Article

Failure Modes, Effects and Criticality Analysis for Wind Turbines Considering Climatic Regions and Comparing Geared and Direct Drive Wind Turbines

Samet Ozturk[1], Vasilis M. Fthenakis[1,*], Stefan Faulstich[2]

[1] Columbia University, 116th St & Broadway, New York, NY 10027

[2] Fraunhofer Institute for Energy Economics and Energy System Technology, Kassel, Germany

* Corresponding author: vmf5@columbia.edu

Abstract: The wind industry is looking for ways to accurately predict the reliability and availability of newly installed wind turbines. Failure modes, effects and criticality analysis (FMECA) is a technique utilized for determining the critical subsystems of wind turbines. There are several studies which applied FMECA for wind turbines in the literature, but no studies so far have considered different weather conditions or climatic regions. Furthermore, various design types of wind turbines have been analyzed applying FMECA but no study so far has applied FMECA to compare the reliability of geared and direct-drive wind turbines. We propose to fill these gaps by using Koppen-Geiger climatic regions and two different turbine models of direct-drive and geared-drive concepts. A case study is applied on German wind farms utilizing the WMEP database which contains wind turbine failure data from 1989 to 2008. This proposed methodology increases the accuracy of reliability and availability predictions and compares different wind turbine design types and eliminates underestimation of impacts of different weather conditions.

Keywords: Reliability; FMEA; wind turbines; climatic conditions; wind turbine type

1. Introduction

Wind energy is one of the most profitable among renewable and clean energy sources and its deployment is constantly increasing having doubled during the last six years [1]. However, large deployment of a variable energy creates some concerns regarding reliability and availability. Reliability is defined as the ability to perform as required, without failure, for a given time interval under given conditions, whereas availability is defined as the ability to be in a state to perform as required in the International Electrotechnical commission (IEC) 60050 standards [2, 3]. In order to improve the reliability and availability of wind turbines the first step is to determine the causes of failures, failure frequencies, effects of failures and criticalities accurately. The aim of this study is to generalize the findings on the reliability predictions so that they guide the deployment of new wind turbines.

Failure Modes and Effects Analysis (FMEA) is a method which detects potential failure modes of a product during its life cycle; the effects of these failures; and the criticality of these failure effects in product functionality [4]. It is widely utilized for mechanical, electrical, electronical and structural systems as well as chemical processes in the industry to sufficiently allocate budget for high priorities. Failure Modes, Effects and Criticality Analysis (FMECA) is an extension of FMEA by including criticality analysis which is used to quantify criticality of the failure modes in a specific subsystem or component. There are several studies which applied FMEA for wind turbines in the literature [5 - 10, 15 - 20].

Andrawus et al [5] conducted FMECA to optimize the maintenance strategy for 26x600 kW wind farm whereas qualitative FMEA is utilized to prioritize the failure modes in other studies using data from specific turbine models [6-8]. Dinmohammadi and Shafiee [9] used a fuzzy-FMEA and compared the results with traditional FMEA but they only used a single turbine model and did not consider climatic conditions. Shafiee and Dinmohammadi [10] compared onshore and offshore FMEA results using field data from several resources [11-14] whereas a combined field data is utilized in [15] to apply FMEA. Direct-drive wind turbine model is distinctively considered for FMEA in [16] whereas other studies either used combined field data or geared-drive wind turbine models for FMEA application. FMEA is applied for design improvement perspective in [17, 18] considering a specific turbine model while required maintenance action is added to FMEA in [19]. Tazi et al [20] proposed a hybrid cost-FMEA for wind turbine reliability analysis and used a combined field data from several sources [14, 21-24]. However, no studies have, so far, applied FMECA considering different weather conditions or climatic regions. Also, in several references FMEA is applied to different turbine configurations as considering geared or direct drive or combination of these turbine types but no study compared the FMEA results from direct drive and geared wind turbine technologies comparatively. Nevertheless, as it is stated in [20] the criticality outcomes are influenced by the weather impacts. Therefore, our study aims to fill these literature gaps in by achieving the following:

1- Determining impacts of climatic regions on wind turbine subsystem annual failure rate and downtime per failure values by using failure data from an identical turbine model.

2- Investigating wind turbine subsystem and component failure causes, effects and criticalities considering climatic regions.

3- Defining the differences in annual failure rate and downtime for direct drive and geared wind turbines and revealing differences in failure causes of such failures, effects and criticalities.

2. Materials and Methods

This study has four different methodological dimensions; these are a) obtaining reliability and availability metrics for an identical turbine model for different climatic regions, b) applying FMECA on the identical turbine models for different climatic regions, c) revealing reliability metrics for two different turbine types for same climatic region and d) applying FMECA on different turbine types. To reach the first objective, there is a need to classify wind turbine locations based on the meteorological parameters. To attain the second objective a FMECA is applied to all wind turbines considering a turbine model which is spread to different climatic regions. To reach the third objective, two turbine models which represent two different turbine designs are selected from WMEP database and FMECA is applied considering on them.

2.1. Climatic regions

Koppen-Geiger is a climate classification and being cited by almost 5,000 studies in variety of disciplines [25]. Koppen-Geiger climatic regions which are determined based on annual precipitation and temperature records along with seasonal temperature records utilize 12,396 precipitation and 4,844 temperature data stations globally and apply several temperature and precipitation criteria [25]. In Germany, there are four Koppen-Geiger climatic regions as it is seen in Figure 1. Climatic regions which are present in Germany as follows:

- Cfa: Temperate-without dry season-hot summer
- Cfb: Temperate-without dry season-warm summer
- Dfb: Cold-without dry season-warm summer
- Dfc: Cold-without dry season-cold summer

Criteria for the classification of the climatic regions of interest are given in Table 1 [25].

Table 1. Criteria for the climatic region classifications for Germany

1st	2nd	3rd	Description	Criteria*
C			Temperate	$T_{hot} \geq 10$ & $0 < T_{cold} < 18$
	s		- Dry Summer	$P_{sdry} < 40$ & $P_{sdry} < P_{wwet}/3$
	w		- Dry Winter	$P_{wdry} < P_{swet}/10$
	f		- Without dry season	Not (Cs) or (Cw)
		a	- Hot Summer	$T_{hot} \geq 22$
		b	- Warm Summer	Not (a) & $T_{mon10} \geq 4$
		c	- Cold Summer	Not (a or b) & $1 \leq T_{mon10} < 4$
D			Cold	$T_{hot} \geq 10$ & $T_{cold} \leq 0$
	s		- Dry Summer	$P_{sdry} < 40$ & $P_{sdry} < P_{wwet}/3$
	w		- Dry Winter	$P_{wdry} < P_{swet}/10$
	f		- Without dry season	Not (Ds) or (Dw)
		a	- Hot Summer	$T_{hot} \geq 22$
		b	- Warm Summer	Not (a) & $T_{mon10} \geq 4$
		c	- Cold Summer	Not (a, b or d)
		d	- Very Cold Winter	Not (a or b) & $T_{cold} < -38$

*T_{hot} = temperature of the hottest month, T_{cold} = temperature of the coldest month, T_{mon10} = number of months where the temperature is above 10, P_{dry} = precipitation of the driest month, P_{sdry} = precipitation of the driest month in summer, P_{wdry} = precipitation of the driest month in winter, P_{swet} = precipitation of the wettest month in summer, P_{wwet} = precipitation of the wettest month in winter.

2.2. WMEP data

The source of our failure data is the WMEP database which covers wind turbines operating in Germany between 1989 and 2008. The events in WMEP database include scheduled maintenance, scheduled maintenance with replacement or repair, and unscheduled maintenance with a replacement or repair with additional information such as energy delivery. The WMEP survey collected operations and maintenance data from more than 1500 wind turbines, in this study data from 575 of them are ready to be utilized with 6188 turbine years of operation and including 19,242 events considering a repair or replacement.

Figure 1 shows the wind turbine locations in Germany in the WMEP database that we use in this study. There are 427 wind turbines – 4526 turbine years in Cfb region, 122 wind turbines – 1346 turbine years in Dfb region, 25 wind turbines – 306 turbine years in Dfc region in the WMEP database.

For the investigation of the climatic region effect, a control wind turbine model is selected among the highest most common in the WMEP database. For the investigation of turbine type impact, two different wind turbine models are selected as the details are given in Table 2. A sensitivity analysis has been conducted to see the impacts of turbine capacity, rotor diameter and hub heights for wind turbine model reliability comparison.

Table 2. Selected wind turbines from WMEP database for this study

	Direct-drive WTs	Geared-drive WTs	Control group of WTs (geared-drive)			
			All	Cfb	Dfb	Dfc
Number of WTs	48	15	39	15	18	6
Operation years	493 turbine-years	152 turbine-years	432	152	208	73
Capacity	500 kW	500 kW	500 kW			
Rotor Diameter	40 m	39 m	39 m			

Fig. 1. Map of 575 wind turbines (black dots) in different climatic regions in Germany

2.3. FMECA approach and components

FMECA requires a taxonomy for wind turbine subsystems. In this study, subsystems and assemblies of wind turbines are adopted considering the classification in [15] and WMEP database classifications. Table 3 lists the subsystems and assemblies of a typical wind turbine.

Table 3. Subsystems and assemblies of wind turbines

Subsystems of wind turbines	Components of wind turbines
Hub	Hub body, pitch mechanism, pitch bearings
Structure	Foundations, tower/tower bolts, nacelle frame, nacelle cover and ladder
Rotor blades	Blade bolts, blade shell and aerodynamic brakes
Mechanical brake	Brake disc, brake pads and brake shoe
Drive train	Rotor bearings, drive shafts and couplings
Gearbox	Bearings, wheels, gear shaft and sealings
Generator	Generator windings, generator brushes and bearings
Yaw system	Yaw bearings, yaw motor, wheels and pinions
Sensors	Anemometer/wind vane, vibration switch, temperature, oil pressure switch, power sensor and revolution counter
Hydraulic System	Hydraulic pump, pump motor, valves and hydraulic pipes/hoses

Electrical System	Converter, fuses, switches and cables/connections
Control System	Electronic control unit, relay, measurement cables and connections

FMECA consists of four main components such as failure modes, failure causes, effects of the failures and failure mode criticality numbers. Failure modes represent the type of failure occurring in every subsystem whereas failure mechanisms are the causes that lead to failures. Effects of the failures are simply consequences whereas failure mode criticality numbers are calculated as sum of expected cost from the failures and loss of energy production for every subsystem.

2.3.1. Failure modes

Failure modes can be classified as the failures which happen in the specific subsystem (i.e. blade failure, gearbox failure, generator failure, etc.) [18] or more specifically such as fatigue and fracture in toothed shaft of a gearbox, loss of function in lubricant system [26] depending on the data availability. Database which is used in this study does not include detail data about the failure modes beyond the subsystem where the failure occurs.

2.3.2. Failure causes

In this study, failure causes in WMEP database which are given in Table 4 are used. They are high wind, grid failure, lightning, icing, malfunction of control systems, component wear or failure, loosening of parts, other causes and unknown causes. Grid failures depend on the region in which wind turbine is operated, however it is not a climatic impact, so it is not an interest of investigation.

Table 4. Locations, causes and effects of the failure which are included in WMEP database

Failure locations	Failure causes	Failure effects
Structures failures	High wind	Overspeed
Rotor blade failures	Grid failure	Overload
Mechanical brake failures	Lightning	Noise
Drive train failures	Icing	Vibration
Gearbox failures	Malfunction of control system	Reduced power
Generator failures	Component wear or failure	Causing follow-up damage
Yaw system failures	Loosening of parts	Plant stoppage
Sensor failures	Other causes	Other consequences
Hydraulic System failures	Cause unknown	
Electrical System failures		
Control System failures		
Hub failures		

2.3.3. Failure effects

Failure effects can be classified in the same way with failure causes which are given in Table 4. Eight effects of failures are used for FMECA in this study. They are overspeed, overload, noise, vibration, reduced power, causing follow-up damage, plant stoppage and other consequences.

2.3.4. Criticality of failure modes

Criticality Priority Number (CPN) is the one of the most important outcomes of this FMECA application. It is estimated as in the following product:

$$\text{Criticality Priority Number} = Occurrence\ Severity * Consequence\ Severity *$$
$$Non-detection\ Severity \quad (1)$$

It is stated in the literature that 99% of the equipment failures give malfunctioning signals about the potentiality of the malfunction of the equipment [20]. Condition monitoring systems (CMS) enable the detection of the failures in wind turbine subsystems such as gearbox, drive train, generator and tower by use of vibration, heat and pressure sensors [27]. In wind turbines, however, failures often suddenly appear and can not be detected. Visual inspection in scheduled maintenances is also another way to detect potential anomalies in a wind turbine. WMEP database consists of information of scheduled maintenances which were applied regularly on the wind turbines but does not cover the detection rate for the failures. Therefore, it is assumed that visual inspection detects potential failures equally for every subsystem. Although this is a strong assumption, there is no other practical option for estimating detection rate other than assuming that it is equal for every subsystems for this study.

In this study, CPN is demonstrated by two different metrics such as Cost Criticality Number (CCN) and Downtime Criticality Number (DCN). Although in most cases cost criticality is important for the wind operators, downtime criticality would be more important for some rare cases such as energy security for military or health operations. Furthermore, the behavior of CCN and DCN can be very different depending on the external and internal conditions of wind turbines and thus operators can arrange their actions based on their prioritization. CCN measures the risk of having failure in terms of cost in a subsystem of wind turbine while DCN represents the risk of having failure in terms of time. To estimate DCN downtime per failure is calculated by multiplying total downtime per failure and annual failure rate. Evaluation of cost criticality number requires two subcomponents which are cost for the failure mode and cost for loss of energy production for this study. Cost for the failure mode is evaluated by multiplication of annual failure rate and cost per failure whereas cost for loss of energy production is calculated by multiplying lost energy production and electricity price. The generic cost criticality number is estimated by Equation (2). Equations (3 and 4) are used to estimate the cost for the failure mode and loss of energy production, respectively [13]. Equation (5) evaluates lost energy production and equation (6) estimates the downtime criticality number.

$$\text{Cost Criticality Number} = Cost\ for\ the\ failure\ mode$$

$$+cost\ of\ lost\ energy\ production \qquad (2)$$

$$\text{Cost for the failure mode} = \sum\nolimits_{n_{components}} p_n c_n \qquad (3)$$

$$\text{Cost of lost energy production} = Lost\ Energy\ production * Electricity\ selling\ tariff \quad (4)$$

$$\text{Lost energy production} =$$
$$Capacity\ factor * Wind\ turbine\ nominal\ power * Downtime\ per\ failure * Annual\ Failure\ Rate \ (5)$$

$$\text{Downtime Criticality Number} = Downtime\ per\ failure * Annual\ failure\ rate \ (6)$$

where n represents subsystems, p_n is annual failure rate occurring and c_n is cost per failure in subsystem "n". To estimate the lost energy production in Equation (5), the capacity factor is assumed to be 33% and average electricity selling tariff in the US is assumed to be 12 cents/kWh in Equation (4). It should be noted that this is a conservative assumption since most of the failures occur with the high wind rather than no wind conditions.

The FMECA methodology is applied as in the following:
1- Annual failure rates and downtime per failure values are determined.
2- Downtime and cost criticality values are computed for every subsystem for wind turbines.
3- The failures in wind turbines in different climatic regions are sorted.
4- Failure rates, downtime per failures, failure modes, and effects of different subsystems in different climatic regions are determined and their downtime and cost criticality values are computed.
5- The results are compared between climatic regions and targeted turbine population.

The comparison between geared and direct-drive wind turbines are applied on 500 kW geared and direct-drive wind turbines in the same climatic region Cfb.

A short example on CCN and DCN computations for rotor blades for climatic region Cfb are demonstrated in Table 5.

Table 5. An example of calculation of CCN and DCN

	Replacement cost $ [25, 26]	AFR	Downtime per failure	Cost of lost energy production	CCN ($)	DCN (hr)
Rotor blades	47,584	0.26	22	0.33*500*22*0.26*0.12 = $112	47,584*0.26+112= $12,621	22*0.26 = 6 hrs

3. Results

3.1. Investigation of climatic region impact on WT reliability and availability

Figure 2 shows the average failure rate and downtime values if the breakdown for climatic regions are not considered. Figure 3 shows that annual failure rate per turbine values are at similar range in all climatic regions for subsystems except for hub, rotor blades, generator, gearbox and hydraulic system which happen in Dfc. Rotor blade failures have higher annual failure rates in Dfc than in the other climatic regions whereas hub, generator, gearbox and hydraulic system failures have lower failure rates in Dfc than in the others. Dfc as being a colder climatic region than the rest of the climatic regions in Germany, intuitively, impacted on rotor blade failures however lower hub, generator and gearbox failure rates are counterintuitive. The distortion of the results in gearbox, generator and hub might be attributed to scarcity of data in Dfc climatic region where there are only six wind turbines. For example, six turbines in Dfc region had no more than 0.23 annual failure rate in their gearboxes with two of them had no failure during their survey period, whereas eight in eighteen wind turbines having more than 0.23 annual failure rates in Dfb region six of them being more than 0.5.
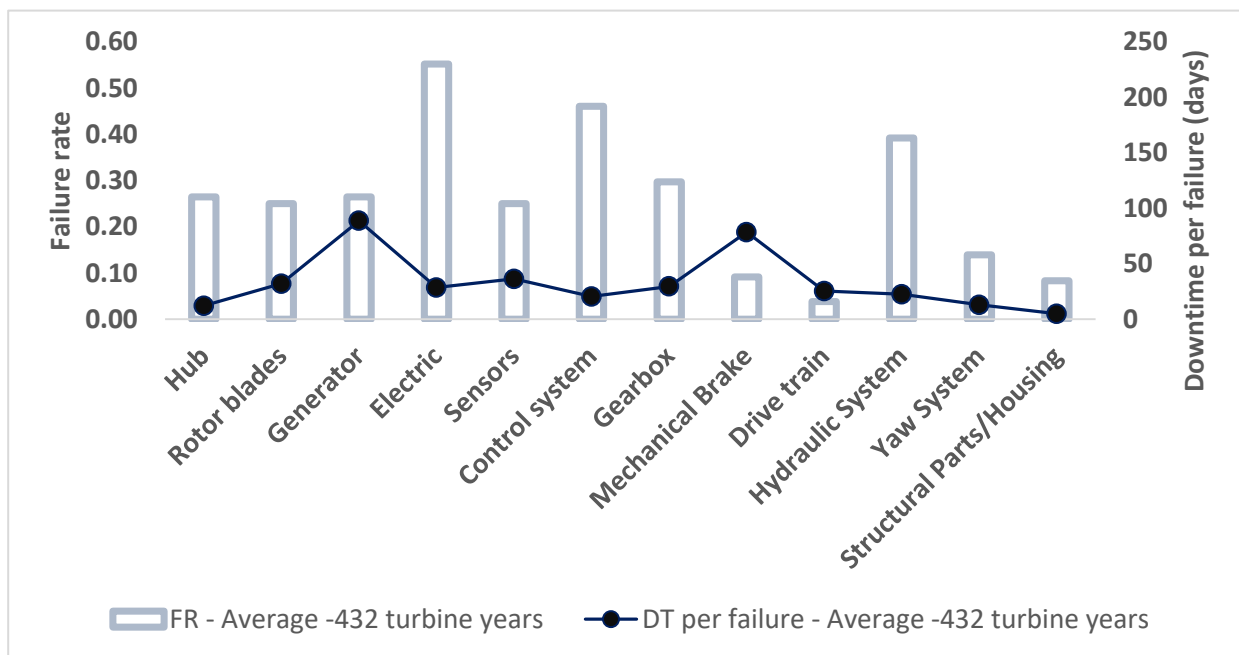

Fig. 2. Averaged failure rate and downtime per failure values for subsystems of one 500-kW geared-drive wind turbine model with 40 m tower height in different climatic regions
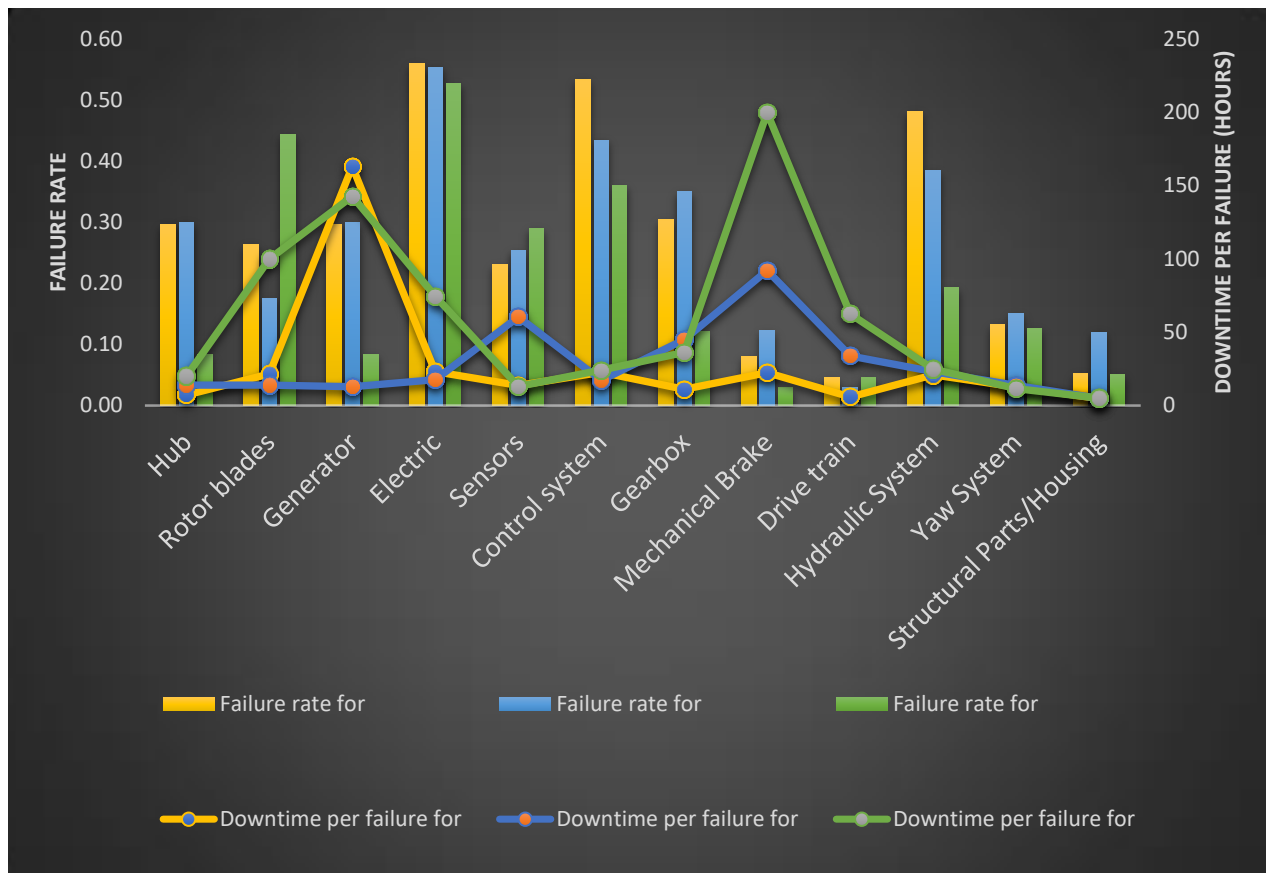
Fig. 3. Annual failure rate and downtime per failure values of subsystems of 500-kW height geared-drive wind turbine model with 40 m tower in different climatic regions

Figure 3 also demonstrates that the downtime per failure values tend to change depending on the climatic regions. Hub, control system, hydraulic system, yaw system, structures and housing subsystems show comparable results in different climatic regions. Rotor blades and electric system failures show significantly higher downtime per failure values in Dfc, whereas sensor failures have the highest downtime value in Dfb. This might be attributed to severe operational conditions in cold climates. Subsystems in Cfb region tend to have low downtime per failure - below 24 hours except for generator.

3.2. FMECA results considering climatic regions

Table 6 shows the results of downtime and cost criticality values for every subsystem of wind turbines considering their climatic regions. Cost criticality of a subsystem is calculated using equations (1), (2), (3) and (4). Downtime criticality is calculated by multiplying downtime per failure and annual failure rate per subsystem as in Equation (5).

As shown in Table 6 that downtime criticality of subsystems differs depending on the climatic regions. Generator, electric system and control system have higher downtime criticality in Cfb, sensors and gearboxes have higher downtime criticality in Dfb whereas rotor blades and electric

system have much higher downtime criticality in the climatic region Dfc comparing to the other subsystems.

There is no common cost critical subsystem for wind turbines among different climatic regions as it can be seen from Table 6. Electric system and gearbox are the most critical subsystems for Cfb and Dfb whereas rotor blades are the most cost critical subsystem in climatic region Dfc.

Although structural parts and housing cost criticality shows a significant value in Dfb since the replacement cost imposes a total replacement of tower, foundations and nacelle which is not in the case in the WMEP database, it is ignored for this study.

The main cause for all failures of components of three critical subsystems is component wear or failure, and the associated effect is wind turbine stoppage.

Blade shells are the most affected component by climatic conditions in the rotor blade subsystem as it can be inferred from Figure 4. The climatic region impact is observed in the shares of causes and effects on the components of rotor blades. Loosening of parts are the second major cause after wear of blade components in Cfb whereas lightning is the biggest major cause for blade shell repairs or replacement in Dfc. Effects of failures in rotor blades are observed to be similar in all climatic regions and being mostly plant stoppage and reduced power.
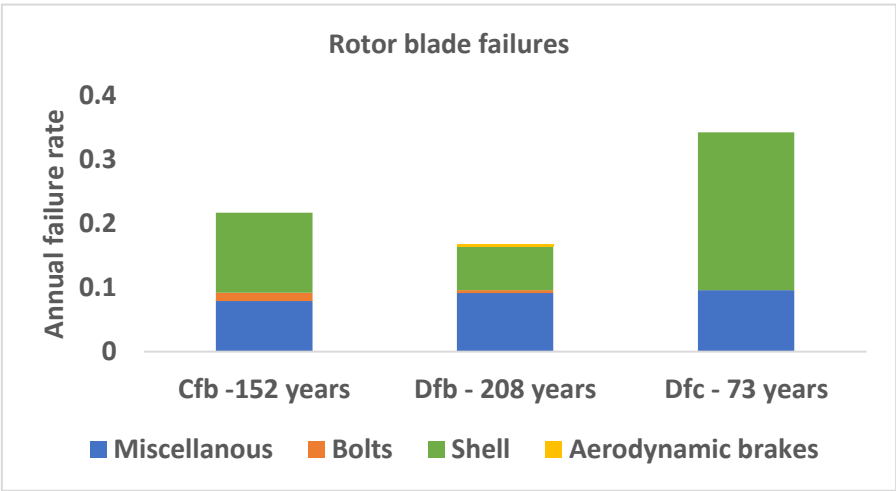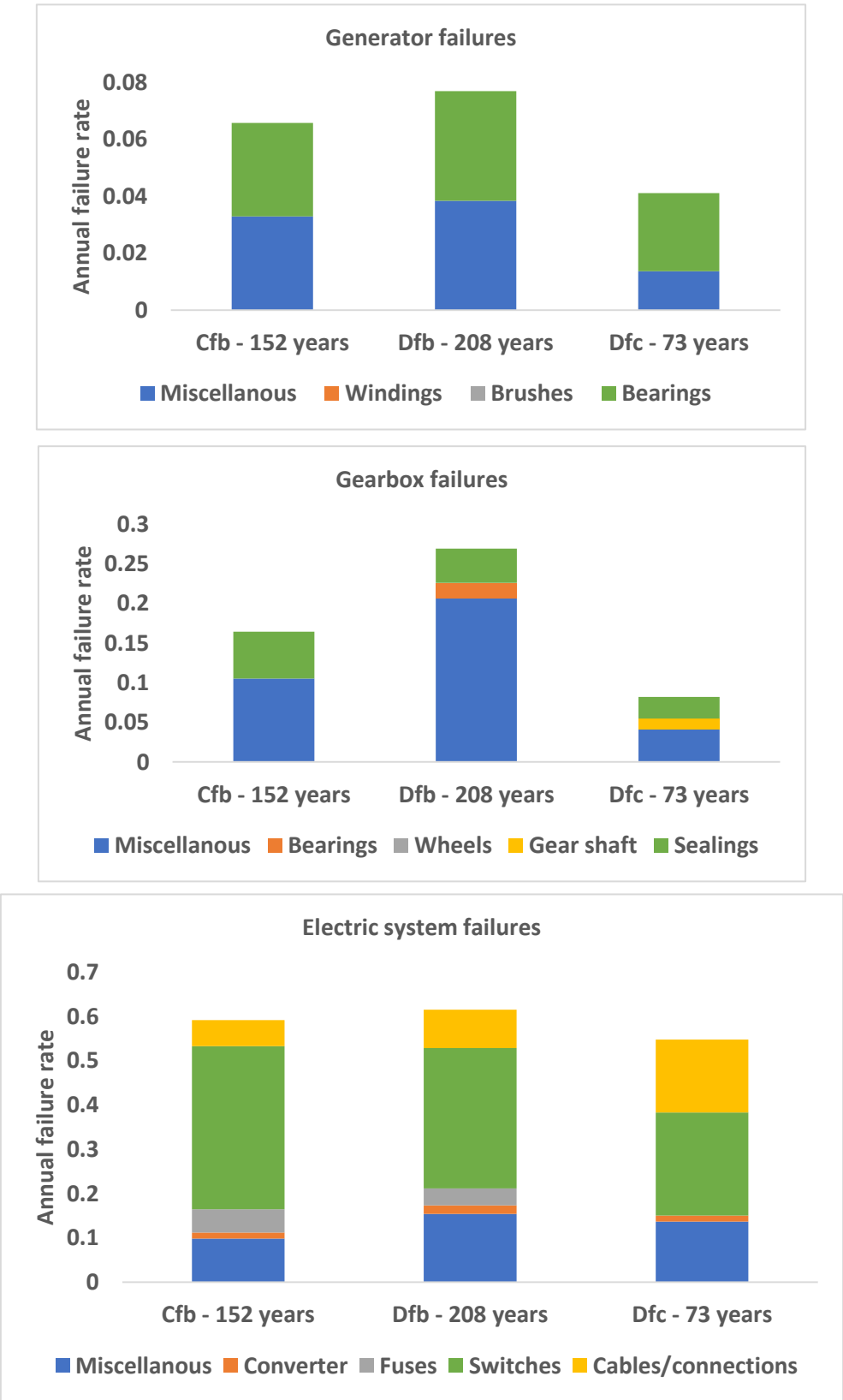
Fig. 4. Distribution of failure rates in components of the most critical subsystems which are mentioned in Table 3 based on climatic regions

The most critical components in the generator subsystem are bearings as it can be seen in Fig 4. Wear is the only failure cause in all climatic regions. The significant effect of generator failures is noise, and this is observed in Cfb and Dfb.

Figure 4 shows that miscellaneous gearbox parts are the most affected components in every climatic region followed by sealings in gearbox failures. Wear is the dominant failure cause whereas plant stoppage is the main effect for gearbox in every component. Bearing failures have the noise and vibration effect following plant stoppage predominantly in Dfc climatic region. If it is not the artifact of the data, the reason might be the colder climate with more turbulence that induces more vibration.

The highest failed component in the electric system is switch where in climatic region Cfb have the highest share with 62% of total failures as can be seen in Figure 4. This share is reduced to the minimum 43% in Dfc where cables and connections are the other highly failed components with 30% of the failures. Only 10% of the total failures occurred in cables and connections in Cfb region. The dominant cause is wear in all climatic regions, but the second highest cause vary depending on the region. Lightning and malfunction of control system are the other main failure causes in Cfb whereas grid failure, which has no contributions in Cfb and Dfb, significantly contributes to the failures in climatic region Dfc. However, it should be noted that although grid failures are related with regions they are however not related with climatic effects. Plant stoppage is the main cause after failures in all climatic regions only follower is reduced power with slight shares in the failures of switches only in Dfb and Dfc.

Table 6. Downtime and cost criticality comparison based on climatic regions

	Downtime Criticality Number (hours)				Cost Criticality Number ($)				
	Average (432 t-years)	Cfb (152 t-years)	Dfb (207 t-years)	Dfc (73 t-years)	Replacement cost ($) [28,29]	Average (432)	Cfb (152)	Dfb (207)	Dfc (73)
Hub	3	2	4	2	38,271	10,205	11,388	11,535	3,236
Rotor blades	8	6	2	44	47,584	12,052	12,621	8,365	21,958
Generator	23	48	4	12	43,298	11,939	13,792	13,033	3,860
Electric	16	13	10	39	59,804	33,307	33,709	33,307	32,274
Sensors	9	3	15	4	25,000	6,429	5,817	6,639	7,304
Control system	9	12	8	9	10,000	4,796	5,574	4,492	3,766
Gearbox	9	3	16	4	51,750	15,551	15,788	18,434	6,368
Mechanical Brake	7	2	11	6	1,185	251	130	370	150
Drive train	1	0	1	3	13,912	558	645	441	695

Hydraulic System	9	10	9	5	6,114	2,573	3,142	2,526	1,272
Yaw System	2	2	2	1	15,900	2,252	2,134	2,427	2,025
Structural Parts/Housing	0	0	1	0	132,257	10,987	6,867	15,861	6,664

3.3. Direct-drive and geared-drive reliability and availability comparison controlling the climatic region effect

Figure 5 shows that annual failure rate per subsystem differs between direct-drive and geared-drive wind turbines. Hub, generator, sensors, control system, structural parts and housing subsystems have significantly higher annual failure rates in a 500 kW-direct-drive turbine than a 500 kW-geared-drive wind turbine whereas rotor blades, electric and yaw systems have slightly higher values in the same climatic region.   Mechanical brake and drive train have slightly higher annual failure rate in the direct-drive turbine than geared-drive turbine whereas hydraulic system has significantly higher value.
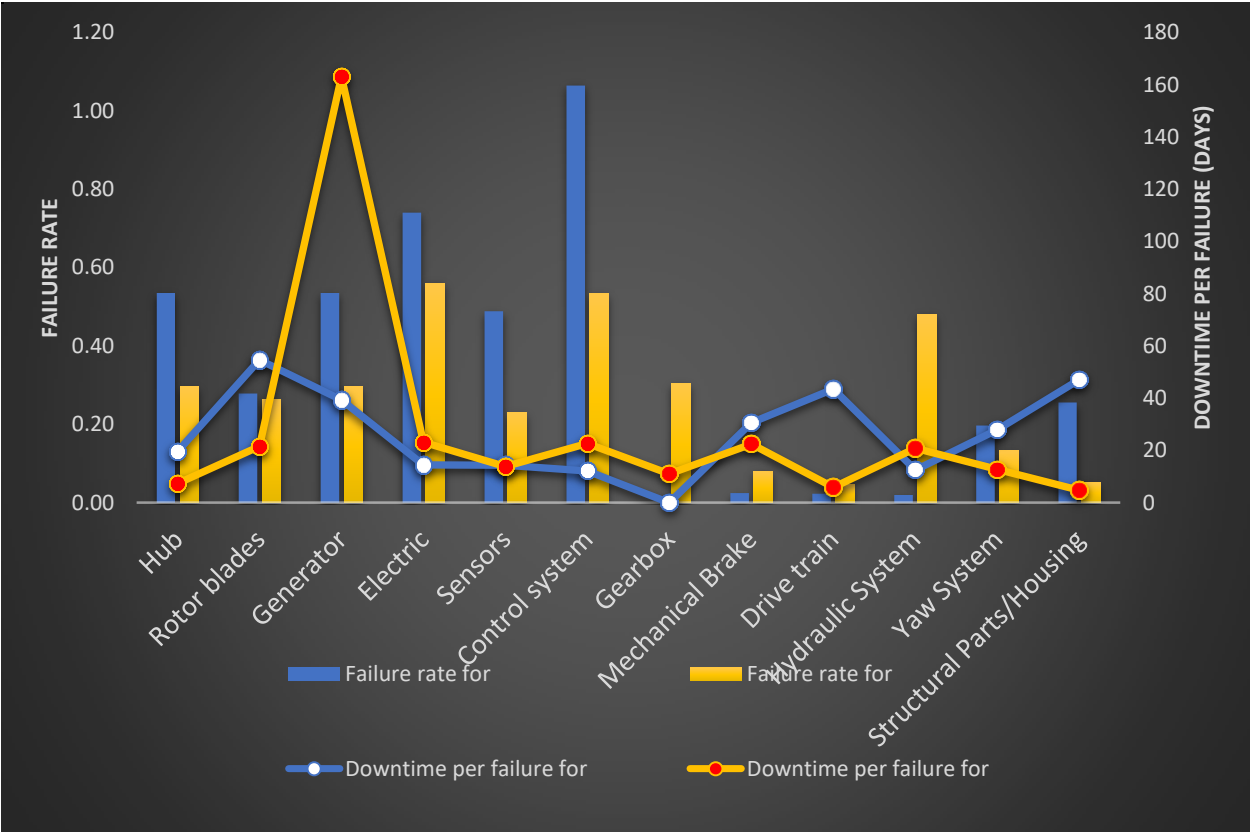

Fig. 5. Annual failure rate per subsystems comparison for direct-drive and geared-drive concept wind turbines

Figure 5 also demonstrates that downtime per failures vary with the drive design types of wind turbines. Hub, rotor blades, yaw system, structural parts and housing subsystems have significantly higher downtime per failure in 500 kW direct-drive turbines while generator and hydraulic system have significantly higher downtime per failure in 500 kW geared-drive wind turbines. Sensors and drive train have slightly higher downtime per failure in direct drive concept whereas electric system, control system and mechanical brake have higher downtime per failure in geared-drive concept.

Furthermore, sensitivity analysis results in Table 7 show that geared-drive capacity change has impacts on downtime per failure values. 200 kW and 500 kW turbine models are the same while 300 kW turbine is another brand. Table 7 shows that the downtime per failure values are significantly higher in 300 kW turbine for gearbox, rotor blades, drive train and yaw system. Gearbox annual failure rates seem to be increased with capacity increase while downtime per failure has no trend. Control system and electric system are the common highest frequently failed subsystems.

Table 7. Sensitivity analysis for wind turbine capacities

	Direct-drive-500Kw (493 turbine years)		Geared-drive-200Kw (524 turbine years)		Geared-drive-300kW (508 turbine years)		Geared-drive-500kW (152 turbine years)	
	Annual Failure Rate	Downtime Per failure (hrs)	Annual Failure Rate	Downtime Per failure (hrs)	Annual Failure Rate	Downtime Per failure (hrs)	Annual Failure Rate	Downtime Per failure (hrs)
Hub	0.54	20	0.10	10	0.15	12	0.30	7
Rotor blades	0.28	55	0.09	16	0.08	75	0.26	22
Generator	0.54	39	0.10	8	0.15	90	0.30	163
Electric	0.74	14	0.32	19	1.15	17	0.56	23
Sensors	0.49	14	0.05	13	0.30	15	0.23	14
Control system	1.06	12	0.36	16	0.52	20	0.53	23
Gearbox	0.00	0	0.09	39	0.15	138	0.30	11
Mechanical Brake	0.02	31	0.01	6	0.13	23	0.08	22
Drive train	0.02	43	0.03	6	0.08	52	0.05	6
Hydraulic System	0.02	13	0.11	9	0.40	15	0.48	21
Yaw System	0.20	28	0.09	8	0.38	28	0.13	13
Structural Parts/Housing	0.26	47	0.04	16	0.19	26	0.05	5

3.4. FMECA results on direct-drive and geared-drive wind turbines

Table 8 shows that the cost criticality of rotor blades, generator, hub, control system and yaw system are significantly higher in direct-drive concepts. Electric system, generator and gearbox are the most cost critical subsystems in the geared-drive wind turbines while generator and electric system have

the highest cost criticality in direct-drive wind turbines. On the other hand, generator shows the highest downtime criticality for both turbine types.
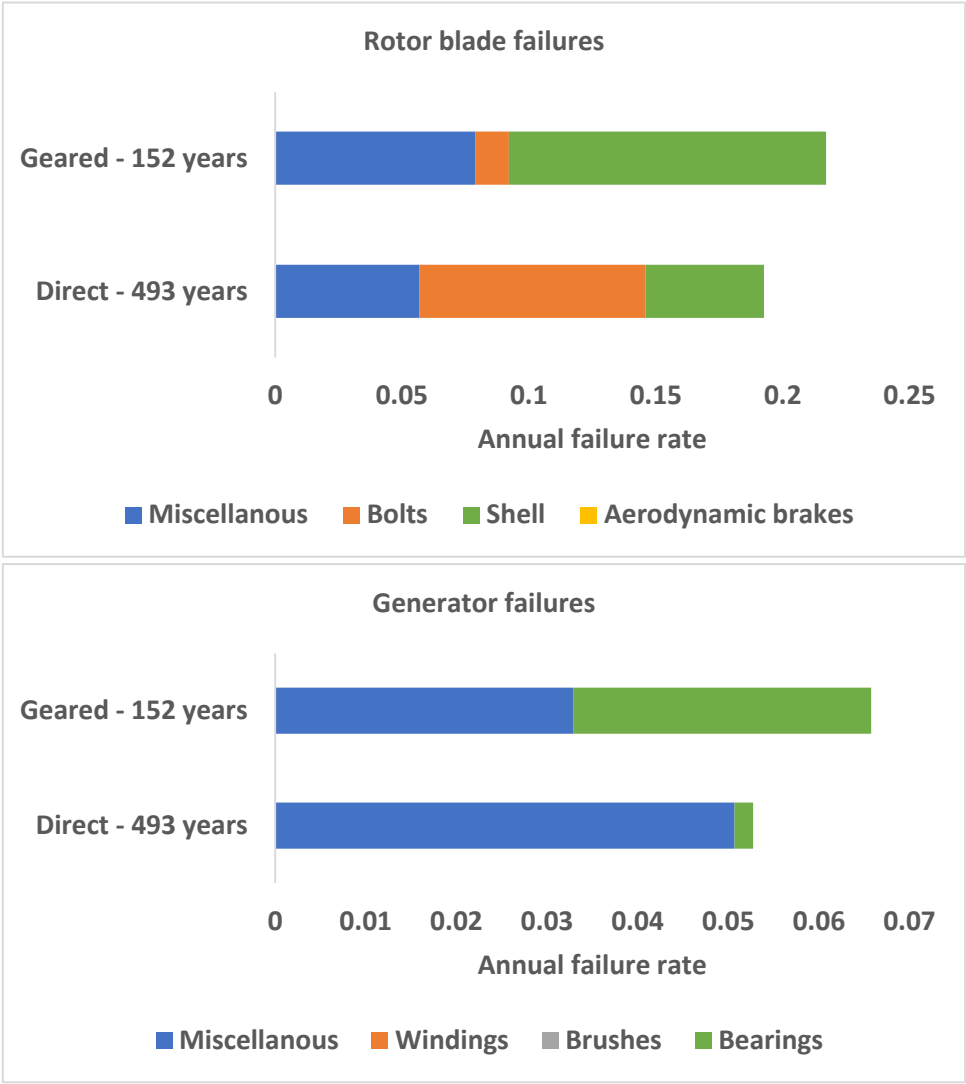
The dominant failure cause for direct-drive designed wind turbines for rotor blades is wear whereas loosening of parts, high wind and lightning come into play for geared-drive wind turbines. Blade bolts are the most problematic components in the rotor blades subsystems in the direct-drive turbine model whereas the highest failure rate occurred in blade shells in geared-drive wind turbines as it can be seen in Figure 6. The effects of the failures vary depending on the gearing concept of the turbines. The dominant effect is the plant stoppage while noise is the second highest for the direct-drive turbines, whereas reduced power is the main effect for geared-drive wind turbines.

It can be seen from Figure 6 that generator bearings are where the failures mostly occur in geared-drive wind turbines. It is observed that the dominant failure effect is noise in the generator bearings. In direct-drive designed wind turbines miscellaneous parts in the generator subsystem are observed to be as the most affected parts by failures.

Table 8. Downtime and cost criticality comparison based on drive concept of wind turbines in climatic region Cfb

	Downtime Criticality Number (hours)		Cost Criticality Number ($)					
	500 kW Direct-drive (493 t-years)	500 kW geared-drive (152 t-years)	Direct drive turbine Replacement cost ($) [25,26]	Cost of lost energy production ($)	500 kW direct-drive (493 t-years)	Geared-drive turbine Replacement cost ($) [25,26]	Cost of lost energy production ($)	500 kW geared-drive (152 t-years)
Hub	11	2	38,200	208	20,646	38,271	43	11,388
Rotor blades	15	6	51,262	301	14,569	47,584	112	12,621
Generator	21	48	120,463	416	64,865	43,298	957	13,792
Electric	11	13	59,804	211	44,461	59,804	256	33,709
Sensors	7	3	25,000	139	12,343	25,000	63	5,817
Control system	13	12	10,000	256	10,900	10,000	240	5,574
Gearbox	0	3	13,097	0	0	51,750	67	15,788
Mechanical Brake	1	2	1,185	15	44	1,185	35	130
Drive train	1	0	13,997	20	338	13,912	5	645
Hydraulic System	0	10	6,114	5	127	6,114	199	3,142
Yaw System	5	2	16,260	109	3,305	15,900	33	2,134

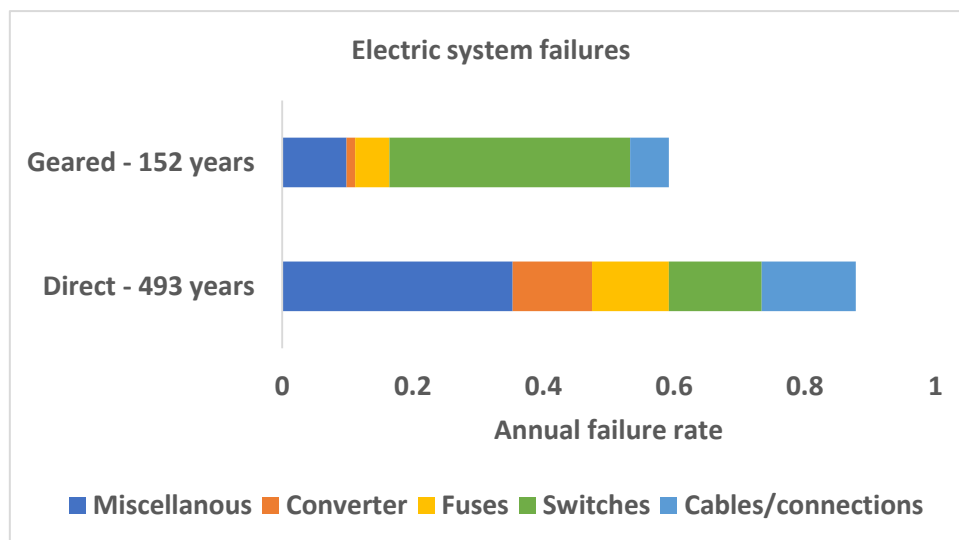| Structural Parts/Housing	12	0	228,095	238	58,511	132,257	5	6,867

Fig 6. Distribution of failure rates in the components of the common critical subsystems which are mentioned in Table 3 in geared and direct-drive wind turbines

Converter, fuses and switches fail mainly because of the wear or component failure followed by the malfunction of control system in direct-drive design wind turbines as it is seen in Figure 6. 62% of the failures occur in switches in a geared-drive wind turbine, while this is reduced to 16% for switches in direct-drive turbine. It seems that lightning can be accounted for being a significant failure cause for electric system for geared-drive wind turbines but not for direct-drive turbines. All these differences might be attributed to the quality and durability of materials used in these turbines.

4. Discussion

Comparing different wind turbines, the main differences are in generator types of two wind turbine types and namely those having gearbox and those with direct-drive. The rest of the subsystems have same functionality while they might be made of different materials with varying quality. The considered direct-drive wind turbine in this study has a synchronous type generator with 38 rotations per minute (rpm) generating 440 V output whereas the geared-drive wind turbine has an asynchronous generator with 1522 rpm and 690 V output. The total weight of the direct-drive wind turbine is much higher than the geared-drive wind turbine generator, 125 t and 85 t, respectively. Furthermore, electric system, control system, yaw system and hydraulic system might differ in two turbine designs, as well as in general between any turbine models.

Shafiee and Dinmohammadi [10] found the highest criticalities in rotor blades, gearbox and transformer with 5,326 €, 4,542 € and 1,371 € cost criticality numbers for onshore wind turbines, respectively. For offshore wind turbines, cost criticality of rotor blades increased dramatically to 16,831 €, as it confirms the results from our study that criticality of subsystems can change abruptly in a harsh environment [10]. Kahrobaee and Asgarpoor [16] used 3 MW direct drive wind turbine as a case study. Generator is determined as the highest critical subsystem with $14,110 followed by electrical system with $3,274 and rotor blades $2,541 This represents the similar criticality order for

subsystems with our study for a direct drive turbine, but the scale of cost criticality values is different than our study. This difference may be attributed to the differences of replacement cost assumptions of two studies. Tazi et al [20] found gearbox, rotor blades and yaw system with the highest cost criticality numbers of 49,356 €, 45,367 € and 30,811 €, respectively, ignoring tower, for 2 and 3 MW wind turbines. We found that electric system, generator and gearbox as the most critical subsystems in a geared-wind turbine with \$33,709, \$13,792 and \$12,621 cost criticality, respectively. In our study, electric system seems to be an addition into the highest cost critical subsystems mainly because of having higher material and installation cost share in a small-scale turbine like 500 kW than a bigger turbine such as 2-3 MW turbine. The highest cost critical subsystems agree between our study and studies in the literature which used same approach for cost criticality evaluations [10, 16, 20]. Slight differences are observed as it is supposed to be because of the differences of reference wind turbine sizes, locations and types.

5. Conclusions

This paper aims to assess the impacts of weather and turbine type by applying Failure Modes Effects and Criticality Analysis (FMECA) on a large number of wind turbines. The reliability and availability behavior of the wind turbine design in different climatic regions of Germany are investigated and differences determined. Also, FMECA is applied to compare criticalities of geared-drive and direct-drive wind turbine subsystems controlling climatic conditions as a first time in the literature. Our findings can be summarized as follows:

- Considering climatic regions in FMECA revealed differences in failure rate and downtime behaviors of subsystems in the wind turbines that were not reported in previous studies.
- Climatic regions have an impact on the critical subsystems and failure causes in wind turbines. This implies that the wind turbine operations and maintenance strategies for subsystems should be arranged taking local climatic conditions of the turbines into account. For example, rotor blade downtimes and failure rates are impacted by colder climates where longer downtime and higher failure rates are observed. Also, lightning became an important failure cause in cold climatic regions for rotor blade failures.
- In most of the subsystems direct-drive wind turbines seemed to have a higher failure rate than geared-drive wind turbine in the same climatic region. Direct-drive technology would be thought to be an ideal design for offshore applications because of its less complexity, however this study shows opposite. To come to a solid conclusion though, this comparison should be done with and extensive data with many different make and models of wind turbines in the future.

The main outcome from the current study is that downtime and cost criticalities of subsystems of wind turbines depend on the locations and types of wind turbines. Wind farm operators should consider location and type of turbine factors for their O&M budget allocation and arrange the maintenance strategies correspondingly. Furthermore, the insurance companies can benefit utilizing

climatic regions such as Koppen-Geiger to evaluate and classify the risk of turbine subsystems. Although this study is limited to 1989-2008 data, the proposed methodology and lessons from this study are expected to be globally applicable. Further research would include relatively newer wind turbines which spread on a geographic area with many different climatic regions along with failure data to better improve our understanding on distinguishing climatic regions effect on FMECA for wind turbines.

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