its operating limit*". The basic design requirement for a control system is defined in IEC 61400-1 section 8. However, Stiesdal H (1998) explained that there are possibilities of error no matter how high the quality of installed sensors, cables, software and hardware. Indeed, the *National Renewable Energy Laboratory* (2004) states that the "…*reliability of software is not readily calculated and its failure modes are not predictable, even though a watch-dog timer is a prudent mechanism for monitoring and detecting some software faults. There are large numbers of potentially unsafe software faults that will not be detected as it is not possible to test all in-put sequences*". Some causes of control system failure are listed in the *European Wind Turbine Certification Guidelines* (2001).

- **The Protection System**

The protective system also known as the safety system comprises the hydraulic system, the mechanical brakes and the pitch system. The *European Wind Turbine Certification Guidelines* (EWTCG-2001) states that "…*where the pitch system is used as part of the braking system it shall be considered as part of the protecting system and evaluated as such*" (Page 21 of the EWTCG).

2.3.2.20 Nacelle Canopies and Spinners

The canopy covers and protects the wind turbine's components from weather elements. The spinner covers the hub and the pitch assembly. Nacelle canopies and spinners are usually made from composite materials (light weight) such as fibreglass reinforced plastic (GRP). This is to reduce the overall imposed load of the wind turbine, and ensure high strength and stiffness to weight ratio. Composite materials are corrosion resistant and good electrical insulators.

2.3.2.21 Tower

The tower of a wind turbine raises the main parts of the turbine to a height where conversion of energy from the wind can be optimised. The tower transmits self and imposed loads of the turbine to the foundation. Wind turbine towers can be made from *reinforced concrete* and *painted* or *galvanised steel*. Some common tower designs include; *free-standing lattice* (truss), *guyed-lattice* (pole) and *tubular towers* (Manwell et al. 2002). Tubular towers are commonly used in offshore wind turbines because they are fabricated in sections of significant lengths and erected on site with less bolted connections. Tubular towers require less periodic inspection for loose torque. The tower also provides a safe climbing access to nacelle, and is aesthetically better than the other types of towers afore mentioned.

2.3.2.22 Foundation

The foundation of a wind turbine keeps it in an upright and stable position even under extreme weather conditions. The foundation transfers the weight of all imposed loads to the surrounding soil. Two common materials used in the construction of wind turbine's foundations are *concrete* and *steel*. Common designs include *pad foundation* often used onshore while *concrete caissons, steel gravitational, tripod and mono piles* foundations are usually used offshore.

2.4 COST SIGNIFICANT ITEMS WITHIN A WIND TURBINE

This section identifies cost significant items within a wind turbine i.e. where consequences of failure will result in significant financial loss. Figure 2.6 presents a cost breakdown of a typical wind turbine. The nacelle which contains the main-drive and the generator is about 56% of the total cost of a wind turbine. The rotor which comprises the blades, the hub and associated components is about 29%, and the tower is approximately 15%.

A further breakdown of cost of components/subsystems within a nacelle of a wind turbine is shown in figure 2.7. The gearbox, converter and the generator have 33%, 17% and 13% respectively of the total cost of a nacelle. Thus, the gearbox, converter and the generator are the cost significant items within a nacelle of a wind turbine.

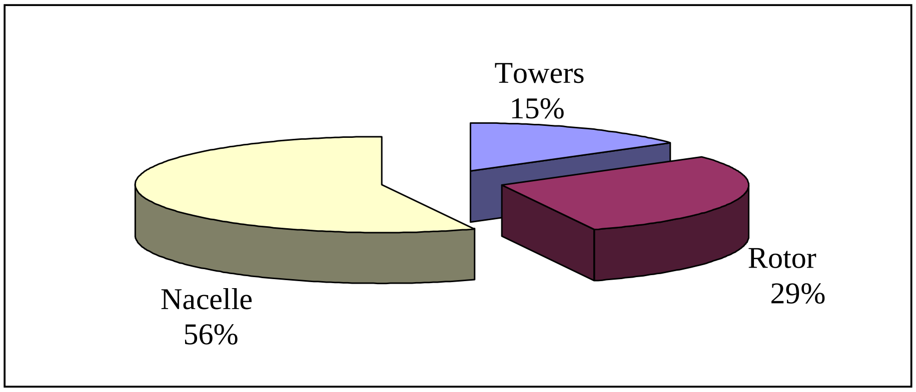

Figure 2.6 cost significant items of a typical 600 kW wind turbine

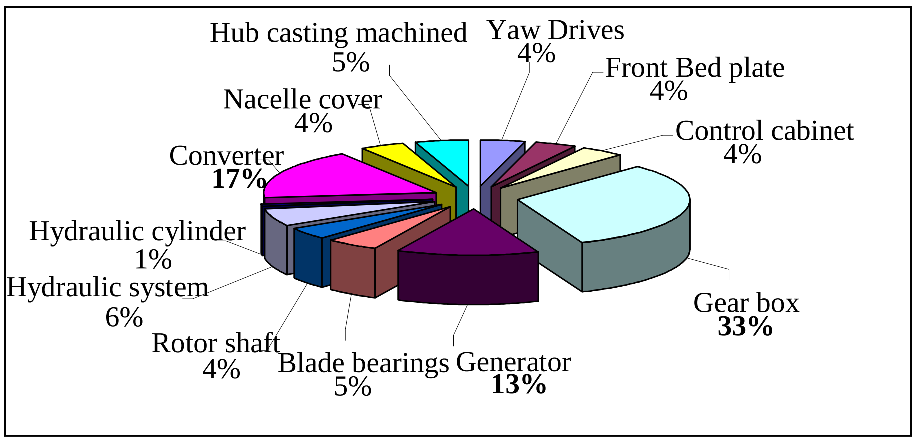

Figure 2.7 Percentage costs of components within a Nacelle of 600 kW Turbine

Figures 2.2-2.4 have shown the blades, gearbox, generator, yaw system, hydraulic system, electrical and control system are the major causes of failure of wind turbines. Coincidentally, the blades, gearbox, generator, electrical and control system are cost significant items within a wind turbine (figures 2.6 and 2.7). Therefore, it is crucial to improve the performance of wind turbines by implementing suitable maintenance tasks aimed at meeting equipment specific needs.

2.5 TOOLS AND TECHNIQUES OF ASSET MANAGEMENT

This section gives a brief description as well as the uses of some tools and techniques used in asset management.

2.5.1 Hazard and Operatibility Study

Hazard and Operatibility Study (HAZOP) is a *Bottom-Up* detailed hazard identification technique that examines processes, procedures and organisational change to identify critical deviations in process units. It identifies all possible hazards associated with the deviations and determines the resultant effects. The effects are analysed so that the risk of the events can be quantified in tangible terms (Smith D.J., 2001). HAZOP is used in organisations where micro details are required to address both *hard-ware* and *people-ware* systems. It reduces or removes hazards that can cause process interruption or production losses due to mistakes made by operators, and to some limited extent equipment breakdown (Smith D.J., 2001).

2.5.2 Fault Tree Analysis

Fault Tree Analysis (FTA) is a frequency and probability analysis technique that permits the assessment of an undesirable event or accident. It starts with a major 'Top' event and works its way down, in a bid to investigate and identify possible combinations of factors that can lead to the occurrence of the event (Huggett, J. et al. 2003). FTA is used to find the root-causes of an undesirable event in order to determine a solution. It can also be used to estimate consequences and probabilities of occurrence of a top-event (Huggett, J. et al. 2003).

2.5.3 Event Tree Analysis

Event Tree Analysis (ETA) is a technique which permits sequential assessment of an *initiating event* to identify and quantify all possible effects of the event. It identifies remedies for minimising the consequences of the event (Huggett, J. et al. 2003). ETA is often used during the design phase of an equipment to assess potential accidents resulting from a postulated initiating event. It is also used on operating facilities to assess the adequacy of existing safety features or to examine the potential out comes of equipment failures (Huggett, J. et al. 2003).

2.5.4 Critical Task Analysis

Critical Task Analysis (CTA) is a *Top-Down* hazard identification technique that analyses work in terms of the tasks performed to determine criticality rating of all possible risks associated with the tasks that are not performed properly. CTA is used in task-based activities to highlight critical tasks that need to be carried out correctly. It outlines appropriate procedures and indicates actions and precautions that will prevent or minimise potential losses. CTA is used to structure working procedures (Huggett, J. et al. 2003).

2.5.5 Quantified Risk Analysis

Quantified Risk Analysis (QRA) is a technique that analyses risks associated with a particular event. It assesses the nature of the risks and the probability of occurrence. The impact of various available options to attenuate the risks is assessed. Financial values are assigned to each of the identified options (Kolluru, 1996). QRA is used to establish a priority ranking for risk reduction, so that management can prioritise their expenditure to get the best HSE benefit for the least cost (Kolluru, 1996).

2.5.6 Root Cause Analysis

Root Cause Analysis (RCA) is a technique that conducts a full-blown analysis to identify the latent root causes of 'Why' any undesirable event occurred. It identifies necessary steps to eliminate the event in its entirety and prevent reoccurrence (Reliability Center Inc, 2000). RCA finds and corrects the causes of a problem, hence it is used where solutions are sought to stop problems from happening again (Reliability Center Inc, 2000)

2.5.7 Structured What-if Technique

Structured What-if Technique (SWIFT) is a high level *Top-Down* system-oriented hazard identification method. It examines the whole system or subsystem to identify all possible hazards, causes and frequency of occurrence to produce risk priority ranking. The technique is based on structured brain storming efforts by a team of experienced process experts with supplemental questions from a structured what-if check list (Cox and Tait, 1998). SWIFT is often used in hazard based operations as an indicator of the seriousness of risks and how quickly actions must be taken by management to remove or mitigate the hazards based on the causes (Cox and Tait, 1998).

Other AM tools and techniques include the Reliability-Centred Maintenance (RCM), Failure Modes and Effects Analysis (FMEA), Risk Based Inspection (RBI) and Total Productive Maintenance (TPM). These are discussed in chapter 3.

2.6 CONDITION MONITORING TECHNIQUES AND WIND TURBINES

Condition-Based Maintenance (CBM) strategy depends on the utilisation of appropriate condition monitoring techniques. Condition monitoring is "…*extracting information from machines to indicate their condition and to enable them be operated and maintained with safety and economy*" (Moubray, 1991). Verbruggen (2003) and Infield (2004) listed some condition monitoring techniques that are potentially applicable to wind turbines. Some of these techniques are discussed below.

2.6.1 Strain Measurement

Strain-gauges attached to the surfaces of a wind turbine's blades are used to measure strain in the blades. This is done by measuring changes in electrical resistance in the strain gauge. The technique is used for laboratory life-time prediction and safeguarding of the stress level of blades (Verbruggen T. W. 2003).

2.6.2 Acoustic Analysis Technique

Acoustic monitoring involves attaching acoustic sensors to wind turbine blades, and then *listening* to the sounds generated by the blades. The sensors are attached to the blades by using flexible glue with low attenuation. Abnormal sounds which are not related to the dynamic loading of the turbine are indicators of possible blade failure. The variability of wind speed, wave, turbulence as well as the dynamic operating nature of wind turbines can limit the use of acoustic analyses technique.

2.6.3 Vibration Analysis Technique

Vibration monitoring involves the use of vibration sensors mounted rigidly on equipment to register its local motion. The technique is used to monitor the condition of rotating components of a wind turbine such as the blades, main bearings, main shaft, gearbox and associated components (gearwheels, shafts, bearings), generator and associated components (bearings, rotor, stator) (Infield, 2004). There are 3 sensors commonly used in vibration monitoring; transducers, displacement and acceleration (Mitchell, 1993). Wind turbines, unlike other equipment, operate on both steady and dynamic loads as well as high and low rotational speeds. These make signal analysis and diagnosis difficult (Verbruggen T. W. 2003). Vibration analysis of wind turbines components and subsystems are expounded upon in chapter 8.

2.6.4 Performance/ Process Parameter Technique

A wind turbine is designed to operate within a defined wind speed limit. The controller of a wind turbine measures the wind speed and the main-shaft rotational speed as analogue signals. The main-shaft rotational speed is supposed to be directly proportional to the wind speed. Any significant variation in the measured parameters indicates possible failure of the rotor (Infield, 2004). However, the variation does not precisely indicate the equipment associated with the failure; hence failure detection using parameter/process technique leaves the specific causes of failure and the extent unknown.

In addition to the wind and main-shaft rotational speed, the controller measures the high-speed-shaft rotational speed as an analogue signal. For every in-put speed of the main shaft, there is a predetermined corresponding speed of the high-speed-shaft as an out-put from the gearbox. Variation between the actual and the predetermined rotational speed of the high-speed-shaft is an indication of failure of the gearbox. Also, the bearings and gear-oil temperatures are measured as analogue signals. Excessive bearing temperature is an indication of bearing failure or insufficient lubrication.

Furthermore, the controller of the wind turbine measures wind speed, generator temperature, high-speed-shaft rotational speed, voltage, current, all as analogue signals. The voltage and current are used to calculate the actual power out-put. For a given high-speed-shaft rotational speed, there is a corresponding expected power out put. Significant variations between the expected and calculated power is indicative of generator failure.

The performance/process parameter technique lacks real-time fault diagnosis. Its effectiveness depends on the mode of calculation and comparison. Measurement errors may indicate failure which will invariably affect the operation of the wind turbine. Robust application will involve developments of algorithms such that measurements and comparisons can be generated automatically. Another draw back is the dependence of the monitoring system on the controller. This means that a fault on the controller could affect the monitoring process.

2.6.5 Visual Examination

One of the reasons for installing condition monitoring systems on wind turbines is to reduce the number of maintenance activities which could be very expensive and sometimes restricted by weather conditions. Visual examination involves physical examination of the condition of wind turbine's components and subsystems such as detection of cracks in blades, etc. The technique may require the deployment of cranes and crane-vessels in onshore and offshore wind farms respectively. In addition to the access costs, invisible failures are not be detectable by using this technique.

2.6.6 Fibre Optics Measurement

Optical fibre sensors can be embedded in the blade structure to enable the measurement of five parameters which are critical to blade failure. The five parameters include; *strain measurement* which monitors the blade loading and vibration level, *temperature measurement* for likely over-heating, *acceleration measurement* to monitor pitch angle and rotor position, *crack detection measurements*, and *lightning detection* which measures front steepness, maximum current and specific energy. The loading data from blades sensors can be used for real-time pitch control. This reduces significantly the out-of balance loading on the tower and foundation.

2.6.7 Oil Analysis Technique

This technique serves a dual-function; first to safeguard the quality of lubrication oil (contamination by parts, moisture) and secondly, to safeguard the components involved (characterisation of parts). In order to safeguard the oil quality, on-line sensors are used for part-counting and moisture detection. The oil analyses are done off-line by taking samples at prescribed intervals. The majority of maintenance activities require climbing the turbine's tower, and working either within the confines of the nacelle or outside by using the platform below the nacelle. Thus the remoteness of work place and accessibility for sample taking are factors to be considered.

For safeguarding components, samples are taken at intervals for off-line analysis. The interval for sample taking constitutes a problem with the technical applicability of the technique. For instance, if the level of deterioration is not identified, then it is difficult to determine whether the component or equipment will not fail before the next sample taking. The technique is best used as a supporting test to indicate components with excessive wear.

CHAPTER 3
APPROACH AND METHODOLOGY

3.1 INTRODUCTION

This chapter presents and discusses the approach and methodology adopted to achieve the research aim and objectives stated in Chapter 1. The methodology to design a framework for re-organising the wind energy industry into an asset management-based industry is presented in section 3.2. Section 3.3 presents the methodology for the selection of a suitable maintenance strategy for wind turbines. Sections 3.4 and 3.5 present the approach and methodology for quantitative maintenance optimisation; Modelling System Failures and Delay-time Mathematical Maintenance model respectively. Data requirements for the optimisation processes and the collection technique are discussed in section 3.6. Finally, section 3.7 presents the summary of the chapter.

3.2 DESIGN OF A STRUCTURED ASSET MANAGEMENT MODEL

Asset Management (AM) has evolved as a means to describe a holistic application of business best practices in order to satisfy all stakeholders' requirements. Successful AM organisations utilise a framework or a model (Holland, 2002) to link all the vital requirements for effective management of assets (Townsend, 1998). AM models are not information management systems but a method or process through which valid decisions can be made in the wider context of external business expectations (Gyimothy and Dunay, 2004). In the past, generic business models were used for management of assets but these fail to consider and align assets specific needs with corporate business values. Levery (2004) for example observed that there is a need to develop an industry-specific AM model to incorporate suitable maintenance management strategies that will maximise the return on investments in physical assets.

The AM process commences by identifying business values which control the industry's performance (Liyanage and Kumar, 2001) and the assets that are indispensable to drive and sustain the future of these values (Woodhouse, 2000).

These ensure that the "*strategic and tactical decisions that are required to deliver the asset management mission are clearly driven by the asset itself rather than any activity*" (Townsend, 1998). Appropriate Key Performance Indicators (KPI) and Key Performance Measurement (KPM) frameworks are formulated (Liyanage and Kumar, 2001) to allow effective evaluation of actual performance in comparison to intended targets. This sets continuous performance improvements in motion by identifying gaps and opportunities so that appropriate strategies for harnessing the benefits can be determined and implemented.

The subject of Asset Management has been addressed by Townsend (1998) using a *three-tiered model* (i.e. *Business Values*, *Asset Management Life-Cycle Phases*, and *Asset Management Processes*). The first tier identifies strategic business values which the asset manager is seeking to contribute. The second tier identifies the phase of asset management life-cycle that must be managed in order to deliver these values. Finally, the third tier identifies the process in which the asset manager will be engaged as the life-cycle phases are managed. Similar philosophical thinking is presented by Woodhouse (2000), Hammond and Jones (2000).

The wind industry currently lacks a holistic framework to combine and rationalise opposing stakeholders' demands, and to also ensure that assets remain in a satisfactory condition over the life-cycle of wind farms. A methodology to design a structured model for asset management in the wind energy industry is outlined in the following six (6) key steps:

- Review of literature pertinent to AM to understand the generic concept of AM processes, models, tools and techniques existing in other industries.
- Critical assessment of the wind energy industry to identify business values and assets that drive the long-term survival and profit generation of wind farms.
- Identification of crucial requirements for effective management of the identified business values and assets of the wind farms.
- Designing a frame-work to harness and transform the crucial requirements for the effective management of wind farms into AM processes for the wind industry.

- A detailed design of each AM process with an explicit explanation including the incorporated AM tools and techniques.
- Logical integration of all the designed process by using a unique process modelling technique to form a robust structured model for AM in the wind energy industry.

These six (6) key steps are followed logically in chapter 4 to design a structured model for asset management in the wind energy industry.

3.3 THE SELECTION OF A SUITABLE MAINTENANCE STRATEGY

One of the fundamental issues raised in chapter 2 was the common maintenance strategies applied to wind turbines are inadequate to meet the current commercial drivers of the wind industry. Consequently, a need exists to determine an appropriate[8] maintenance strategy for wind turbines within the wider context of asset management methodology. A number of approaches to determine appropriate maintenance strategies for physical assets exist in the field of asset management, these include:

3.3.1 Total Productive Maintenance

This approach evaluates potential causes of asset failure by focusing on the machine, methods of operation, measurement styles, manpower error and materials. Total Productive Maintenance (TPM) assesses a failure mode by asking 'Why' up to five times, in a bid to trace the problem to its root cause. The approach is used often in the manufacturing sector to treat, tolerate, transfer or terminate a problem (DeHaas, 1997). However, TPM is constrained on the specific tools needed to determine which tasks are worth doing in terms of risk consideration and equipment life expectancy (Woodhouse, 2002).

3.3.2 Risk Based Inspection

Risk Based Inspection (RBI) systematically assesses static-equipment to determine appropriate condition monitoring methods for equipment with high likelihood and

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[8] technically feasible and economically viable over the life-cycle of wind turbines

consequence of failure. It uses risk as a basis for prioritising and managing inspection programs of static-equipment. The approach allows development of equipment-specific inspection plans as well as optimising inspection methods and intervals (Wintle et al. 2001; Favvennec, 2001). However RBI is notably weak in determining how much to spend on inspections and condition monitoring systems and also in pointing to alternative risk-treatment options (Woodhouse, 2002).

3.3.3 Reliability-Centred Maintenance

Reliability-Centred Maintenance (RCM) identifies ways in which components or systems at the design stage or already in operation can fail to perform their intended design functions. The approach focuses on the functions of equipment in order to predict failure modes and the resultant consequences so that suitable maintenance actions can be determined (Moubray, 1991; Latino, 1997). This makes RCM unique from the other approaches. Moubray (2000) explains that no comparable technique exists for identifying the true, safe minimum of what must be done to preserve the functions of physical assets in the way that RCM does. RCM originated in the aircraft industry and has been applied with considerable success in several industrial sectors, for example, Railways (Marquez et al. 2003); Offshore Oil & Gas (Arthur and Dunn, 2001); Manufacturing sector (Decade and Modak, 2003) etc.

The entire purpose of maintenance is to ensure that machines continue to do what their users want of them. Therefore the first step to determine a suitable maintenance strategy is to understand what is required of an asset, how this can be affected and the consequences. RCM which is defined as "….*a systematic consideration of system functions, the way functions can fail, and a priority-based consideration of safety and economics that identifies applicable and effective preventive maintenance tasks*" (Rausand, 1998), provides the necessary underlying concepts to do this by asking and building upon seven basic questions (Moubray, 1991) in the sequence shown below:

- What are the functions and associated desired standards of performance of the asset in its present operating context (functions)?
- In what ways can it fail to fulfil its functions (functional failures)?

- What causes each functional failure (failure modes)?
- What happens when each failure occurs (failure effects)?
- In what way does each failure matter (failure consequences)?
- What should be done to predict or prevent each failure (proactive tasks and task intervals)?
- What should be done if a suitable proactive task cannot be found (default actions)?

Answering the 7 basic RCM questions about a wind turbine will identify ways in which a wind turbine already in operation can fail to perform its design intentions and the resultant consequences. However, RCM alone is limited in determining which maintenance strategies are the most cost effective options available (Woodhouse, 2002).

3.3.4 A Hybrid Approach (RCM plus ALCA)

Given the limitation of RCM to assess the economic viability of selected options, a very strong economic assessment technique known as the Asset Life-Cycle Analysis is in this thesis integrated into the RCM to form a hybrid approach. Asset Life-Cycle Analysis (ALCA) is defined as "…*the combined evaluation of capital costs with future performance, operating and maintenance implications, life expectancies and eventual disposal or replacement of an asset*" (Woodhouse, 2002).

In the hybrid approach, RCM approach is used to determine possible failure modes, causes and the resultant effects on system operation. Failure consequences of critical components and subsystems are evaluated and expressed in financial terms. Then, the ALCA technique is used to assess the commercial viability of selected maintenance activities; taking into account geographical location, intermittent operation and value of generation. Uncertainties in the financial calculations are identified and risk assessed using a probabilistic technique of the Crystal Ball Monte Carlo simulation software. The Crystal Ball Monte Carlo simulation software is commercially available (http://www.decisioneering.com/crystal_ball/index.html). It is a leading software suite for financial and economic risk assessment. Non-financial aspects of the selected activities are identified and assessed using a Weighted Evaluation (WE) technique and Benefit-to-cost ratio. This hybrid approach is applied in chapter 5 to select a suitable maintenance strategy for wind turbines.

3.4 MAINTENANCE OPTIMISATION

Maintenance optimisation is *"…a process that attempts to balance the maintenance requirements (legislative, economic, technical, etc.) and the resources used to carry out the maintenance program (people, spares, consumables, equipment, facilities, etc.)"*(Systems Reliability Centre). In chapter 2, we explained that determining and implementing suitable maintenance strategies for physical assets is not in itself a means to an end, but that maintenance activities ought to be optimised. It was further explained that maintenance optimisation is not a one-off procedure but a continuous process which requires periodic evaluation of performance and improving on the successes of the past.

The main purpose of maintenance optimisation is to determine the most cost-effective maintenance strategy. This strategy should provide the best possible balance between direct maintenance costs (labour, materials, administration) and the consequences or penalty of not performing maintenance as required (i.e. labour, materials, administration, loss of production and anticipated profit, etc) without prejudice to Health, Safety and Environmental (HSE) factors. The concept of maintenance optimisation is illustrated conceptually in Figure 3.1.

Evidently, carrying out maintenance activities such as inspection, preventative maintenance, and replacement of components more frequently, increases the direct cost of maintenance. Thus, the risk exposure or the consequences of not performing maintenance activities as required, reduces. However, the less frequent the maintenance activities, the lower the maintenance cost, and the higher the risk exposure. Optimisation deals with the interaction between these factors and aims to determine the optimum level. This is usually obtained at the lowest point on the total combination of the key variables, where maintenance activities are carried out at the lowest total impact (optimal cost and interval) as shown in Figure 3.1.

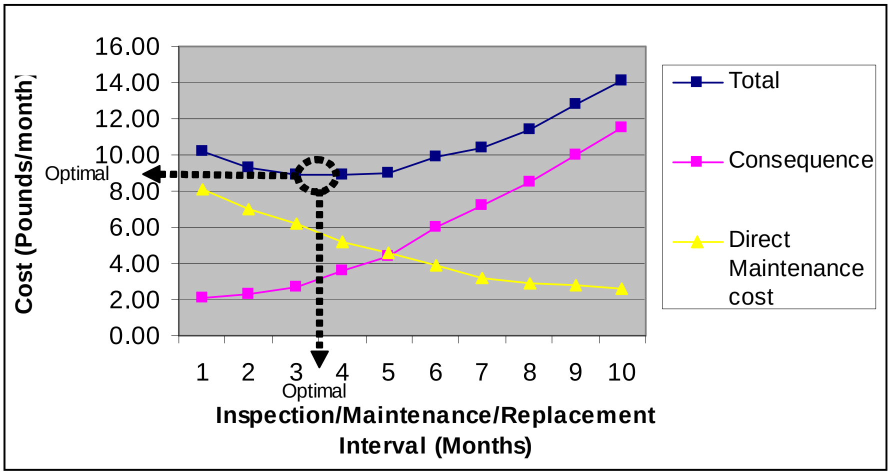


Figure 3.1 Maintenance Optimisation Concept

3.4.1 Types of Maintenance Optimisation

There are two common approaches to maintenance optimisation; qualitative and quantitative. Arthur (2005) and Scarf (1997) observed that *qualitative* maintenance optimisation is often clouded with subjective opinion and experience, and further suggest the utilisation of *quantitative* methods to optimise the maintenance activities of physical assets.

3.4.1.1 Quantitative Maintenance Optimisation

Quantitative maintenance optimisation (QMO) techniques employ a mathematical model in which both costs and benefits of maintenance are quantified and an optimum balance between both is obtained (Dekker, 1996). There are a number of QMO techniques in the field of Applied Mathematics and Operational Research, for example, Markov Chains and Analytical hierarchy processes (Chiang and Yuan, 2001); Genetic Algorithms (Tsai et al. 2001), etc. However, most of the approaches are criticised by Scarf (1997), Dekker (1996), and Arthur (2005) for being developed for mathematical purposes only and are seldom used in practical asset management to solve real-life maintenance problems. Furthermore, Arthur (2005) observed that, "*…quantitative maintenance optimisation can be clouded through the rigorous data demands of mathematical modelling and these same models require data that is often unavailable*".

Modelling System Failures (MSF) is a QMO technique that has been recommended as the best approach to assess the reliability and optimise the maintenance of mechanical systems (Davidson and Hunsley, 1994). Delay-Time Maintenance Model (DTMM) (Scarf, 1997) is attractive for its simplified mathematical modelling and has been applied practically to optimise the inspection intervals of some physical assets with considerable success. For example, Arthur (2005) has employed it to optimise inspection intervals for an Oil and Gas water injection pumping system. The approaches of the two QMO are now discussed in more detail.

3.5 MODELLING SYSTEM FAILURES

The modelling System Failures (MSF) technique enables the investigation of operations and failure patterns of equipment by taking into account failure distribution, repair delays, spare-holding, and resource availability to determine optimum maintenance requirements (Davidson and Hunsley, 1994). The first step in the approach is to identify a suitable *statistical distribution* that will best fit the assessed failure characteristics of the physical asset. Secondly, a suitable *parameter estimation* method is selected to calculate the parameters of the identified statistical distribution. Then, the calculated parameters are used to design Reliability Block Diagrams (RBD) to model the failures of the asset. The RBD permits the use of Monte Carlo simulations software to assess and determine the optimal levels of key maintenance variables such as costs, spare holdings, the level of reliability and availability required, etc.

3.5.1 Statistical Distributions

Fundamentally, there are three *patterns of failure* that describe the failure characteristics of mechanical systems (Davidson and Hunsley, 1994). These include *reducing*, *constant* and *increasing* failure patterns as illustrated in Figure 3.2. The figure displays a curve usually referred to as a *hazard rate* or most commonly a *bath-tub curve*. The reducing failure pattern usually known as the *infant mortality* denotes failures that occur at the early-life of equipment and the likelihood of occurrence reduces as the age of the equipment increases. The constant failure pattern represents failures that are independent of equipment age, that is, the likelihood of occurrence is invariable through out the life-cycle of the equipment. Lastly, the increasing failure pattern commonly referred to as *wear-out* symbolises failures that occur at the later life of equipment, that is, the likelihood of occurrence increases with the age of the equipment. It is worth noting, that the bath-tub curves differ for different pieces of equipment in the wind turbine. The reader is referred to (Moubray, 1991) for a more detailed study on types of failure pattern.

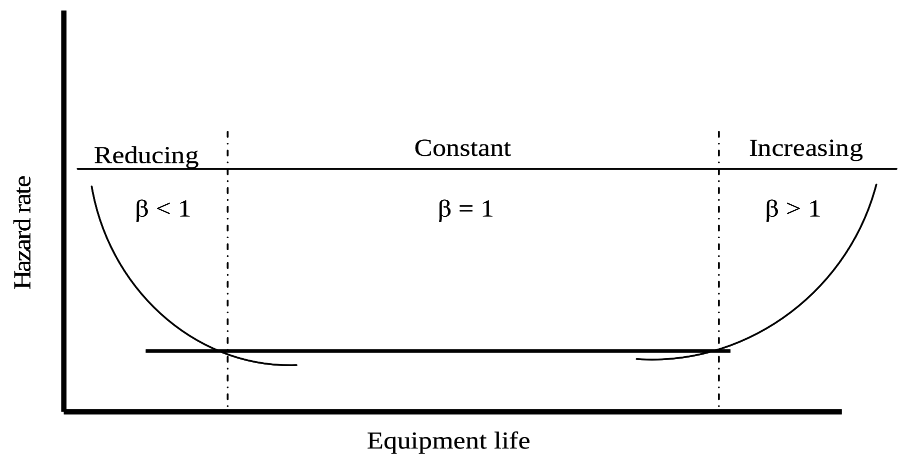


Figure 3.2 'Bath-Tub' curve showing failure patterns

A number of statistical distributions exist to fit the failure patterns described. The Exponential distribution describes a constant hazard rate while Normal and Lognormal describe effectively the period of increasing hazard rate (Davidson and Hunsley, 1994). However, the most commonly used distribution is the *Weibull*, named after a Swedish engineer Waloddi Weibull (1887-1979) who formulated and popularised the use of the distribution for reliability analysis. The distribution is very versatile as it fits all the three basic patterns of failure. Note that the Weibull distribution is also employed in the analysis of wind speed distribution but this is outside the scope of this research work.

3.5.2 The Weibull Distribution

The Weibull distribution can be represented in 3 different forms; 3-parameter, 2-parameter and 1-parameter. The 3-parameter and 1-parameter Weibull distribution *probability density function* is given in Equations 3.1 and 3.2 respectively.

$$f(T) = \frac{\beta}{\eta}\left(\frac{T-\gamma}{\eta}\right)^{\beta-1} e^{-\left(\frac{T-\gamma}{\eta}\right)^{\beta}} \quad (3.1)$$

Where,

$f(T) \geq 0, T \geq 0\, or\ \gamma, \beta > 0,\ \eta > 0, -\infty < \gamma < \infty$. β, η and γ represent the *shape*, *scale* and *location* parameter respectively. Note that the location parameter does not necessarily represent failure free interval.

$$f(T) = \frac{C}{\eta}\left(\frac{T}{\eta}\right)^{C-1} e^{-\left(\frac{T}{\eta}\right)^{C}} \quad (3.2)$$

The one parameter Weibull *pdf* is obtained by setting γ = 0 in the equation 3.1, and assuming β = C or assumed value from past experience on identical or similar products. The only unknown parameter is the scale parameter (η).

The 2-parameter Weibull distribution denoted by a *probability density function (pdf)* and *cumulative distribution function (cdf)* given in Equations 3.3 and 3.4 respectively is considered exclusively due to its broad acceptability.

$$f(T) = \frac{\beta}{\eta}\left(\frac{T}{\eta}\right)^{\beta-1} e^{-\left(\frac{T}{\eta}\right)^{\beta}}\ ; T \geq 0,\ \beta > 0,\ \eta > 0 \quad (3.3)$$

$$F(T) = 1 - e^{-\left(\frac{T}{\eta}\right)^{\beta}} \quad (3.4)$$

Where β and η represent the *shape* and *scale* parameter respectively. The value of β describes the failure pattern of the equipment. As a general rule, (β < 1) means a reducing failure pattern, (β =1) signifies a constant failure pattern and (β >1) indicates an increasing failure pattern, as depicted in Figure 3.2. Conversely, the scale parameter denotes the characteristic life of the equipment; the time at which there is an approximately 0.632 probability that the equipment will have failed (Davidson and Hunsley, 1994). Estimating the parameters requires a suitable method that will best fit the characteristics of the collected data.

3.5.3 Parameter Estimation Methods

Common parameter estimation methods include probability plot, regression analysis and Maximum Likelihood Estimation (MLE). The characteristics of collected data influence the estimation method to be used. The regression analysis is suitable for a complete data sample, that is, all the equipment under assessment has failed within the period under consideration. Field or life failure data are seldom complete as they are often subjected to *suspensions* or *censorings*. An item could have been temporarily removed from the test during the test interval or the test interval could elapse before an item fails. The probability plot and the regression analysis are limited in dealing with data sets containing a relatively large number of suspensions or censorings (Cohen, 1965).

3.5.4 Maximum Likelihood Estimation

The Maximum Likelihood Estimation (MLE) takes into account the times-to-suspension or censoring in the estimation process which makes it a more robust and rigorous estimation method. The process of using the maximum likelihood to estimate the parameters of the Weibull distribution when data are censored or suspended is now discussed.

Consider a random failure sample consisting of multiple censoring or suspension. Suppose that censoring occurs progressively in k stages at times T_i where $T_i > T_{i-1}$, $i = 1, 2......k$ and that at the ith stage of censoring r_i sample specimens selected randomly from the survivors at time T_i are removed from further observation. If N designates the total sample size and n the number of specimens which fail at times T_j and therefore provide completely determined life spans (Cohen, 1965), it follows that

$$N = n + \sum_{i=1}^{k} r_i \tag{3.5}$$

The likelihood function is

$$L = C \prod_{j=1}^{n} f(T_j) \prod_{i=1}^{k} [1 - F(T_i)]^{r_i} \tag{3.6}$$

Where C is a constant, $f(T)$ is the *pdf*, and $F(T)$ is the *cdf*.

Note: Harris and Stocker (1998) defined a likelihood function L (α) as "*the probability or probability density for the occurrence of a sample configuration x_1, …, x_n given that the probability density f(x; α) with parameter α is unknown i.e. L (α) = f(x_1; α)… f(x_n; α)*". Substituting equations 3.3 and 3.4 in 3.17, then taking the natural logarithm and partial derivative of the equation with respect β and η will result in Equations that can be used to estimate the values of β and η respectively.

ReliaSoft Weibull ++7 software (http://www.ReliaSoft.com) which is based on the fundamental mathematical principles of the MLE discussed above will be used to analyse field failure data of wind turbines. The software package is commercially available, and robust in life data analysis. It calculates automatically the β and η parameters of the Weibull distribution and allows a number of graphs such as the *Weibull probability plots, reliability graphs, failure verses time plots, probability density function graphs, etc* to be generated. In chapter 6, MLE in the Weibull distribution is used to analyse collected field failure data of wind turbines.

The estimated values of β and η of each component within a subsystem will be used to design Reliability Block Diagrams (RBD) to model the failures of the subsystem. The β and η values for each subsystem within a system are estimated to model the failures of the system. For example, consider a wind turbine as a system and the gearbox of the turbine as a subsystem with the following components; shafts, intermediary speed shaft (IMS) bearings, high speed shaft (HSS) bearings, key ways, gear-teeth etc. The β and η of each of the components are estimated to model the failure behaviour of the gearbox. Similarly, the β and η of each subsystem of the turbine such as the generator, yaw, hub etc are estimated to model the failures of the wind turbine.

In the modelling, Reliability Block Diagrams (RBD) are designed for the subsystems to incorporate the failure characteristics of the components. Then, the RBD of the subsystems are used to model the failures of the wind turbine as illustrated conceptually in figure 3.3. Thus, the failure behaviour of the wind turbine can be used in modelling the failure characteristics of a selected wind farm. It is worth noting however, that the modelling processes depend on the availability of failure data to estimate the β and η values for the components and subsystems of the wind turbine. The models are simulated to assess and optimise the reliability, availability and maintainability of the wind turbine as well as the wind farm; taking into account the costs and availability of maintenance crew and spare holdings. 'ReliaSoft BlockSim-7' software (http://www.ReliaSoft.com) will be used in chapter 7 to model and assess the reliability, availability and maintainability of a selected wind turbine and a wind farm, the software uses Monte Carlo simulation.

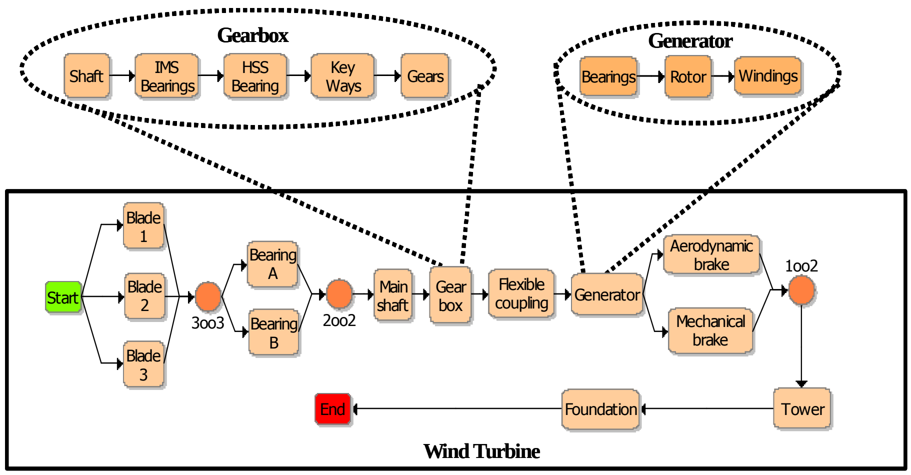


Figure 3.3 Modelling wind turbine failures

3.6 DELAY-TIME MAINTENANCE MATHEMATICAL MODEL

The delay-time mathematical model examines equipment failure patterns by taking into account failure consequences, inspection costs and intervals to determine an optimal inspection interval. The time taken by an incipient failure to deteriorate from inception to catastrophic event is fundamental to determining maintenance intervals. This is illustrated in Figure 3.4.

In an RCM approach, P-F intervals are determined subjectively on the basis of engineering judgement and experience (Rausand, 1998). The P-F interval determines the frequency of CBM activities and is usually carried out at a time $\leq P\text{–}F \ Interval/2$. Moubray (1991) although questionable suggested five ways to determine P-F intervals for equipment but concludes: "*it is either impossible, impracticable or too expensive to try to determine P-F intervals on an empirical basis*". A simple quantitative mathematical model known as the delay-time maintenance model (Scarf, 1998) allows the determination of optimal inspection interval by taking into account costs, risks and performance. The delay-time is the time between a defect becoming apparent and functional failure actually occurring. This is synonymous to the P-F interval. The concept of the delay-time model is discussed in the next subsection.

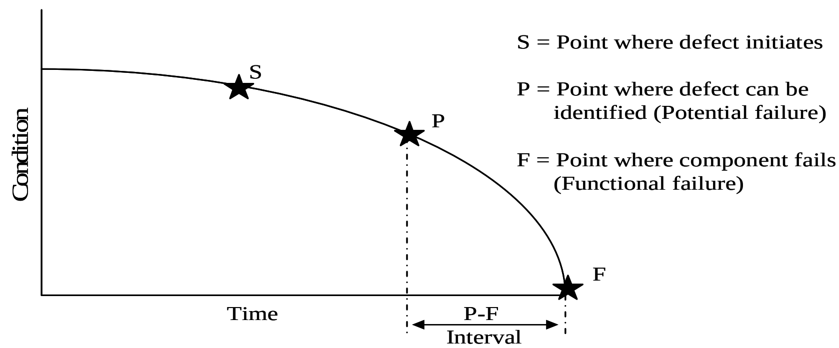


Figure 3.4 Potential-to-Functional failure intervals

3.5.1 Concept of the Delay-time Maintenance Mathematical Model

This maintenance mathematical model proposes a Poisson process of defects rate of arrival (α); exponentially distributed delay-times with mean ($1/\gamma$), and perfect inspection. Perfect inspection permits the detection of all expected failure modes. Note the defects rate of arrival connote complete failure of an item or defects found during inspection. Suppose all the gearboxes of wind turbines in a particular wind farm are subjected to regularly spaced inspections (such as vibration analysis) with inspections occurring every Δ in the interval [0, T]; where T is a multiple of Δ as shown conceptually in figure 3.5. Two defect arrival scenarios (F_1 and F_2) underpinning the principles of the delay-time mathematical model are shown in the figure. Incipient failure F_1 occurs between inspection intervals, is detected at the next inspection 2Δ which is then followed by a repair or F_2 occurs, fails catastrophically at t_i before the next inspection 3Δ.

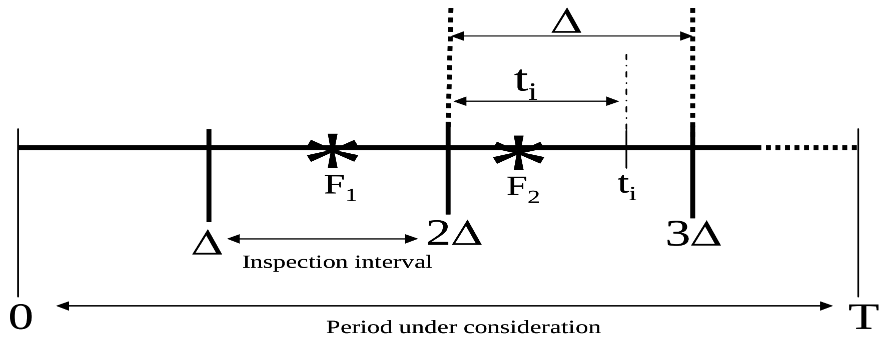


Figure 3.5 delay-time concept

Thus, for a component observed over a period of T days with inspections equally spaced at intervals of Δ days, the maximum likelihood estimates satisfy the expressions;

$$\hat{\alpha} = \frac{n}{T} \text{ [Baker et al. 1997]} \tag{3.7}$$

Where; $\hat{\alpha}$ = defect rate, n = total number of defects observed (i.e. the sum of failed and repaired equipments), and T = period under consideration. Also

$$\sum_{i=1}^{k} \frac{\hat{\gamma} t_i}{e^{\hat{\gamma} t_i} - 1} + \frac{(n-k)\,\hat{\gamma}\Delta}{e^{\hat{\gamma}\Delta} - 1} = (n-k) \text{ [Baker et al. 1997]} \tag{3.8}$$

Where k failures are observed at times t_i $(i = 1, \ldots\ldots\ldots\ldots, k)$ from the last inspection, and $n-k$ defects are found at inspections. $\hat{\gamma}$ *and* $\hat{\alpha}$ are estimates of γ *and* α respectively. The optimal inspection interval, Δ^* satisfies the expression

$$(1+\gamma\Delta^*)e^{-\gamma\Delta^*} = 1 - \frac{\gamma c_1}{\alpha c_2} \text{, which has a solution provided } \gamma c_1 < \alpha c_2 \tag{3.9}$$

Where c_1 is the cost of inspection and repair, and c_2 the cost or consequences of failure (Baker et al. 1997). Equations 3.8 and 3.9 can be solved by amending them to equations 3.10 and 3.11 respectively, and using an iterative procedure or trial and error approach to find the values of γ and Δ for which $f(\gamma)$ and $f(\Delta^*)$ are zero.

$$f(\gamma) = \sum_{i=1}^{k} \left(\frac{\hat{\gamma} t_i}{e^{\hat{\gamma} t_i} - 1} \right) + (n-k) \left(\frac{\hat{\gamma}\Delta}{e^{\hat{\gamma}\Delta} - 1} \right) - (n-k) \tag{3.10}$$

$$f(\Delta^*) = (1+\gamma\Delta^*)e^{-\gamma\Delta^*} - \left(1 - \frac{\gamma c_1}{\alpha c_2}\right) \tag{3.11}$$

The reader is referred to [Baker et al. 1997; Baker and Christer, 1994; Baker and Wang, 1991] for a detailed study on the concept and derivation of the delay-time maintenance mathematical model.

3.7 DATA REQUIREMENT AND COLLECTION

Historical failure data pertinent to the critical components and subsystems of wind turbines will be extracted from the Supervisory Control and Data Acquisition (SCADA) system of wind farms. The SCADA system records failures and the date and time of occurrence; this will be used in conjunction with maintenance Work Orders (WOs) of the same period to ascertain the specific type of failure and the components involved. Information will be sourced from wind farms (comprising turbines of different capacity ratings) located within the same geographical region. The collected data will be organised in accordance with the type, design and capacity of the wind turbines. For example, failure data of all 600 kW horizontal axis turbines will be extracted and collated. This will further re-grouped according to subsystems and components of the wind turbine and then re-arranged in order of failure modes and dates. The asset identification number and the serial numbers for the subsystems and the components are essential for a very detailed analysis.

3.8 SUMMARY

The outlined methodology for designing a structured model for asset management in the wind energy industry will be applied in chapter 4. The hybrid approach to selection of a suitable maintenance strategy will be used in chapter 5 to determine an appropriate maintenance strategy for wind turbines. The modelling system failures maintenance optimisation technique will be applied in chapters 6 and 7 to assess and optimise the reliability, availability and maintainability of wind turbines on a selected wind farm. The delay-time maintenance mathematical model will be used in chapter 8 to optimise the inspection intervals of critical subsystems of wind turbines on a selected wind farm. A number of case studies will be used to demonstrate the practical application of the discussed methodologies.

CHAPTER 4

A STRUCTURED MODEL FOR ASSET MANAGEMENT IN THE WIND INDUSTRY

4.1 INTRODUCTION

In chapter 2 it was explained that achieving a return on investment in wind farms is affected by inter-related stakeholders' requirements as well as technical issues associated with the assets. It was further explained that inter-related issues require a holistic framework to combine and rationalise stakeholders' demands, and ensure assets remain in a satisfactory condition over the life-cycle of wind farms. Consequently, six (6) key steps were outlined in chapter 3 to re-organise the wind energy industry to support the applicability of asset management methodologies.

This chapter applies the outlined steps to design a structured model for asset management in the wind energy industry. Asset management processes in the wind energy industry are identified and arranged in a logical framework in section 4.2. Detailed design of each of the identified structured AM processes is presented in section 4.3. The overall picture of the structured model, highlighting the need to pull them together into a more coherent and effectively focused whole is presented in section 4.4. The potential benefits of the model are outlined in section 4.5. Institutional barriers in the way of practical implementation as well as individual responsibilities are discussed in sections 4.6. Finally, the summary of the chapter is presented in section 4.7.

4.2 ASSET MANAGEMENT PROCESSES IN THE WIND ENERGY INDUSTRY

Literature pertinent to Asset Management was reviewed in chapter 2 to understand its processes, tools and techniques existing in other industries. Andrawus et al. (2006a) critically assessed the wind energy industry and identified business values and assets which drive the long-term survival and profit generation of wind farms. Crucial requirements for the effective management of wind farms were also identified. The business values, assets and the crucial requirements are logically harnessed and rationalised into a 3-level AM model as shown conceptually in Figure 4.1 and described as follows. Level 1 comprises "stakeholders' requirements" (process A-B) and "Mission and vision statements" (process B-C). This is similar to the 'Business Values' in the AM model described in Chapter 3 section 3.2. Level 2 consist of "Assets classification and maintenance management" (process C-F) which is synonymous to the 2nd and 3rd tier in the model previously described. Finally, level 3 comprise of "Overall continuous performance improvements" (process F-A or F-G). The detailed design of these processes is reported in the next section.

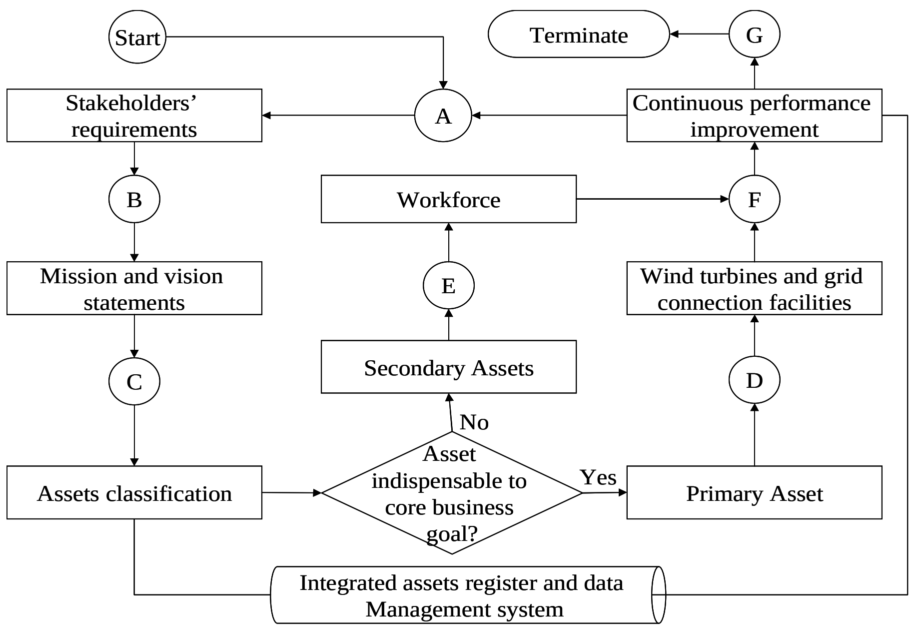


Figure 4.1 an outline framework for the Asset Management process

4.3 DETAILED DESIGN OF THE MODEL

This section presents a detailed design of each of the asset management processes shown in figure 4.1.

4.3.1 Stakeholders' Requirements

The first stage involves recognising and assembling all stakeholders' requirements which are often incompatible, and to unveil fundamental business values that will drive the performance and long-term survival of the wind farms. This process will facilitate negotiation with appropriate parties and permit a rational trade-off between conflicting priorities.

In the wind industry, the government creates a business-enabling environment through appropriate laws and also regulates the activities of the industry through regulatory bodies. Non-compliance with these laws and regulations will result in penalties and subsequent withdrawal of operating licenses. Investors in the wind energy sector desire a long-term business survival, increased profitability as well as enlarged market share in the global energy market. The end users expect lower prices of energy in comparison to other sources. The public expect absolute protection of the environment. These varying and opposing requirements need to be harnessed and balanced for a sustainable future of the wind energy industry. Figure 4.2 shows the stakeholders' requirements flow process.

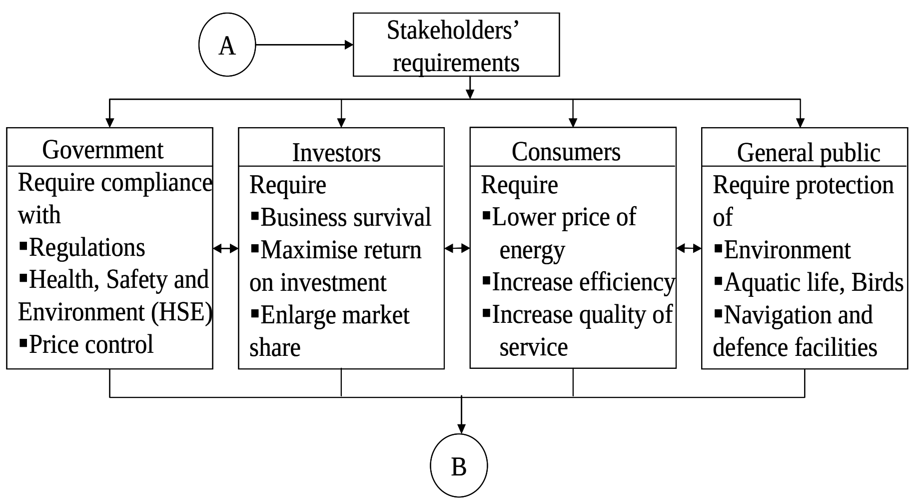


Figure 4.2 stakeholders' requirements flow process

4.3.2 Mission and Vision Statements

This process provides a bond between differing stakeholders' requirements and the overall business objectives. Unambiguous mission and vision statements are essential (Woodhouse, 2000) to give clear and sustainable direction to manage business values of the wind industry. The overall business objectives to uphold these values should be defined to satisfy all the stakeholders' requirements. This often results in contradicting objectives and it is imperative therefore to minimise the variability in the objectives by translating the objectives into concise and well communicated functions. Thus it is crucial the overall strategies align the departmental and individual responsibilities. An overall Key Performance Measurement (KPM) system should be designed to reflect the requirements of the stakeholders. Figure 4.3 shows the mission and vision statements flow process.

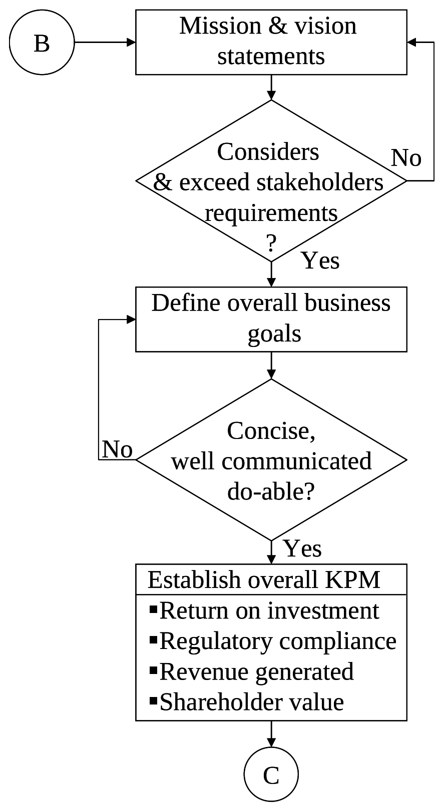


Figure 4.3 Mission and Vision statement flow process

4.3.3 Asset Classification

Assets are basically classified into five main groups (Eyre-Jackson and Winstone, 1999), these include physical (e.g. equipment, property, etc); human (e.g. labour, skills, knowledge etc); intellectual (e.g. data, information, patents, copy right, design, etc); financial (e.g. money, credit, etc) and intangible (e.g. public image, morale, goodwill, communication etc) assets. A wind farm holds a variety of these assets, some are primary to the core business objectives and others facilitate the performance of the primary assets. Classifying assets in this manner will draw attention to assets that are indispensable to the long-term survival of the wind industry and also elucidate boundaries and inter-dependencies of the assets. Figure 4.4 shows the asset classification flow process.

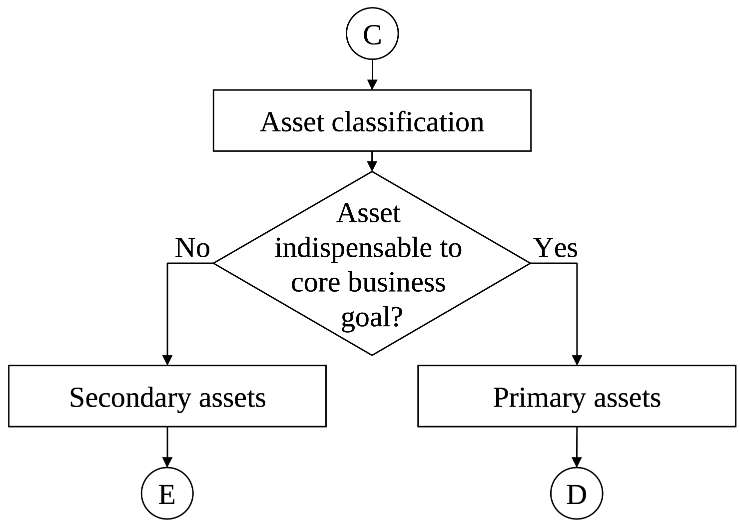


Figure 4.4 asset categorisation flow process

4.3.4 Primary Asset

Wind turbines operate within defined wind speed limits (cut-in and cut-out). The generated energy is then transmitted and connected to the electricity network for distribution to consumers. Effective management of wind turbines and the associated grid connection facilities will require the formulation of asset-based business objectives to align the overall goals of the wind farms. The objectives will include; effective management of Health, Safety & Environmental (HSE) factors, improving Reliability, Availability and Maintainability (RAM), minimising the Whole Life-Cycle Costs (WLCC), and failure elimination. Desirable and achievable targets should be set to reflect the expected level of performance. Suitable strategies for achieving the objectives should be determined by using appropriate AM tools and techniques.

Reliability-Centred Maintenance (RCM) is an AM technique used mostly to select suitable maintenance strategies for physical assets (Moubray, 1991). The approach has been applied in several industrial sectors with considerable success. The wind industry is yet to explore the full potentials of RCM to determine appropriate maintenance strategies for wind turbines and the associated grid connection facilities. RCM alone is limited in determining which maintenance strategies are the most cost effective options available. Therefore, an ALCA technique which is defined as "*…the combined evaluation of capital costs with future performance, operating and maintenance implications, life expectancies and eventual disposal or replacement of an asset*" (Woodhouse, 2000) should be incorporated into RCM to assess the commercial viability of maintenance activities over the life-cycle of wind turbines. The integration of RCM and ALCA will provide a sustainable method of determining appropriate (technically feasible and economically viable) maintenance strategies for wind turbines and the associated grid connection facilities to maximise the return on investment in wind farms (Andrawus et al. 2006b & c).

Appropriate Key Performance Indicators (KPI) and the measurement systems should be designed (Liyanage and Kumar, 2001) to align the maintenance activities and the overall strategic business values. Actual performance should be evaluated periodically and checked against intended targets. This will provide a baseline for maintenance optimisation to achieve the best combination of costs, risks and performances. Gaps and opportunities should be identified continuously and appropriate strategies to harvest the benefits should be determined and implemented. Figure 4.5 shows the flow process of primary assets.

4.3.5 Secondary Assets

This section discusses the secondary assets which facilitate the performance of the primary assets discussed in subsection 4.3.4.

4.3.5.1 Data

The significance of collecting and storing the correct type of data from the commencement of the AM process has been emphasised by Townsend (1998), Hammond and Jones (2000), Sherwin (2005). Improving the reliability, availability and maintainability of wind turbines and the associated grid connection facilities will depend on the availability of useful historical failure and maintenance data. It is imperative therefore to have a comprehensive inventory (including specific location) of all wind turbines and grid connection facilities in an integrated asset register and data management system. The system should be robust to accommodate sequential recording of maintenance and failure data in an RCM format. This will keep the maintenance track record of each asset in a meaningful format that can be used for optimisation processes and for an informed decision making process.

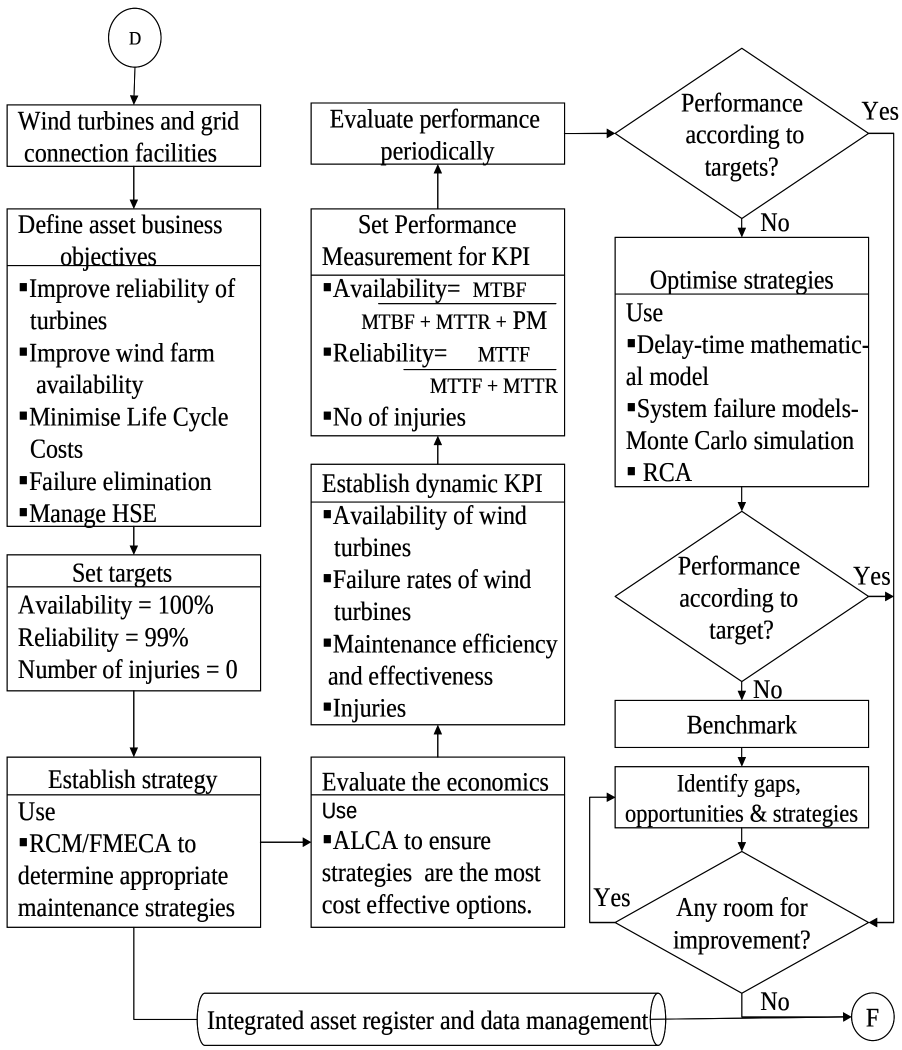


Figure 4.5 primary asset flow process

4.3.5.2 Workforce

The work force ensures effective operation and maintenance (O&M) of wind turbines and the associated grid connection facilities to achieve the expected level of performance. The quest for excellent performance revolves around a competent workforce with the right people on the right jobs, having manageable work backlogs and zero human error. Achieving this level of excellence will require an effective training and communication scheme, clear work procedures, team work and effective shift and reward systems. The performance of individuals should be evaluated periodically to identify training needs for the purposes of continuous staff development. Figure 4.6 shows the flow process of the work force.

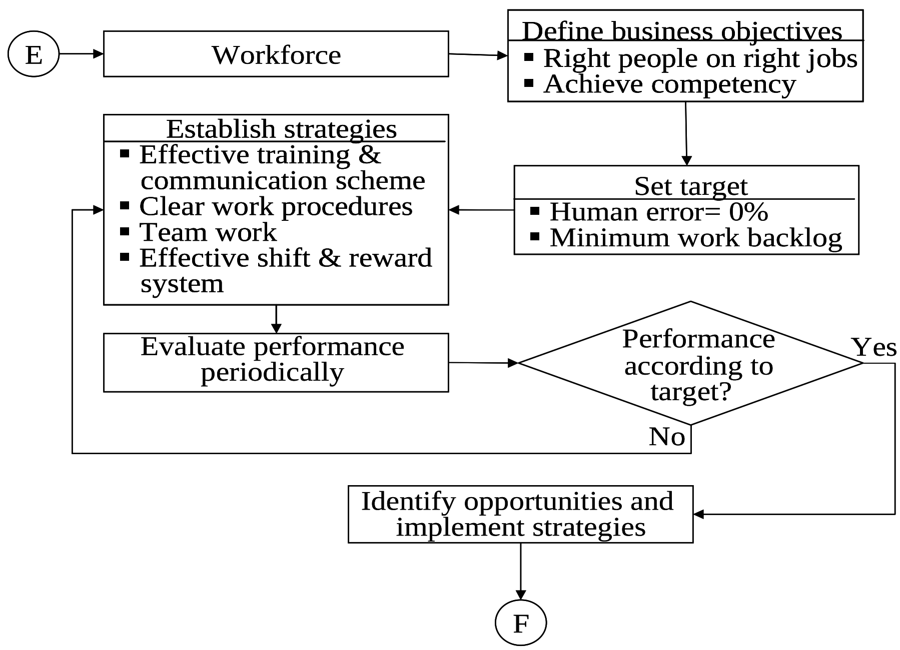


Figure 4.6 secondary assets flow process

4.3.6 The overall continuous performance improvement

This process involves periodic evaluation of the overall business performance of wind farms to satisfy all the requirements of the stakeholders. The overall Performance Measurement (PM) will indicate the level of success or failure attained in the period under consideration; this will reveal the gaps and opportunities on a continuous basis. Furthermore, it will motivate the desire to determine and implement appropriate strategies that will bridge the identified gaps and to explore new opportunities. Nonetheless, if no significant improvements are achieved by applying the appropriate strategies and the root-causes cannot be identified, then benchmarking (Benson and McGregor, 2005) against pace-setters within or across the industry should be used to yield useful success factors that will drive the continuous performance improvement process. Figure 4.7 shows the process flow of the overall continuous performance improvement.

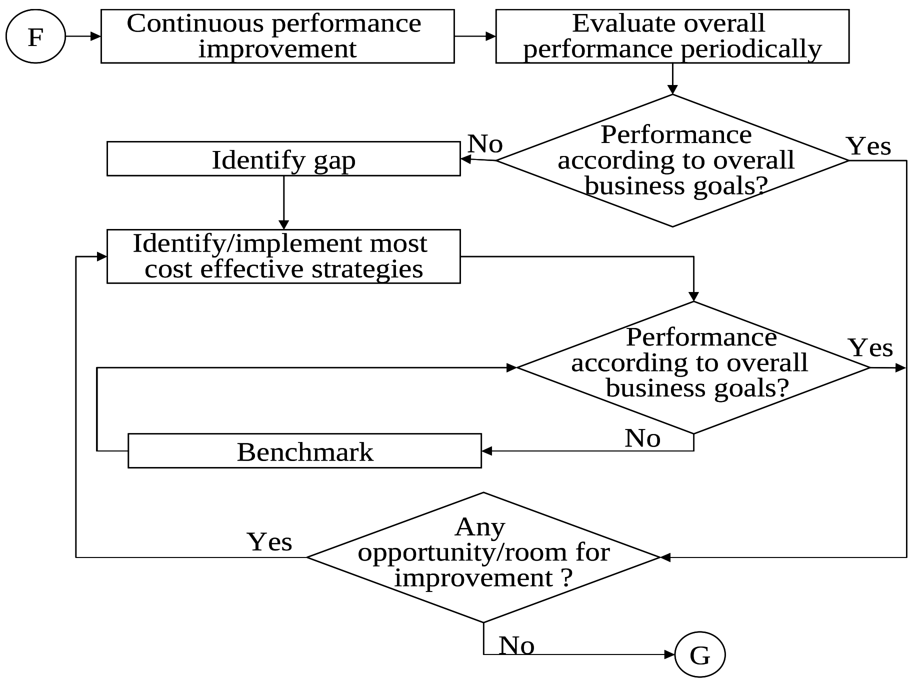


Figure 4.7 continuous performance improvement flow process

4.4 THE OVERALL PICTURE

The overall picture showing the holistic interaction and interdependencies of the asset management processes is shown in figure 4.8. This represents the structured model for asset management in the wind industry.

4.5 THE BENEFITS OF THE SYSTEM

The model when fully implemented will aid long-term survival of businesses operating in the wind energy industry as well as maximising the return on investments in wind farms.

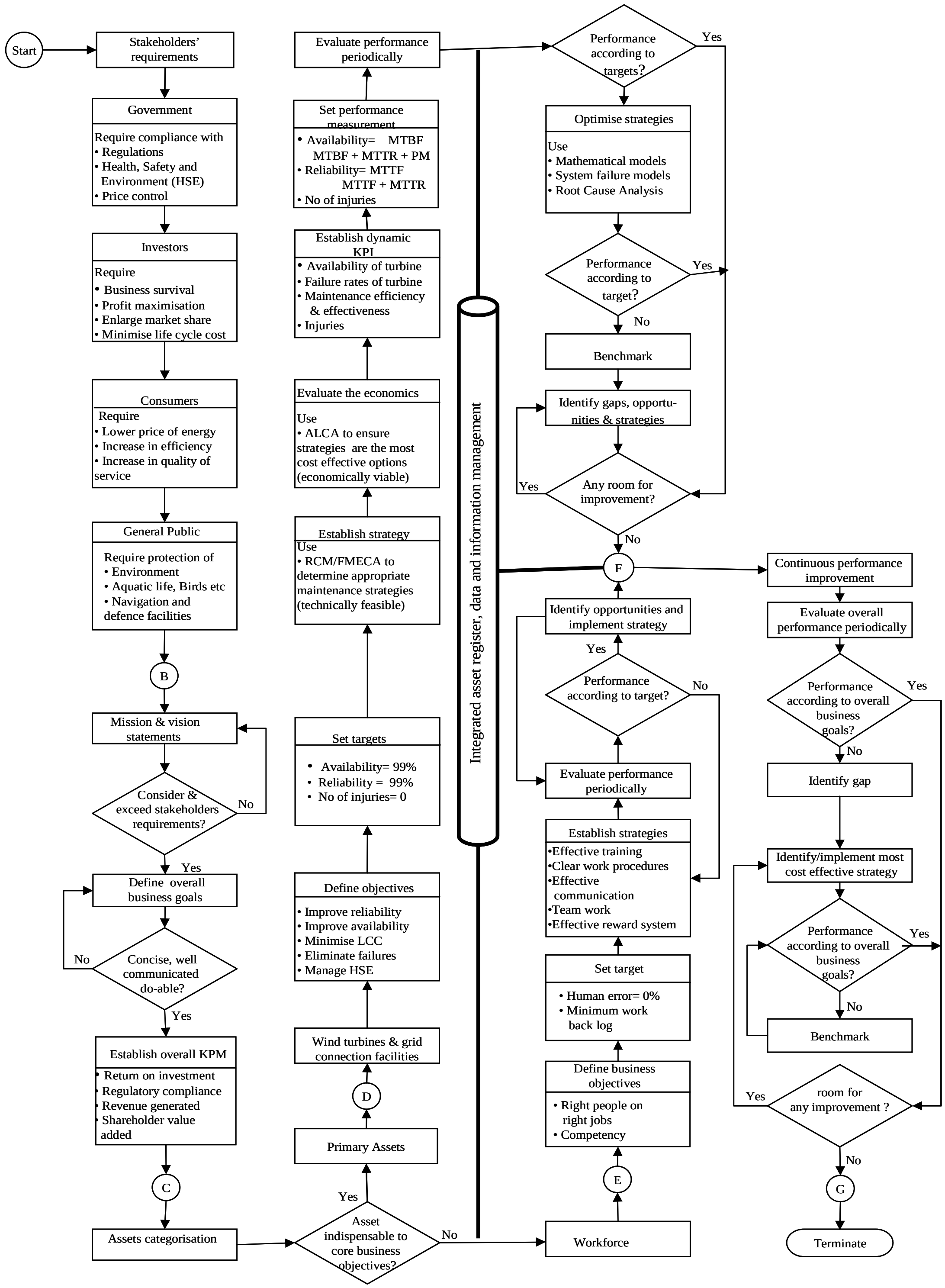


Figure 4.8 the overall flow process of AM in the wind industry

- Stakeholders will be kept in touch with all the necessary information they will require to perform their task effectively.

- The system will preserve knowledge and improve the quality of decision making on crucial issues such as the Health, Safety and Environment (HSE), Operational & Maintenance etc through out the life-cycle of wind farms.

- The system will improve the ability to trace causes of incidents by providing a specific operation and maintenance diagnosis of equipment to the end user. This will reduce the number of operational incidents such as emergency shutdowns.

- Maintenance will be based on observed conditions. This will reduce the number of down-times due to breakdowns, defects or damage, thus improving the productivity of wind turbines and also reducing the cost of energy generation.

- Replacements or overhauls of components in good operating condition will be avoided.

- The time interval between repairs and overhauls will be maximised through an optimisation process. This will allow better planning of suitable maintenance periods, logistics, spare holding and the associated man-hours.
- Access and logistic costs will be reduced significantly.
- The overall return on the investments in wind farms will be maximised.

4.6 PRACTICAL IMPLEMENTATION

This section discusses some institutional barriers in the way of practical implementation of the AM model as well as individual responsibilities to make it happen.

4.6.1 Institutional barriers

One key barrier to the practical implementation of the model is getting all the stakeholders to recognise and accept the strategic importance of AM, and to be fully and visibly committed to its implementation. Also, confidentiality among wind farm operators can limit data and information sharing. This will affect the update of the data base which is fundamental to long-term sustenance of the system.

4.6.2 Responsibilities

The right climate and a mechanism to make known the strategic importance of AM to the wind industry are fundamental to successful implementation. It is imperative that all the key stakeholders should take responsibilities as discussed below:

- **National**

Government should, through appropriate policies and bye-laws, ensure that the wind farm operators take full responsibility of maintaining assets within the wind industry in the wider context of asset management methodology.

- **Company**

The establishment of a policy at the national level to ensure practical implementation of AM in the wind industry must be supported with a significant allocation of human, material and financial resources. To this end, wind farm management must be fully and visibly committed before the system can yield its rich dividends. The management must be committed to initiating the required expenditure as rapidly as possible at the start of the programme and maintaining it while the programme continues. It is important to state that the wind farm operators should strive to be the primary custodian of the model, even if government is reluctant to support the system.

- **Workforce**

The commitment of the entire personnel to the implementation of AM will be the driving force to ensure success. The degree of benefit will be directly proportional to the level of commitment of the personnel. It is paramount that the entire workforce accepts the change and to be fully committed to the implementation so that the full benefits of the system can be harvested.

4.7 SUMMARY

The wind energy industry is face with incompatible stakeholders' requirements and the lack of a holistic framework to harness stakeholders' needs with assets technical issues. A structured model for asset management in the wind industry was developed. In the development of the model, AM processes, tools and techniques existing in other industries were drawn down and integrated for the effective management of wind farms. Crucial requirements for effective management of wind farms have been identified and transformed into AM processes. These processes were logically arranged to form the structure of the model. Each process was subsequently discussed and appropriately represented in a flowchart. Finally, the overall flow process indicating a holistic interaction of decision making and asset interdependence has been outlined by integrating the individual process chart.

The model coherently harnesses and rationalises stakeholders' requirements and ensures that assets remain in a satisfactory condition over the life cycle of wind farms. Such a model initiates the basic concept of AM in the wind industry as a prelude to developing dedicated AM software for the industry. The activities presented in the "primary asset flow process" (figure 4.5) will be carried out in chapters 5-8 due to its strategic function in the overall model.

CHAPTER 5

SELECTION OF A SUITABLE MAINTENANCE STRATEGY FOR WIND TURBINES

5.1 INTRODUCTION

The previous chapters had explained that the common maintenance strategies applied to wind turbines are inadequate to meet the current maintenance demands of the wind energy industry. Chapter 2 highlighted the need to determine an appropriate maintenance strategy for wind turbines using asset management tools and techniques. In chapter 3, section 3.3, a hybrid approach comprising Reliability Centred Maintenance (RCM) and Asset Life-Cycle Analysis (ALCA) techniques was developed to select an appropriate maintenance strategy for wind turbines.

This chapter presents and discusses the practical application of the hybrid approach to determine a suitable maintenance strategy for wind turbines. A generic horizontal axis wind turbine is critically assessed in section 5.2 to determine its failure characteristics by using the Reliability-Centred Maintenance approach. A case study is presented in section 5.3 to demonstrate the practical application of the hybrid RCM and ALCA to determine suitable maintenance activities for critical components and subsystems of a 600 kW wind turbine on a 26 x 600kW wind farm. The commercial viability of CBM activities is assessed using the ALCA technique; taking into account geographical location, intermittent operation and value of generation. Uncertainties in the financial calculations are risk assessed using a probabilistic technique of the Crystal Ball Monte Carlo simulation software. Non-financial factors are identified and assessed using a Weighted Evaluation (WE) technique and Benefit-To-Cost ratio. Finally, the summary of the chapter is presented in section 5.4.

5.2 APPLICATION OF RCM TO A GENERIC HORIZONTAL AXIS WIND TURBINE

The first four RCM questions, listed in chapter 3, subsection 3.3.3, identify ways in which a wind turbine already in operation can fail to perform its design intentions and the resultant effects on the components and systems of the turbine. This is usually referred to as a Failure Mode and Effect Analysis (FMEA).

5.2.1 Functions and performance standards of a wind turbine

The primary function of a wind turbine is to convert wind kinetic energy into electrical energy within a defined speed limit (cut-in and cut-out wind speed). This function is solely considered to minimise complexity in the analysis. The reader is referred to *Wind Turbine Standards IEC 61400-22* for other functions and standards of performance.

5.2.2 Functional failures

Three functional failures are defined in view of the primary function stated in subsection 5.2.1; these include (i) Complete loss of energy conversion capability (ii) Partial loss of energy conversion capability and (iii) Over speeding. This broad classification permits the analysis of critical components and subsystems that are indispensable to the normal operation of a wind turbine.

5.2.3 Failure Mode and Effect Analysis

Failure modes for the defined functional failures are presented logically in Table 5.1. These were further scrutinised sequentially to identify possible causes up to a third level as shown in Appendixes A1, A2 and A3. The result of this analysis can be applied to a generic horizontal axis wind turbine.

5.3 A CASE STUDY

In this section, a case study is presented to demonstrate the practical applicability of the approach. The last three RCM questions determine failure consequences and suitable maintenance tasks to mitigate the penalties. Data from a 26 x 600 kW onshore wind farm (total capacity of 15.6 MW) operating at an average capacity factor of 33% is used to answer the last three questions. The selection of this category of wind farm and turbine is deliberate for a number of reasons; first, onshore wind farms have ease of access for maintenance activities; secondly, it has been suggested (Verbruggen, 2003) that the failure of a low-rated-power wind turbine such as 600 kW does not greatly affect the revenue generation of a wind farm because wind turbines operate stand-alone and the financial margins in the wind industry is relatively small.

Table 5.1 Functional Failure and Failure Modes for Horizontal Axis Wind Turbines

Function	**Functional failure**	**Failure modes**
WT to covert wind kinetic energy into electrical energy within defined speed limit (cut-in and cut-out)	*WT-1* Complete loss of energy conversion capability	*WT-1-1* Catastrophic blade failure *WT-1-2* Catastrophic hub failure *WT-1-3* Main bearing failure *WT-1-4* Main shaft failure *WT-1-5* Shaft-gearbox coupling failure *WT-1-6* Gearbox failure *WT-1-7* Gearbox-generator coupling failure *WT-1-8* Generator failure *WT-1-9* Meteorological system failure *WT-1-10* Premature brake activation *WT-1-11* Electrical system failure *WT-1-12* Tower failure *WT-1-13* Foundation failure
	WT-2 Partial loss of energy conversion capability	*WT-2-1* Crack in blade *WT-2-2* Deteriorating blade root stiffness *WT-2-3* Blades at different pitches *WT-2-4* Dirt build-up on blades *WT-2-5* Ice build-up on blades *WT-2-6* Damping in blades *WT-2-7* Hub spins on shaft *WT-2-8* Low speed shaft misalignment *WT-2-9* Nacelle not yawing *WT-2-10* Nacelle yaws too slowly *WT-2-11* Nacelle yaws too fast *WT-2-12* Large yaw angle *WT-2-13* Cable twist *WT-2-14* Wind speed measurement error *WT-2-15* Wind direction measurement error
	WT-3 Over speeding	*WT-3-1* Controller failure *WT-3-2* Hydraulic system failure *WT-3-3* Pitching system failure *WT-3-4* Mechanical brake failure *WT-3-5* Grid connection failure

5.3.1 Data Collection

Current market prices of major components of a 600kW wind turbine, including transportation cost to site, were obtained from manufacturers. Labour requirements for replacements of these components as well as the access costs were obtained from the collaborating wind farm operator (see table 5.2). Historical failure data pertinent to failure modes *WT-1-1*, *WT-1-2*, *WT-1-3*, *WT-1-4*, *WT-1-6* and *WT-1-8* of the 600kW turbine were extracted from the SCADA (i.e. Supervisory Control and Data Acquisition) system for a period of 6 years. The SCADA system records failures and the date and time of occurrence; this was used in conjunction with maintenance Work Orders (WOs) of the same period to ascertain the specific type of failure and the components involved. Over this period, the catastrophic failure (by "catastrophic" in this case, we mean failures beyond repair which require replacement of the system) of a gearbox (failure mode WT-1-6) occurred twice, while the catastrophic failure of a generator (failure mode *WT-1-8*) occurred on one occasion. Activities for inspection of wind turbines drive trains were obtained from the collaborating wind farm operator (see table 4.3) while current market prices of vibration monitoring systems for failure modes *WT-1-3*, *WT-1-4*, *WT-1-5*, *WT-1-6* *WT-1*-7 and *WT-1*-8 were obtained from vendors of condition monitoring system (see table 5.4).

5.3.2 Failure Consequences

Our analysis is based on the following equations, using functions given in the Glossary (Appendix B):

$$TC_{IT} = \left(C_{IT} + C_{TP} + C_{Ld} + C_{OLd}\right)\left(1 + \frac{V_{AT}}{100}\right) \tag{5.1}$$

$$TC_{LB} = N_{Pn} \times N_{dy} \times W_{hr} \times L_{RT} \tag{5.2}$$

$$TC_{AS} = \left(C_{CR} \times N_{dy}\right) + \left(C_{CR} \times N_{dy} \times \frac{V_{AT}}{100}\right) \tag{5.3}$$

$$T_{PL} = \left(L_{hc} + R_{dy}\right) \times 24 \times WT_{PR} \times C_{EH} \times \left(\frac{C_f}{100}\right) \tag{5.4}$$

$$F_C = TC_{IT} + TC_{LB} + TC_{AS} + T_{PL} \tag{5.5}$$

$$PW = \frac{1}{\left(1 + d\right)^T} \tag{5.6}$$

Table 5.2 Data for calculating failure consequences

Materials	Blade	Main-bearings	Main shaft	Gearbox	Generator
Cost of item (£)	28,000.00	7,985.00	9,024.00	50,000.00	19,000.00
Cost of transportation (£) at 4% of material cost	1,120.00	319.40	360.96	2,000.00	760.00
Cost of Loading (£) at 0.5% of material cost	140.00	39.93	45.12	250.00	95.00
Cost of off loading (£) at 0.5% of material cost	140.00	39.93	45.12	250.00	95.00
Value Added Tax (%)	17.5	17.5	17.5	17.5	17.5
Labour					
Number of person to replace components	3	3	3	3	3
Number of days required to replace components	2	2	4	3	2
Work hours per day	8	8	8	8	8
Skilled labour rate per hour (£)	50.00	50.00	50.00	50.00	50.00
Access costs					
Cost of crane hire per hour including driver (£)	100.00	100.00	100.00	100.00	100.00
Number of hours per day	24	24	24	24	24
Cost of crane hire/day including Mob & Demob (£)	2,400.00	2,400.00	2,400.00	2,400.00	2,400.00
Number of days	3	3	4	4	3
Value Added Tax (%)	17.5	17.5	17.5	17.5	17.5
Production loss					
Lead time to supply material (days)	180	21	30	120	60
Lead time to hire a crane (days)	4	4	4	4	4
Number of repair days including travel time	3	3	4	4	3
Hours per day	24	24	24	24	24
Wind turbine power rating (kW)	600	600	600	600	600
Capacity factor (%)	33	33	33	33	33
Cost of energy per MWh (£)	50	50	50	50	50

Table 5.3 Inspection activities of 26 x 600 kW wind turbine drive trains

Number of wind turbines in wind farm (NT_{WF})	26	
Rated power per wind turbine	600	kW
Capacity factor	33	%
6-monthly service inspection of drive train		
Number of turbines serviced/day/ 2 personnel (NT_{SD})	1	turbine
Number of full-service per year (N_{FS})	2	
Number of full service days/year = (NT_{WF} / NT_{SD}) N_{FS}	52	days
Number of personnel (N_{Pn})	2	
Work hours per day (W_{hr})	6	hours
Labour rate per hour (L_{RT})	17	pounds
Annual cost of 6-monthly inspection = 52 x N_{pn} x W_{hr} x L_{RT}	**10,608.00**	**Pounds**
Annual gearbox inspection		
Number of gearbox inspected/day/2 personnel (N_{GB})	6	
Number of inspection per year (N_I)	1	
Number of days = (NT_{WF} / N_{GB}) N_I	4.333	days
Number of personnel (N_{Pn})	2	
Work hours per day (W_{hr})	6	hours
Labour rate per hour (L_{RT})	50	pounds
Annual cost of gearbox inspection = 4.33 x N_{Pn} x W_{hr} x L_{RT}	**2,600.00**	pounds
Total Annual Cost of Inspection (10,608.00 + 2,600.00)	**13,208.00**	**Pounds**

Table 5.4 CBM tasks of 26 x 600 kW wind turbine drive trains

Number of wind turbines (NT_{WF})	26	
Rated power per wind turbine	600	kW
IMU 16 channel H/W & S/W D5DA3/turbine (C_{IMU})	7,300	pounds
Park server/ wind farm (P_{SF})	2,500	pounds
Maintenance spares/ wind farm (M_{SF})	7,300	pounds
WEBCON/turbine/annum (WEB_{CON})	294	pounds
Diagonostic support vibration analysis consultancy/ wind farm/annum (D_{SV})	1,800	pounds
Application engineering & bearing inspection/wind farm/inspection/report (AE_{BI})	600	pounds
Aptitude exchange licence/wind farm/annum (AE_{LF})	696	pounds
Annual condition based servicing of drive trains		
Number of turbines serviced/day/ 2 personnel (NT_{SD})	6	turbine
Number of full-service per year (N_{FS})	1	
Number of full service days/year = (NT_{WF} / NT_{SD}) N_{FS}	4.33	days
Number of personnel (N_{Pn})	2	
Work hours per day (W_{hr})	6	hours
Labour rate per hour (L_{RT})	17	pounds
Costs of CBM activities		
Capital Cost of Condition Monitoring (CM) System = (NT_{WF} x C_{IMU})+ P_{SF}+M_{SF}	**199,600.00**	**pounds**
Annual maintenance cost of CM = WEB_{CON} + D_{SV} + AE_{BI} + AE_{LF}	**3,390.00**	**pounds**
Annual cost of condition-based servicing of drive trains = 4.33 x N_{Pn} x W_{hr} x L_{RT}	**884.00**	**pounds**

$$PWA = \frac{(1+d)^T - 1}{d\,(1+d)^T} \tag{5.7}$$

$$NPV_{TBM} = TA_{CI} \times PWA \tag{5.8}$$

$$NPV_{CBM} = (C_{cm} \times PW) + (AM_{cm} + AC_{CBM})\,PWA \tag{5.9}$$

$$A_{CR} = \varphi F_C N_T \tag{5.10}$$

$$A^* = A_i \left| S_i = \bigvee_{i=1,\,n} \sum_{j=1}^{m} W_j \, . S_{ij} \right. \tag{5.11}$$

$$A^* = A_i \left| BTC_i = \bigvee_{i=1,\,n} \frac{S_i}{NPV_i} \right. \tag{5.12}$$

Table 5.5 shows the failure consequences of critical components of a 600kW wind turbine expressed in financial terms. These were determined by using equation 5.5 and the data in Table 5.2, taking into account cost of material (Equation 5.1), cost of labour (Equation 5.2), cost of access (Equation 5.3) and production losses (Equation 5.4).

A single day outage of a 600kW wind turbine (at 33% capacity factor and ₤50/MWh energy value) would result to a revenue loss of about ₤237/day. Moreover onshore wind farms have the potential to operate at higher average capacity factors which results to a greater loss of revenue. Figure 5.1 shows the effect of capacity factors and down times on revenue generation of a 600kW wind turbine. A month down time at 33% and 36% capacity factors will result to a revenue loss of ₤7,128 and ₤7,776 respectively, approximately 8% of the total annual revenue. Furthermore, the effects of two or more turbines failure on revenue generation are significantly higher (see figure 5.2). A month outage of seven 600kW wind turbines at 33% capacity factor will result to a revenue loss of about ₤49,896. Hence, implementing a Failure Based Maintenance strategy only, where a certain number of wind turbines are allowed to fail before repairs are carried out will result in a significant loss of revenue in addition to the effect on the electricity network and cost of component replacement, given that, the lead time to supply most of the critical components ranges between 3-4 months.

Table 5.5 Failure consequences of critical components of a 600kW wind turbine

Failure Modes	Failure consequences F_C (£)				
	TC_{MT}	TC_{LB}	TC_{AS}	P_{LS}	Total
WT-1-1 Catastrophic blade failure	34,545.00	2,400.00	8,460.00	1,663.20	47,068.20
WT-1-3 Catastrophic main bearings failure	9,851.49	2,400.00	8,460.00	1,663.20	22,374.69
WT-1-4 Catastrophic main shaft failure	11,133.36	4,800.00	11,280.00	1,900.80	29,114.16
WT-1-6 Catastrophic gearbox failure	61,687.50	3,600.00	11,280.00	1,900.80	78,468.30
WT-1-8 Catastrophic generator failure	23,441.25	2,400.00	8,460.00	1,663.20	35,964.45

5.3.3 Selection of CBM tasks

The diagram in figure 5.4 was designed to select suitable on-condition tasks also known as the Condition-Based Maintenance activities. These were selected on the basis that an appropriate condition monitoring task is available to detect incipient dominant failure modes (that occur gradually with warning signs and are independent of age) so that actions can be taken to avoid the resultant consequences (Wiggelinkhuizen E, et al 2006; Infield D, 2004; Verbruggen T 2003; Caselitz, P et al 1997). Condition Monitoring Systems for Wind Turbines are now commercially available, and have been installed on wind turbines in many wind farms around the world, for example; the Enertrag Wind farm in Germany (see reference page), the Cathedral Rocks wind farm in South Australia (see reference page), etc. The collaborating wind farm operator has installed a vibrations monitoring system on the drive train of one of the 600 kW wind turbines as a pilot project. Indeed, installation of vibration monitoring system on the drive train of wind turbines is now becoming a requirement for insurance purposes.

Vibration analysis was identified as the suitable condition based maintenance technique to mitigate dominant causes of failure modes *WT-1-3*, *WT-1-4*, *WT-1-5*, *WT-1-6*, *WT-1-7*, *WT-1-8*, *WT-1-12*, *WT-2-7* and *WT-2-8* while strain gauge measurements were employed for dominant causes of failure modes; *WT-1-1*, *WT-1-2*, *WT-2-1*, *WT-2-2*, *WT-2-4*, *WT-2-5*, and *WT-2-6*. Catastrophic failures of critical components such as the blades, main bearings and shaft, gearbox and associated components, the generator and associated components, towers and foundations can be prevented through the application of appropriate CBM activities.

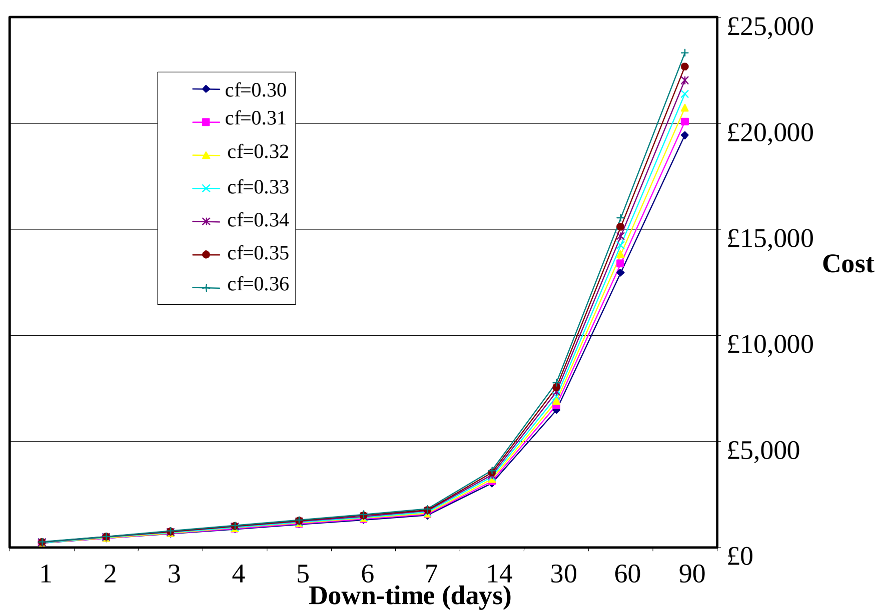


Figure 5.1 Effect of capacity factor and down time on revenue generation

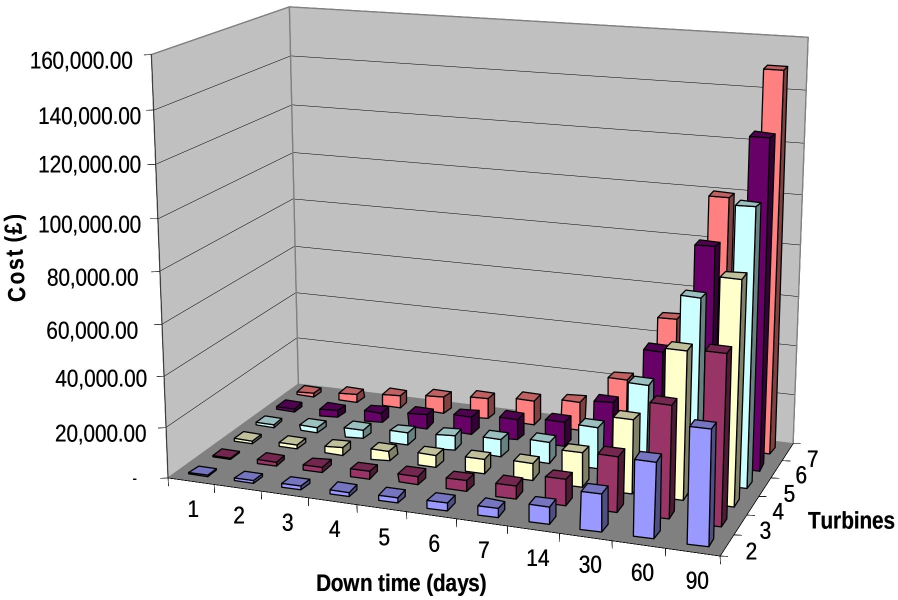


Figure 5.2 the effects of two or more turbines failure on revenue generation

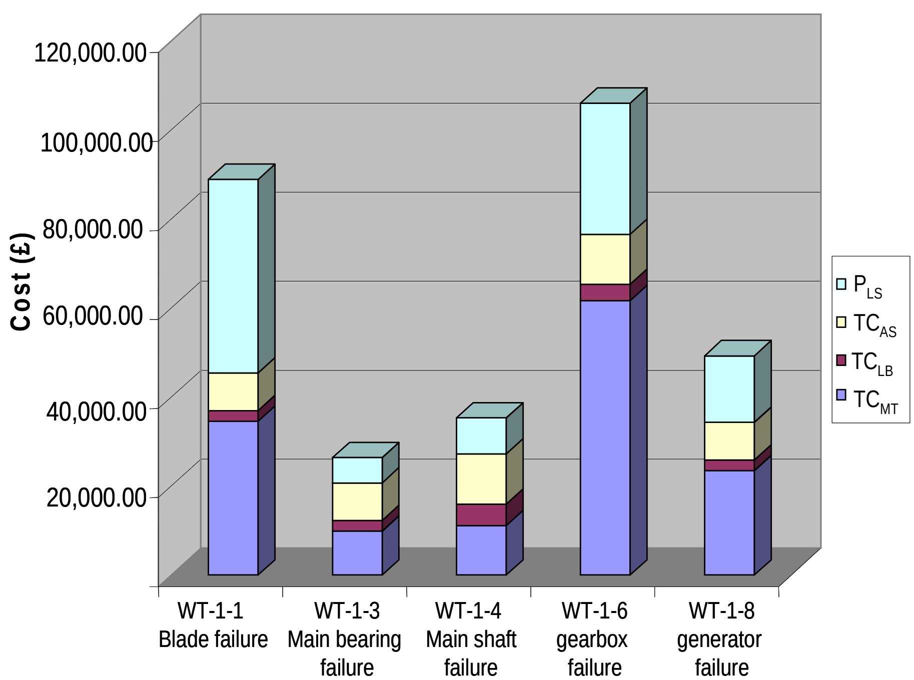


Figure 5.3 Failure consequences of critical components of a 600kW wind turbine

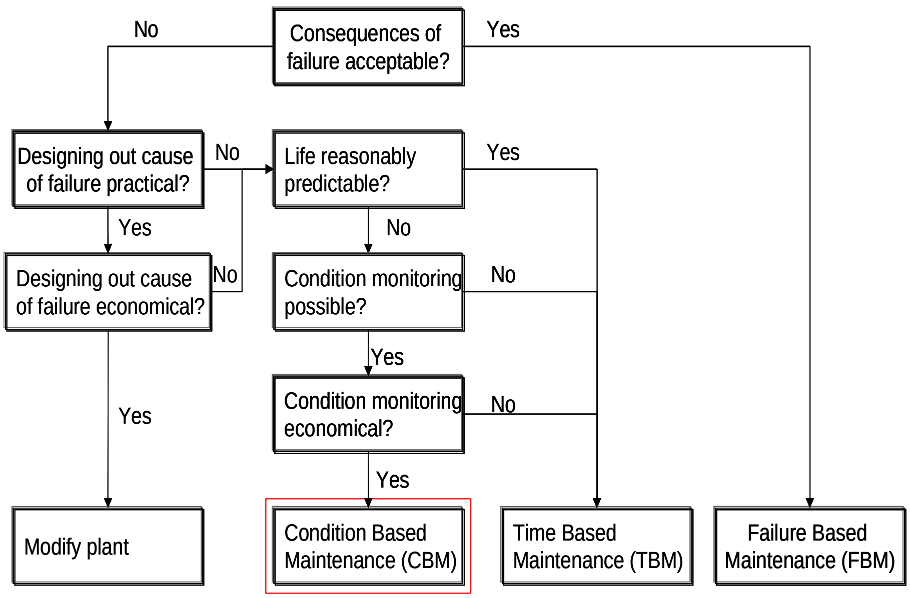


Figure 5.4 Maintenance Selection Model

5.3.4 Economic Analysis of CBM and comparison with TBM

The economic life of a wind turbine is 20 years (Lenzen and Munksgaard, 2002), (Kaldellis and Gavras, 2000) but an analysis period of 18 years is used in this paper to account for the 2 years all-in-service contract and obsolescence with changing technology. The corporate organisation of the collaborating wind farm operator utilises a discount rate of 8.2% for all financial analysis. Also, a spare pool of 1 gearbox, 1 generator, 3 blades etc is held by the wind farm under the TBM strategy. If any of these systems fail and it can not be repaired in-situ, the failed system is replaced with a spare before repairs are carried out and then transferred into the spare pool (note; the maximum number of spares that can possibly be in the re-supply chain of the wind farm at one time is beyond the scope of this paper). Using this information and the data in tables 5.3 and 5.4, the economics of TBM and CBM are evaluated and compared.

The Present worth (PW) and Present Worth per Annum (PWA), which is used for discounting initial non-recurring costs and annual recurring costs respectively, are determined by using equations 5.6 and 5.7 to obtain the values of 0.24 and 9.24

respectively. Then, the Net Present Value (NPV) of TBM and CBM, are calculated by using equations 5.8 and 5.9 respectively to obtain the values of £122,085 and £239,105 respectively. The results show that scheduled inspection of the drive trains of wind turbines is the most cost effective option over the 18 year life-cycle with a total savings of about £117,020. Indeed, the NPV of inspection (£122,085) is less than the initial capital cost of installing condition monitoring systems (£199,600).

5.3.5 Uncertainties and Risks Assessment

The NPV analysis deals with future costs which invariably contain uncertainties and risks that require critical assessments to ensure the accuracy of results for valid decision making. A probabilistic approach of 'Crystal Ball Monte Carlo' simulation was used to assess the risks and uncertainties of the key variables in the Net Present Value calculations. After a 10,000 trials, the result of the TBM simulation is presented in table 5.6. The mean Net Present Value of the TBM is £122,407. This is slightly greater than the calculated NPV of the TBM (subsection 5.3.4) with about £322. The standard deviation is about £12,487 and the mean standard error is £125. The skewness and coefficient of variability are 0.21 and 0.10 respectively.

Table 5.6 TBM Simulation Result

Statistics	Forecast values
Trials	10,000
Mean	122,407.55
Median	121,936.82
Mode	---
Standard Deviation	12,487.39
Variance	155,934,950.27
Skewness	0.21
Kurtosis	3.04
Coeff. of Variability	0.10
Minimum	80,113.10
Maximum	172,893.77
Range Width	92,780.67
Mean Std. Error	124.87

The result of the CBM simulation after a 10,000 trials is presented in table 5.7. The mean Net Present Value of the CBM is £239,070. In this case, the mean Net Present Value of the CBM is less than its calculated NPV with about £35. The standard deviation is about £19,202 and the mean standard error is about £192. The skewness and coefficient of variability are almost zero.

Table 5.7 CBM Simulation Result

Statistics	Forecast values
Trials	10,000
Mean	239,070.30
Median	238,856.63
Mode	---
Standard Deviation	19,201.98
Variance	368,715,966.09
Skewness	0.04
Kurtosis	3.02
Coeff. of Variability	0.08
Minimum	162,846.43
Maximum	309,711.35
Range Width	146,864.92
Mean Std. Error	192.02

Figures 5.5 and 5.6 show the overlay and trend chart of the NPVs of the TBM and the CBM. The overlay chart shows no significant effect of uncertainties on the NPVs as the two forecast are widely apart. Similarly, the trend chart clearly shows a constant increasing NPV from TBM to CBM as shown in the figure 5.6. The trend chart data at various percentiles are shown in table 5.8. Note the median NPV of the TBM and CBM are £121,937 and £238,857 respectively.

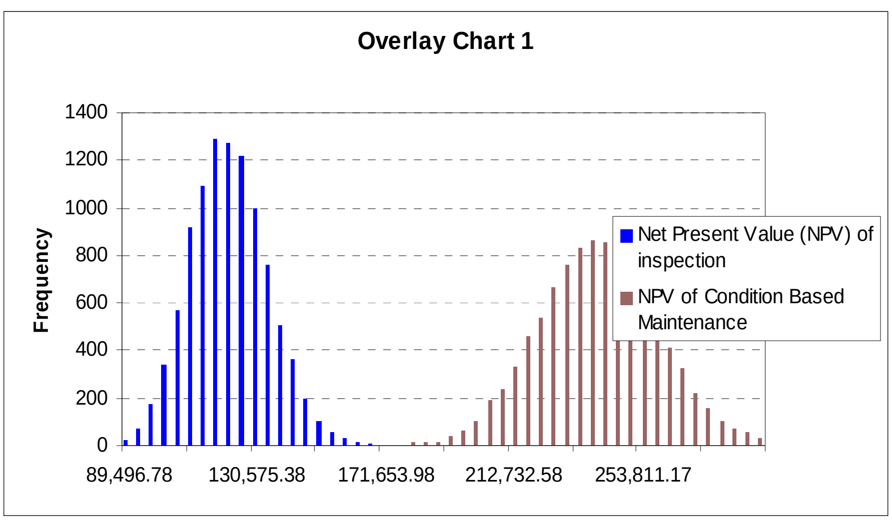


Figure 5.5 NPV overlay chart

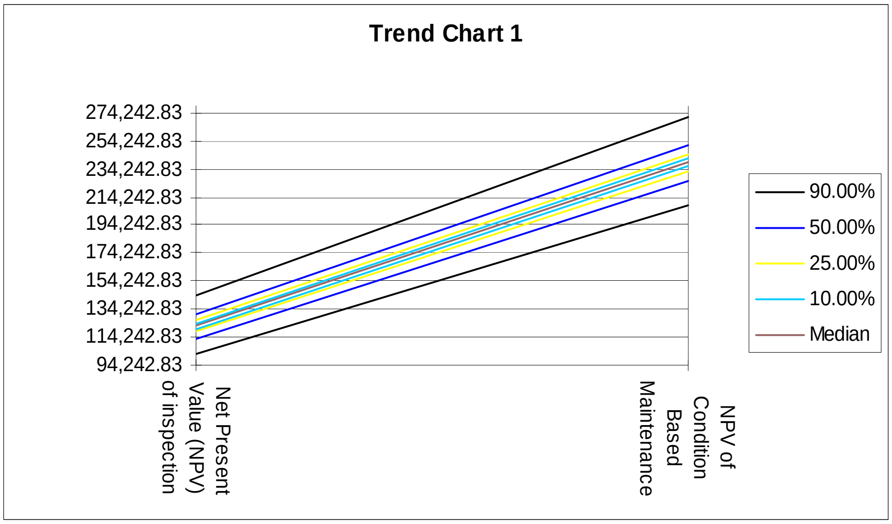


Figure 5.6 NPV trend chart

Table 5.8 The trend Chart data at various percentages

Trend Chart Data	NPV of TBM	NPV of CBM
90.0%	102,658.44	207,669.46
50.0%	113,685.65	226,151.86
25.0%	118,031.91	232,918.82
10.0%	120,402.80	236,493.54
Median	121,936.82	238,856.63
10.0%	123,556.95	241,231.86
25.0%	126,164.56	244,886.78
50.0%	130,498.37	251,734.79
90.0%	143,609.60	270,970.68

The sensitivity report of the TBM and CBM Net Present Value calculation are presented in figures 5.7 and 5.8 respectively. Labour cost per hour is found to be the most sensitive variable in the TBM Net Present Value calculation with about 64.3% sensitivity. On the other hand, the discount rate is found to be the most insensitive variable with about minus 31.7% sensitivity.

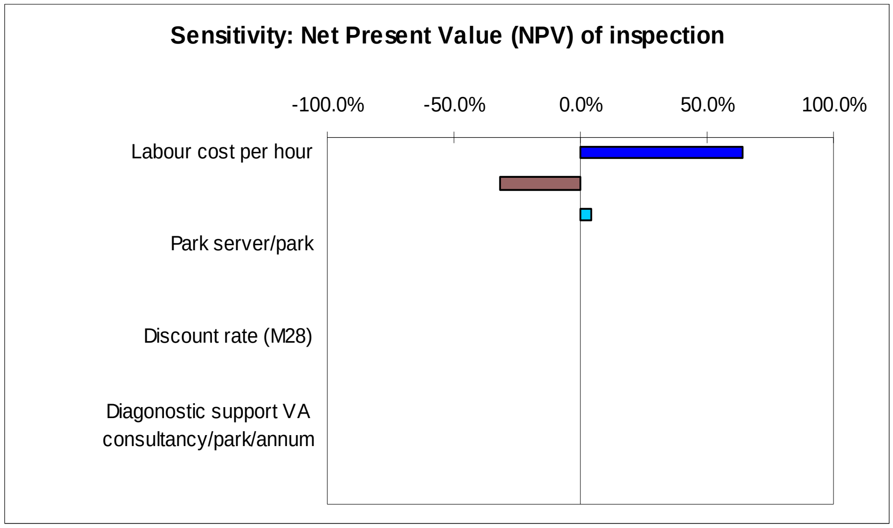


Figure 5.7 TBM sensitivity report

The initial cost of the condition monitoring systems (i.e. IMU 16 channel H/W & S/W D5DA3/ turbine) is found to be the most sensitive variable in the CBM Net Present Value calculation with about 93.3% sensitivity as shown in the figure 5.8. Diagnostic support vibration analysis consultancy has sensitivity of about 1.1%. Also the discount rate is found to be insensitive variable with sensitivity value of about minus 1.1%.

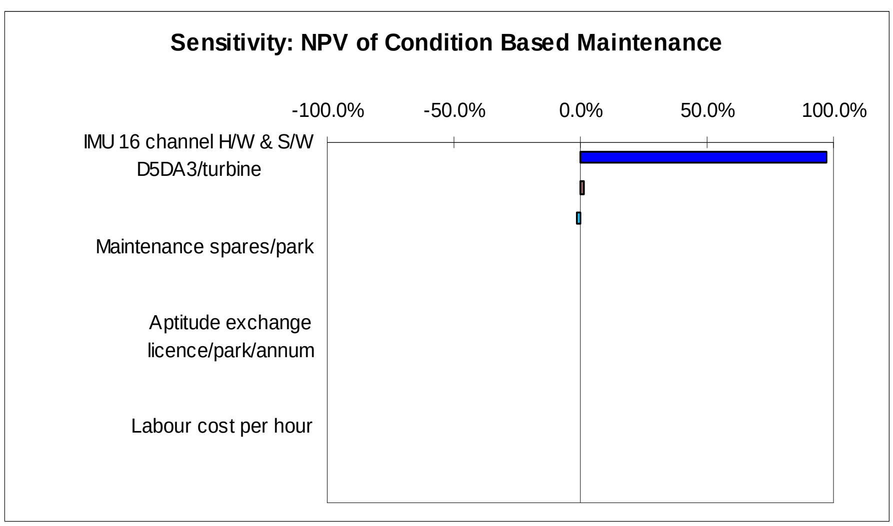


Figure 5.8 CBM sensitivity report

5.3.6 Evaluation of Non-financial Factors

An economic analysis based on purely financial criteria is not in itself adequate for valid decision making (Kirk and Dell'lsola, 1995). Non-financial factors, which are not reducible to monetary values should be identified and incorporated into the overall economic analysis (Kishk, 2002). A maintenance strategy that is appropriate for a specific physical asset should be reliable to uphold the integrity of the asset and also to fulfil all statutory and health and safety requirements. These non-financial factors are fundamental and can not be compromised in the selection of a suitable maintenance strategy. In figure 5.9, a screening model (Kishk and Pollock, 2004) for maintenance strategies is presented and a weight of 3 (i.e. good) was established as the minimum standard requirement for each of the decisive criteria.

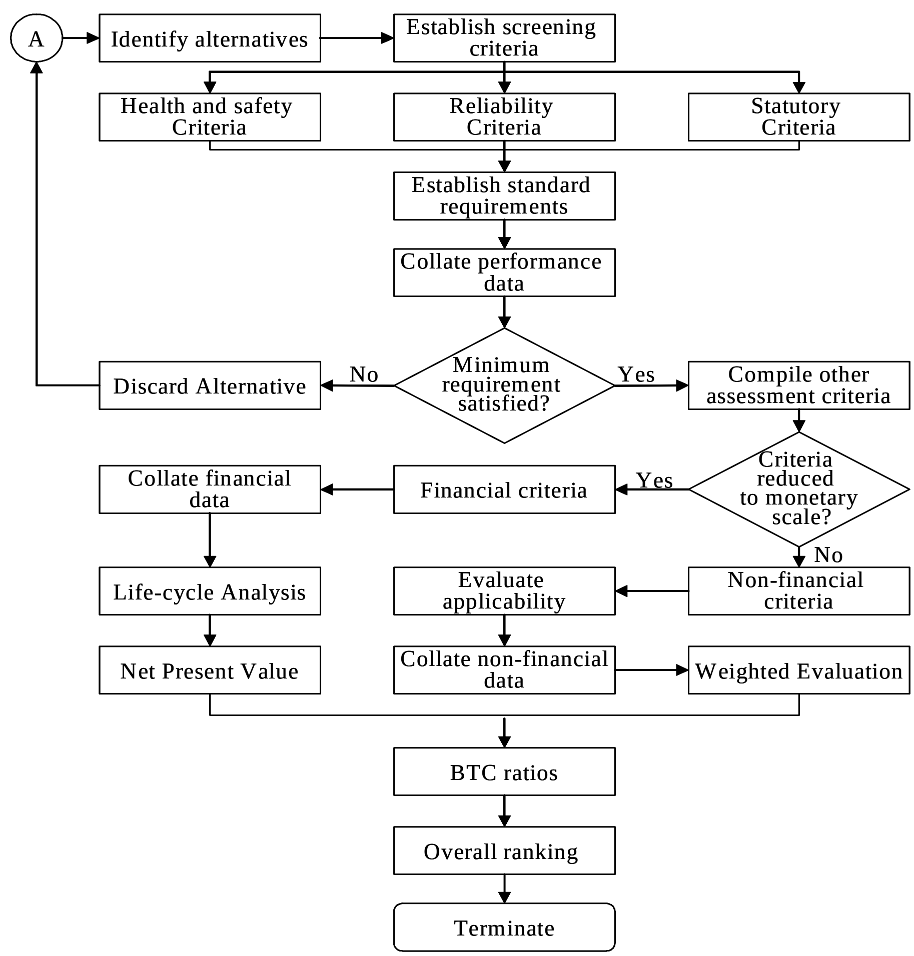


Figure 5.9 Model for screening options and criteria

In addition to the crucial factors, five other criteria were identified. These includes '***fault detection'*** which is the ability to discover faults at an early stage so that appropriate actions can be taken to avoid the consequences; '***fault identification'*** which is the ability to identify the subsystem or component most relevant to diagnosing the fault within the shortest time possible; '***fault diagnosis'*** is the ability to determine the cause of the fault within the shortest time possible; '***process recovery***' is the ease of rectifying the fault in good time and '***Efficiency'*** is the effectiveness of restoring the asset to a normal operating condition. These were assessed using the Weighted Evaluation (WE) technique (Kirk and Dell'lsola, 1995); (Kishk, 2002) and the result is presented in figure 5.10. It is worth noting however, that the non-financial factors can be subjective and figure 5.10 was established through discussion with wind farm operators.

The WE approach consists of two processes; first, assessment criteria are identified and the weights of their relative importance are established. These are sequentially compared in pairs and the most vital criterion is scored according to its comparative preference of scale 1 to 4, for example in figure 5.10, criterion 'A' (fault detection) is compared with criterion 'E' (health and safety), E is found to be more important than A and it is a major preference, hence the value 'E-4' was recorded.

The scores of each criterion are summed up (Raw Score in figure 5.10) and the final weights W_j are determined such that the maximum weight is assigned a value of 10 (Weight of importance in figure 5.10). Secondly, the rating S_{ij} of each strategy (TBM and CBM) in terms of each criterion is determined on a scale of 1 to 5 (i.e. poor to excellent), for instance, the performance of CBM in terms of criterion 'A' (fault detection) was found to be 'good' (i.e. 3). These values were then multiplied by the corresponding criterion final weights W_j and the summation gives the total score of the strategy (equation 5.11). As a rule, the best alternative A* should have the highest total score (Kishk, 2002). In figure 5.10, the total scores of TBM and CBM are 105 and 142 respectively; this suggests that the CBM strategy is the best alternative.

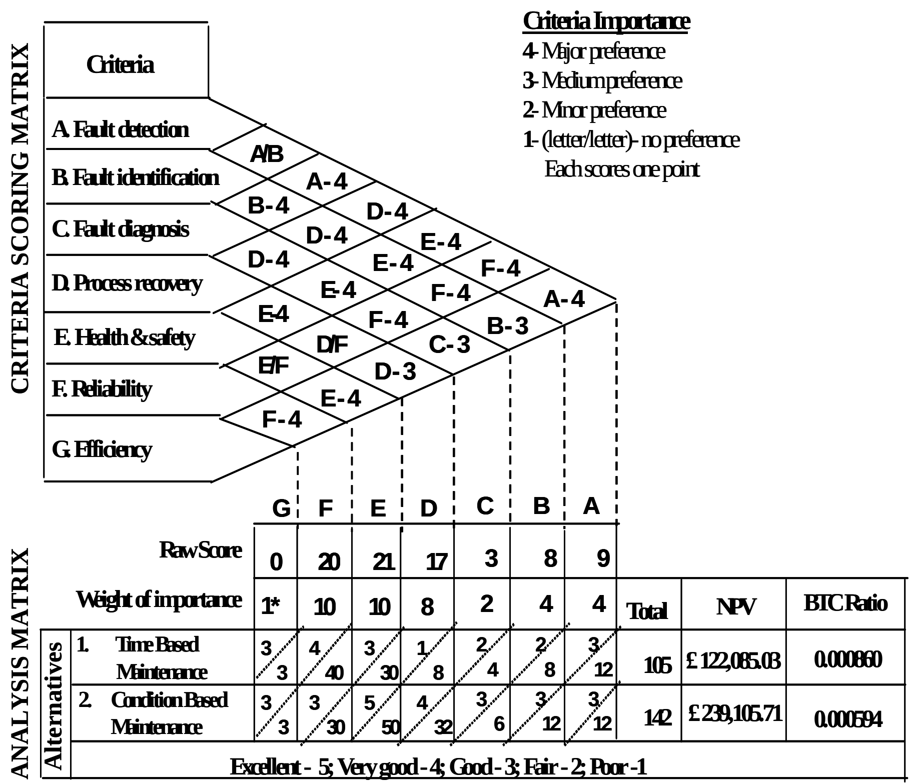


Figure 5.10 Weighted Evaluation of non-financial factors of TBM and CBM

5.3.7 Benefit-To-Cost Ratio Evaluation

The benefit-to-cost (BTC) ratio evaluation combines the results of the financial and the non-financial calculations to determine and compare the benefits derived from the competing options. The higher the ratio the better the benefit derived from the alternative. Equation 5.12 was used to determine the BTC ratio of TBM and CBM to obtain the values of 0.000860 and 0.000594 respectively (figure 5.10). This indicates that the BTC ratio of CBM strategy is very low in comparison to TBM because of the high initial capital investments required for installing condition monitoring systems. However, the life-cycle analysis is not complete unless the effect of failure rate of the critical components is assessed and incorporated into the overall analysis (Andrawus et al. 2006c).

5.3.8 Effect of Failure Rate

The failure rate (φ) of failure modes *WT-1-3*, *WT-1-4*, *WT-1-6* and *WT-1-8* were estimated by determining firstly 'wind turbine operational years' which is the product of the number of turbines in a wind farm (26) and the period under consideration (6 years) to obtain 156 operational years. The number of events for each failure mode is then divided by the wind turbine operational years to get the failure rate of the components. For example, 2 catastrophic failures of a gearbox occurred in the period under consideration to give φ = 0.01282 per year. These were further converted into annual cash reservations using equation 5.10; the summation (£32,150 per annum) is discounted by PWA to get a Net Present Value of £297,172.

The actual NPV of TBM is established by summing the NPV of inspection and NPV of annual cost reservation to get £419,257.59. Using this value to repeat the WE and BTC ratios shows CBM is the most cost effective strategy with a total savings of £180,151 over the 18 year life cycle.

Table 5.6 Effect of failure characteristics on maintenance strategy.

Number of turbines	**26**			
Number of failure years	**6**			
Failure Modes	**Number of Event**	**Failure rate α**	**Failure consequences F_C**	**Annual cost reservation A_{CR}**
WT-1-3 Catastrophic bearings failure	0	0	22,374.69	0
WT-1-4 Catastrophic mainshaft failure	0	0	29,114.16	0
WT-1-6 Catastrophic gearbox failure	2	0.01282	78,468.30	26,156.10
WT-1-8 Catastrophic generator failure	1	0.00641	35,964.45	5,994.08
			Total A_{CR}	**32,150.18**
			NPV of A_{CR}	**297,172.56**
			NPV of TBM (Inspection + A_{CR})	**419,257.59**

5.4 SUMMARY

This chapter has presented a methodology for selecting suitable maintenance strategies for wind turbines using a hybrid of RCM and ALCA techniques, and has used the methodology to determine an appropriate CBM strategy for a 26 x 600 kW wind farm. Industrial data pertaining to the wind farm has been sourced from the farm operator and have been collated to determine inspection activities and failure history of the wind turbines. Current market prices of critical components of the wind turbines as well as the condition monitoring systems have been sourced from manufactures and vendors. The RCM approach has been used to determine wind turbines failure modes, causes and effects. Failure consequences of critical components have been determined and expressed in financial terms.

Suitable CBM tasks have been determined and compared with TBM activities using the ALCA technique. In the comparison, the NPV of TBM and CBM has been calculated. It has been shown that comparison of the NPV of the two strategies is not absolute for a valid decision making since the NPV considers only financial criteria. The non-financial aspects of the two strategies have been identified and assessed using the 'WE technique' and 'benefit-to-cost ratio'. Failure data was extracted from the SCADA system of the wind farm, and was validated by the maintenance work orders of the same period. The failure rate of the critical components was calculated and included in the analysis since the selection of a suitable maintenance strategy depends upon the failure characteristics of the wind turbines. The overall result shows CBM is the most cost effective option with a total savings of about £180,152 over 18 year life-cycle.

CHAPTER 6

ASSESSMENT OF WIND TURBINES FIELD FAILURE DATA

6.1 INTRODUCTION

This chapter and the next, will demonstrate the practical application of one the quantitative maintenance optimisation approach known as the Modelling System Failures (MSF). This chapter focuses on the analyses of field failure and maintenance data of horizontal axis wind turbines collected from wind farms. The characteristics of the collected data are discussed in section 6.2. The data are analysed in section 6.3 using Maximum Likelihood Estimation (MLE) to estimate the *shape* (β) and *scale* (η) parameters of the Weibull distribution for critical components and subsystems of a particular type of 600 kW wind turbine. *Weibull probability plots*, *reliability graphs*, *failure verses time plots*, and *probability density function graphs* for the components and subsystems are presented along side the estimated *shape* (β) and *scale* (η) parameters. A case study of the 26 x 600 kW wind farm is presented in section 6.4 to demonstrate the practical application of the estimated β and η values to determine and optimise maintenance activities for the critical components and subsystems of the wind turbine. The summary of the chapter is presented in section 6.5.

6.2 DATA COLLECTION

In addition to the failure data collected from the 26 x 600 kW wind farm, more data were sourced from 26 wind farms (comprising turbines of different capacity ratings) located within the same geographical region. The collected data was first organised in accordance with the type, design and capacity of the wind turbines. This was further re-grouped according to subsystems and components of the wind turbine and then re-arranged in order of failure modes and dates. Tables 6.1, 6.2, 6.3 and 6.4 contain the field failure data for the main shaft, main bearings, gearbox and the generator respectively of 600 kW wind turbines.

In order to evaluate the wind farms in confidentiality, they were labelled alphabetically (*A to Z; AB)*; *WF-C* in column 1 of Table 6.1 denotes *Wind Farm C*. The wind turbines were named according to their respective wind farms; *WF-A-WT-10* (Table 6.2, column 2) denotes *Wind Farm A-Wind Turbine number 10*. The manufacturers of the failed components were numbered and recorded in column 3 of tables 6.1-6.4. The *fail-date* and *fail-time* from the *base-date* as well as the *causes of failure* are recorded in the same tables. Note that table 6.4 shows additional information about the serial numbers of the failed generators. This information is essential to identify re-occurring failure modes and to effectively trace the failure history of each component or subsystem of the wind turbine.

Table 6.1 Failure Data for the Main Shafts of 600 kW Wind Turbine

Wind Farm (*WF*)	Wind Turbine (*WT*)	Component Manufacturer	Fail date dd/mm/yyyy	Fail time (days)	Main shaft	Causes of failure
WF-C	*WF-C-WT-13*	2	"19/11/2003"	315	F	Other
WF-K	*WF-K-WT-7*	5	"01/03/2004"	424	F	Poor design
WF-F	*WF-F-WT-16*	1	"07/05/2004"	492	F	Unknown
WF-A	*WF-A-WT-27*	1	"13/06/2004"	529	F	Fatigue
WF-L	*WF-L-WT-3*	7	"29/12/2004"	698	F	Fatigue
WF-N	*WF-N-WT-3*	2	"25/07/2005"	936	F	Fatigue
WF-M	*WF-M-WT-3*	7	"14/06/2006"	1233	F	Fatigue

Table 6.2 Failure Data for the Main Bearings of 600 kW Wind Turbine

Wind Farm (*WF*)	Wind Turbine (WT)	Component Manufacturer	Fail date dd/mm/yyyy	Fail time (days)	Main Bearings	Causes of failure
WF-A	*WF-A-WT-10*	1	"29/01/2003"	29	F	Poor design
WF-B	*WF-B-WT-4*	2	"09/05/2003"	129	F	Poor design
WF-A	*WF-A-WT-13*	1	"19/05/2003"	139	F	Poor design
WF-A	*WF-A-WT-3*	1	"27/06/2003"	178	F	Poor design
WF-C	*WF-C-WT-4*	2	"31/07/2003"	212	F	Unknown
WF-D	*WF-D-WT-13*	1	"05/11/2003"	309	F	Unknown
WF-A	*WF-A-WT-34*	4	"10/02/2004"	406	F	Fatigue
WF-E	*WF-E-WT-2*	3	"15/05/2004"	500	F	Poor design
WF-A	*WF-A-WT-22*	1	"15/12/2004"	714	F	Fatigue
WF-D	*WF-D-WT-13*	1	"27/12/2004"	726	F	Fatigue
WF-A	*WF-A-WT-26*	1	"17/01/2005"	747	F	Fatigue
WF-A	*WF-A-WT-34*	3	"18/01/2005"	748	F	Fatigue

Table 6.3 Failure Data for the Gearboxes of 600 kW Wind Turbine

Wind Farm (*WF*)	Wind Turbine (WT)	Component Manufacturer	Fail date dd/mm/yyyy	Fail time (days)	HSS bearing	IMS bearing	Gear wheels	Key way	Gearbox catastrophic	Causes of failure
WT-F	WF-F-WT-1	8	"24/11/1999"	329	F	S	S	S	F	"Unknown"
WT-F	WF-F-WT-18	8	"13/01/2000"	378	F	S	F	F	F	"Fatigue"
WT-F	WF-F-WT-24	8	"26/03/2001"	815	F	S	S	F	F	"Fatigue"
WT-F	WF-F-WT-07	8	"23/07/2001"	934	F	S	S	F	S	"Fatigue"
WT-F	WF-F-WT-15	8	"19/11/2001"	1043	F	S	F	S	S	"Fatigue"
WF-A	*WF-A-WT-8*	9	"05/05/2003"	1585	F	F	S	S	S	"Fatigue"
WF-A	*WF-A-WT-14*	9	"06/06/2003"	1649	F	F	S	S	S	"Fatigue"
WF-A	*WF-A-WT-23*	9	"04/08/2003"	1676	F	S	S	S	S	"Fatigue"
WF-A	*WF-A-WT-9*	9	"27/08/2003"	1699	F	F	S	S	S	"Fatigue"
WF-B	*WF-B-WT-6*	9	"11/09/2003"	1714	F	F	S	S	S	"Fatigue"
WF-B	*WF-B-WT-10*	9	"04/11/2003"	1768	S	S	S	S	S	"Fatigue"
WF-B	*WF-B-WT-6*	10	"04/11/2003"	1768	S	S	S	S	S	"Fatigue"
WF-B	*WF-B-WT-14*	9	"22/11/2003"	1786	S	S	S	S	S	"Fatigue"
WF-F	*WF-F-WT-19*	9	"18/06/2004"	1985	S	S	F	S	S	"Fatigue"
WF-G	*WF-G-WT-9*	9	"30/06/2004"	2006	F	F	S	S	F	"Unknown"
WF-A	*WF-A-WT-33*	8	"09/10/2004"	2107	S	S	F	S	F	"Fatigue"
WF-A	*WF-A-WT-1*	8	"18/10/2004"	2116	S	S	S	S	S	"Fatigue"
WF-A	*WF-A-WT-19*	8	"30/10/2004"	2128	S	S	S	S	S	"Fatigue"
WF-C	*WF-C-WT-7*	11	"01/11/2004"	2130	F	S	F	S	S	"Fatigue"
WF-D	*WF-D-WT-20*	10	"04/02/2005"	2225	S	S	F	S	S	"Poor design"
WF-A	*WF-A-WT-19*	10	"02/04/2005"	2282	S	S	F	S	S	"Poor design"
WF-D	*WF-D-WT-2*	8	"11/05/2005"	2321	S	S	S	S	S	"Poor design"

To illustrate the importance of the additional information in the table 6.4, consider the failure data recorded in row 3 of the table. A generator with a serial number *GSN-2* failed in wind turbine 22 of wind farm F. Also in row 4 of the table, another generator failure is recorded with a serial number *GSN-2* but this time in wind turbine 15 of the same wind farm. It will be noticed that the serial numbers of the generators are the same, indeed, it is the same generator. The first failure of the generator in wind turbine 22 was due to bearing failure, it was removed for repairs and the turbine was fitted with a spare. The failed generator (*GSN-2)* was repaired and transferred into the spare pool.

The generator in wind turbine 15 failed and it was fitted with the *GSN-2* from the spare pool. The generator (*GSN-2*) eventually failed catastrophically as a result of a stator winding failure. A similar failure event is recorded in rows 9-11 of the table. It is worth noting that this type of detailed recording of failure data was found only in wind farm F and is specific to the generators.

Table 6.4 Failure Data for the Generators of 600 kW Wind Turbine

Farm (*WF*)	Wind Turbine (WT)	Serial number	Component Manufacturer	Fail date dd/mm/yyyy	Fail time (days)	Windings	Bearings	Generator catastrophic	Causes of failure
WF-F	*WF-F-WT-1*	GSN-1	4	"24/02/1997"	55	S	S	F	Fatigue
WF-F	*WF-F-WT-22*	GSN-2	4	"15/02/1998"	411	S	F	S	Fatigue
WF-F	*WF-F-WT-15*	GSN-2	4	"01/06/2000"	424	F	S	F	Fatigue
WF-F	*WF-F-WT-15*	GSN-3	4	"01/03/1999"	789	S	F	S	Fatigue
WF-F	*WF-F-WT-18*	GSN-4	4	"01/06/1999"	881	S	F	S	Other
WF-F	*WF-F-WT-12*	GSN-5	4	"01/12/2000"	548	S	S	F	Other
WF-F	*WF-F-WT-12*	GSN-6	4	"01/10/1999"	1003	F	S	S	Poor Design
WF-F	*WF-F-WT-17*	GSN-7	4	"15/12/1999"	1080	F	S	S	Unknown
WF-F	*WF-F-WT-15*	GSN-7	4	"01/01/2002"	746	F	S	S	Poor Design
WF-F	*WF-F-WT-15*	GSN-7	4	"01/07/2002"	181	F	S	S	Poor Design
WF-F	*WF-F-WT-5*	GSN-8	4	"08/01/2000"	1307	S	F	S	Fatigue
WF-F	*WF-F-WT-24*	GSN-9	4	"08/01/2000"	1307	S	S	F	Poor Design
WF-F	*WF-F-WT-16*	GSN-10	4	"01/11/2000"	1399	S	F	S	Poor Design
WF-F	*WF-F-WT-7*	GSN-11	4	"01/06/2002"	1977	S	F	S	Poor Design
WF-D	*WF-D-WT-26*	*GSN-12*	4	"21/01/2003"	2211	S	F	S	Fatigue
WF-A	*WF-A-WT-29*	*GSN-13*	4	"29/01/2003"	2219	S	F	S	Fatigue
WF-A	*WF-A-WT-20*	*GSN-14*	4	"09/04/2003"	2289	S	F	S	Fatigue
WF-C	*WF-C-WT-11*	*GSN-15*	4	"09/05/2003"	2319	S	F	S	Fatigue
WF-A	*WF-A-WT-18*	*GSN-16*	4	"09/06/2003"	2349	F	S	S	Fatigue
WF-A	*WF-A-WT-8*	*GSN-17*	4	"24/06/2003"	2364	S	F	S	Fatigue
WF-D	*WF-D-WT-4*	*GSN-18*	4	"07/08/2003"	2409	S	F	S	Fatigue
WF-D	*WF-D-WT-2*	*GSN-19*	4	"28/08/2003"	2430	F	S	S	Fatigue
WF-D	*WF-D-WT-27*	*GSN-20*	4	"15/09/2003"	2445	S	F	S	Fatigue
WF-A	*WF-A-WT-21*	*GSN-21*	4	"11/11/2003"	2535	F	F	F	Fatigue
WF-H	*WF-H-WT-11*	*GSN-22*	4	"13/11/2003"	2537	S	F	S	Fatigue
WF-A	*WF-A-WT-7*	*GSN-23*	4	"29/12/2003"	2553	S	F	S	Fatigue
WF-A	*WF-A-WT-20*	*GSN-24*	4	"29/01/2004"	2584	S	F	S	Other
WF-C	*WF-C-WT-8*	*GSN-25*	4	"04/03/2004"	2618	S	F	S	Other
WF-E	*WF-E-WT-20*	*GSN-26*	4	"25/03/2004"	2639	F	S	S	Poor Design
WF-F	*WF-F-WT-20*	*GSN-27*	4	"25/03/2004"	2639	S	S	S	Unknown
WF-I	*WF-I-WT-1*	*GSN-28*	4	"20/04/2004"	2665	S	F	S	Poor Design
WF-D	*WF-D-WT-15*	*GSN-29*	4	"23/04/2004"	2668	S	S	S	Fatigue
WF-A	*WF-A-WT-1*	*GSN-30*	4	"04/05/2004"	2679	F	F	F	Poor Design
WF-D	*WF-D-WT-27*	*GSN-31*	4	"07/05/2004"	2682	S	F	S	Poor Design
WF-E	*WF-E-WT-4*	*GSN-32*	4	"18/06/2004"	2724	S	F	S	Poor Design
WF-I	*WF-I-WT-6*	*GSN-33*	4	"26/06/2004"	2732	S	F	S	Poor Design
WF-G	*WF-G-WT-9*	*GSN-34*	4	"08/07/2004"	2744	S	S	S	Other
WF-A	*WF-A-WT-29*	*GSN-35*	4	"13/07/2004"	2749	S	F	S	Poor Design
WF-A	*WF-A-WT-17*	*GSN-36*	4	"16/07/2004"	2752	S	F	F	Poor Design
WF-C	*WF-C-WT-19*	*GSN-37*	4	"30/07/2004"	2766	S	S	S	Poor Design
WF-C	*WF-C-WT-10*	*GSN-38*	4	"12/08/2004"	2779	S	S	F	Poor Design
WF-E	*WF-E-WT-11*	*GSN-39*	4	"17/09/2004"	2815	S	F	S	Poor Design
WF-D	*WF-D-WT-28*	*GSN-40*	4	"21/09/2004"	2819	S	F	S	Poor Design
WF-E	*WF-E-WT-16*	*GSN-41*	4	"25/10/2004"	2853	F	S	S	Fatigue
WF-E	*WF-E-WT-13*	*GSN-42*	4	"07/11/2004"	2866	F	S	S	Fatigue
WF-I	*WF-I-WT-7*	*GSN-43*	4	"29/12/2004"	2918	F	S	S	Poor Design
WF-A	*WF-A-WT-24*	*GSN-44*	4	"02/01/2005"	2922	F	S	S	Poor Design
WF-A	*WF-A-WT-6*	*GSN-45*	4	"28/02/2005"	2969	F	F	F	Poor Design
WF-I	*WF-I-WT-13*	*GSN-46*	4	"07/04/2005"	3007	S	F	S	Poor Design
WF-A	*WF-A-WT-19*	*GSN-47*	4	"26/04/2005"	3026	S	F	S	Poor Design
WF-J	*WF-J-WT-9*	*GSN-48*	4	"12/09/2005"	3165	S	F	S	Poor Design

6.3 SHAPE AND SCALE PARAMETERS OF COMPONENTS AND SUBSYSTEMS OF 600 kW WIND TURBINE

The shape and scale parameters for components and subsystems of the various types of wind turbines are estimated in this section. It was mentioned previously that the value of β describes the failure pattern of the equipment, that is, β<1 means a reducing failure pattern, β=1 signifies a constant failure pattern and β>1 indicates an increasing failure pattern. The scale parameter (η) denotes the characteristic life of the equipment; the time at which there is probability of approximately 0.632 that the equipment will have failed.

The reducing failure pattern (β<1) usually known as the *infant mortality* denotes failures that occur at the early-life of equipment and the likelihood of occurrence reduces as the age of the equipment increases. The constant failure pattern (β=1) represents failures that are independent of equipment age, that is, the likelihood of occurrence is invariable through out the life-cycle of the equipment. Lastly, the increasing failure pattern (β>1) commonly referred to as *wear-out* symbolises failures that occur at the later life of equipment, that is, the likelihood of occurrence increases with the age of the equipment.

The shape (β) and scale (η) parameters of critical components and subsystems of the 600 kW wind turbine are estimated using the ReliaSoft Weibull ++7 software. The results are presented in table 6.5. The probability distribution and the parameter estimation technique are shown in columns 3 and 4 of the table respectively. In the analysis, the Fisher Matrix (FM) confidence bound method and median (MED) ranking was used to underpin the statistical evaluation. The *Mean Life* or *Mean Time Between Failures* (MTBF) of each of the critical components and subsystems are presented in column 10 of the same table. Note that the scale parameters and the mean time between failures are in days.

Table 6.5 Shape and Scale parameters for critical components of 600 kW wind turbine

Sub-system	Components	Distribution	Analysis	Shape (β)	Scale (η)	Likeli-hood	Failed	Suspended	Mean Life (MTBF)
Blade									
Main shaft		Weibull-2P	MLE	1.43	6389	-72.90	7	70	5807
Main bearing		Weibull-2P	MLE	1.09	3835	-112.79	12	65	3711
Gearbox		Weibull-2P	MLE	1.05	29051	-56.99	5	72	28521
	Gears	Weibull-2P	MLE	2.50	5715	-75.10	7	70	5070
	HSS bearings	Weibull-2P	MLE	1.52	7244	-125.00	12	64	6528
	IMS bearings	Weibull-2P	MLE	3.63	4694	-53.99	5	72	4232
	Key way	Weibull-2P	MLE	0.84	101790	-35.69	3	74	111720
Generator		Weibull-2P	MLE	1.11	17541	-98.70	9	68	16888
	Bearings	Weibull-2P	MLE	1.39	4956	-300.00	31	46	4524
	Windings	Weibull-2P	MLE	1.62	7158	-155.00	15	62	6412

6.3.1 The Main Shaft

The estimated values of β and η for the main shaft are 1.43 and 6389 respectively. The β value of 1.43 indicate a *wear out failure pattern* while the η value of 6389 implies that there is a probability of approximately 0.632 that all the main shafts in a wind farm of 600 kW turbine would have failed within 6389 days or approximately 18 years, given the assessed failure behaviour of the main shafts and the current maintenance strategy employed. The Weibull plot (graphical data analysis) for the main shafts failure data is shown in figure 6.1.

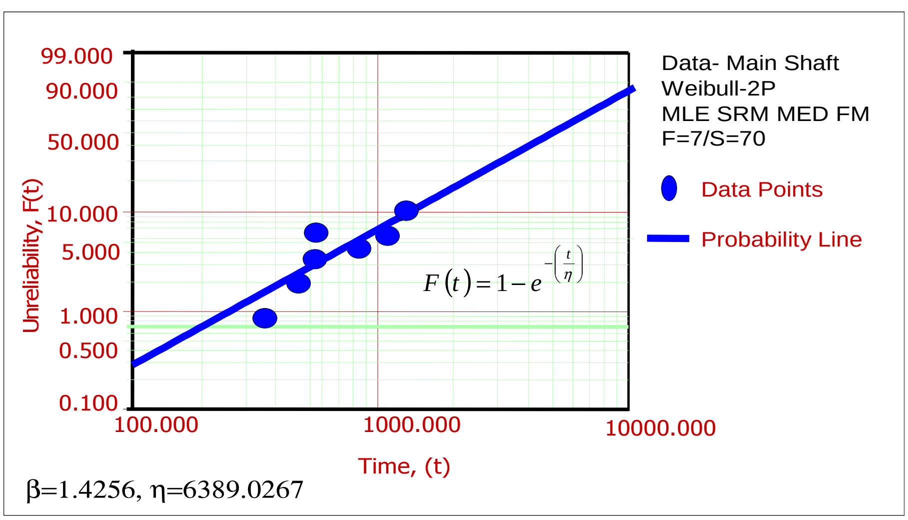


Figure 6.1 Main Shaft Weibull Plot

The probability density function (pdf) plot for the main shaft is presented in figure 6.2. The plot is skewed to the left showing that bulk of the failure modes occur between 0 and 4000 days even though the estimated MTBF is 5807 days.

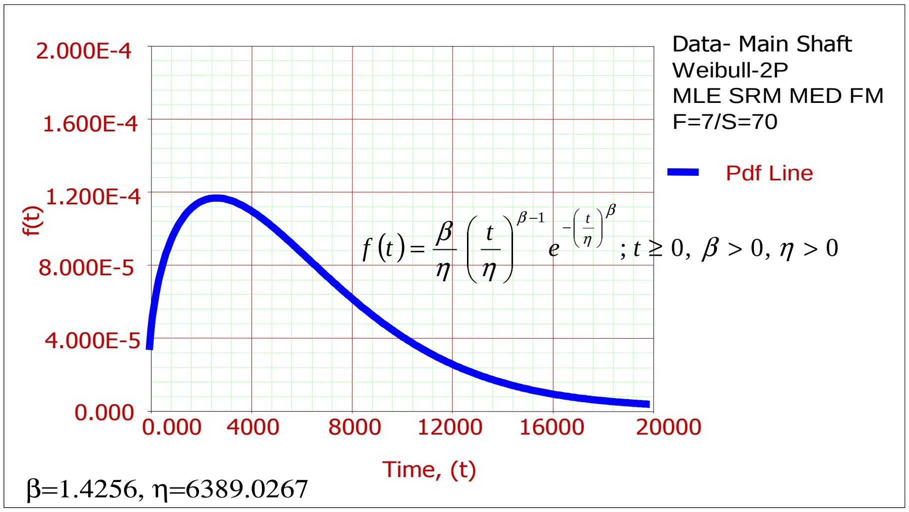


Figure 6.2 Main Shaft pdf plot

The main shaft failure rate plot is presented in figure 6.3. The plot shows a constantly increasing failure rate and not a clear wear out even though the value of β is greater 1. This demonstrates the significance of the plots to provide more information to support the calculated values.

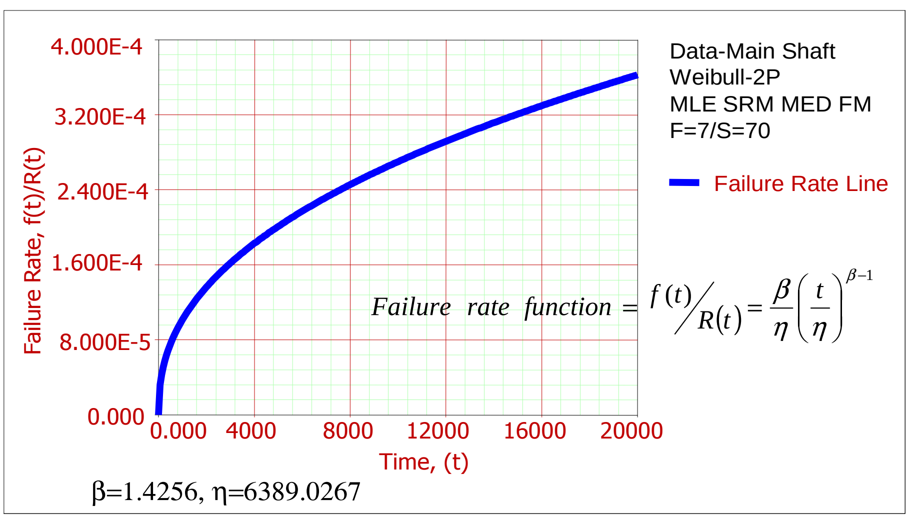


Figure 6.3 Main Shaft Failure Rate Plot

6.3.2 The Main Bearing

The estimated β and η values for the main bearing are 1.09 and 3835 respectively. The 1.09 value of β indicates a *random failure pattern.* The Weibull plot is shown in figure 6.4.

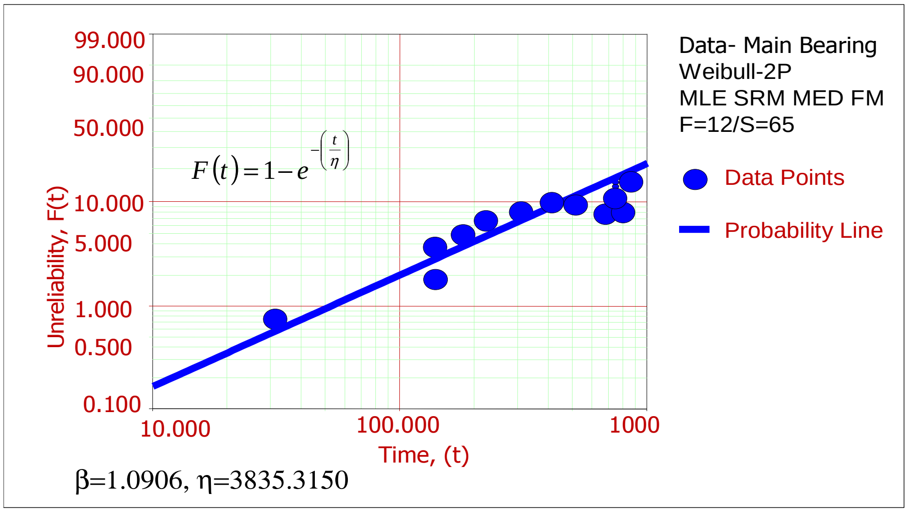


Figure 6.4 Main Bearing Weibull plot

The *pdf* plot of the main bearings is shown in Figure 6.5. The plot is also skewed to the left and the right side of the pdf steeply drops down before 1300 days; this means that that most of the failures will occur before this time.

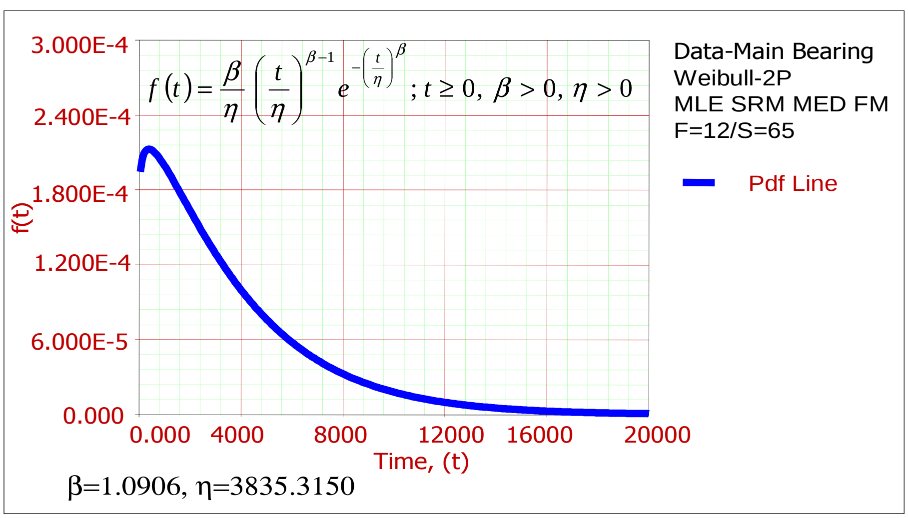


Figure 6.5 Main Bearing pdf plot

The main bearing failure rate plot in figure 6.6 shows the randomness of the failure pattern.

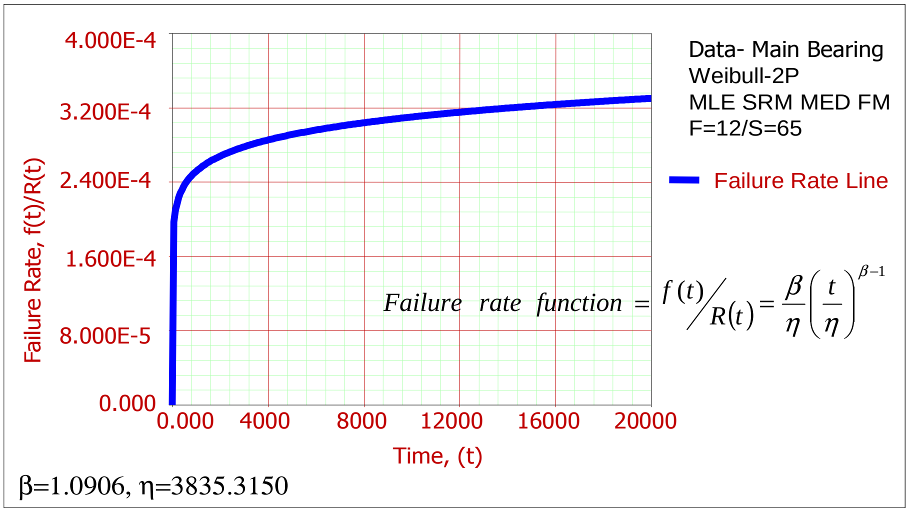


Figure 6.6 Main Bearing Failure Rate Plot

6.3.3 The Gearbox

The estimated values of β and η for the gearbox are 1.05 and 29051 respectively. The β value of 1.05 indicate a *random failure pattern* while the η value of 29051 implies that there is an approximately 0.632 probability that all the gearboxes in a wind farm of 600 kW turbine would have failed within 29051 days or approximately 79 years, given the assessed failure behaviour of the gearbox and the current maintenance strategy employed. The *Weibull probability plot* of the failure characteristic is shown in Figure 6.7.

The *probability density function (pdf)* and the *failure rate* plots are shown in Figures 6.8 and 6.9 respectively. The pdf plot is skewed to the left; it shows a classic failure characteristic of the gearboxes as a result of many failure modes. Unfortunately, the assessed failure data did not capture the exact failure modes due poor recording of failure information. The failure rate plot shows a horizontal line which explains the randomness of the failure pattern of the gearboxes. The gear-wheels and the intermediate stage (IMS) bearing of the gearbox have β values of 2.50 and 3.63 respectively. These indicate a *wear-out failure pattern*. The key-way of the gearbox has a β value of 0.8 which denotes an *in-born failure pattern or infant mortality*.

The MTBF for the gearbox is about 28521 days. The gear-wheels, HSS bearing, IMS bearing and the key ways have MTBF of 5070, 6528, 4232 and 111720 days respectively.

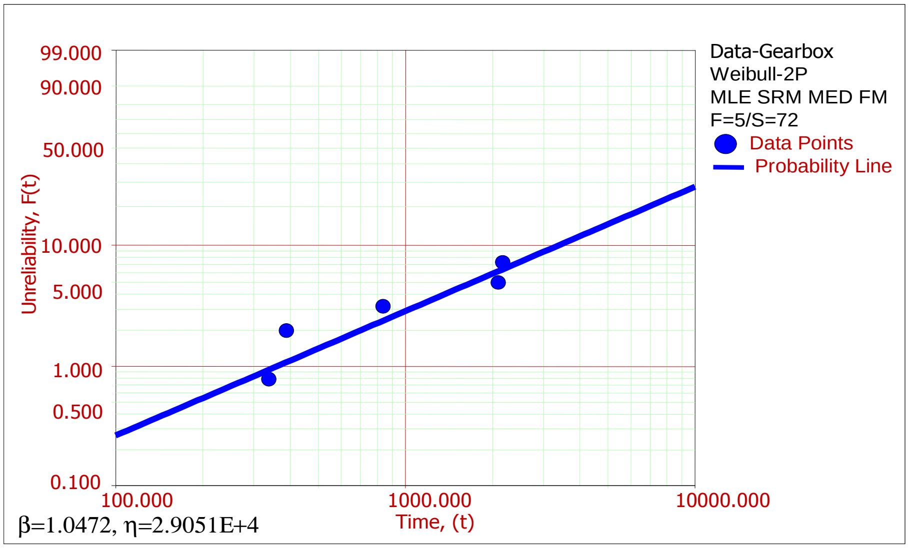


Figure 6.7 Gearbox Weibull Plot

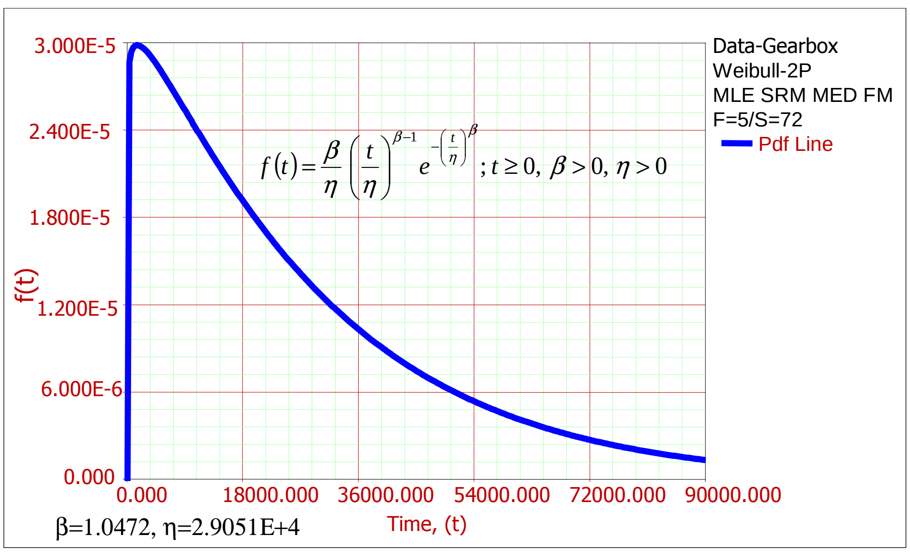


Figure 6.8 Gearbox pdf plot

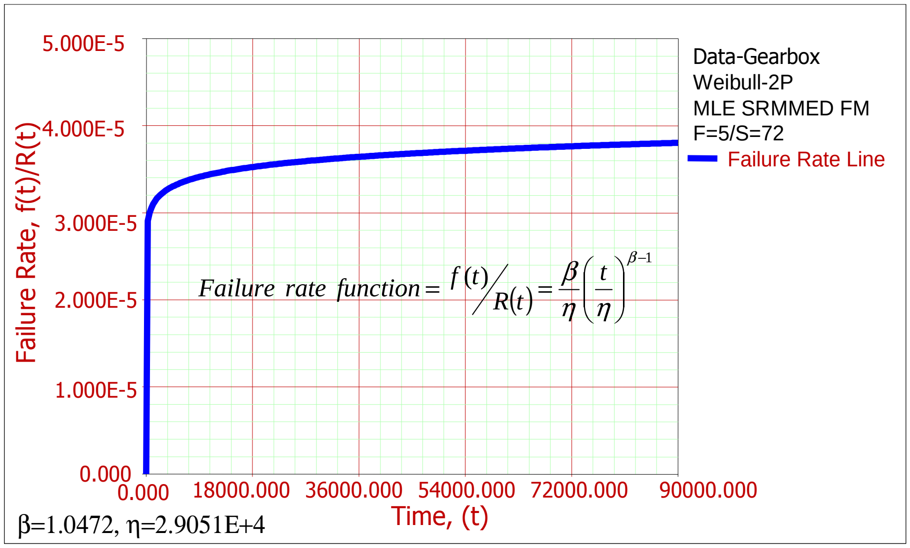


Figure 6.9 Gearbox failure rate plot

6.3.4 Generator

The estimated values of β and η for the generator are 1.107 and 17541 respectively. The β value of 1.11 indicates a *random failure pattern*. The Weibull plot is shown in figure 6.10. The pdf and failure rate plots are shown in figures 6.11 and 6.12 respectively. The pdf plot of the generator is slightly skewed to the left.

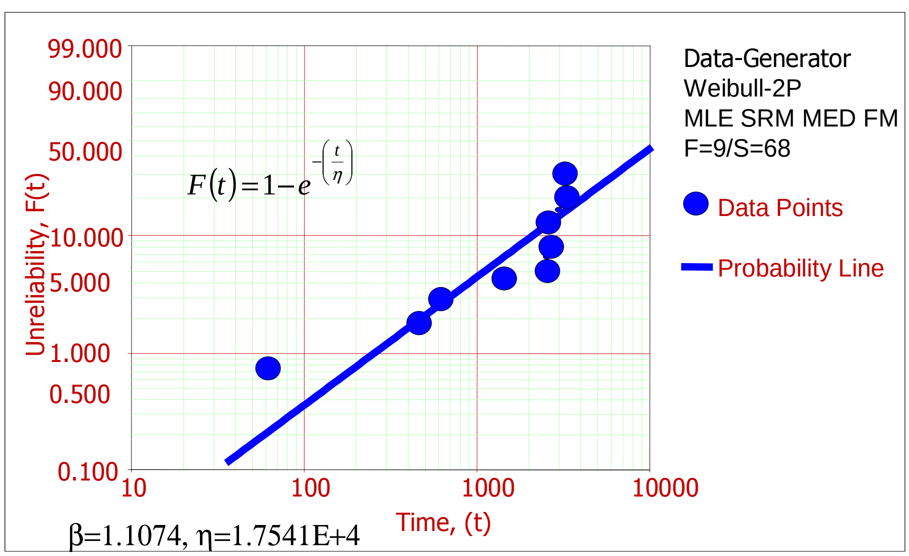


Figure 6.10 Generator Weibull Plot

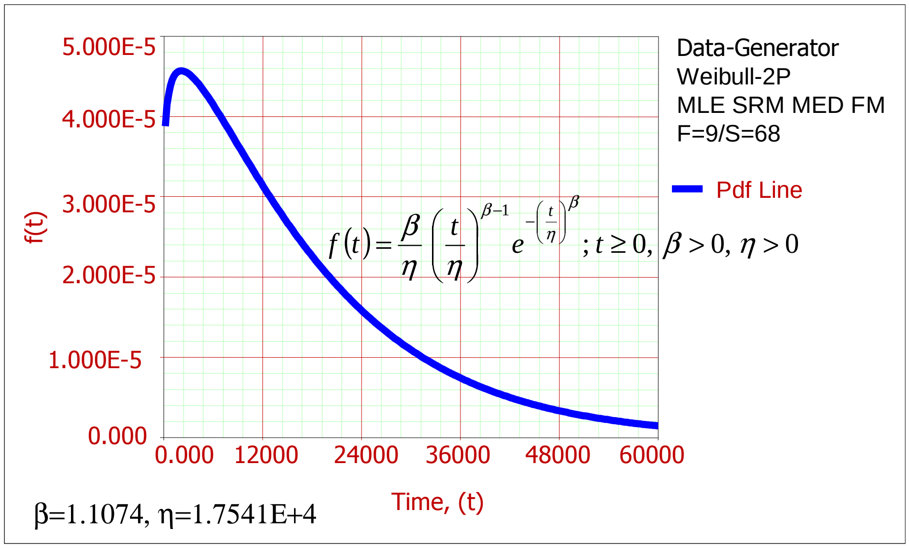


Figure 6.11 Generator pdf plot

The failure rate plot of the generator in figure 6.12 shows a horizontal line which explains the randomness of the failure characteristics of the generator. Note that the estimated mean time between failures of the generator is 16888 days.

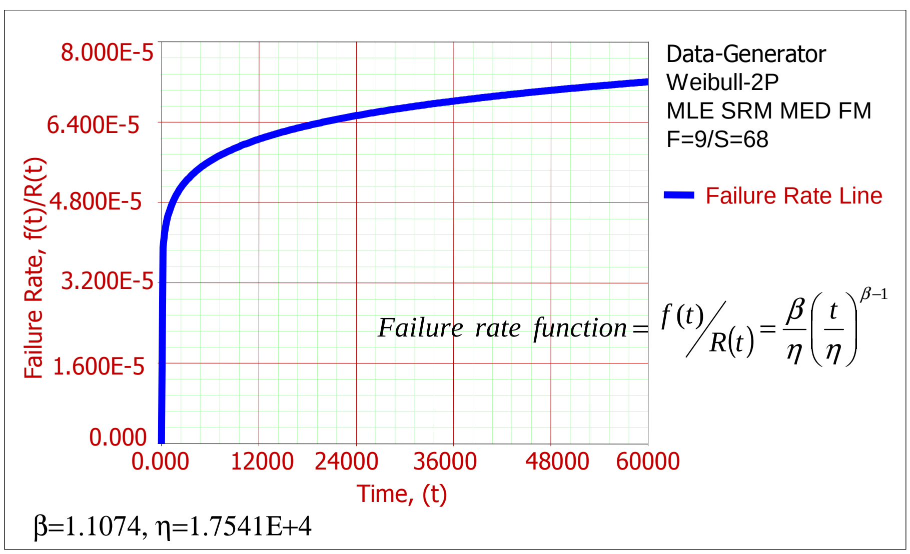


Figure 6.12 Generator failure rate plot

6.4 A CASE STUDY

This section presents a case study to demonstrate the practical application of the estimated β and η values to determine and optimise maintenance activities for the critical components and subsystems of the 600 kW wind turbine.

6.4.1 Reliability Trend of Critical Components of the 600 kW Wind Turbine

Table 6.12 presents the reliability trend of the critical components of the 600 kW wind turbine over a period of 20 years. The table shows the upper and the lower limits of the reliabilities at 95% confidence bound. The reliability of the main-shaft reduces from 0.98 in the first year to about 0.30 at the end of the 20 years life-cycle. The lower limit of the reliability reduces significantly from 0.93 in the first year to 0.25 in the 9th year and subsequently to about 0.01 at the end of the 15th year.

On the other hand, the reliability of the main bearing reduces from 0.93 in the first year to about 0.53 in the 7th year and further degenerates to about 0.13 at the end of the 20 years life-cycle. The lower limit reduces from 0.86 in the first year to 0.00 at end of the 15th year. The gearbox appears to be more reliable than any of the other subsystems in the first year with a reliability of 1. However, this reduces drastically to about 0.66 at the end of the 7th year and further degenerates to 0.29 and 0.00 in the 11th and the 20th year respectively. The lower limit of the reliability reduces to 0.15 and 0.00 in year 10 and 14 respectively. The reliability of the generator reduces from 0.99 in the first year to 0.35 and 0.01 in the 9th and 18th year respectively. The lower limit deteriorates to 0.00 in the 16th year from 0.97 in the first year.

Figure 6.13 shows the reliability trend of the critical components. Assuming a reliability of 0.95 is desired as a minimum threshold, it is worth noting that the components (main bearing, main shaft, gearbox and the generator) will fall below this target in year 3, 1, 4 and 3 respectively, given the current failure behaviour and the maintenance strategy employed.

Table 6.6 Reliability trend for critical subsystems of a 600 kW wind turbine

	Year	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Main Shaft	Reliability	0.98	0.96	0.92	0.89	0.85	0.80	0.76	0.72	0.68	0.64	0.60	0.56	0.52	0.48	0.45	0.41	0.38	0.35	0.33	0.30
	Upper	1.00	0.98	0.96	0.94	0.93	0.92	0.91	0.90	0.90	0.89	0.89	0.88	0.88	0.87	0.87	0.86	0.86	0.86	0.85	0.85
	Lower	0.93	0.89	0.84	0.77	0.67	0.57	0.45	0.35	0.25	0.17	0.11	0.07	0.04	0.02	0.01	0.01	0.00	0.00	0.00	0.00
Main bearings	Reliability	0.93	0.85	0.78	0.71	0.64	0.58	0.53	0.48	0.43	0.39	0.35	0.31	0.28	0.25	0.23	0.21	0.18	0.17	0.15	0.13
	Upper	0.96	0.91	0.87	0.84	0.82	0.80	0.78	0.76	0.75	0.74	0.72	0.71	0.70	0.69	0.68	0.67	0.66	0.65	0.65	0.64
	Lower	0.86	0.75	0.62	0.49	0.37	0.27	0.19	0.13	0.08	0.05	0.03	0.02	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00
Gearbox	Reliability	1.00	0.98	0.95	0.90	0.83	0.75	0.66	0.56	0.46	0.37	0.29	0.21	0.15	0.11	0.07	0.04	0.03	0.02	0.01	0.00
	Upper	1.00	0.99	0.98	0.94	0.89	0.83	0.76	0.70	0.64	0.59	0.54	0.49	0.45	0.40	0.36	0.33	0.29	0.26	0.24	0.21
	Lower	0.98	0.94	0.89	0.82	0.75	0.65	0.52	0.39	0.26	0.15	0.08	0.03	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Generator	Reliability	0.99	0.96	0.91	0.83	0.75	0.65	0.54	0.44	0.35	0.27	0.20	0.14	0.10	0.07	0.04	0.03	0.02	0.01	0.01	0.00
	Upper	1.00	0.98	0.95	0.89	0.82	0.73	0.63	0.54	0.46	0.38	0.32	0.26	0.21	0.17	0.14	0.11	0.08	0.07	0.05	0.04
	Lower	0.97	0.91	0.84	0.75	0.65	0.55	0.45	0.34	0.25	0.17	0.11	0.06	0.03	0.02	0.01	0.00	0.00	0.00	0.00	0.00

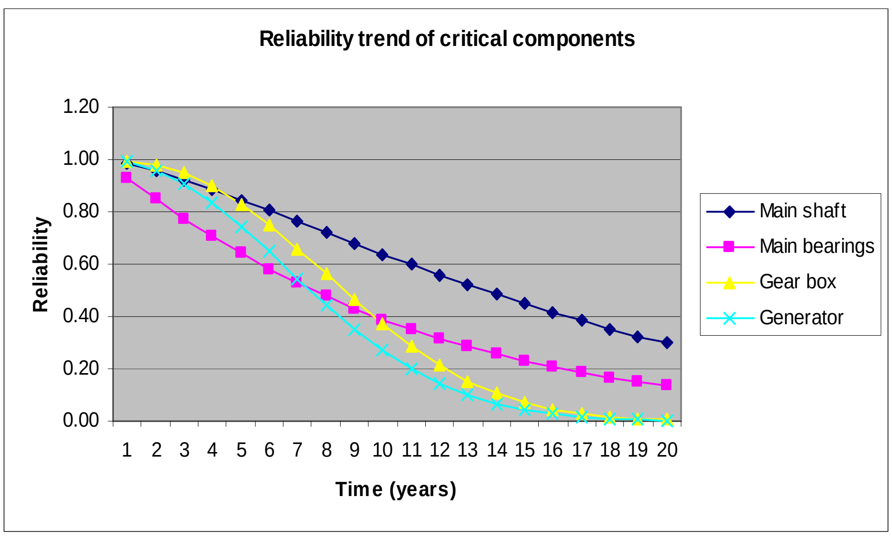


Figure 6.13 Reliability Trends of Critical Components over a 20 year Life-Cycle

6.4.2 Maintenance Optimisation

A *Condition-based maintenance (CBM)* strategy is suitable for components or subsystems with a *random failure pattern* (β=1) if identifiable and measurable warning signs exist to assess the actual conditions of incipient failures, and the availability of reasonable time to take proactive action to prevent the failures from escalating to catastrophic events. Therefore, where there are no identifiable and/or measurable warning signs, and/or the lack of reasonable time to take proactive action such as components with very short P-F interval, CBM will not apply. Moreover, CBM is not applied to components or subsystems with a random failure pattern if failure consequences will not result in revenue losses, customer's dissatisfaction or health, safety and environmental impact. *Time-based (TBM)* is suitable for components or subsystems exhibiting *wear-out failure pattern* (i.e. $\beta>1$) while *Failure-based (FBM)* (corrective actions performed upon failure of the component or subsystems) is appropriate for components and subsystems with negligible failure consequences.

Thus, given the failure patterns of the components and subsystems of the 600 kW wind turbine in table 6.5, and their failure consequences in table 5.5, Condition-Based Maintenance is the most suitable strategy to maintain the main bearing, gearbox and the generator. The strategy enables early detection of incipient failures that can potentially cause catastrophic failure of the subsystems. *Time-based* as well as *corrective actions based on unanticipated failures* are suitable for the gear wheels and the main shaft.

Recall that Time-Based and Failure-Based Maintenance are the strategies commonly adopted by wind farm operators to maintain wind turbines. In chapter 5, we established that these strategies are not adequate to meet the current maintenance requirement of the wind industry. In the next subsection we will re-assess the suitability of the TBM tasks using quantitative optimisation technique.

6.4.3 Optimisation of Time-Based Maintenance Tasks

We have seen in the previous section that the gearwheels and the IMS bearing of the gearbox exhibit a wear out failure pattern, and that time-based maintenance is appropriate for these components. In this subsection we will determine the optimum cost and time to carry out the TBM task. Furthermore, the suitability of TBM tasks for the other components and subsystems will be assessed.

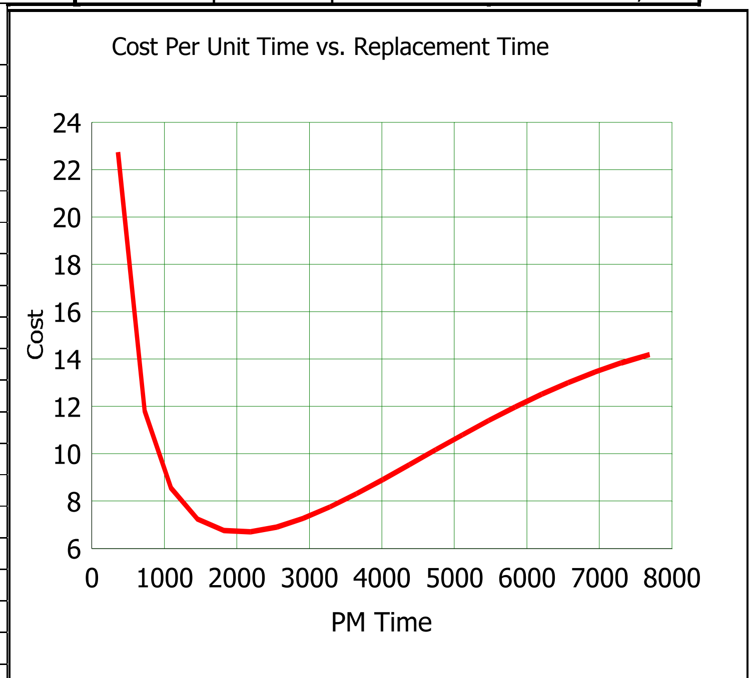
6.4.3.1 The Gear Wheels

In chapter 3, we had explained the concept of maintenance optimisation to denote the best possible balance between costs/risks/performance (figure 3.1). In chapter 5, the failure consequences or unplanned replacement of critical components and subsystems of the 600 kW wind turbine were determined and presented in table 5.5. The cost of planned replacement of gear wheels is given in chapter 8, table 8.2. Using this information the optimal time and cost are determine and the result is presented in figure 6.14.

Start Time:	365
Increment:	365

Cost for planned replacement:	£8,182
Cost for unplanned replacement:	£78,468

Time Units	Cost/Unit Time
365	22.62287
730	11.79035
1095	8.53828
1460	7.23868
1825	6.75484
2190	6.70032
2555	6.90344
2920	7.27316
3285	7.75424
3650	8.30936
4015	8.91100
4380	9.53755
4745	10.17125
5110	10.79719
5475	11.40279
5840	11.97761
6205	12.51323
6570	13.00333
6935	13.44363
7300	13.83189
7665	14.16780



Minimum point = 6.7003

Figure 6.14 Gearwheels Optimum Replacement

The minimum point on the curve is at 6.7003, this represents the optimal point. The optimal cost per unit time is £6.7003 and the optimal interval is at 2190 days i.e. 6 years. For the purposes of comparison, the cost of PM must be reduced to a common unit such as cost/year. Thus, the PM cost/year at the optimal point is the product of the cost per unit time (i.e. 6.7003) and the number of days in a year (i.e. 365) to give £2,445.61 as the optimum cost/year of the PM task. In table 6.5, the estimated Mean

Time Between Failures (MTBF) for the gearwheels is 5070 days. The PM tasks are often scheduled at the MTBF, however we need to determine the cost/year at this period and compare it with the optimal point. Measuring from figure 6.14, the unit cost at 5070 days is about £10.8679. Thus, the PM cost/year at the MTBF is about £3,966.78. This is about 62% higher than the cost/year at the optimum interval. Alternatively, about £1,521.17 will be saved per PM task if it is carried out at the optimum interval.

6.4.3.2 The Intermediary Speed Shaft Bearing

Figure 6.15 shows the optimised Time-Based Maintenance task for the intermediary Speed Shaft Bearing of the gearbox. The cost of planed replacement of the IMS bearing is about £2,742 (Chapter 8, Table 8.2) and the failure consequences is about £78,468 (Chapter 5, Table 5.5).

Start Time:	365	Cost for planned replacement:	£2,742
Increment:	365	Cost for unplanned replacement:	£78,468

Time Units	Cost/Unit Time
365	7.53192
730	3.87734
1095	2.85601
1460	2.62649
1825	2.84222
2190	3.39856
2555	4.25152
2920	5.36996
3285	6.71743
3650	8.24388
4015	9.88252
4380	11.55136
4745	13.15962
5110	14.61889
5475	15.85715
5840	16.83193
6205	17.53757
6570	18.00296
6935	18.28003
7300	18.42757
7665	18.49720

Minimum point = 2.62649

Figure 6.15 IMS Bearings Optimum Replacement

The minimum value on the curve in figure 6.15 is about 2.62649; this represents the optimal replacement cost per unit time. The optimum time is about 1460 days i.e. 4 years. Thus, the optimal PM cost/year is the product of the optimal cost i.e. £2.62649 and the number of days in a year (365) to give £958.69. The estimated MTBF of the IMS bearing is 4232 days (Table 6.5). The cost per unit time at the MTBF is about 10.42156, thus the cost/year of PM at the MTBF is about £3,803.87. Carrying out the PM task at the optimum time will save about £2,845.18 per PM task.

6.4.3.3 The Main Shaft

Figure 6.16 shows no optimum cost and interval for performing PM task on the main shaft.

Start Time:	365	Cost for planned replacement:	£12,885
Increment:	365	Cost for unplanned replacement:	£29,114

Time Units	Cost/Unit Time
365	36.29810
730	18.98762
1095	13.35339
1460	10.61503
1825	9.02437
2190	8.00153
2555	7.29934
2920	6.79491
3285	6.42041
3650	6.13540
4015	5.91432
4380	5.74026
4745	5.60160
5110	5.49013
5475	5.39985
5840	5.32632
6205	5.26618
6570	5.21684
6935	5.17627
7300	5.14288
7665	5.11540

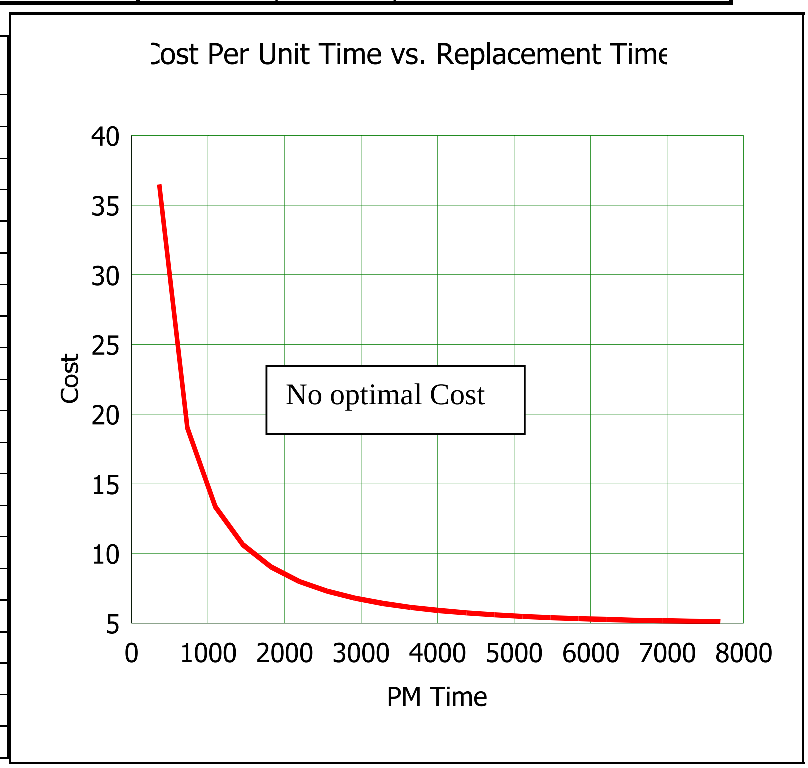


Figure 6.16 Main Shaft Optimum Replacement

The shape parameter (β) for the main bearing in table 6.5 and the failure rate plot in figure 6.3 show that the main shaft failure characteristic is neither a complete random failure pattern nor a complete wear out as indicated by the constantly increasing failure pattern. The cost for planned replacement of the main shaft is about £12,885 (Chapter 8, Table 8.2) while the cost for unplanned replacement or the consequences of failure is £29,114 (Chapter 5, Table 5.6). The cost per unit time decreases continuously as time increases. This means that PM task is not suitable for maintaining the main shaft of the 600 kW wind turbine.

6.4.3.4 The Main Bearing

Figure 6.17 shows no optimum cost and interval for performing PM task on the main bearing.

Start Time:	365	Cost for planned replacement:	£10,763
Increment:	365	Cost for unplanned replacement:	£22,374

Time Units	Cost/Unit Time
365	33.02744
730	18.52287
1095	13.76032
1460	11.41797
1825	10.03768
2190	9.13540
2555	8.50448
2920	8.04203
3285	7.69109
3650	7.41764
4015	7.20008
4380	7.02410
4745	6.87980
5110	6.76016
5475	6.66002
5840	6.57556
6205	6.50384
6570	6.44259
6935	6.39004
7300	6.34475
7665	6.30558

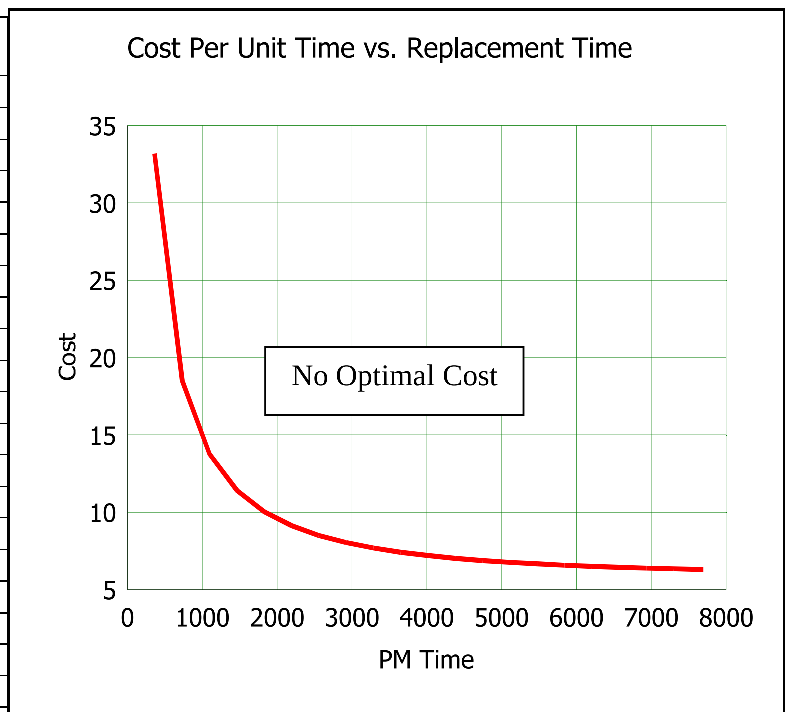


Figure 6.17 Main Bearing Optimum Replacement

The shape parameter of the main bearings in table 6.5 and the failure rate plot in figure 6.6 show the random failure pattern of the main bearing. Recall that PM tasks are not suitable for components or subsystems which exhibits random failure pattern if there is an identifiable warning signs that can be measured to assess the actual condition of incipient failures and the availability of reasonable time to take proactive action to prevent the failures from escalating to catastrophic events. The cost for planned replacement of the main bearing is 10,763 (Chapter 8, Table 8.2) while the cost for unplanned replacement or the consequences of failure is £22,374 (Chapter 5, Table 5.6). The cost per unit time decreases continuously as the time increases. This means that PM task is not suitable for maintaining the main bearing of the 600 kW wind turbine.

6.4.3.5 The Gearbox HSS Bearing

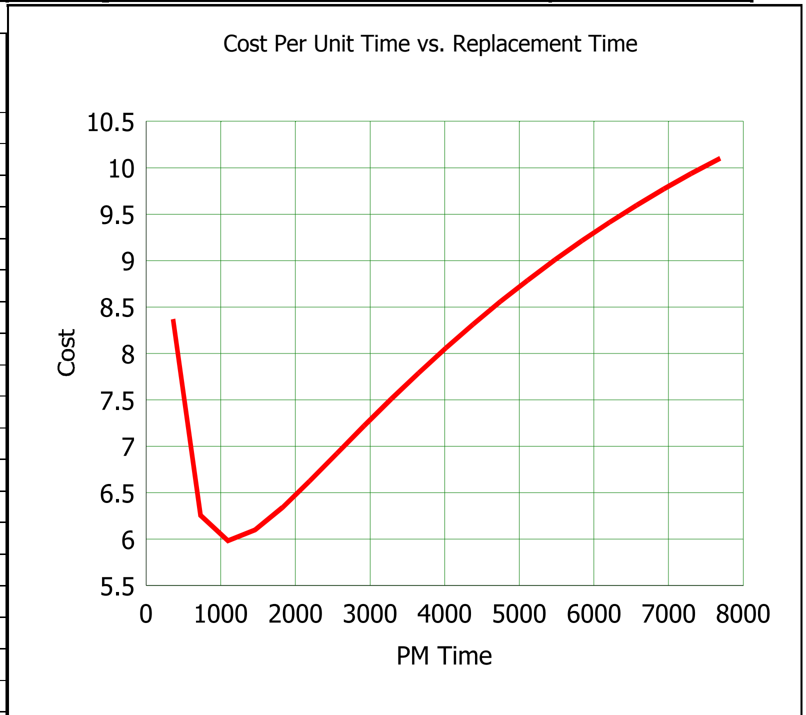
The estimated shape parameter (β) of the gearbox high speed shaft bearing is 1.52. This is neither a complete random nor a wear out failure pattern but a constant increasing failure rate plot. The cost for planned replacement of the HSS bearing is given in chapter 8, table 8.2 and the cost for unplanned replacement or consequences of failure of the bearing in chapter 5, table 5.6. Using this information the optimisation graph is plotted as shown in figure 6.18.

The minimum point on the graph in the figure is 5.9834474. This represents the optimal cost per unit time, and the optimal interval is at 1095 days (3 years). The optimal cost/year is determined by multiplying the optimal cost per unit time (5.9834) and the number of days in a year (365) to obtain £2,183.94. In table 6.5, the estimated MTBF of the HSS bearing is 6,528 days.

Thus, the cost per unit time at the MTBF is 9.9009. Multiplying the cost per unit time at the MTBF and the number of days in a year (365) will give £3,613.83 cost/year at MTBF. By carrying out the PM task at the optimal interval will save the sum £1,429.89/PM task.

Start Time:	365	Cost for planned replacement:	£2,230
Increment:	365	Cost for unplanned replacement:	£78,468

Time Units	Cost/ Unit Time
365	8.344
730	6.257
1095	5.983
1460	6.099
1825	6.340
2190	6.625
2555	6.923
2920	7.220
3285	7.510
3650	7.790
4015	8.058
4380	8.314
4745	8.557
5110	8.788
5475	9.007
5840	9.215
6205	9.411
6570	9.596
6935	9.771
7300	9.935
7665	10.09



Minimum = 5.9834474

Figure 6.18 Gearbox HSS Bearing Optimum Replacement

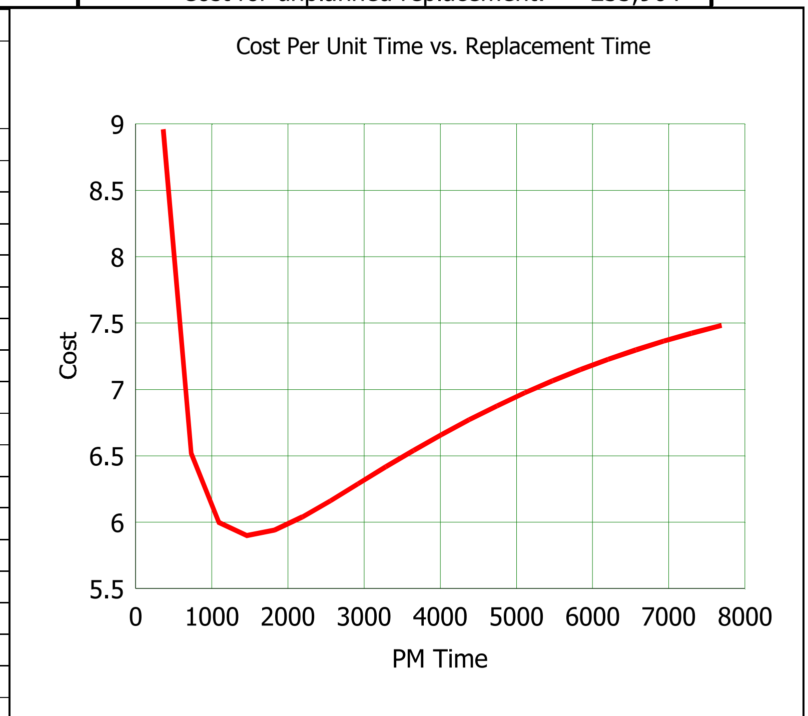
It is worth noting however, that the gearwheels, the IMS and HSS bearings are components within a gearbox, and the gearbox failure is characterised by a random failure pattern as indicated by the estimated shape parameter and the failure rate plot in table 6.5 and figure 6.9 respectively. The gearbox is a repairable subsystem with a number of components, thus the failure characteristic of the subsystem in this case will override the PM tasks for the individual components because of the random pattern of failure.

6.4.3.6 The Generator bearing

Figure 6.19 shows the optimisation plot for the generator bearing. The minimum point on the curve in the figure is 5.89848 which represent the optimal cost per unit time. The optimal interval for performing the PM task is 1460 days (4 years). The optimal cost/year is £2,152.77. The estimated MTBF of the generator bearing is 4524 days (table 6.5); the cost per unit time at the MTBF is 6.9936. The cost/year for doing the PM task at the MTBF is £2552.67.

Start Time:	365	Cost for planned replacement:	£2,332
Increment:	365	Cost for unplanned replacement:	£35,964

Time Units	Cost/ Unit Time
365	8.941
730	6.51
1095	5.997
1460	5.898
1825	5.941
2190	6.039
2555	6.160
2920	6.288
3285	6.416
3650	6.541
4015	6.659
4380	6.771
4745	6.876
5110	6.974
5475	7.065
5840	7.149
6205	7.226
6570	7.298
6935	7.363
7300	7.423
7665	7.478



Minimum = 5.89848

Figure 6.19 Generator Bearing Optimum Replacement

6.5 SUMMARY

This chapter has analysed the collected field failure and maintenance data of 600 kW wind turbines. The failure and maintenance data was collected from 27 wind farms located in the same geographical region. The Maximum Likelihood Estimation (MLE) was used to determine the shape and scale parameters of the Weibull distribution for critical components and subsystems of the wind turbines. ReliaSoft Weibull ++7 software was used in the analyses. The Weibull probability plots, probability density function (pdf) plots and the failure rate plots were generated for the critical components and subsystems of the wind turbines.

A case study was undertaken to demonstrate the practical application of the estimated β and η values to determine and optimise maintenance activities for the critical components and subsystems of the 600 kW wind turbine. The main bearing and shaft of the wind turbine have no optimal cost and interval to carry out PM tasks. The optimal interval for performing PM task on the gearwheels, IMS bearing and the HSS bearing of the gearbox of the 600 kW wind turbine are 2190, 1460 and 1095 days respectively while the optimal cost/year are £2,445, £958 and £2,183 respectively. Similarly, the optimal interval and cost/year for performing PM task on the bearing of the generator are 1460 days and £2152 respectively. The gearbox and the generator are repairable subsystems of the wind turbine with estimated shape parameters of 1.09 and 1.11 respectively. Thus the random pattern of failures of the subsystems will not allow effective implementation of the PM tasks for the components as PM will not be suitable for the subsystems.

CHAPTER 7

MODELLING WIND TURBINE FAILURES TO OPTIMISE MAINTENANCE

7.1 INTRODUCTION

The shape and scale parameters of critical components and subsystems of the 600 kW wind turbines were estimated in chapter 6. The parameters were further used to determine appropriate maintenance tasks for the components and subsystems of the turbine. This chapter present a case study to model and assess the Reliability, Availability and Maintainability (RAM) of the 600 kW wind turbine and the 26 x 600 kW wind farm. The estimated values of β and η (chapter 6, table 6.5) of each component within a subsystem of the 600 kW wind turbine will be used to populate the *BlockSim* of the 'ReliaSoft BlockSim-7' simulation software to model the failures of the subsystem. The β and η values of each subsystem of the 600 kW wind turbine will be used to populate the BlockSim to model the failures of the wind turbine. The model of the wind turbine is then used to model the failure characteristics of the wind farm. *Monte Carlo simulation* is used by the 'ReliaSoft BlockSim-7' software to assess the RAM of the wind turbine and the wind farm; taking into account the costs and availability of maintenance crew and spare holdings.

7.2 Modelling Failures of the 600 kW Wind Turbine

A failure model of a typical gearbox in the 600 kW horizontal axis wind turbine is shown in Figure 7.1. The components (represented by Reliability Block Diagrams) are connected in *series*, that is, the function of each component is dependent on the functionality of the other components. Conversely, failure of a component within the subsystem will result to the subsystem's breakdown. The estimated β and η values of each component are incorporated into the Reliability Block diagrams (RBD).

Note that any component which failure data was not available has been set to '*block cannot fail*' in the models. This is to avoid subjective and illogical assumptions about the components, and to ensure the modelling is based solely on field failure data. The incorporated β and η values of the gear wheels, key ways, intermediary speed shaft (IMS) and high speed shaft (HSS) bearings are shown in the figure. The complete reliability equation of the gearbox model is shown in Equation 7.1.

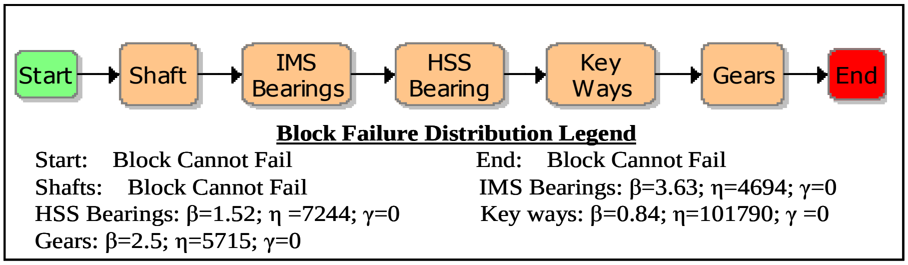


Figure 7.1 Gearbox Failure Model

$$R_{Gearbox} = R_{Shaft} \cdot R_{IMS\ Bearings} \cdot R_{Key\ Ways} \cdot R_{HSS\ Bearing} \cdot R_{Gears} \quad \ldots \qquad (7.1)$$

Where, R= Reliability

Failure model of generators within the 600 kW wind turbines is shown in Figure 7.2. The components; stator winding, bearing, rotor, etc are connected in *series*. The incorporated β and η values of the stator windings and the bearings are shown in the figure. The complete reliability equation of the generator's model is presented in Equation 7.2.

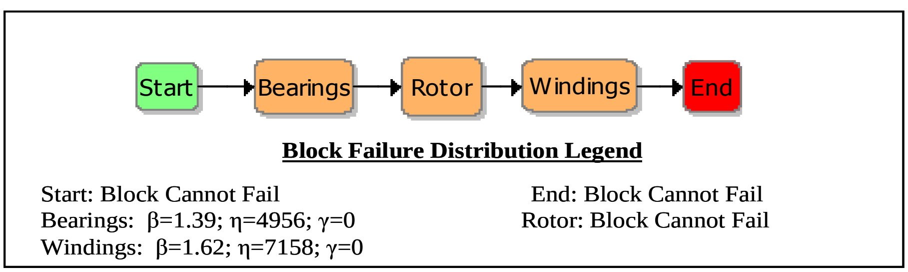


Figure 7.2 Generator Failure Model

$$R_{Generator} = R_{Windings} \cdot R_{Bearings} \cdot R_{Rotor} \quad \ldots \qquad (7.2)$$

Where, R= Reliability.

Figure 7.3 shows the failure model of the 600 kW wind turbine. The figure shows the RBD of key subsystems and their estimated values of β and η. The blades of the turbine are connected in *parallel* as they operate independently. However, all the blades must be in good operating condition before the wind turbine can function. This operating condition is depicted in the *3-out of-3* node (*3oo3*) shown in the figure 7.3. Similar condition applies to the main bearings which require a *2-out of-2*. The operating condition of the mechanical and aerodynamic brakes are however different, one of the brake is enough to stop the turbine (i.e. *1-out of-2*). Safety requirements demand a *2-out of-2* to avoid failures related to over speeding of the turbine. These parallel arrangements are connected in series to the other subsystems of the wind turbine. The appropriate β and η values of each component and subsystem are incorporated in the model. The *start* and *end* blocks as well as the *connecting nodes* are set to *'block cannot fail'*.

The gearbox and the generator models in figures 7.1 and 7.2 respectively are incorporated to represent the gearbox and the generator in the wind turbine's failure model shown in the figure 7.3. The incorporated values of β and η of each subsystem are shown in the figure. The complete reliability equation of the wind turbine's model is presented in Equation 7.3.

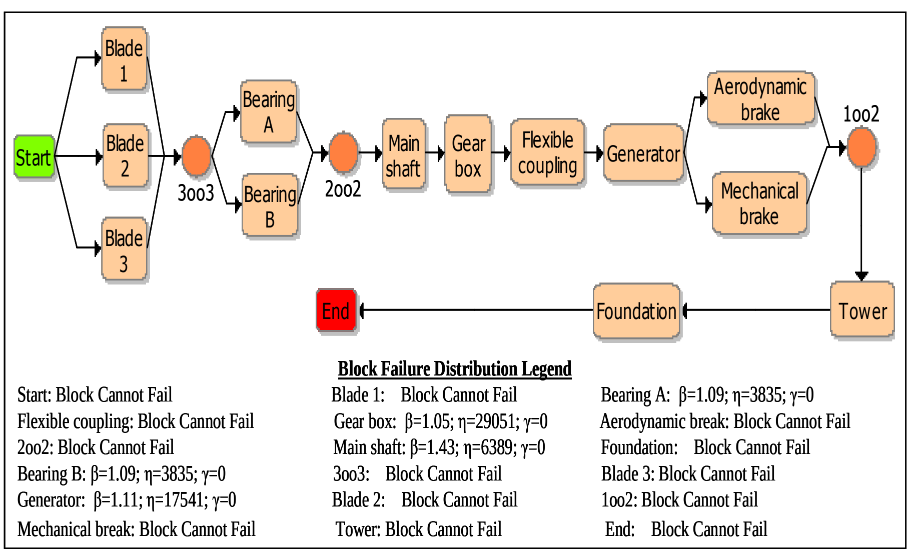


Figure 7.3 Failure Model of 600 kW Wind Turbine

$$R_{Turbine} = (R_{Mian\ Shaft} \cdot R_{Gearbox} \cdot R_{Flexible\ coupling} \cdot R_{Tower} \cdot R_{Foundation} (R_{3oo3} (R_{Blade\ 1}^{3})) (R_{2oo2} (R_{Bearing\ A}^{2})) (R_{Generator} \cdot R_{1oo2} (2R_{Mechanical\ Brake} - R_{Mechanical\ Brake}^{2})))... \quad (7.3)$$

Where,

R= Reliability

$R_{Blade\ 1}=R_{Blade\ 2}=R_{Blade\ 3}$

$R_{Bearing\ A}=R_{Bearing\ B}$

$R_{Aerodynamic\ brake} =R_{Mechanical\ Brake}$

The failure model of the 26 x 600 kW wind farm is shown in Figure 7.4. Each of the Reliability Blocks (numbered 1-26) represent one of the 26 wind turbines in the farm. All the 26 turbines are a replica of the 600 kW wind turbine failure model presented in figure 7.3. Generally, wind turbines operate independently in a wind farm, that is, failure of a wind turbine on a wind farm does not affect the operation of the other turbines on the farm. This operational independency of the wind turbines is depicted in the *parallel* connection of the blocks in the wind farm model as shown in the figure 7.4. The 1-out of-26 (i.e. *1oo26)* operating condition represents the autonomy of each wind turbine on the wind farm.

7.3 600 kW Wind Turbine Model Assessment

The reliability, availability and maintainability (RAM) of the wind turbine is assessed over a period of 4 years; taking into account the costs and availability of maintenance crew and spares holding. The '4 years' is a short term economic analysis period required by the collaborating wind farm operator. Recall that *CBM strategy (i.e. corrective maintenance based on inspection)* is suitable for components or subsystems with a *random failure pattern* (i.e. β=1) if there is an identifiable and measurable warning signs that permit the assessment of the actual conditions of incipient failures and the availability of reasonable time to take proactive action to prevent the failures from escalating to catastrophic events.

Tables 7.1, 7.2 and 7.3 show the current spare pool policy, corrective maintenance crew policy, and inspection and preventative maintenance (PM) crew policy respectively. Note that tables 7.2 and 7.3 are developed based on a discussion with the collaborating wind farm operators to initiate the process of quantitative maintenance optimisation. The detailed breakdown of the *direct cost per item* in table 7.1 and the *failure consequences* in table 7.2 are given in Chapter 5, Section 5.3.2. The current spare pool policy and the maintenance crew policies were used to populate the appropriate RBD of the wind turbine's model.

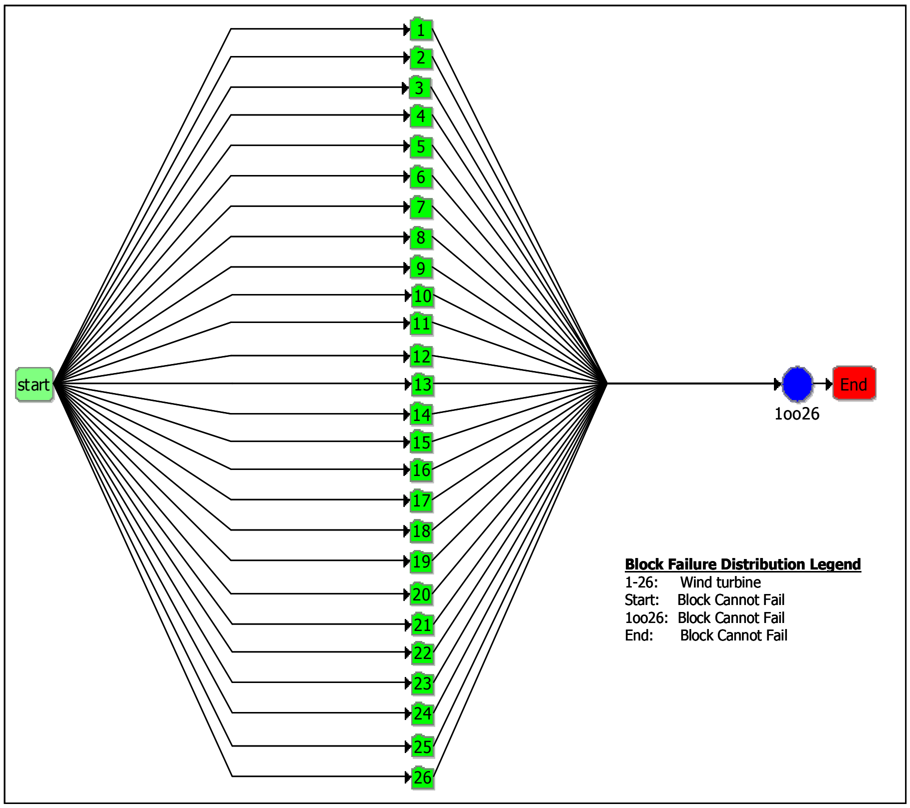


Figure 7.4 Failure Model of the 26 x 600 kW Wind Farm

Table 7.1 Current Spare Pool Policy

Subsystem	Direct cost per item (£)	Indirect cost (£)	Initial stock level	Restock when stock level drops to	Number of stock to be added	Total Initial stock cost (£)
Mean bearings	9,851	100	4	2	2	39804
Main shaft	11,133	100	2	1	1	22466
Gear box	61,687	100	1	0	1	61787
Generator	23,441	100	2	1	1	47082

Note the indirect cost in the Table 7.1 is the cost of keeping an item in a spare pool measured per annum.

Table 7.2 Crew Policy for Corrective Maintenance

Subsystem	Repair Distribution	Parameters (days)	Crew A (Person)	Labour cost/ hour (£)	Work hours/ day	Tasks crew can perform at the same time	Labour Cost per incident (£)	Failure Consequence (£)
Mean bearings	Normal	μ = 2 σ = 1	3	50	8	1	2,400	22,375
Main shaft	Normal	μ = 4 σ = 1	3	50	8	1	4,800	29,114
Gear box	Normal	μ = 3 σ = 1	3	50	8	1	3,600	78,468
Generator	Normal	μ = 2 σ = 1	3	50	8	1	2,400	35,964

Table 7.3 Crew Policy for Inspection and Preventative Maintenance

Subsystem	Task	Fixed interval (days)	Crew A (Person)	Labour cost/ hour (£)	Task duration (hours)	Tasks crew can perform at the same time	Labour Cost per incident (£)	Cost of crane per hour (£)	Direct cost of crane (£)	Total cost of task (£)
Mean bearings	CBM (Inspection)	180	3	50	1.33	1	200	300	399	599
Main shaft	TBM (PM)	365	3	50	1.33	1	200	300	399	599
Gearbox	CBM (Inspection)	180	3	50	2	1	300	300	600	900
Generator	CBM (Inspection)	180	3	50	1.6	1	240	300	480	720

The wind turbine model is populated with the information in the tables, and then simulated over a period of fours years. The simulations start from 0 to 365, 730, 1095 and 1460 days respectively. The wind turbine and its subsystems up/downtime trend are shown in Figure 7.5. The subsystems uptime is relatively consistent over the 4 year period; given the defined maintenance strategy, crew and spare pool availability. The overview result and the cost summary are shown in Tables 7.4 and 7.5 respectively. The mean availability (all events) of the wind turbine in the first and the fourth year are 97% and 98% respectively. The total down time increases from about 10 days in the first year to about 27 days in the fourth year. The total costs increases from £180,912 in the first year to about £208,758 in the fourth year. The break down of the total cost is shown in table 7.5. It is evident that the spare pool costs constitute the greater percentage of the total costs.

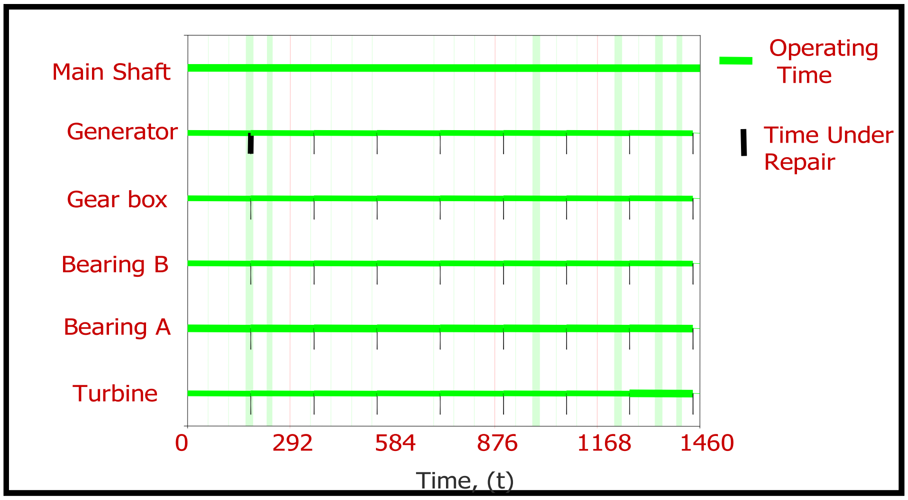


Figure 7.5 Wind Turbine and Subsystems up/down

Table 7.4 Wind Turbine Overview result

System Overview	Year 1	Year 2	Year 3	Year 4
General				
Mean Availability (All Events):	0.97	0.98	0.98	0.98
Std Deviation (Mean Availability):	0.09	0.06	0.04	0.04
Mean Availability (w/o PM & Inspection):	0.97	0.98	0.98	0.98
Point Availability (All Events):	1	1	1	1
Reliability:	0.88	0.79	0.74	0.67
Expected Number of Failures:	0.13	0.23	0.29	0.39
Std Deviation (Number of Failures):	0.35	0.47	0.52	0.60
MTTFF:	2787	3134	3615	3640
System Uptime/Downtime				
Uptime:	355	713	1075	1433
CM Downtime:	0	1	1	1
Inspection Downtime:	0	0	0	1
PM Downtime:	0	0	0	0
Total Downtime:	10	17	20	27
System Downing Events				
Number of Failures:	0	0	0	1
Number of CMs:	0	1	1	1
Number of Inspections:	2	4	6	8
Number of PMs:	0	0	0	0
Total Events:	2	5	7	10
Costs				
Total Costs:	180,912.16	191,029.01	199,886.83	208,758.54

7.4 Wind Farm Model Assessment

The wind farm's up/downtime trend is shown in Figure 7.6. At 44 days, some wind turbines failed which brought the wind farm into a non-full operating time. The non-full operating time is as a result of repairs of failed turbines and/or delays waiting for crew/spare parts. In this case, the maintenance crew can only perform one task at a time, hence resulting in the long delay. Similar non-full operating times are recorded at 308, 902 and 1099 days respectively.

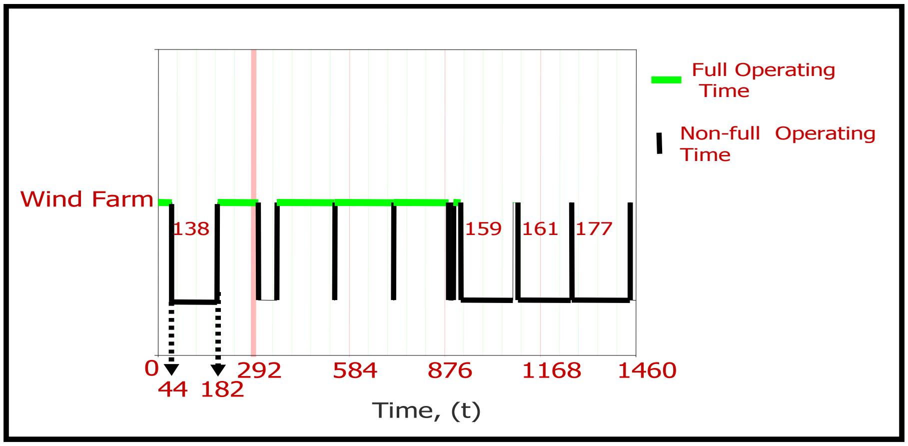


Figure 7.6 Wind Farm up/downtime trend

Tables 7.5, 7.6, 7.7 and 7.8 show the overview result, cost summary, crew costs summary and spare pool cost summary of the wind farm respectively. The mean availability *A (t)* of the farm at the end of the first and the fourth year are 46% and 40% respectively. The reliability of the wind farm in the first and the fourth year are 0.02 and 0 respectively. The mean time to functional failure (MTTFF) decreases from 90 days in the first year to about 87 days in the 4^{th} year. The total down time increases from 196 days in the first year to about 877 days in the 4^{th} year.

The number of failure resulting to downing of the wind farm increases from 2 events in the first year to about 7 events in the 4^{th} year. The total cost of managing the farm as the results the maintenance strategies in the first and the 4^{th} year are £376,246 and £1,006,068 respectively. The *spare pool costs* (i.e. overall costs of keeping the spares in the pool) are added to the total corrective maintenance (CM) costs and inspection costs to obtain the total costs of the strategies in each year (see table 7.6).

Table 7.5 Wind Farm Overview Result

System Overview	Year 1	Year 2	Year 3	Year 4
General				
Mean Availability (All Events):	0.46	0.43	0.42	0.40
Std Deviation (Mean Availability):	0.25	0.20	0.17	0.16
Mean Availability (w/o PM & Inspection):	0.46	0.43	0.42	0.40
Point Availability (All Events):	0.90	0.78	0.68	0.57
Reliability:	0.02	0.00	0.00	0.00
Expected Number of Failures:	2	4	5	7
Std Deviation (Number of Failures):	1	1	1	2
MTTFF:	90	90	90	87
System Uptime/Downtime				
Uptime:	169	316	457	583
CM Downtime:	4	7	11	14
Inspection Downtime:	0.16	0.31	0.45	0.57
PM Downtime:	0	0	0	0
Total Downtime:	196	414	638	877
System Downing Events				
Number of Failures:	2	4	5	7
Number of CMs:	2	3	5	6
Number of Inspections:	3	6	10	12
Number of PMs:	0	0	0	0
Total Events:	7	13	20	25
Costs				
Total Costs:	376,246.42	592,209.73	809,132.55	1,006,068.97

Table 7.6 Wind Farm Cost summary

System Cost Summary	Year 1	Year 2	Year 3	Year 4
Misc. Corrective Costs:	46,985.86	89,071.99	131,930.76	170,188.67
Costs for Parts (CM):	24,095.69	45,245.73	66,223.59	85,569.96
Costs for Crews (CM):	4,248.77	8,155.32	12,152.62	15,599.70
Total CM Costs:	75,330.33	142,473.05	210,306.97	271,358.33
Misc. Preventive Costs:	0	0	0	0
Costs for Parts (PM):	0	0	0	0
Costs for Crews (PM):	0	0	0	0
Total PM Costs:	0	0	0	0
Misc. Inspection Costs &	129,777.10	257,595.69	384,000.58	508,334.64
Costs for Crews (IN):				
Total Inspection Costs:	129,777.10	257,595.69	384,000.58	508,334.64
Spare Pool Costs:	171,139.00	192,141.00	214,825.00	226,376.00
Total Costs:	376,246.42	592,209.73	809,132.55	1,006,068.97

Table 7.7 shows the maintenance crew summary. The numbers of calls made to the crew in each year, the accepted and rejected calls, the time used to repair the failures

as well as the total costs of the crew are shown in the table. For example, a total of 15 and 31 calls were made to the crew in the 1st and the 4th year out of which 6 and 12 calls were accepted and, 9 and 19 calls were rejected respectively, given that, the crews can only work on one job at a time. A total of about 4 and 14 days were used to attend to the calls at the cost of £4,248 and £15,599 respectively.

Table 7.7 Wind Farm Crew summary

	Maintenance Crew Summary					
Period	**Crew Policy**	**Calls**	**Accepted**	**Rejected**	**Time Used**	**Cost**
Year 1	Crew A	15	6	9	3.86	4,248.77
Year 2	Crew A	18	13	5	7.44	8,155.32
Year 3	Crew A	23	10	13	11.16	12,152.62
Year 4	Crew A	31	12	19	14.39	15,599.70

The summary of the spare parts re-supplied to the pools of each subsystem consumed are shown in Table 7.8. Average Stock Level (ASL) and item dispensed of each of the subsystems are indicated in columns 3 and 4 of the table respectively. For example, 1 bearing was dispensed to carry out repairs in the first year, reducing the ASL in spare pool of bearings to 3. The indirect cost of spares (the cost of keeping the item in the spare pool per annum) is added to the direct cost per item to obtain the total cost of each spare.

Table 7.8 Wind Farm Spare Pool Summary

Period	Pool	ASL	Items Dispensed	Cost Per Item	Total Cost	Total Annual Cost
	Spare Pool gearbox	1	0	61,687	61,787.00	
	Spare Pool Shaft	2	0	11,133	22,466.00	
365	Spare Pool Bearings	3	1	9,851	39,804.00	
	Spare Pool Generator	2	0	23,441	47,082.00	171,139.00
	Spare Pool gearbox	1	0	61,687	61,887.00	
	Spare Pool Shaft	2	0	11,133	22,666.00	
730	Spare Pool Bearings	3	3	9,851	60,306.00	
	Spare Pool Generator	2	0	23,441	47,282.00	192,141.00
	Spare Pool gearbox	1	0	61,687	61,987.00	
	Spare Pool Shaft	2	1	11,133	34,299.00	
1095	Spare Pool Bearings	3	4	9,851	71,057.00	
	Spare Pool Generator	2	0	23,441	47,482.00	214,825.00
	Spare Pool gearbox	1	0	61,687	62,087.00	
	Spare Pool Shaft	2	1	11,133	34,599.00	
1460	Spare Pool Bearings	3	5	9,851	82,008.00	
	Spare Pool Generator	2	0	23,441	47,682.00	226,376.00

7.5 RELIABILITY, AVAILABILITY & MAINTAINABILITY OPTIMISATION

The fixed CBM and TBM task intervals in table 7.3 are responsible for the very long downtime of the wind farm shown in figure 7.6. The intervals are rather ambitious, thus not ideal for the subsystems because their PF-intervals are far less than the tasks interval (see chapter 5). Furthermore, TBM task is not suitable for the maintenance of the main shaft due the constant increasing pattern of failure. Thus, we recommend a monthly inspection interval for the gearbox, generator, main bearing and shaft; taking into account their P-F intervals. Table 7.9 shows the adjusted the tasks intervals for the subsystems.

Table 7.9 Optimised Task Intervals for the Subsystems

Subsystem	Task	Fixed interval (days)	Crew A (Person)	Labour cost/ hour (£)	Task duration (hours)	Tasks crew can perform at the same time	Labour Cost per incident (£)	Cost of crane per hour (£)	Direct cost of crane (£)	Total cost of task (£)
Mean bearings	CBM (Inspection)	30	3	50	1.33	1	200	300	399	599
Main shaft	CBM (Inspection)	30	3	50	1.33	1	200	300	399	599
Gearbox	CBM (Inspection)	30	3	50	2	1	300	300	600	900
Generator	CBM (Inspection)	30	3	50	1.6	1	240	300	480	720

7.5.1 The Wind Turbine

Using the adjusted information and then repeating the simulations described in section 7.3, the overview results and up/down trend for the wind turbine are shown in table 7.10 and figure 7.7 respectively. Note the improvement in the mean availability, reliability and the total downtime of the wind turbine recorded in table 7.10 when compared to the result in table 7.4.

Table 7.10 shows the mean availability of the wind turbine in the first 3 years is 100%; this reduces to about 98% in the fourth year as a result of the failure shown in figure 7.7. Also, the reliability of the wind turbine in the first 3 years is 1 which reduces to about 0.79 in the fourth year. The optimisation reduces drastically the total downtime of the wind turbine from 74 days as recorded in table 7.4 to 19 days in table 7.10. The total downing events in the first three years is zero (0); this increases to 2 events in the fourth year. This shows a great improvement in the operating time of the turbine when compared to the initial total downing events of 2, 5, 7 and 10 events in the first, second, third and fourth year respectively (see table 7.4).

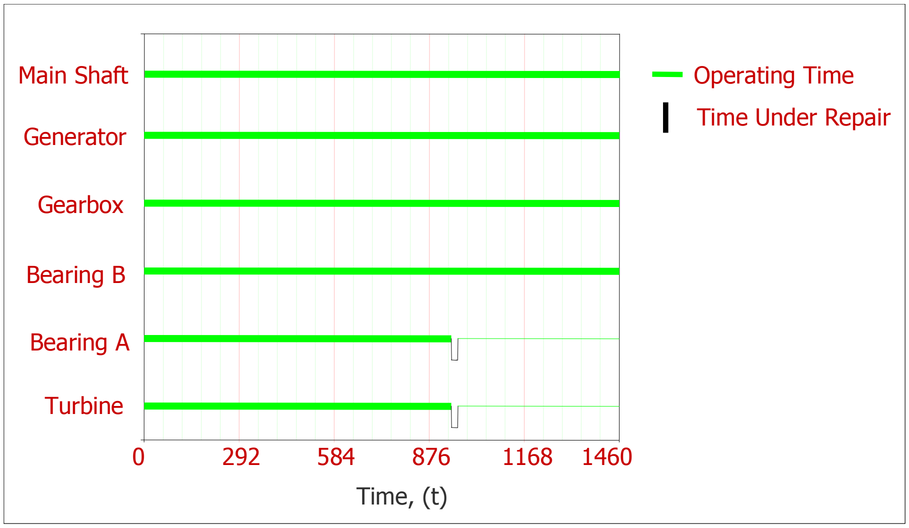


Figure 7.7 Optimised Wind Turbine's up/down trend

Table 7.10 Optimised Wind Turbine's overview result

System Overview	Year 1	Year 2	Year 3	Year 4
General				
Mean Availability (All Events):	1	1	1	0.99
Std Deviation (Mean Availability):	0	0	0	0
Mean Availability (w/o PM & Inspection):	1	1	1	0.99
Point Availability (All Events):	1	1	1	1
Reliability:	1	1	1	0.79
Expected Number of Failures:	0	0	0	1
Std Deviation (Number of Failures):	0	0	0	0
MTTFF:	527	1053	1580	944
System Uptime/Downtime				
Uptime:	365	730	1095	1441
CM Downtime:	0	0	0	3
Inspection Downtime:	0	0	0	0
PM Downtime:	0	0	0	0
Total Downtime:	0	0	0	19
System Downing Events				
Number of Failures:	0	0	0	1
Number of CMs:	0	0	0	1
Number of Inspections:	0	0	0	0
Number of PMs:	0	0	0	0
Total Events:	0	0	0	2

7.5.2 The Wind Farm

The wind farm's up/down trend, overview result, cost summary, crew summary and spare pool summary are shown in figure 7.8, tables 7.11, 7.12, 7.13 and 7.14 respectively. These are compared with the initial wind farm up/down trend, overview result, cost summary, crew summary and spare pool summary presented in figure 7.6, tables 7.5, 7.6, 7.7 and 7.8 respectively. The optimised up/down trend in figure 7.8 shows a significant improvement in the wind farms operating time in comparison to the initial up/down trend presented in figure 7.6. The monthly inspection permits the rectification of incipient failures before they escalate to catastrophic events. This reduces significantly the wind farm's total downtime.

Table 7.11 shows the mean availability of the wind farm remained consistently at about 99% over the four year period. This is a great improvement over the mean availability of 46%, 43%, 42% and 40% in year 1, 2, 3 and 4 respectively as reported in the initial overview result presented in table 7.5. Also, the reliability of the wind farm is significantly improved to 1 from 0 over the four year period. The total downtime of the wind farm is reduced to 2 days as against the initial 196, 414, 638 and 877 days in the first, second, third and fourth year respectively. The number of unexpected failures is reduced to zero (0) from 2, 4, 5 and 7 in the first, second, third and the fourth year respectively as reported in the initial overview result recorded in table 7.5.

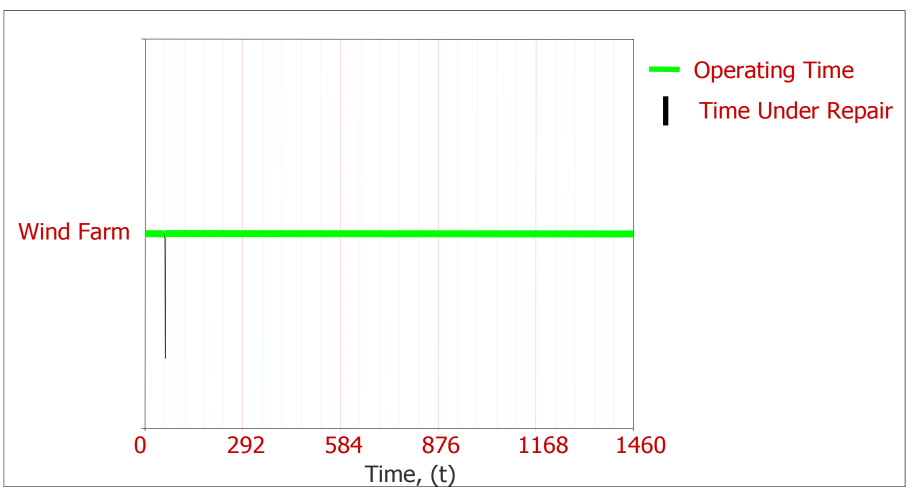


Figure 7.8 Optimised wind farms' up/down trend

Table 7.12 shows a significant reduction in the cost of corrective maintenance of the wind farm over the four year period as a result of the optimisation. The initial corrective maintenance costs ranged between £75, 330.33 in the first year and £271, 358.33 in the fourth year (see table 7.6). However, table 7.13 shows the reduction of the corrective maintenance costs to about £34,711.13. Also, the miscellaneous inspection and crew costs were significantly reduced from the second year. It is worth noting that the initial result presented in table 7.6 shows a better miscellaneous inspection and crew costs in the first year than the optimised result in table 7.12. Similarly, the spare pool costs for the wind farm starts reducing in the second year due to the lower number of unexpected failures when compared with the initial result presented in table 7.6. Thus, the total costs of the optimised wind farm starts reducing drastically in the second year as shown in table 7.12 when compared to the initial result presented in table 7.6.

Table 7.11 Optimised Wind Farm Overview result

System Overview	Year 1	Year 2	Year 3	Year 4
General				
Mean Availability (All Events):	0.9953	0.9977	0.9984	0.9988
Std Deviation (Mean Availability):	0	0	0	0
Mean Availability (w/o PM & Inspection):	0.9953	0.9977	0.9984	0.9988
Point Availability (All Events):	1	1	1	1
Reliability:	1	1	1	1
Expected Number of Failures:	0	0	0	0
Std Deviation (Number of Failures):	0	0	0	0
MTTFF:	527	1053	1580	2106
System Uptime/Downtime				
Uptime:	363	728	1093	1458
CM Downtime:	1.703	1.703	1.703	1.703
Inspection Downtime:	0	0	0	0
PM Downtime:	0	0	0	0
Total Downtime:	2	2	2	2
System Downing Events				
Number of Failures:	0	0	0	0
Number of CMs:	1	1	1	1
Number of Inspections:	0	0	0	0
Number of PMs:	0	0	0	0
Total Events:	1	1	1	1
Costs				
Total Costs:	382,336	383,236	384,136	384,735

Table 7.12 Optimised Wind Farm Cost Summary

System Cost Summary	Year 1	Year 2	Year 3	Year 4
Misc. Corrective Costs:	22,375.00	22,375.00	22,375.00	22,375.00
Costs for Parts (CM):	9,851.00	9,851.00	9,851.00	9,851.00
Costs for Crews (CM):	2,485.13	2,485.13	2,485.13	2,485.13
Total CM Costs:	34,711.13	34,711.13	34,711.13	34,711.13
Misc. Preventive Costs:	0	0	0	0
Costs for Parts (PM):	0	0	0	0
Costs for Crews (PM):	0	0	0	0
Total PM Costs:	0	0	0	0
Misc. Inspection Costs &	176,486.00	176,486.00	176,486.00	176,185.00
Costs for Crews (IN):				
Total Inspection Costs:	176,486.00	176,486.00	176,486.00	176,185.00
Spare Pool Costs:	171,139.00	172,039.00	172,939.00	173,839.00
Total Costs:	382,336.13	383,236.13	384,136.13	384,735.13

Table 7.13 shows the summary of the wind farm's crew cost as a result of the optimisation. The number of calls made to maintenance crew as presented in table 7.7, ranged between 15 calls in the first year and 31 calls in the fourth year. These calls are reduced significantly to 1 call over the 4 year period. All calls under the optimised wind farm were accepted (see table 7.13) as against the high number of rejected calls in the initial crew summary shown in table 7.7. Also, the total time used to repair failures have been reduced to an average of 2 days over the four year period as against the 4, 7, 11 and 14 days for the first, second, third and the fourth year respectively as shown in table 7.7.

Table 7.13 Optimised wind farms crew cost summary

Period	Crew Policy	Calls	Accepted	Rejected	Time Used	Cost
Year 1	Crew A	1	1	0	1.7026	2485.13
Year 2	Crew A	1	1	0	1.7026	2485.13
Year 3	Crew A	1	1	0	1.7026	2485.13
Year 4	Crew A	1	1	0	1.7026	2485.13

Table 7.14 shows the spare pool cost summary after the optimisation. Note the significant difference between the spare pool cost summary presented in table 7.8 and table 7.14. The items dispensed for maintenance purposes are reduced in table

7.14 which resulted in the lower total cost of spare pool starting from the second year.

Table 7.14 Optimised Spare Pool cost summary

Period	Spare Pool	ASL	Items Dispensed	Cost Per Item	Total Cost/ Item	Total Cost of Spares
	Main Bearings	3	1	9,851	39,804.00	
Year 1	Main Shaft	2	0	11,133	22,466.00	
	Gearbox	1	0	61,687	61,787.00	171,139.00
	Generator	2	0	23,441	47,082.00	
	Main Bearings	3	1	9,851	40,204.00	
Year 2	Main Shaft	2	0	11,133	22,666.00	
	Gearbox	1	0	61,687	61,887.00	172,039.00
	Generator	2	0	23,441	47,282.00	
	Main Bearings	3	1	9,851	40,604.00	
Year 3	Main Shaft	2	0	11,133	22,866.00	
	Gearbox	1	0	61,687	61,987.00	172,939.00
	Generator	2	0	23,441	47,482.00	
	Main Bearings	3	1	9,851	41,004.00	
Year 4	Main Shaft	2	0	11,133	23,066.00	
	Gearbox	1	0	61,687	62,087.00	173,839.00
	Generator	2	0	23,441	47,682.00	

7.6 SUMMARY

This chapter has modelled the failure characteristics of the 600 kW wind turbine and the 26 x 600 kW wind farm. The estimated values of β and η of critical components and subsystems of the wind turbine were used to populate Reliability Block Diagrams of the models. ReliaSoft BlockSim software which uses Monte Carlo simulation was used to assess the reliability, availability and maintainability of the wind turbine and the wind farm over a period of 4 years; taking into account the cost and availability of maintenance crew and spare-holding of the critical components.

Initial fixed maintenance task intervals were defined for the subsystems of the wind turbine. These intervals were meant to reduce access and crew costs associated with shorter maintenance tasks intervals. The models were simulated based on the initial information and the results were discussed. However, the intervals were ambitious, resulting to a very long downtime of the wind farm. The P-F intervals of the critical components range between 1 and 2 months. Thus, the maintenance task intervals were reduced to 30 days from 180.2 days. Then, the models were re-simulated over the same period; incorporating the same number of crew and spare holding.

The results of the re-simulation (i.e. optimised) were compared with the results of the initial simulation. In the comparison, the optimised result showed an initial increase in the cost of inspection due to shorter interval. The result further shows that adopting the shorter maintenance interval increases the overall availability and reliability of the wind turbine as well as the wind farm. The total downtime and the overall cost of the wind farm were drastically reduced through the optimisation. For instance, the total costs of maintaining the wind farm based on the initial interval are about £376,246 and £1,006,068 in the first and the fourth year respectively while the total costs of maintaining the wind farm based on the shorter (optimised) interval are about £382,336 and £384735 in the first and the fourth year respectively.

CHAPTER 8

DELAY-TIME APPROACH TO MAINTENANCE OPTIMISATION

8.1 INTRODUCTION

The last two chapters had assessed the failure characteristics of wind turbines, and optimised the reliability, availability and maintainability of a 26 x 600 kW wind farm using the modelling system failures approach. This chapter will examine the failure characteristics of the 600 kW horizontal axis wind turbine using the Delay-Time Maintenance Mathematical Model (*DTMM).* The concept and relevance of DTMM have been discussed in chapter 3, section 3.6. Also, the failure modes of critical components and subsystems of the wind turbine were identified using the Reliability Centred Maintenance approach (see chapter 5). The failure consequences of the critical subsystems was determined and expressed in financial terms. Section 8.2 of this chapter will present a case study to demonstrate the practical application of the delay-time maintenance model to optimise the inspection intervals of the critical subsystems of the wind turbine. Cost of inspections and repairs of components within the subsystems will be calculated. The defect rate for each component of the subsystems will be evaluated. Optimal inspection intervals for the subsystems will be determined. The summary of the chapter is presented in section 8.3.

8.2 A CASE STUDY

This section presents a case study to demonstrate the practical application of the DTMM techniques to optimise the inspection intervals of critical subsystems of the 600 kW wind turbine.

8.2.1 Failure Mode Effect and Criticality Analysis

The Failure Mode and Effect Criticality Analysis (FMECA) technique has been used to predict the failure modes of the 600 kW horizontal axis wind turbine. The result is logically presented in table 5.1 of chapter 5.

Suitable Condition-Based Maintenance tasks to mitigate the effects of the identified failure modes were identified and presented in subsection 5.3.3 of chapter 5. Recall that vibration analysis was identified as the suitable condition based maintenance task to mitigate dominant causes of failure modes *WT-1-3*, *WT-1-4*, *WT-1-5*, *WT-1-6*, *WT-1-7*, *WT-1-8*, *WT-1-12*, *WT-2-7* and *WT-2-8* while strain gauge measurements were employed for dominant causes of failure modes; *WT-1-1*, *WT-1-2*, *WT-2-1*, *WT-2-2, WT-2-4, WT-2-5*, and *WT-2-6*. Catastrophic failures of critical components of the wind turbine such as the blades, main bearings and shaft, gearbox and associated components, the generator and associated components, towers and foundations should therefore be detectable and prevented through the application of the appropriate CBM activities.

8.2.2 Vibration Analysis

All rotating equipment produces ultrasonic or acoustic vibration regardless of the state of lubrication (Smith, 1989). Vibration analysis (VA) is used for monitoring the failure behaviour of rotating equipment such as the wheels and bearings of the gearbox, generator bearings, main shaft and bearings of the wind turbine. The principle of vibration monitoring to detect incipient faults is illustrated in Figure 8.1. Vibration monitoring involves using sensors. The sensors employed depend on the frequency range of the equipment to be monitored. Low frequency range equipment requires position transducers (Mitchell, 1993), middle frequencies require velocity sensors (Mitchell, 1993) and high frequency requires accelerometers (Mitchell, 1993). Appropriate vibration sensors are mounted rigidly on the components to register the local motion.

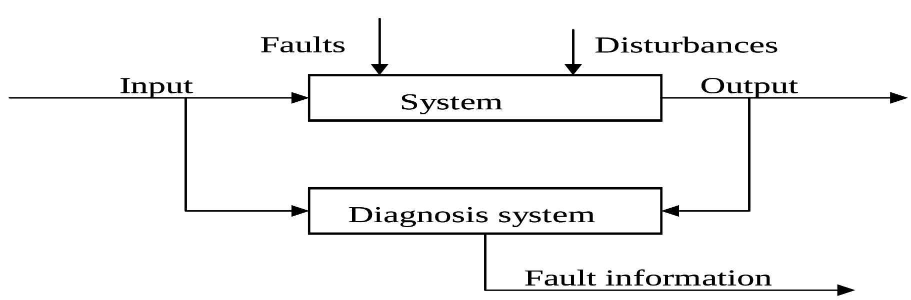


Figure 8.1 Fault detection model

Accelerometers are commonly used to monitor the rotating equipment of the wind turbine (Caselitz et al. 1997). Although displacement sensors seem more appropriate for monitoring the performance of the main bearings and shaft since they operate at a low speed. However, wind turbines differ from other mechanical equipment because it operates on both steady and dynamic loads, high and low rotational speeds which make signal analysis and diagnostic difficult (Caselitz et al. 1997). This requires a specialised knowledge which the suppliers of the system often execute in addition to the maintenance of the monitoring system.

The cost of installing condition monitoring system on a wind turbine is expected to be covered by the benefits of preventing the consequences of catastrophic failures. The trade-off between the cost of installing vibration monitoring system on the drive train of the 600 kW wind turbines and the benefits of preventing the consequences of failure of critical subsystems in the 26 x 600 kW wind farm has been carried out in chapter 5.

Vibration information of the wind turbine's drive train is collected on a monthly basis by a trained employee. A portable device is utilised to register the vibration characteristics of the components from the mounted sensors. These are downloaded to a system and the results are compared with the threshold and previous results, to determine if there are deviations.

8.2.3 Failure Consequences of Subsystems

The failure consequences (C_2) of critical subsystems of the 600 kW wind turbine represented by failure modes *WT-1-1*, *WT-1-3*, *WT-1-4*, *WT-1-6* and *WT-1-8* (table 5.1) were determined and expressed in financial terms. The result is presented in Table 5.5. The C_2 were calculated by taking into account total cost of material (TC_{MT}), total cost of labour (TC_{LB}), total cost of access (TC_{AS}) and production losses (P_{LS}). The consequence of catastrophic[9] failure of a gearbox is about £78,468. The generator, main bearings and the main shaft have failure consequences

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[9] We use "catastrophic" to refer to failures beyond repair which require replacement of the system.

of £35,964, £22,374 and £29,114 respectively. The reader is referred to chapter 5 for a detailed calculation of the failure consequences of critical subsystem of the 600 kW wind turbine.

8.2.4 Cost of Inspection and Repair of Components

The cost of inspection and repair of components of the subsystems are present in Table 8.1. The cost per hour and the time required to repair each component were estimated from the information obtained from collaborating wind farm operators. The cost and time needed to inspect the components of the subsystems are estimated from the information obtained from the vendors of condition monitoring system. In the table, the total cost of labour (TC_{LB}) is obtained by multiplying repair time, cost of labour per hour and the number of repair crew. Also, the cost of inspection per hour is multiplied by the inspection duration and the number of inspection crew to obtain the total cost of inspection (TC_{INP}). The total cost of material (TC_{MT}) includes the cost of loading and off-loading, cost of transportation to site, and a value added tax (VAT) at 17.50% (see chapter 5). Thus, the cost of inspection and repair (C_1) is the summation of TC_{INP}, TC_{LB} and TC_{MT}. For example, the C_1 of high speed shaft (HSS) bearings and intermediary shaft (IMS) bearings of the gearbox are £2,230 and £2,742 respectively.

Table 8.1 Cost of inspection and repair of critical components

Sub-system	Activity & Component	Repair duration (hrs)	Inspection duration (hrs)	Cost of inspection per hour(£)	Cost of repair per hour (£)	Inspection & Repair crew	TC_{INP} (£)	TC_{LB} (£)	TC_{MT} (£)	Total (C_1)
Blade	Replace blade									
Main Shaft	Replace shaft	32	2	12	17.5	3	72.0	1,680.0	11,133.4	12,885.4
Main Bearing	Replace bearing	16	2	12	17.5	3	72.0	840.0	9,851.5	10,763.5
Gearbox	Replace gear wheels	16	2	12	17.5	3	72.0	840.0	7,270.0	8,182.0
	Replace HSS bearing	16	2	12	17.5	3	72.0	840.0	1,318.0	2,230.0
	Replace IMS bearing	16	2	12	17.5	3	72.0	840.0	1,830.0	2,742.0
Generator	Replace bearing	16	2	12	17.5	3	72.0	840.0	1,420.0	2,332.0

8.2.5 Defects Rate

The defects rate (α) of each component of the critical subsystems of the 600 kW wind turbine is presented in Table 8.2. The (α) were estimated by determining firstly the '*wind turbine operational years*' which is the product of the number of wind turbine assessed (i.e. 77 turbines) and the period under consideration. From tables 6.1-6.4, the period under consideration for the main-shaft, main-bearings, gearbox and the generator are 4, 3, 7 and 8 years respectively. These result to '*wind turbine operational years*' of 539, 616, 308 and 231 for the gearbox, generator, main shaft and bearings respectively. The (α) of each component is obtained by dividing the total defects observed (i.e. the sum of number of defects failed and defects repaired) of the component by the corresponding '*wind turbine operational years*'. For example, twelve (12) HSS bearings of the gearbox failed and replaced, while 5 gearboxes failed catastrophically (table 6.3). Thus, the total number of defects observed for the HSS bearing is 17 in the 7 years under consideration. Similarly, thirty one (31) bearings of the generator failed and replaced while 9 generators failed catastrophically (see table 6.4). Therefore, the total number of defects observed for the bearing of the generator is 40 in the 8 years under consideration. Hence, the defects rate (α) of the HSS bearing of the gearbox and the bearing of the generator are 0.0315 and 0.0649 respectively. The components defects rates were further converted to *Mean-Time-Between-Failures* (MTBF). The MTBF are obtained by determining the inverse value of (α). For example, the MTBF of the main bearings is $\frac{1}{5.19\,x10^{-2}}$ to give 19.25 *wind turbine years* as shown in the table 8.2.

Table 8.2 Defects Rate of Critical Components

Sub-system	Components	Equipment-years	No of defects repaired	No of defects failed	Total defects observed	Defects rate (α) x 10^{-2}	MTBF (Equipment-years)
Blade	Blade						
Main shaft	Shafts	308	0	7	7	2.27	44
Main bearing	Bearings	231	0	12	12	5.19	19.25
Gearbox	Gears	539	7	5	12	2.22	44.92
	HSS bearings	539	12	5	17	3.15	31.71
	IMS bearings	539	5	5	10	1.86	53.9
Generator	Bearings	616	31	9	40	6.49	15.4

8.2.6 Delay-Time

As mentioned in chapter 3, section 3.6 that the *P-F* interval of a component is synonymous to its delay-time. Historical maintenance data were sourced from collaborating wind farm operators to calculate the mean delay-time ($1/\gamma$) of the components of the subsystems. The $1/\gamma$ will be used in conjunction with the calculated consequences of failure (C_2), cost of inspection and repair (C_1), and the defects rate (α) to determine optimal inspection interval (Δ^*) for the subsystems.

Table 8.3 contains the estimated times to failures (T_i) for the components of the critical subsystems. The lower, most-likely and the upper values of the times to failure are presented in the table. Ideally, if inspection intervals are equally spaced and failure occurs between the inspections, then the period from the date of last inspection to the time failure actually occurred is the delay-time of the component as shown conceptually in figure 3.5 of chapter 3. This type of data is seldom available in the wind energy industry due to poor recording of maintenance and failure data. Furthermore, vibration monitoring is not well established in the wind energy industry. It is worth noting however, that table 8.3 was established through discussion with wind farm engineers. The current inspection intervals for the subsystems are also presented in the same table.

Table 8.3 Mean time to failures

Sub-system	Components	Inspection interval Δ (Months)	Time to failure T_i (months)			Mean (μ) T_i
			Lower	Most likely	Upper	
Blade	Blade					
Main shaft	Shafts	1	0.93	0.95	0.97	0.95
Main bearing	Bearings	1	0.85	0.90	0.95	0.90
Gearbox	Gears	1	0.70	0.80	0.90	0.80
	HSS bearings	1	0.85	0.90	0.95	0.90
	IMS bearings	1	0.75	0.85	0.95	0.85
Generator	Bearings	1	0.70	0.80	0.90	0.80

The total numbers of defects observed (n) and the defects repaired (k) presented in table 8.2, the times-to-failure (T_i) and the current inspection intervals (Δ) presented in table 8.3 were assessed using Equation 3.46 to determine the mean delay-time ($1/\gamma$) of the components. The result is presented in Table 8.4. Note that each of the defects repaired were assumed to have failed at the estimated mean time to failures in table 8.3. The mean delay-time for the gear wheels, HSS and IMS bearings of the gearbox are 0.918, 1.469 and 0.735 respectively.

Table 8.4 Mean delay-time for critical components

Sub-system	Components	Mean delay-time 1/γ (months)
Blade	Blade	
Main shaft	Shafts	0.038
Main bearing	Bearings	0.038
Gearbox	Gears	0.918
	HSS bearings	1.469
	IMS bearings	0.735
Generator	Bearings	1.948

Optimal inspection intervals for the critical subsystems are determined by using Equation 3.47. The failure consequences of the subsystems (c_2) in table 5.5, the cost of the inspection and repair (c_1) in table 8.1, the components defects rates (α) in table 8.2, and the mean delay-time ($1/\gamma$) in table 8.5 were substituted in the equation 3.46. The result of optimal inspection intervals for the subsystems is presented in table 8.5. Recall, the prerequisite to determining the optimal inspection intervals using the delay-time mathematical model is $\gamma C_1 < \alpha C_2$ (see chapter 3). Thus, the result in the table 8.5 shows that the main bearing and shaft, the gearwheels and IMS of the gearbox have no optimal inspection interval as the pre-condition is not satisfied.

Table 8.5 Optimal inspection interval of the critical components

Sub-system	Components	Total number of defects	Defects rate α	Mean delay-time (1/γ) (months)	Inspec-tion Cost C_1 (£)	Failure Cost C_2 (£)	$\gamma * C_1$	$\alpha * C_2$	Optimal inspection interval Δ* (months)
Blade	Blade								
Main shaft	Shaft	5	0.0227	0.038	12,885.00	29,114.00	338,012.12	661.68	No optimal
Main bearing	Bearings	12	0.0519	0.038	10,763.00	22,374.00	282,345.78	1,162.28	No optimal
Gearbox	Gears	12	0.0222	0.918	8,182.00	78,468.00	8,913.07	1,746.97	No optimal
	HSS bearings	17	0.0315	1.469	2,230.00	78,468.00	1,517.77	2,474.87	3.045
	IMS bearings	10	0.0185	0.735	2,742.00	78,468.00	3,731.79	1,455.81	No optimal
Generator	Bearings	40	0.0649	1.948	2,332.00	35,964.00	1,196.98	2,335.32	3.349

The HSS bearing of the gearbox and the bearing of the generator have optimal inspection intervals of 3.035 and 3.349 months respectively; given the assessed failure data.

8.3 SUMMARY

This chapter has presented a quantitative optimisation of condition-based maintenance inspection intervals for critical subsystems of 600 kW wind turbine using the delay-time mathematical maintenance model (DTMM). Industrial data pertaining to the wind turbine has been sourced from wind farm operator and have been collated to determine inspection activities and failure history of the wind turbines. Current market prices of critical components of the wind turbines as well as the activities of condition monitoring have been sourced from manufactures and vendors. The FMECA approach has been used to determine failure modes of the wind turbines. Failure consequences of critical subsystems have been determined and expressed in financial terms. The costs of inspection and repair as well as the failure rate of the components of the subsystems have been calculated. The DTMM has been used to determine mean delay-time and optimal inspection intervals for the critical subsystems of the wind turbine. The optimal inspection interval for the HSS bearing of the gearbox and the bearings of the generator, are 3.045 and 3.349 months respectively. The main shaft and bearings, the gearwheels and the IMS bearing of the gearbox have no optimal inspection; given the assessed failure data and the methodology applied.

Comparative studies between the result of the modelling system failures as presented in chapters 7 and 8, and the result of the delay-time maintenance mathematical model will be carried out in the next chapter.

CHAPTER 9

COMPARISON OF THE MODELLING SYSTEM FAILURES AND DELAY-TIME MAINTENANCE MODEL

9.1 INTRODUCTION

The Modelling System Failures approach to quantitative maintenance optimisation was used in chapters 6 and 7 to assess the collected field failure data of wind turbines. The reliability, availability and maintainability of the 600 kW wind turbines on a 26 x 600 kW wind farm were optimised. The delay-time maintenance mathematical model was used in chapter 8 to assess the failure data. Optimal inspection intervals for critical subsystems of the 600 kW wind turbine were determined.

This chapter will compare the two approaches to quantitative maintenance optimisation by taking into account the results of the assessments presented in chapters 6, 7 and 8. The overview results of the MSF and DTMM are presented in sections 9.2 and 9.3 respectively. Detailed comparison of the two approaches in terms of data requirements, analysis robustness, practical implementation and the potential benefits are presented in section 9.4. The summary of the chapter is presented in section 9.5.

9.2 OVERVIEW OF THE MODELLING SYSTEM FAILURES

The estimated *shape (β)* and *scale (η)* parameters of the Weibull distribution, the *probability density function* and *failure rate* plots revealed the failure characteristic of each of the components and subsystems of the 600 kW wind turbine. The failure attributes of the components and subsystems were described by one of the three basic failure patterns of the bath-tub curve. The gearbox and the generator consist of a number of components. Each component had a distinctive shape parameter which described its pattern of failure. Similarly, each subsystem within the wind turbine; the main bearing, main shaft, gearbox, generator, etc had individual patterns of failure. The failure characteristics were used to determine a suitable maintenance task for each of the components and subsystems of the wind turbine. Optimal replacement intervals for components with $\beta > 1$ were determined. The optimal replacement interval for the gear-wheels, IMS bearings and HSS bearings of the gearbox are 6, 4 and 3 years respectively. The optimal replacement interval for the bearings of the generator is 4 years.

Failure models were designed for the wind turbine and the wind farm to forecast their future performance over a defined period of time. Optimum maintenance tasks for effective future operational performance were determined. The initial assessment of the wind turbine and the wind farm models in sections 7.3 and 7.4 respectively, showed poor levels of reliability and availability. The wind turbine and the wind farm's mean availability after the 4 year period were 98% and 42% while their reliabilities were 0.67 and 0 respectively. The total costs of managing the wind turbine and the wind farm over the 4 year period were £208,758 and £1,006,068 respectively. Significant amount of resources (direct costs) are expended on fixing failed wind turbines in addition to the huge down-time (indirect) costs.

In sections 7.5 and 7.6, the models were re-simulated to explore all possible options to improve their overall performance. The optimum maintenance tasks were selected to improve future performance of the wind turbines and maximise the return on investment in wind farm. The availability of the wind turbine and the wind farm in the 4th year were 99% and 100% and their reliabilities were 0.79 and 1 respectively. The total cost of managing the wind farm was reduced from £1,006,068 to about £384,735.

9.3 OVERVIEW OF THE DELAY-TIME MODEL

The delay-time maintenance mathematical model considered the failure history of components of repairable subsystems within the 600 kW wind turbine. It assessed the field failure data of each component in relation to its subsystem. It took into cognisance the diverse failure behaviour of components within a subsystem. The defects rate and mean delay-time of each component within a repairable subsystem were determined. For instance subsections 8.2.5 and 8.2.6 contain the assessment of a typical gearbox. Each of the components of the gearbox had individual *defects rate* and *mean delay-time*. The defects rate of the gearwheels, HSS bearings, IMS bearings are 0.022, 0.0315 and 0.0185 respectively while the mean delay-times are 0.918, 1.469 and 0.735 respectively. These influenced the inspection intervals for the gearbox. Similarly, the inspection interval for the generator is dependent on the defects rate and mean-delay-time of its components.

The optimal inspection intervals for the components of the gearbox and generator were determined based on; the estimated defects rate and mean delay-time of each component within a subsystem, the failure consequences of the subsystem and, the cost of inspection and repair of each component within the subsystem. These provided a good compromise between costs, risks and performance. The optimal inspection intervals for the HSS bearings of the gearbox and the bearings of the generator were 3.045 and 3.349 respectively.

9.4 COMPARISION OF THE MSF AND DTMM

This section will compare and contrast the two quantitative approaches to maintenance optimisation; taking into account data requirements, analysis robustness, practical implementation and the potential benefits.

9.4.1 Practical Implementation

The results of both the MSF and DTMM can be implemented in practical terms, provided the analyses are not clouded with illogical and subjective assumptions. Thus, for practical implementation purposes, analyses should consider field failure and maintenance data wherever possible, and minimise all forms of assumption.

9.4.2 Potential Benefits

The potential benefits of the MSF include:-

- identification of components and subsystems susceptible to failure;
- identification of dominant failure modes of critical components and subsystems;
- identification of root causes of failure modes such as poor design, human error, wear-out and fatigue;

- ability to improve the reliability and availability of systems to reduce failure rates and the overall cost of maintenance;
- determination and optimisation of appropriate maintenance strategy for systems, subsystems and components; and
- optimisation of spare-holding, and maintenance crew.

The potential benefits of the DTMM include:-

- ability to determine defects rate for components and subsystems;
- ability to determine in real terms, mean delay-time which is synonymous with P-F intervals for components and subsystems;
- ability to determine optimum balance between risks, costs and performance; and
- optimisation of inspection intervals for repairable systems.

9.5 SUMMARY

This chapter has reviewed the result of the MSF and the DTMM. It has compared and contrasted the two approaches to quantitative maintenance optimisation. The data requirements, analyses robustness, ease of practical implementation and potential benefits of the approaches were compared and discussed.

The two approaches emerged to be complimentary in contrast with the earlier assertion made in chapter 3 that there are independent techniques to maintenance optimisation. Hence, where field failure data exist to carry out quantitative analyses, the MSF technique should be used first to assess the collected data. Thereafter, the components and subsystems with random failure patterns (β=1) should further be assessed using the DTMM technique to determine optimal inspection intervals. If the result of the DTTM shows no optimal inspection intervals for the components, then the calculated failure consequences should be used to determine the most appropriate maintenance strategy. The strategy can be condition monitoring, run-to-failure or predetermined replacements. The DTMM result presented in table 8.5 showed no optimal inspection intervals for the gearwheels, IMS bearings, main shafts and main bearings. This implies that there are no conclusive optimal inspection intervals for the gearbox, generator, main shaft and main bearing. Thus, condition monitoring can be used since the consequences of failure will not permit the use of run-to-failure strategy as shown in chapter 5. The MSF result presented in table 6.5 shows that main bearing exhibits a random failure pattern while the gearwheels, IMS bearing and the main shaft exhibit a wear-out failure pattern.

The DTMM technique can be incorporated into an RCM process as presented in chapter 8. RCM is a qualitative technique for maintenance optimisation while DTMM is quantitative. This blend provides a good balance between the qualitative which is often clouded with subjective assumptions and the quantitative which usually require rigorous data sets that are difficult to obtain.

CHAPTER 10

SUMMARY, CONCLUSIONS AND RECOMMENDATIONS FOR FURTHER RESEARCH

10.1 SUMMARY

Wind is fast becoming one of the most utilised renewable energy sources to reduce the emission of greenhouse gases and mitigate the effects of global warming. Improvement in the design of wind turbines and the availability of wind resources in most parts of the world are contributing to the rapid development of the wind energy industry. In recent years, the wind industry has experienced a shift in the development of wind farms to offshore from onshore locations due to more favourable wind resources and the possibility of installing higher power turbines. These factors have increased significantly the potential for investment in the industry as well as the range of possible stakeholders. A clear corollary exists between the current status of the wind energy industry and that of the Oil and Gas (O & G) industry of 30 years ago: the O & G industry in the UK increased in size dramatically over one to two decades, with little consideration of the impact that Asset Management might have in terms of reducing total Asset Life-Cycle Costs (LCC). Subsequently, the O & G industry has historically suffered from ineffective and inefficient maintenance practices with significant impact on productivity and Health, Safety and Environment. As a result, the sector has perpetually been reactively attempting to address these issues by re-engineering maintenance through application of Asset Management methodologies.

Thus, the wind energy industry and the field of Asset Management were reviewed critically. The main findings from the review are summarised in the following:

- The wind energy industry has a clear opportunity to consider the strategic importance of Asset Management, and implement its methodologies to effectively manage assets over their life-cycle.

- Achieving return on investment in wind farms is affected by inter-related stakeholders' requirements and technical issues associated with the assets. These issues require a holistic frame-work currently not applied consistently across the wind industry to combine and rationalise stakeholders' demands, and ensure assets remain in a satisfactory condition over the life-cycle of wind farms.

- Asset Management processes, tools and techniques exist in other industries. These processes, tools and techniques can be assessed and adopted for effective management of wind farms.

- Effective maintenance of wind turbines is indispensable to the core business objectives of the wind energy industry, and crucial to maximising the return on investment in wind farms.

- Wind turbines are often purchased with a 2-5 years all-in-service contract, which includes warranties, and corrective (failure-based) and preventive (time-based) maintenance strategies. These strategies are usually adopted by wind farm operators at the expiration of the contract period to continue the maintenance of wind turbines.

- Failure Based Maintenance (FBM) involves using a wind turbine or any of its components until it fails. The strategy is usually implemented where failure consequences will not result in revenue losses, customers' dissatisfaction or health and safety impact. However, critical component failures within a wind turbine can be catastrophic with severe operational and Health, Safety and Environmental (HSE) consequences.

- Time Based Maintenance (TBM) involves carrying out maintenance tasks at predetermined regular-intervals. TBM strategy is often implemented to avoid invalidating the Original Equipment Manufacturers' (OEM) warranty, and to maintain sub-critical machines where the pattern of failure is well known.

However, the choice of the correct TBM interval poses a problem as too frequent an interval increases operational costs, wastes production time and unnecessary replacements of components in good condition, whereas, unexpected failures frequently occur between TBM intervals which are too long. Thus, time and resources are usually wasted on maintenance with little knowledge of the current condition of the equipment.

- Condition-Based Maintenance (CBM) strategy which constitutes maintenance tasks being carried out in response to the deterioration in the condition or performance of an asset or component as indicated by a condition monitoring process, has largely been ignored in the wind energy industry. Limited work has been undertaken in monitoring the structural integrity of turbine blades using thermal imaging and acoustic emission; the use of performance monitoring and temperature monitoring and on-line analysis systems. Generally, as reported, this work is considered in isolation, and is not considered within the wider context of a maintenance, integrity and asset management strategy.

- Optimisation of wind turbines' maintenance strategies is crucial to the long term survival of the wind energy industry.

Based on the findings, three vital research areas were identified. These included the need to; **(i)** develop a structured model for asset management in the wind energy industry (objective 2), **(ii)** select a suitable maintenance strategy for wind turbines that is technically feasible and economically viable over the life-cycle of wind turbines (objectives 3 and 4), **(iii)** optimise the maintenance of wind turbines to determine the most cost effective strategy (objectives 5, 6 and 7).

10.1.1 A structured model for asset management in the wind energy industry

Asset management models existing in other industries were reviewed. Key steps to design a structured model for asset management in the wind energy industry were outlined in chapter 3, section 3.2. The key steps were applied in chapter 4 to design a structured model for asset management in the wind industry. The main points are summarised in the following:

- Crucial requirements for the effective management of wind farms were identified. The requirements were transformed into Asset Management processes which are specific to the wind energy industry.

- Stakeholders' requirements which are often opposing were outlined and harnessed. The fundamental business values that drive the performance and long-term survival of the wind farms were identified.

- The strategic importance of unambiguous mission and vision statements and the need to outline them to reflect the stakeholders' requirement were highlighted and discussed.

- Assets within the wind energy industry were categorised into *primary* and *secondary*. Wind turbine and associated grid connection facilities were found to be primary because they drive and sustain the future of the wind energy industry. The workforce, assets' failure and maintenance data were found to be secondary because they facilitate the performance of the primary assets.

- Appropriate asset management tools and techniques necessary for the effective management of the various assets were identified and integrated into the model.

- A structured model showing a holistic interaction of decision making processes as well as assets requirements and management was designed for the wind industry.

- Institutional barriers in the way of practical implementations of the model as well as individual responsibilities to make it happen were highlighted and discussed.

10.1.2 Suitable maintenance strategies for wind turbines

Suitable maintenance tasks that are technically feasible and economically viable over the life-cycle of wind turbines were selected. A number of asset management approaches to the selection of appropriate maintenance strategies for physical assets were reviewed. Total Productive Maintenance (TPM), Risk Based Inspection (RBI) and Reliability-Centred Maintenance (RCM) were critically evaluated in chapter 3, section 3.3. RCM was found to be unique from the other approaches to the selection of a suitable maintenance strategy. It was also found that RCM is limited in determining which maintenance strategy is the most cost effective option available. Thus, a hybrid approach comprising RCM and Asset Life-Cycle Analysis technique was developed in chapter 3, subsection 3.3.4. The hybrid approach was used in chapter 5 to select a suitable maintenance strategy for wind turbines. The main points are summarised in the following:

- A generic horizontal axis wind turbine was critically assessed. Possible failure modes, causes and the resultant effects on the wind turbine's operation were determined. Failure consequences of critical subsystems were evaluated and expressed in financial terms.

- The failure consequences of critical subsystems of the wind turbine were found to limit the common maintenance strategies (failure-based and time-based) to support the current commercial drivers of the wind energy industry.

- Appropriate Condition-Based Maintenance (CBM) tasks for critical subsystems of a 600 kW wind turbine on a 26 x 600 kW wind farm were determined. Vibration analysis was identified as the suitable condition based maintenance task to mitigate the dominant causes of failure of the main bearings, main shaft, gearbox and associated components, the generator and associated components, towers and foundations. Strain gauge measurements were employed for dominant causes of failure of blades.

- The CBM task for drive-trains of the wind turbines on the 26x600 kW wind farm were compared with Time-Based Maintenance (TBM) activities using the Asset Life-Cycle Analysis technique. The Net Present Value (NPV) of the TBM and CBM were calculated and compared. It was shown that comparison of the Net Present Values is not absolute for a valid decision making since it considers only financial criteria.

- Non-financial factors of the CBM and TBM strategies were identified and assessed using the Weighted Evaluation technique. Benefit-To-Cost ratio of each of the option was calculated and the values were compared.

- The overall result showed Condition-Based Maintenance is the most cost effective option over 18 year life-cycle.

10.1.3 Optimise maintenance of wind turbines

Approaches to maintenance optimisation; qualitative and quantitative were reviewed and discussed in chapter 3, section 3.4. Two quantitative maintenance optimisation (QMO) techniques; Modelling System Failures (MSF) and Delay-time Maintenance Mathematical model (DTMM) were recommended for the optimisation of wind turbine maintenance. The concept, relevance and applicability of the two QMO techniques to the wind industry were discussed in chapter 3, sections 3.5 and 3.6 respectively. The MFS technique was used in chapters 6 and 7 while the DTMM was applied in chapter 8 to assess the collected field failure data of wind turbines.

The results from the application of the modelling system failures approach to quantitative maintenance optimisation are summarised in the following:

- The shape and scale parameters of the Weibull distribution for critical components and subsystems of the 600 kW wind turbines were determined from the collected field failure data. The Weibull probability plots, failure rate plots and probability density function plots were generated for the components and subsystems of the wind turbines.

- The estimated shape parameters for the critical components and subsystems were described by one of the three basic failure patterns of the bath-tub curve.

- A case study of a 26 x 600 kW wind farm was undertaken. The estimated β and η values for the critical components and subsystems of the 600 kW wind turbine were used to optimise their Preventative Maintenance (PM) tasks. It was found that the main bearing and shaft of the wind turbine have no optimal cost and interval for carrying out Preventative Maintenance tasks. The optimal interval for performing PM task on the gearwheels, IMS bearing and the HSS bearing of the gearbox of the 600 kW wind turbine are 2190, 1460 and 1095 days respectively while the optimal cost/year are £2,445, £958 and £2,183 respectively. Similarly, the optimal interval and cost/year for performing PM task on the bearing of the generator are 1460 days and £2152 respectively. The gearbox and the generator are repairable subsystems of the wind turbine with estimated shape parameters of 1.09 and 1.11 respectively. Thus the random pattern of failures of the subsystems will not allow effective implementation of the PM tasks for their components. Hence, the PM tasks were not suitable for the subsystems.

- The failure characteristics of the 600 kW wind turbine and the 26 x 600 kW wind farm were modelled; cost and availability of maintenance crew and spare-holding of the critical components were taken into account. The models were simulated to assess the reliability, availability and maintainability of the wind turbine and the wind farm over a period of 4 years. Initial inspection interval of 180.2 days was defined for the components and subsystems with β=1. The interval was meant to reduce failure frequency, access and crew costs. The models were simulated based on the initial information. The interval was found to be inappropriate due to long and frequent downtime of the wind farm as shown in figure 7.6. The Potential-to-Functional failure intervals of the critical components were found to range between 1-2 months. Thus, interval was reduced to 30 days from the 180.2 days. The models were then re-simulated over the same period; taking into account the same numbers of crew and spare holding. The results of the re-simulation (i.e. optimised) were compared with the results of the initial simulation. In the comparison, the optimised result showed an initial increase in the cost of inspection due to shorter interval. The result further showed the shorter interval increases the overall availability and reliability of the wind turbine and the wind farm. Furthermore, the total downtime and the overall cost of the wind farm were drastically reduced through the optimisation. The total costs of maintaining the wind farm in the first and the fourth year based on the initial interval were £376,246 and £1,006,068 respectively. Conversely, the total costs of maintaining the wind farm in the first and the fourth year based on the shorter (optimised) interval were £382,336 and £384,735 respectively.

The findings from the application of the delay-time mathematical maintenance model (DTMM) approach to quantitative maintenance optimisation are summarised in the following:

- A case study of a 26 x 600 kW wind farm was undertaken to determine optimal inspection intervals for critical subsystems of the 600 kW wind turbine. The costs of inspection and repair as well as the defects rate of the components within the subsystems of the wind turbine were calculated from the collected field failure data.

- The mean delay-time for the critical components and subsystems of the wind turbine were determined. The mean delay-time of the main bearing, main shafts, gearwheels, IMS bearing, HSS bearing, and the bearing of the generator are 0.038, 0.038, 0.918, 0.735, 1.469 and 1.948 respectively.

- The optimal inspection interval for the HSS bearing of the gearbox and the bearings of the generator, were 3.045 and 3.349 months respectively. The main shaft and bearings, the gearwheels and the IMS bearing of the gearbox had no optimal inspection intervals; given the assessed failure data.

10.2 CONCLUSIONS

The following key conclusions can be drawn from the research work reported in this thesis:

- Achieving the return on investments in wind farms is affected by inter-related stakeholders' requirements and technical issues associated with the assets. These issues require a well-founded Asset Management frame-work to deal with the inter-related complexities.

- The common maintenance strategies applied to wind turbines are not the most effective to support the current commercial drivers of the wind energy industry. A hybrid approach to the selection of a suitable maintenance strategy for wind turbines was developed. Practical application of the hybrid approach was demonstrated and validated through a case study.

- Suitable Condition-Based Maintenance activities for critical subsystems of 600 kW wind turbine on a 26 x 600 kW wind farm were determined. Catastrophic failures of critical components and subsystems of a wind turbine such as the blades, main bearings and shaft, gearbox and associated components, the generator and associated components, towers and foundations are detectable and can be prevented through the application of the appropriate CBM activities.

- The technical feasibility and economic viability of the selected Condition-Based Maintenance strategy was assessed and compared with Time-Based maintenance strategy. The overall result showed CBM is the most cost effective option over 18 year life-cycle.

- Maintenance optimisation is fundamental to profit maximisation of the wind energy industry due to its impact on costs, risks and performance.

- Optimisation of the maintenance of wind turbines is a promising way to maximise the return on investment in wind farms over a defined period. The process of maintenance optimisation is not a one-off procedure but a continuous process which requires periodic evaluation of performance and improving on the successes of the past.

- Two quantitative maintenance optimisation techniques; MSF and DTMM were recommended for practical application in the wind energy industry due to their simplicity and robustness in solving real life maintenance problems.

- Practical application of the MSF approach was demonstrated through the assessment of the field failure and maintenance data collected from 27 wind farms. The MSF and DTMM approaches were validated through a case study of 600 kW wind turbines on a 26 x 600 kW wind farm.

10.3 RECOMMENDATIONS FOR FURTHER RESEARCH

The research work reported in this thesis has clearly identified critical parameters pertinent to the development of optimal maintenance and spares for the wind industry. It has clearly addressed key maintenance challenges of the wind energy industry such as; minimisation of the direct and indirect maintenance costs associated with wind energy generation, optimisation of wind turbines' reliability and availability in order to maximise the return on investment in wind farms. In spite of the critical assessment and the designed methodologies to tackle the key challenges of the wind energy industry, there exist some areas which requires further research work. These areas include:

10.3.1 Modelling Wind Turbine Failures

The RAM assessment in chapters 6 and 7 did not incorporate all components and subsystems of the wind turbine. Some field failure data of the components and subsystems were not available as at the time of data collection. The unexplored subsystems include:

- Fatigue and reliability modelling of the wind turbine blades. This will require a concerted effort to engage willing collaborating wind farm operators to initiate and measure degradation in the blades of wind turbines and other composite materials. Data measurement and collection procedure needs to be design to suit the methodology described in chapter 3, section 3.5.

- Structural modelling of towers to assess their failure characteristic. The structural integrity of wind turbine towers is crucial to the reliability modelling of wind turbines. Tower failure can be catastrophic with a huge economic, health, safety and environmental consequences.

It is essential therefore to collect and analyse field failure and maintenance data of the blades and towers. Then incorporating the result into the models presented in chapters 6 and 7. These will give more detailed failure behaviour of the wind turbine and the wind farm. The reliability, availability, maintainability, spares-holding, crew requirements, etc can then be assessed in more detail.

10.3.2 Development of a Novel Web-Based Software

A need also exists to develop an online software tool that can determine optimal maintenance and spares holding for wind farms based on critical, site-specific criteria. This will involve development of algorithms specifically for the wind farm environment. First, a robust financial algorithm to integrate all the financial models such as the failure consequences of subsystems, cost of repair and inspection of components, cost of crew and spares will be developed. Secondly, mathematical maintenance optimisation algorithms will be developed from the combination of the two quantitative maintenance optimisation techniques discussed in chapter 3. Optimised spares inventory algorithms will be developed for planed and unplanned maintenance activities.

The algorithms will then be embodied in a web-based software tool that will provide wind farm operators/engineers with an optimal maintenance program for wind farms based on specific criteria entered by the user. The tool will be able to be used for the development of maintenance and spares program for new wind farms, and can act as an audit/benchmark for existing facilities. Online help will be provided and individual applications will be able to be customised to suit specific requirements.

CHAPTER 11

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APPENDIX A1

Functional Failure A: *Complete Loss of Energy Conversion Capability*

SYSTEM: Horizontal Axis Wind Turbine (HAWT) comprising of 3 blades up wind and pitch controlled, 3 -stage planetary gearbox, 4-poles asynchronous generator, etc.	System No: 1	Facilitator:
	Sub-system No	Auditor:

Function: To convert wind kinetic energy into electrical energy within defined speed limit.			**Consequence Evaluation**				**H1 S1 O1 N1**	**H2 S2 O2 N2**	**H3 S3 O3 N3**	**Default action**			**Proposed Tasks**
Functional failures	**Failure modes**	**Failure causes**	**H**	**S**	**E**	**O**				**H4**	**H5**	**S4**	
A. **COMPLETE LOSS OF ENERGY CONVERSION CAPABILITY**	**1. Catastrophic blade failure**	a. Lightening	Y	Y			N	N	N	Y			Inspect blades lightening protection devices
		b. Loose blades-hub joint	Y	Y			Y						Vibration monitoring of blades
		c. Cracks	Y	Y			Y						Fibre optic measurement
		d. Fatigue	Y	Y			N	N	Y				Replace blades of wind turbine
	1a. Lightening	a. Damaged lightening receptor	Y	Y			N	N	N	Y			Inspect blades lightening protection devices
	1b. Loose blade-hub joint	a. Damaged shrink disc	Y	Y			Y						Vibration monitoring of blades
		b. Broken or loose bolts	Y	Y			Y						Vibration monitoring of blades
		c. Improper fitting	Y	Y			Y						Vibration monitoring of blades
	1c. Cracks	a. Matrix or resin crack	Y	Y			Y						Fibre optics measurement
		b. De-bonding of matrix and fibre	Y	Y			Y						Fibre optics measurement
		c. De-lamination of composite materials	Y	Y			Y						Fibre optics measurement
		d. Fatigue	Y	Y			N	N	Y				Replace blades at end of life-cycle
	1d. Fatigue	a. Wear and tear	Y	Y			N	N	Y				Replace blades at end of life-cycle
	2. Catastrophic hub failure	a. Loose hub – main shaft connection	Y	Y			Y						Variation in performance parameter of the blades and the main shaft
		b. Slip or spin on shaft	Y	Y			Y						Variation in performance parameter of the blades and the main shaft

		c. Fatigue	Y	Y			N	N	Y				Replace blades at end of life-cycle
		d. Improper fitting	Y	Y			Y						Variation in performance parameter of the blades and the main shaft
	3. Main bearing failure	a. Inadequate lubrication	Y			Y	Y						Vibration monitoring of the main bearing
		b. Use of wrong lubricant	Y			Y	Y						Lubrication oil analysis
		c. Lubricant breakdown	Y			Y	Y						Lubrication oil analysis
		d. Bearing binding on shaft	Y			Y	Y						Vibration monitoring of the main bearing
		e. Bearing turning on shaft	Y			Y	Y						Vibration monitoring of the main bearing
		f. Excessive vibration	Y			Y	Y						Vibration monitoring of the main bearing
		g. Overheating	Y	Y			Y						Temperature measurement of the main bearing
		h. Normal wear and tear	Y			Y	N	N	Y				Replace main bearing at end of life-cycle
		i. False brinelling[10]	Y			Y	Y						Vibration monitoring of the main bearing
		j. Corrosion due to water ingression	Y			Y	N	N	Y				Inspect main bearing for corrosion creep
	3c. Lubricant breakdown	a. Lubricant churning due to too soft a consistency	N			Y	Y						Lubrication oil analysis
		b. Lubricant deterioration due to excessive operating temperature	N			Y	Y						Temperature monitoring of the main bearing

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[10] False brinelling occurs when a non-rotating bearing is subjected to external vibration e.g. during transportation, storage etc (Machelor J.M. 1999) (Moubray J. 1997)

		c. Operating beyond lubricant life	N			Y	N	N	Y				Lubrication oil analysis
		d. Lubricant foaming due to air flow through housing	N			Y	Y						Lubrication oil analysis
	3d. Bearing binding on shaft	a. Lack of lubricant	N			Y	Y						Vibration monitoring of the main bearing
		b. Contaminated lubricant	N			Y	Y						Lubrication oil analysis
		c. Housing distortion	N			Y	Y						Vibration monitoring of the main bearing
		d. Preload build up	N			Y	Y						Vibration monitoring of the main bearing
		e. Loss of clearance due to excessive adapter tightening	N			Y	Y						Vibration monitoring of the main bearing
		f. Thermal shaft expansion	N			Y	Y						Vibration monitoring of the main bearing
	3e. Bearing turning on shaft	a. Growth of race due to over heating	N			Y	Y						Temperature monitoring of the main bearing
		b. Normal wear and tear of bearing	N			Y	N	N	Y				Replace main bearing at end of life
		c. Fitting error	N			Y	Y						Vibration monitoring of the main bearing
		d. Excessive shaft deflection	N			Y	Y						Vibration monitoring of the main bearing
	3f. Abnormal vibration	a. Dirt or chips in bearing	N			Y	Y						Vibration monitoring of the main bearing
		b. Pitting or crack on outer race	N			Y	Y						Vibration monitoring of the main bearing
		c. Pitting or crack on rolling elements	N			Y	Y						Vibration monitoring of the main bearing
		d. Rotor unbalance	N			Y	Y						Vibration monitoring of the main bearing

		e. Out of round shaft	N			Y	Y						Vibration monitoring of the main bearing
		f. Race misalignment	N			Y	Y						Vibration monitoring of the main bearing
		g. Housing resonance	N			Y	Y						Vibration monitoring of the main bearing
		h. Bearing housing normal wear and tear	N			Y	N	N	Y				Replace bearing housing at end of life
		i. Mixed rolling element diameters	N			Y	Y						Vibration monitoring of the main bearing
		j. Race turning due to excessive clearance during initial fit	N			Y	Y						Vibration monitoring of the main bearing
	3g. Bearing over heating	a. Inadequate lubrication	N			Y	Y						Vibration monitoring of the main bearing
		b. Excessive lubrication	N			Y	Y						Vibration monitoring of the main bearing
		c. Lubricant liquefaction or aeration	N			Y	Y						Vibration monitoring of the main bearing
		d. Housing distortion due to warping or out-of-round	N			Y	Y						Vibration monitoring of the main bearing
		e. Abrasion or corrosion due to contaminants	N			Y	Y						Vibration monitoring of the main bearing
		f. Housing wear	N			Y	Y						Vibration monitoring of the main bearing
		g. Inadequate bearing clearance or bearing preload	N			Y	Y						Vibration monitoring of the main bearing

		h. Race turning	N			Y	Y							Vibration monitoring of the main bearing
	4. Main shaft failure	a. Fitting error												
		b. Elastic deflection under load												
		c. Thermal expansion												
		d. Wear and tear												
	5. Main shaft - gearbox coupling failure	a. Damaged shrink disc	Y			Y	Y							Vibration monitoring of the main shaft
		b. Broken or loose bolts	Y			Y	Y							Vibration monitoring of the main shaft
		c. Improper fitting	Y			Y	Y							Vibration monitoring of the main shaft
		d. Grease in coupling	Y			Y	Y							Vibration monitoring of the main shaft
	6. Gearbox failure	a. Bearing seizes	Y			Y	Y							Vibration monitoring of the gearbox
		b. Gear teeth pitting	Y			Y	Y							Vibration monitoring of the gearbox
		c. Misalignments	Y			Y	Y							Vibration monitoring of the gearbox
		d. Thermal instability	Y			Y	Y							Vibration monitoring of the gearbox

		e. Torsional and lateral vibration	Y			Y	Y						Vibration monitoring of the gearbox
		f. Unexpected load	Y			Y	Y						Vibration monitoring of the gearbox
		g. Lubrication failure	Y			Y	Y						Vibration monitoring of the gearbox
		h. Foreign object in gearbox	Y			Y	Y						Vibration monitoring of the gearbox
		i. Manufacturing error	Y			Y	Y						Vibration monitoring of the gearbox
		j. Corrosion due to water ingression	Y			Y	N	N	N	Y			Strip gearbox to inspect for corrosion creep
		k. Wear and tear	Y			Y	N	N	Y				Replace gearbox at end of life
	6a. Gearbox bearings seizes	a. Lack of lubricant	N			Y	Y						Vibration monitoring of the gearbox
		b. Lubrication deficiencies	N			Y	Y						Gearbox oil analysis
		c. Operating beyond lubricant life	N			Y	N	N	Y				Gearbox oil analysis
		d. Debris in gearbox	N			Y	Y						Vibration monitoring of the gearbox
		e. Misalignment	N			Y	Y						Vibration monitoring of the gearbox
		f. Vibration and shock	N			Y	Y						Vibration monitoring of the gearbox
		g. Excessive force used during fitting of couplings	N			Y	Y						Vibration monitoring of the gearbox
	6b. Gear teeth pitting and wear	a. Wheels misalignments	N			Y	Y						Vibration monitoring of the gearbox
		b. Shafts misalignments	N			Y	Y						Vibration monitoring of the gearbox
		c. Particles in lubricant	N			Y	Y						Gearbox oil analysis
		d. Vibration and shock	N			Y	Y						Vibration monitoring of the gearbox

		e. Eccentricity[11] of tooth wheels	N			Y	Y						Vibration monitoring of the gearbox
		f. Excessive backlash[12] of teeth	N			Y	Y						Vibration monitoring of the gearbox
		g. Normal wear and tear	N			Y	N	N	Y				Replace gear wheels
	6c. Misalignment	a. Setting-up errors	N			Y	Y						Vibration monitoring of the gearbox
		b. Elastic deflection of components under load	N			Y	Y						Vibration monitoring of the gearbox
		c. Thermal expansion of components	N			Y	Y						Vibration monitoring of the gearbox
	6d. Thermal instability	a. Failed cooling system	N			Y	Y						Temperature monitoring of the gearbox
		b. High operating speed	N			Y	Y						Temperature monitoring of the gearbox
		c. External heat conducted into shaft	N			Y	Y						Temperature monitoring of the gearbox
	6e. Torsional and lateral vibrations	a. Interaction between gearbox components masses, inertias and stiffness	N			Y	Y						Vibration monitoring of the gearbox
		b. Interaction between gearbox, mounting and supporting structures	N			Y	Y						Vibration monitoring of the gearbox
	6f. Unexpected load	a. Worn out couplings	N			Y	Y						Vibration monitoring of the gearbox

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[11] Eccentricity: defects caused by a high point, tooth or oval casting (Murphy T.J. 2004)
[12] Backlash – gear teeth cut a little smaller to allow free space between teeth when they mesh (Manwell J.F et al. 2002)

		b. Worn out bearings	N			Y	Y						Vibration monitoring of the gearbox
		c. Shafts tortional deflection	N			Y	Y						Vibration monitoring of the gearbox
	6g. Lubrication failure	a. Shearing of oil molecules	N			Y	Y						On-line oil analysis of gearbox
		b. oxidation of base oil	N			Y	Y						On-line oil analysis of gearbox
		c. additive depletion	N			Y	Y						On-line oil analysis of gearbox
		d. moisture sucked in through breathers and vent or missing lip seals	N			Y	Y						On-line oil analysis of gearbox
		e. build up of sludge	N			Y	Y						On-line oil analysis of gearbox
		f. Use of wrong lubricant	N			Y	Y						On-line oil analysis of gearbox
		g. Lubricant deterioration due to excessive operating temperature	N			Y	Y						Temperature monitoring of the gearbox
		h. Operating beyond lubricant life	N			Y	N	N	Y				Change lubrication oil of the gearbox
	6h. Foreign object in gearbox	a. Left-in objects	N			Y	Y						Vibration monitoring of the gearbox
		b. Loose parts	N			Y	Y						Vibration monitoring of the gearbox
	7. Gearbox – generator coupling failure	a. Damaged flexible coupler	Y			Y	Y						Variation in process parameter measurements of high speed shaft out put and generator rotor input
		b. Broken or loose bolts	Y			Y	Y						Variation in process parameter measurements of high speed shaft out put and generator rotor input

		c. Improper fitting	Y			Y	Y						Variation in process parameter measurements of high speed shaft out put and generator rotor input
		d. Excessive operating torque	Y			Y	Y						Variation in process parameter measurements of high speed shaft out put and generator rotor input
	8. Generator failure	a. Loose rotor on shaft	Y	Y		Y							Vibration monitoring of generator shaft
		b. Rolling bearing seizes	Y			Y	Y						Vibration monitoring of bearing of the generator
		c. Stator insulation breakdown	Y			Y	Y						Variation in performance parameter of the generator
		d. Broken rotor bar	Y			Y	Y						Variation in performance parameter of the generator
		e. Crack between rotor bars and rings	Y			Y	Y						Variation in performance parameter of the generator
		f. Overheating	Y	Y		Y							Temperature monitoring of the generator
		g. Torsional and lateral vibrations	Y			Y	Y						Vibration monitoring of generator
	8a. Loose rotor on shafts	a. Loose couplings	Y			Y	Y						Vibration monitoring of generator
		b. Setting up errors	Y			Y	Y						Vibration monitoring of generator
	8b. Rolling bearing seizes	a. Lack of lubricant	N			Y	Y						Vibration monitoring of bearing of the generator
		b. Contaminated lubricant	N			Y	Y						Oil analysis of generator bearing

		c. Operating beyond lubricant life	N			N	N	N	Y				Clean and apply lubricant to bearing of the generator
		d. Misalignment	N			Y	Y						Vibration monitoring of bearing of the generator
		e. Vibration and shock	N			Y	Y						Vibration monitoring of bearing of the generator
		f. Excessive force used during fitting of couplings	N			Y	Y						Vibration monitoring of bearing of the generator
		g. False brinelling	N			Y	Y						Vibration monitoring of bearing of the generator
		h. Corrosion due to water ingression	N			Y	N	N	N	Y			Inspect generator for corrosion creep
		i. Normal wear and tear	N			Y			Y				Replace bearing of the generator
	8c. Stator insulation breakdown	a. Excessive heat within windings/core iron	N	Y			Y						Temperature monitoring of the generator
		b. Partially or totally blocked ventilation passages	N	Y			Y						Temperature monitoring of the generator
		c. Damaged or destroyed external cooling fan	N	Y			Y						Temperature monitoring of the generator
		d. Foreign substance build-up on generator surface	N	Y			Y						Temperature monitoring of the generator

		e. Generator operating in direct sunlight for long periods of time.	N	Y			Y						Temperature monitoring of the generator
		f. High humidity	N	Y			Y						Variation in process parameter of the generator
		g. Normal wear and tear	N	Y			N	N	Y				Replace generator at end of life
	8c. Rotor bar breaks	a. Worn bearings	N	Y			Y						Vibration monitoring of bearing of the generator
		b. Excessive operating torque	N	Y			Y						Vibration monitoring of bearing of the generator
	8d. Cracks between rotor bars and rings	a. Fatigue	N	Y			Y						Variation in performance parameter technique
		b. Manufacturing defects	N	Y			Y						Variation in performance parameter technique
	8f. Overheating	a. Overloading	N	Y			Y						Temperature monitoring of the generator
		b. Damaged or destroyed external cooling fan	N	Y			Y						Temperature monitoring of the generator
		c. Eddy current losses	N	Y			Y						Temperature monitoring of the generator
		d. Unbalanced voltage	N	Y			Y						Temperature monitoring of the generator
		e. High ambient temperature	N	Y			Y						Temperature monitoring of the generator

	8g. Torsional and lateral vibrations	a. Interaction between generator components masses, inertias and stiffness	N			Y	Y						Vibration monitoring of the generator
		b. Interaction between generator mounting and supporting structures	N			Y	Y						Vibration monitoring of the generator
		c. Worn couplings	N			Y	Y						Vibration monitoring of bearing of the generator
		d. Worn out bearing	N			Y	Y						Vibration monitoring of bearing of the generator
	9. Meteorological system failure	a. Anemometer seizes	N			Y	Y						Variation in wind speed at main mast and wind turbine
		b. Potentiometer wind vane seizes	N			Y	Y						Variation in wind direction at main mast and wind turbine
		c. Barometric pressure sensor seizes	N			Y	Y						Variation in pressure at main mast and wind turbine
	10. Premature brake activation	a. Meteorological measurement error	Y			Y	Y						Variation in process parameters
		b. System controller error	Y			Y	Y						Variation in process parameter
		c. Mechanical brake shoes stuck	Y			Y	N	N	N	Y			Inspect braking system for insipient fault
		d. Too much pretension of spring in calliper	Y			Y	N	N	N	Y			Inspect braking system for insipient fault

	11. Tower failure	a. Buckling	Y	Y			Y						Vibration monitoring of tower
		b. Cracks	Y	Y			N	N	N	Y			Inspection of towers for cracks
		c. Fatigue	Y	Y			Y						Strain measurement
		d. Corrosion	Y	Y			N	N	N	Y			Inspection of towers for corrosion creep
	10a. Buckling	a. Loose or broken bolts at joints	N	Y			Y						Vibration monitoring of tower
		b. Corrosion creep	N	Y			Y						Corrosion monitoring
		c. Erecting error	N	Y			Y						Vibration monitoring of tower
		d. Poor material design	N	Y			Y						Vibration monitoring of tower
		e. Unbalanced interface between tower and nacelle	N	Y			Y						Vibration monitoring of tower
		f. Loose connection between foundation and towers	N	Y			Y						Vibration monitoring of tower
	12. Foundation failure	a. Inappropriate foundation type	Y	Y			Y						Vibration monitoring of tower
		b. Insufficient distance into subsoil	Y	Y			Y						Vibration monitoring of tower
		c. Defects in workmanship	Y	Y			Y						Vibration monitoring of tower
		d. Corrosion creep	Y	Y			Y						Corrosion monitoring
		e. Deterioration due to long term exposure to climatic extremes	Y	Y			Y	N	N	Y			Inspect foundation for fault

APPENDIX A2

Functional Failure B: *Partial Loss of Energy Conversion Capability*

SYSTEM: Horizontal Axis Wind Turbine (HAWT) comprising of 3 blades up wind and pitch controlled, 3-stage planetary gearbox, 4-poles asynchronous generator, etc.										System No 1			Facilitator:
										Sub-system No			Auditor:
Function: To convert wind kinetic energy into electrical energy within defined speed limit.			**Consequence Evaluation**				**H1 S1 O1 N1**	**H2 S2 O2 N2**	**H3 S3 O3 N3**	**Default action**			**Proposed Task**
Functional failures	**Failure modes**	**Failure causes**	**H**	**S**	**E**	**O**				**H4**	**H5**	**S4**	
B. PARTIAL LOSS OF ENERGY CONVERSION CAPABILITY	**1. Crack in blades**	a. Excessive cyclic loading	N			Y	Y						Strain measurement for load monitoring and vibration
		b. Excessive flap-wise loading	N			Y	Y						Strain measurement for load monitoring and vibration
		c. Bad cohesion between skin laminate and matrix	N			Y	Y						Fibre optics measurement
		d. No cohesion between main spar and matrix	N			Y	Y						Fibre optics measurement
		e. Delamination between plies	N			Y	Y						Fibre optics measurement
		f. Porosities in skin	N			Y	Y						Fibre optics measurement
		g. damaged gel coat											
	2. Deteriorating blade root stiffness	a. Fatigue	N			Y	Y						Fibre optics measurement
		b. Delamination	N			Y	Y						Fibre optics measurement
		c. Poor design	N			Y	Y						Fibre optics measurement
	3. Blades imbalance	a. Blades at different pitches	N			Y	Y						Variation in performance: acceleration measurement with relation to pitch angle and rotor position

	4. Dirt build-up on blades	a. Insects	N			Y	N	Y					Clean blades
		b. Debris from surrounding	N			Y	N	Y					Clean blades
	5. Ice build-up on blades	a. Weather elements	N			Y	N	Y					Clean blades
	6. Damping in blades	a. Porous blade finishing	N			Y	Y						Fibre optics measurement
	7. Hub slip or spin on shaft	a. Broken or loose bolts	N			Y	Y						Variation in performance parameter of blades speed and the low-speed shaft
		b. Fitting error	N			Y	Y						Variation in performance parameter of blades speed and the low-speed shaft
	8. Low speed shaft misalignment	a. Blade imbalance	N			Y	Y						Acceleration measurement with relation to pitch angle and rotor position
		b. Deflection under load	N			Y	Y						Vibration monitoring of low speed shaft
		c. Fitting error	N			Y	Y						Vibration monitoring of low speed shaft
	9. Nacelle not yawing	a. Yaw electric drive motor seizes	Y			Y	Y						Variation in process parameter of wind vane and yaw direction
		b. Yaw bearing seizes	Y			Y	Y						Variation in process parameter of wind vane and yaw direction
		c. Foreign object between bull gear and drive pinion gear	Y			Y	Y						Variation in process parameter of wind vane and yaw direction

		d. Premature activation of yaw brake	Y			Y	Y						Variation in process parameter of wind vane and yaw direction
		e. Drive pinion gear teeth wear	Y			Y	Y						Variation in process parameter of wind vane and yaw direction
		f. Bull gear teeth wear	Y			Y	Y						Variation in process parameter of wind vane and yaw direction
	10. Nacelle yaw too slow	a. Misalignment of drive pinion gear and bull gear	N			Y	Y						Variation in process parameter of wind vane and yaw direction
	11. Nacelle yaw too fast	a. Yaw gear reducer seizes	N			Y	Y						Variation in process parameter of wind vane and yaw direction
		b. Insufficient brake friction	N			Y	Y						Variation in process parameter of wind vane and yaw direction
	12. Large yaw angle	a. Yaw error	N			Y	Y						Variation in process parameter technique
	13. Cable twist	a. Failed cable twist sensor	N				N	N	N	Y			Inspect cable twist sensors
		b. Disconnection of signal cables from the controller	N			Y	Y						Electrical effects
		c. cable short circuit of signals to the controller	N			Y	Y						Electrical effects

	14. Wind speed measurement error	a. Faulty electrical wiring in anemometer	N			Y	Y						Variation in process parameter technique
		b. Defective bearing in anemometer	N			Y	Y						Variation in process parameter technique
		c. Anemometer deteriorating due to long term exposure to climatic extremes	N			Y	Y						Variation in process parameter technique
		d. Anemometer not suitable for application	N			Y	Y						Variation in process parameter technique
	15. Wind direction measurement error	a. Potentiometer wind vane deteriorating due to long term exposure to climatic extremes	N			Y	Y						Variation in process parameter technique
		b. Potentiometer wind vane not suitable for application	N			Y	Y						Variation in process parameter technique
	16. Air density measurement error	a. Barometric pressure sensor deteriorating due to long term exposure to climatic extremes	N			Y	Y						Variation in process parameter technique
		b. Barometric pressure sensor not suitable for application	N			Y	Y						Variation in process parameter technique

APPENDIX A3

Functional failure C: *Over Speeding*

SYSTEM: Horizontal Axis Wind Turbine (HAWT) comprising of 3 blades up wind and pitch controlled, 3-stage planetary gearbox, 4-poles asynchronous generator, etc.										System No 1			Facilitator:
										Sub-system No			Auditor:
Function: To convert wind kinetic energy into electrical energy within defined speed limit.			**Consequence Evaluation**				**H1 S1 O1 N1**	**H2 S2 O2 N2**	**H3 S3 O3 N3**	**Default action**			**Proposed Task**
Functional failures	**Failure modes**	**Failure causes**	**H**	**S**	**E**	**O**				**H4**	**H5**	**S4**	
C. OVER SPEEDING	**1. Controller failure**	a. Failed sensors	Y	Y			N	N	N	Y			Inspect controller for failed sensors
		b. Disconnection of signal cables to the controller	Y	Y			Y						Thermography
		c. Cable short circuit of signals to the controller	Y	Y			Y						Thermography
		d. Failed contactors	Y	Y			N	N	N	Y			Inspect controller for failed contactors
		e. failed switching relays	Y	Y			N	N	N	Y			Inspect controller for failed switching relays
		f. failed fuses	Y	Y			N	N	N	Y			Inspect controller for failed fuses
		g. Software design error	Y	Y			Y						Variation in process parameter technique
		h. Measurement error	Y	Y			Y						Variation in process parameter technique
		i. Lightening strike	Y	Y			N	N	N	Y			Inspect lightening protection devices

	2. Hydraulic system failure	a. Contaminated hydraulic oil[13]	N	Y			Y						Hydraulic oil analysis
		b. Wrong oil viscosity	N	Y			Y						Hydraulic oil analysis
		c. High hydraulic fluid temperature	N	Y			Y						Temperature measurement of hydraulic oil
		d. Hydraulic pump failure	N	Y			Y						Variation in process parameter technique- pressure measurement
		e. Hydraulic cylinder failure	N	Y			Y						Variation in process parameter technique- pressure measurement
		f. Hydraulic valve failure	N	Y			Y						Variation in process parameter technique- pressure measurement
		g. Faulty circuit protection devices.	N	Y			Y						Tribology
		h. Hydraulic seal failure	N	Y			Y						Tribology
		i. Hydraulic hose failure	N	Y			Y						Tribology
		j. Operating beyond filters life	N	Y			N	N	Y				Replace filters
	2c. High hydraulic fluid temperature	a. Failed cooling system	N	Y			Y						Temperature measurement of hydraulic oil
	2f.Hydraulic valve failure	a. Cavitations[14]	N	Y			Y						Variation in process parameter – pressure measurement

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[13] Contaminants include solid particles, air, water or any matter that impairs the function of the fluid

[14] Cavitations occur when the volume of hydraulic fluid demanded by any part of a hydraulic circuit exceeds the volume of fluid being supplied.

		b. High temperature	N	Y			Y						Temperature measurement of hydraulic oil
	2h. Hydraulic seal failure	a. Improper installation	N	Y			Y						Tribology
		b. Hydraulic system contamination	N	Y			Y						Tribology
		c. chemical break down of the seal	N	Y			Y						Tribology
		d. Heat degradation	N	Y			N	N	Y				Replace seal
	2j Hydraulic hose failure	a. External damage through pulling, kinking, crushing or abrasion of the hose.	N	Y			N	N	N	Y			Inspect hydraulic hoses for damages
		b. Multi plane bending	N	Y			N	N	N	Y			Inspect hoses for damages
		c. Temperature extremes	N	Y			Y						Temperature measurement of hydraulic oil
	3. Pitching system failure	a. Pitching bearings seizes	Y	Y			Y						Acceleration measurement in relation to pitch angle and rotor position
		b. Disconnection of pitch angle signal to the controller	Y	Y			Y						Acceleration measurement in relation to pitch angle and rotor position
		c. Disconnection of hydraulic pump signal cables from the controller	Y	Y			Y						Acceleration measurement in relation to pitch angle and rotor position
		d. Cable short circuit of signals to the controller	Y	Y			Y						Acceleration measurement in relation to pitch angle and rotor position

		e. Slip-ring fails	Y	Y			Y						Acceleration measurement in relation to pitch angle and rotor position
	3a. Pitching bearing seizes	a. Fatigue deterioration	N	Y			Y						Vibration monitoring of pitch bearing
		b. Misalignment	N	Y			Y						Vibration monitoring of pitch bearing
		c. Lack of lubricant	N	Y			Y						Vibration monitoring of pitch bearing
		d. Contaminated lubricant	N	Y			Y						Vibration monitoring of pitch bearing
		e. wrong lubricant	N	Y			Y						Vibration monitoring of pitch bearing
		f. Fitting error	N	Y			Y						Vibration monitoring of pitch bearing
	4. Mechanical brake failure	a. Insufficient friction	N	Y			N	N	N	Y			Inspect mechanical braking system
		b. Too much friction	N	Y			N	N	N	Y			Inspect mechanical braking system
	4a. Insufficient mechanical brake friction	a. Too much wear of brake pads and shoes	N	Y			N	N	Y				Change mechanical brake pad and shoes
		b. Too little pretension of spring in calliper	N	Y			Y						Variation in performance parameter technique
		c. Spring in calliper broken	N	Y			Y						Variation in performance parameter technique
		d. Degraded hydraulic oil	N	Y			N	N	Y				Change hydraulic oil

		e. Too much wear of brake disc	N	Y			N	N	Y				Replace mechanical brake disc
		f. Malfunctioning of combination valve	N	Y			Y						Variation in performance parameter technique
		g. Leakage in the brake system	N	Y			N	N	N	Y			Inspect braking system for leakage
	4b. Too much friction	a. Brake shoes stuck	N	Y			Y						Variation in performance parameter technique
		b. Too much pretension of spring in calliper	N	Y			Y						Variation in performance parameter technique
	5. Grid connection failure	a. Power line fails	Y	Y			Y						Controller fail safe
		b. Disconnection of generator while turbine is in operation	Y	Y			Y						Controller fail safe

APPENDIX B

GLOSSARY

A^* = Best alternatives
A_{CR} = Annual cost reservation
AC_{CBM} =Annual condition based servicing of drive train
$ALCA$ = Asset Life Cycle Analysis
AM_{cm} =Annual maintenance cost of condition monitoring
AM =Asset Management
$AMOR$ = Applied Mathematics & Operational Research
BTC = Benefit- to-cost ratio
BS = British Standard
CBM = Condition Based Maintenance
C_{MT} = Cost of material
C_{Ld} = Cost of loading
C_{Old} = Cost of offloading
C_{TP} = Cost of transportation
C_{CR} = Cost of crane hire per day (including cost of driver, mobilisation and demobilisation fee)
C_{EH} = Cost of energy per kWh
C_f = Capacity factor
C_{cm} = Capital cost of condition monitoring system
CBM = Condition Based Maintenance
$CREST$ = Centre for Renewable Energy Systems Technology
CTA = Critical Task Analysis
$DTMM$ = Delay Time Maintenance Model
d = Discount rate (% /100)
ECN = Energy Centre Netherlands
ETA = Event Tree Analysis
ESI = Electricity Supply Industry
$EWTCG$ = European Wind Turbine Certification Guidelines
F =Failure
F_c = Failure consequences
FBM = Failure Based Maintenance
$FMEA$ = Failure Mode and Effect Analysis
FTA =Fault Tree Analysis
$F(T)$ =Cumulative Distribution Function
$f(T)$ = Probability Density Function
GRP = Glass fibre Reinforced Plastic
GSN = Generator Serial Number
$HAZAN$ = HAZard ANalysis
$HAZOP$ = HAZard OPeratibility
HSE = Health, Safety and Environment
HSS =High Speed Shaft
i= Alternative
IAM =Institute of Asset Management
IMS =InterMediary speed Shaft
IEC = International Electro-Technical Commission
KPM = Key Performance Measurement
KPI = Key Performance Indicator
LCC = Life Cycle Cost
L_{RT} = Labour rate per hour
L_{hc} = Lead time to hire a crane
m = Decision criteria
$MTBF$ =Mean Time Between Failure
$MTTF$ =Mean Time To Failure
$MTTR$ =Mean Time To Repair
MLE = Maximum Likelihood Estimation
MSF = Modelling Systems Failure
MW = Mega Watt
n = Number of competing alternatives
N_{Pn} = Number of person

N_{dy} = Number of working days
N_T = Number of turbines in a wind farm
NPV_{CBM} = Net present Value of Condition Based Maintenance
NPV_{TBM} = Net present Value of Time Based Maintenance
OEM = Original Equipment Manufacturer
$O\&G$ = Oil &Gas
$O\&M$ = Operation &Maintenance
$P-F$ Interval =P is point where defect can be identified and F point where component fails
PM =Preventive Maintenance
PW = Present worth
PWA = Present worth per annum
QRA = Quantified Risk Assessment
QMO = Quantitative Maintenance Optimisation
R_{dy} = Replacement days including travel time
RAM = Reliability Availability and Maintainability
RBI = Risk Based Inspection
RBD = Reliability Block Diagram
RCM = Reliability Centred Maintenance
RCA = Root Cause Analysis
RPM = Revolution Per Minute
RO = Renewable Obligation order
ROC = Renewable Obligation Certificate
S = Suspension
S_i = Total score of alternative
S_{ij} = Alternative ratings
$SCADA$ = Supervisory Control and Data Acquisition
$SCIG$ = Squirrel Cage Induction Generator
$SWIFT$ = Structured What IF Technique
T = Time
TA_{CI} = Total annual cost of inspection
TBM = Time Based Maintenance
TPM = Total Productive Maintenance
T_{PL} = Total Production loss
TC_{LB} = Total cost of labour
TC_{AS} = Total cost of access
TC_{MT} = Total cost of material
T = Analysis period
V_{AT} = Value added tax
W_j = Criterion weight
W_{hr} = Work hours per day
WE = Weighted Evaluation
WSI = Water Supply Industry
WT = Wind Turbine
WF = Wind Farm
WT_{PR} = Wind turbine power rating in kilowatt (kW)
α = Defects rate
β = Shape Parameter of the Weibull distribution
η = Scale Parameter of the Weibull distribution
φ = Failure rate
$\frac{1}{\gamma}$ = Delay time
Δ = Inspection Interval
Δ^* = Optimal Inspection Interval

APPENDIX C

ABSTRACTS OF PUBLISHED PAPERS

Three (3) journal and three (3) conference papers have been published as a result of the research work that underpins this thesis. Also, two (2) additional papers have been written and are currently under review for journals publication. Abstracts of the six (6) published papers are presented as follows:

C.1 ASSET MANAGEMENT PROCESSES IN THE WIND ENERGY INDUSTRY

Jesse A Andrawus, John Watson and Mohammed Kishk

Proceedings of the 2nd Joint International Conference on "Sustainable Energy and Environment (SEE 2006)" 21-23 November 2006, Bangkok, Thailand, 269-274.

Asset management (AM) has evolved from several industrial sectors to describe holistic application of business best practices to satisfy all stakeholders' requirements. The processes, tools and techniques of AM are currently well-established in the mature industries. On the other hand, wind is becoming an increasingly important source of energy for countries that ratify to reduce emission of greenhouse gases and mitigate global warming. This creates a huge investment potential for the wind energy industry with a wide range of possible stakeholders. However, achieving return on investment in wind farms is affected by interrelated stakeholders' requirements and assets technical issues. These require a well-founded Asset Management (AM) frame-work currently lacking in the wind industry. The main objective of this paper is to identify and transform crucial requirements for effective management of wind farms into AM processes as a first step towards developing a structured model for AM in the wind energy industry. Six fundamental processes are determined and presented with a detailed explanation.

Keywords: *Asset Management, Wind Energy, Business Values, Process modelling.*

C.2 DETERMINING AN APPROPRIATE CONDITION-BASED MAINTENANCE STRATEGY FOR WIND TURBINES

Jesse A Andrawus, John Watson, Mohammed Kishk and Allan Adam

Proceedings of the 2nd Joint International Conference on "Sustainable Energy and Environment (SEE 2006)" 21-23 November 2006, Bangkok, Thailand, 275-280.

Maintenance is fundamental to effective management of wind farms due to its impact on productivity of wind turbines, operational costs and hence revenue generation. Essentially, there are two common maintenance strategies applied to wind turbines; Time-Based Maintenance (TBM) which involves carrying out tasks at predetermined regular-intervals and Failure-Based Maintenance (FBM) which involves using a wind turbine until it fails. However, the impact of failure consequences on revenue generation and electricity network limit the adequacy of these strategies to support the current commercial drivers of the wind industry. Reliability-Centred Maintenance (RCM) is a technique mostly used to select suitable maintenance strategies for physical assets. In this paper, the approach of RCM is applied to Horizontal Axis Wind Turbines to identify possible failure modes, causes and the resultant effects on system operation. Suitable Conditioned Based Maintenance (CBM) activities are identified.

Keywords: *Wind turbines, Reliability-Centred Maintenance, Condition-Based Maintenance.*

C.3 THE SELECTION OF A SUITABLE MAINTENANCE STRATEGY FOR WIND TURBINES

Jesse A. Andrawus, John Watson, Mohammed Kishk and Allan Adam

International Journal of Wind Engineering, 2006, Vol 30 No 6, pp. 471-486.

Common maintenance strategies applied to wind turbines include ‘Time-Based’ which involves carrying out maintenance tasks at predetermined regular-intervals and ‘Failure-Based’ which entails using a wind turbine until it fails. However, the consequence of failure of critical components limits the adequacy of these strategies to support the current commercial drivers of the wind industry. Reliability-Centred Maintenance (RCM) is a technique used mostly to select appropriate maintenance strategies for physical assets. In this paper, a hybrid of an RCM approach and Asset Life-Cycle Analysis technique is applied to Horizontal-Axis Wind Turbines to identify possible failure modes, causes and the resultant effects on system operation. The failure consequences of critical components are evaluated and expressed in financial terms. Suitable Condition-Based Maintenance activities are identified and assessed over the life-cycle of wind turbines to maximise the return on investment in wind farms.

Keywords: *Wind turbines, Reliability-Centred Maintenance, Failure Mode and Effect Analysis, Asset Life-cycle Analysis, Condition-Based Maintenance.*

C.4 WIND TURBINE MAINTENANCE OPTIMISATION: PRINCIPLES OF QUANTITATIVE MAINTENANCE OPTIMISATION

Jesse A. Andrawus, John Watson and Mohammed Kishk

International Journal of Wind Engineering, 2007, Vol 31 No 2, pp. 101-110.

Maintenance optimisation is a crucial issue for industries that utilise physical assets due to its impact on costs, risks and performance. Current quantitative maintenance optimisation techniques include Modelling System Failures MSF (using Monte Carlo simulation) and Delay-Time Maintenance Model (DTMM). The MSF investigates equipment failure patterns by using failure distribution, resource availability and spare-holdings to determine optimum maintenance requirements. The DTMM approach examines equipment failure patterns by considering failure consequences, inspection costs and the period to determine optimum inspection intervals. This paper discusses the concept, relevance and applicability of the MSF and DTMM techniques to the wind energy industry. Institutional consideration as well as the benefits of practical implementation of the techniques are highlighted and discussed.

Keywords: *Wind turbine, Maintenance optimisation, Modelling System Failures, Monte Carlo Simulation, Delay-time maintenance model.*

C.5 MAINTENANCE OPTIMISATION OF WIND TURBINES: LESSONS FOR THE BUILT ENVIRONMENT

Jesse A. Andrawus, John Watson and Mohammed Kishk

Proceedings 23rd Annual ARCOM Conference, 3-5 September 2007, Belfast, UK, Association of Researchers in Construction Management, 893-902.

Maintenance optimisation is indispensable to the core business objectives of industries that utilises physical assets. A quantitative maintenance optimisation technique known as the Modelling System Failures (MSF) is critically reviewed to identify its relevance to industries that employs physical assets. Practical application of the approach to optimise the maintenance activities of wind turbines is explored and discussed in a case study. The analysis is based maximum likelihood parameter estimation in the Weibull distribution. Shape and scale parameters for a gearbox and its components are estimated. The estimated parameters are used to design Reliability Block Diagrams to model the failures of the gearbox of a selected wind turbine. The models are simulated using Monte Carlo simulation software to assess the reliability, availability and maintainability of the gearbox, and the resultant effects on the wind turbine operation. The methodology presented in the paper is sufficiently generic to any mechanical system in the Built Environment/Construction Industry.

Keywords: *Wind Turbine, Maintenance Optimisation, Monte Carlo Simulation, Reliability Block Diagrams.*

C.6 MODELLING SYSTEM FAILURES TO OPTIMISE WIND TURBINE MAINTENANCE

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Modelling System Failures (MSF) is a unique quantitative maintenance optimisation technique which permits the evaluation of life-data samples and enables the design and simulation of the system's model to determine optimum maintenance activities. In this paper, the approach of MSF is used to assess the failure characteristics of a horizontal axis wind turbine. Field failure data are collated and analysed using the Maximum Likelihood Estimation in the Weibull Distribution; hence shape (β) and scale (η) parameters are estimated for critical components and subsystems of the wind turbine. Reliability Block Diagrams are designed to model the failures of the wind turbine and of a selected wind farm. The models are simulated to assess the reliability, availability and maintainability of the wind turbine and the farm; taking into account the costs and availability of maintenance crew and spares holding. Optimal maintenance activities are determined to minimise the total life-cycle cost of the wind farm.

Key words: *Wind turbine, Failure Modelling, Reliability, Availability and Maintenance Optimisation*