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DEMONSTRATION OF REQUIREMENTS FOR LIFE EXTENSION OF WIND TURBINES BEYOND THEIR DESIGN LIFE (LifeWind)

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Executive Summary

The LifeWind project analyzed the inputs of several stakeholders and formulated procedures for extending the operational life of wind turbines. The following definitions for life extension were formulated:

- **Design lifetime**: The time period used in the strength verification of the turbine during its design process as per IEC 61400-1 (IEC 61400-1, 2019).
- **Lifetime extension**: Additional period beyond the original design lifetime that the turbine is operational.
- **Remaining Useful Life**: Additional period from the present for which the turbine may be operated within an acceptable reliability.
- **Operating life**: Lifetime from commissioning to decommissioning of the wind turbine or wind farm.
- **Safety**: Prevention of failure which can result in risk of human injury or social or economic consequences or is in violation of local regulations.

Inspections on several operating wind turbines were made both offshore and onshore and included Vestas V80, V52, V67, Bonus 1 MW and Nordtank turbines. The main inspections points were focused on bolts, blade erosion and effective repair of faults found in past inspection reports. Based on the findings made from the inspected 8 wind turbines, it was concluded that the design-lifetime of 20 years can be extended. Specific tools for the determination of tension in tower bolts were tested and found to be effective in measuring remaining tension of bolts as conducive for life extension.

Operational measurements as obtained from SCADA for several wind farms were analyzed along with the aeroelastic design basis of the turbines to predict life consumption within a wind farm. The prediction of damage consumption is based on training neural networks with input SCADA based measurements. The neural networks reproduce time series of loads wind turbine structures within a wind farm. The predicted loads using the measured mean SCADA signals is validated both with measured loads on a single turbine and with measured power standard deviation as a proxy for loads within large wind farms in complex terrain. The ability to use generic aeroelastic design basis to scale existing turbine design data to different turbine capacities and thereby simulate the damage consumption on those turbines is also shown.

The existing standards (ISO, Eurocode etc.) relevant for the extension of life of wind turbines were examined and a sufficient list of applicable standards and key procedures therein were identified. For decisions on life extension for wind turbines, it is proposed that they be based on a cost-benefit approach, as this will result in economically responsible decisions for the interest of both the owners of the wind turbines and for the society. This might lead to lower target reliability levels than was used in the original design.

Based on the above a detailed list of recommendations was formulated as input to the IEC 61400-28 standard that is presently under development for life extension of wind turbines.

1. Introduction

Many wind farms in Europe, North America and Asia will be reaching their intended design lifetime in the next few years and the turbine/wind farm owner needs to take decisions on whether to extend the operational life of the turbine beyond its presently planned duration and the steps that must be taken to demonstrate that such life extension is safe and economical. There is no available international standard on wind turbine lifetime extension at the moment and there is an active effort in the IEC TC88 committee to draft a new technical specification on lifetime extension titled IEC 61400-28. One of the key objectives of the LifeWind project is to submit its recommedations to the IEC 61400-28 committee so that the findings may be utilized in the larger wind energy community.

Wind turbine rotor nacelle assemblies (RNA) are usually designed to specific classes of wind conditions, based on the IEC 61400-1 (IEC 61400-1, 2019). Further based on specific site conditions, the tower and support structure are designed to meet the specifications on that site. The structural design is made assuming an annual target reliability level, given the acting mechanical loads and material properties. To meet such a reliability target, the characteristic load and material strength are multiplied by partial safety factors, which are based on assumed uncertainties (Sørensen & Toft, 2014). In practice, the overall process of assuming certain wind conditions and assigning safety factors for loads and material may lead to conservative designs due to the large uncertainties assumed in the design process. The wind turbine structure is designed to meet the mechanical loading corresponding to a given wind turbulence class. The fatigue lifetime of the blade, tower etc. is ensured based on the 90% quantile of turbulence for a selected turbulence class. The uncertainties in the wind conditions can be relatively large, especially due to seasonal variations, storms and also changing terrain conditions over the life of the turbine. By using measured wind farm data to reduce the uncertainties, the design life can be re-assessed, thus potentially enabling the wind turbines to operate longer than their original design life, without compromising on the target reliability (Natarajan & Pedersen, Remaining Life Assessment of Offshore Wind Turbines subject to Curtailment, 2018). Further, the fatigue life of blades, main shaft and support structure are strongly influenced by turbulence including wakes within wind farms (Galinos, Dimitrov, Larsen, Natarajan, & Hansen, 2016) . Thus, overall the wind turbines at the center of a wind farm are often the most heavily loaded and with the highest life consumption since they are always under wake flow regardless of the prevailing direction of the free stream wind.

A conservative component design with large safety factors may avoid large downstream maintenance costs or component repair costs and facilitate lifetime extension. However with the significant push for reduction in the levelized cost of energy (LCoE) for both onshore and offshore wind energy, manufacturers would like to design turbines to a prescribed lifetime and generate as much as energy as feasible. Determining an accurate site specific life is also relevant during the design process of wind turbines as manufacturers and wind farm owners would like to design wind turbines and associated structures for a targeted lifetime with accuracy. Many of the methods which are also used to determine the remaining life of an operating wind farm may also be useful during the design of new wind turbines using probabilistic design techniques which are now mentioned in the new IEC 61400-1 Ed.4. Besides determining the duration of life extension, the extension may also require that the turbines are inspected at a prescribed interval during the extended life period, maintained and repaired as needed, so as to ensure

the required safety levels. The requirements for life extension are also subject to various stakeholder objectives such as from certification bodies, insurance companies, power supply companies etc.

Life extension must be based on the level of data available for the wind turbines being considered. This is of varying degree of fidelity with some wind farms having no measurement data available, while many wind farms have 10-minute statistics of basic performance such as wind speed, power, rotor speed, etc. available from its turbines. The next sections will be analyzed different types of wind turbine data, their usage and predict life consumption on existing wind farms. First the needs of the stakeholders are analyzed.

2. Stakeholder Inputs

Various stakeholders in lifetime extension such as Wind turbine/wind farm owners, certification bodies, grid operators, insurance companies and service providers were interviewed to understand their key requirements concerning lifetime extension. The details are provided below.

2.1 WTG owners

Question: Is it in the interest of the owners to extend the lifetime on their WTGs?
Based on the interviews, the financial aspect is highly important when considering lengthen the lifecycle of the WTG. Thereby, it is in the interest of the owner if it is profitable.

Question: Will it be a greater financial risk to extend the lifetime on the WTGs?
It can be concluded that the financial risk will be greater by the incentive of extending the lifecycle. These risks are in the terms of additional costs, i.e. inspections cost. In continuum hereof, components are in the risk of being outdated which will increase the need for investments. Furthermore, increased risks are expected in terms of ownership of tenancy and extension of the lease contract regarding where the WTG is placed. This risk will be minimized when the stakeholder owns the property.
Overall, the perceived risk is highly dependent on the price for extended lifecycle and how the market situation is developing. Based on this, lengthen the lifecycle of the WTG involves high uncertainty and increased risk.

Question: Is the loan of the WTG finished when the WTG is reaching 20 year of lifetime? Is there a difference regarding the size of the WTG?

In general, the loan of the WTG is completed after 20 years. It is indicated that there is a personal interest in going forward with a WTG for a longer period in order to deliver a greater return. Again, the financial aspect is highly important when considering the issue of extending the lifecycle of the WTG.

Question: Has provisions for major repairs been made?

The results are inconclusive regarding reserved reparations. Some owners indicate the importance of electricity prices. This is in relation to the current low electricity prices which complicates the process of doing business yourself and delivering a profitable return. The only way to operate in the current market situation is by being bought up by operators as SA and Wind Estate. These operators will be able to operate at a much cheaper price. Furthermore, some owners state that 10% of the invested capital is reserved to reparations whereas others have not considered this as an issue since they have a good overdraft facility.

Question: Are there any provisions to larger repairer?

It appears to be different considerations when it comes to calculations of the extended lifecycle between the owners. One owner is not interested in spending any resources on calculations but emphasizes the

importance of previous WTG experience and increased focus on inspections. Another owner states that they will provide an overview including a calculation of extending the lifecycle.

Question: The most critical component by lengthen the lifecycle?

Based on the interviews, there are several critical components which highly depend on the situation of the owner. The tower is a critical component when lengthen the lifecycle in case of damage because it will be difficult and expensive to supply. Moreover, the drive train is stated to be the most critical component. Common to all of them, the most critical component is also the most expensive one.

Question: Which component has had the greatest expenses?

The gear has been the greatest expense as well as the on-going service expenses. Furthermore, the main bearing and Yaw ring is considered great expenses for the owners.

Question: Which component has most often been the cause to shut down?

It is very context-specific when it comes to which components that have been the main cause to shutdowns. Often, it is the control that causes the shutdown which also can be hard to troubleshoot. It is also stated that the pitch system is a main cause to shutdowns as well as switch gear by the transformer.

The switch gear was also costly and was the cause to production loss.

2.2 Distribution System Operator (DSO)

Question: Is it possible for the old WTGs to operate with the old grid codes?

Normally, the older WTGs are not perceived as units within the network but more as separate units in the network. This means that the older WTGs are not a part of the regulation of the network and thereby, they can continue fulfilling the old grid codes.

Question: Will it be necessary to make further demand for surveillance of the older WTGs?

It will be a good idea if the older WTGs, especially those that are greater or equal to 7500kW, can be regulated – for instance, incrementally. This will be a greater challenge if the minor WTGs should be downgraded. It will be easier to regulate the new wind farms because they have an increased capacity.

Question: Is there an advantage of having older WTGs if the lifetime will be extended?

It is difficult for the stakeholder to answer the question of having WTGs operating after 20 years because it is related to a high degree of uncertainty.

Question: Which risks can occur if the lifetime of the older WTGs will be extended?

It is not all high voltage (HV) transformers that are in decent order after 20-25 years. Especially, this is an issue related to high voltage transformers placed near the coastline because they are exposed for challenging weather conditions. Additional replacement costs can occur that can be highly costly.

Question: How many years will it be relevant to have them operating?

Based on the view of this stakeholder, it is the HV transformers that is the main challenge when lengthen the lifecycle. A maximum limit of 25-30 years of lifetime is set in order to remain relevant.

Question: Is the removal of the HV transformers be a financial burden for the DSOs?

Normally, the old High Voltage transformers get set aside. Although, it is possible that they are sold together with the WTG.

Question: Will be costs increase for the DSOs?

The billing meter needs replacement every tenth year and, in this case, it is the owners that are responsible for the payment. Regarding the maintenance of High Voltage transformers there are several additional costs which also can be costly for the stakeholder. The older WTGs are often placed all over the country in which more cable damage occur. Though, the reparation is paid by the ones that caused the damage.

Question: Will the administrative costs increase?

The administrative costs regarding interpreting the production/consumption does not increase by extending the lifetime of the WTG.

2.3 Insurance companies

From the insurance companies view, they are highly positive about the development in the industry. By extending the lifecycle of the WTGs, there will be an increased demand for continuously reparations which the insurance companies emphasize as an opportunity. Moreover, there is no relationship between age and the number of damages.

It is stated that it is very positive having a procedure for extending the lifecycle of the WTG. Some companies resign the full comprehensive insurance after 20 years which will cause issues for the owners. The insurance companies cannot demand too expensive insurances from the owners since there will be a risk of deselecting insurance. The owners must keep the WTGs going and cut on the operating expenses in order to pay off the loan. In such case, it is recommended to do a “franchise” with a high excess as the insurance company only will be relevant in case of a great damage. A regular excess for a 750 kW WTG is between 15.000 – 20.000 DKK and for instance, in case of a storm, fire or lightening the owner will be able to save 50% of the insurance premium.

One insurance company (Codan) state that the approach in Germany called WKP could be appropriate to enforce in Denmark as it makes it easier to identify mistakes. Although, some modification to the approach would be beneficial for instance, something in between the WKP and the visual inspection is suggested. Though, it is not in the interest of all insurance companies to do calculations based on current wind data with the purpose of determining when the WTG no longer can operate.

However, Codan recognizes that the WTGs are being reviewed when they reach a lifetime of 20 years and emphasizes the possibility to do calculations based on a new program, Flex5. This program provides more accurate data and decreases the uncertainty associated with older WTGs. Moreover, an individual evaluation is necessary.

There is also concerns about the ability and motivation to solve the inspections services as the WTGs get more and more advanced in the future. Therefore, the question is whether the technical base is acceptable in terms of special designs and features on the old WTGs.

Another concern is how well service the service companies can provide. Are the service companies focused on cutting price in order to maintain the clients and then might not provide the necessary service? It is an interest of conflict. For Codan, it is important that the minor pieces of the older WTGs are being updated. In case of problems, the insurance company (Codan) can determine whether to take out insurance by reaching a certain age which will be a problem for the WTG's owners. Codan will continually with all risk insurance after 20 years.

Typically, the owners only have one liability insurance – maybe also a lightening insurance. In case of simple reparations, Codan will request offers from qualified suppliers. Then, the owners can get some of their money back corresponding to the cheapest offer. The ordinary components as generators and gear are generally not critical.

2.4 Service companies

Question: How many extra workplaces will an extended lifetime provide?

There is a great interest towards extending the lifecycle of WTG. The clients are not only interested in our knowledge about WTG service and maintenance after year 20, but also for how long it is possible to keep the WTG in operation.

Question: Is there a financial advantage for the service companies regarding extending the lifetime?

It is argued to be a great financial advantage to extend the lifecycle of the WTG's as it will create more workplaces, but it cannot be quantified now.

Question: Which critical components will need the most focus?

The need for focus of the most critical components are dependent on how well the WTGs have been serviced. There are expensive components with a long delivery time. Furthermore, the control system is becoming more and more of a challenge.

Question: Are there any greater challenges in regard to HSE?

Many safety wires are being more and more outdated regarding the older WTG's. In that case, a need for climbing assistance is recognized in order to maintain some of the experienced employees – but that is expensive. In such case, the official subsidy (10øreren) is in play again.

With a more modern security control it will be possible to optimize the older WTGs by more measurement points and stop criteria. Potentially, offer the owners of WTG a 10 øre as a subsidy when having executed this extra inspection.

Question: Is it possible to supply replacement parts?

In general, it is possible to supply replacement parts to the WTG's through the established network in the market when it comes to WTG's that is being served for the moment. Although, there are some challenges getting replacement parts to specific WTG's and concerns about expensive replacement parts are also made.

Question: How many changes in manuals will occur?
There is minimal focus on changing manuals and documentation, but the insurance companies rely heavily on previous experience. Previous experience also states that it is not necessary to perform all tasks throughout the service manual but rather choose the most relevant.

Based on all the responses obtained, the following common expectations for lifetime extension across the stakeholders was compiled as given in the below table.

1)	The objective should be to be able to keep the same level of inspections/monitoring after life extension of a turbine as during the original design life of the turbine.
2)	No mandatory inspections from third parties should be necessary if following step 1 allows life extension to be feasible.
3)	Specific inspections for life extension over and above the normal practice should only be done so as to improve future design practice.
4)	For small turbines (less than a MW), life extension is based on a set of rules (such as replace all non-Galvanized bolts). For large wind turbines, wind farms there needs to be computations to understand the risk of failure upon life extension.
5)	For offshore wind farms, the objective is to be able to determine the site specific design life of the farm as early as possible and preferably have wind farms that can run beyond 30 years.

3. Inspections, Onsite Testing and Learnings

Inspections have been carried out in the period 9 May 2018 to 6 November 2018. Eight WTG are inspected as shown in the table below.

Name	Type	Age	Inspection Scope
Allelev 2	NTK 600/43	22	Tower-bolts
Risø	NTK 500/37 (41)	24	Tower-bolts, visual inspection
Risø	V52-850	4	Visual inspection
Horns Rev 1, 01	V80-2,0	16	Visual inspection
Horns Rev 1, 44	V80-2,0	16	Visual inspection
Horns Rev 1, 95	V80-2,0	16	Visual inspection
Georg Clausen	B1300	18	Tower bolts, visual inspection
Tagmarken 5	V66-1,75	16	Blade bolts, blade bearing bolts, visual inspection

The overall scope of the inspections has been to evaluate the possibility of extending the lifetime of the inspected wind turbines.

The number of inspections is however small, and the result cannot be used as an average for all wind turbines in Denmark.

Two different scopes have been used; A visual inspection of all the components in the wind turbine to establish an overall picture of the condition of the wind turbines and the quality of the service-work. Secondly, test of bolt-tightening by measuring the length of the bolts before loosening, after loosening and again after retightening.

3.1 Inspection of Structural Elements

3.1.1 Wind turbine rotor

Which consist of blade, blade-bolt, pitch bearing, hub-bolts and hub.

i. Blades. Inspections show that erosion on leading edge needs further focus. The bigger wind turbines/blades the bigger problem. There are different design repairs and solutions. None of these solutions show satisfying results. Almost all blades show erosion. Therefore, these blade repairs need to be performed in a higher quality and method.
ii. Blade bolts and blade bearing bolts look good. The quality of the bolts is still on a high level regarding corrosion. After year 20, there shall still be focus on tension control.
iii. Hub and hub bolts. There are no cracks or major corrosion on hub and bolts from a visual NDT point of view. No further actions need to be taken.

3.1.2 Main shaft and main bearings

i. All main shafts look good and no cracks can be seen. Corrosion is not an issue. Further lifetime is expected.
ii. Main bearings: Consist of one or two bearings. The bearing-housings have no cracks at all. Some leaks are found from the seals in the housings. Service companies need to exchange seals more frequently!
iii. Main bearing bolts have no visual cracks and no corrosion on surface.

3.1.3 Nacelle frame

Takes the load from rotor and drive train system. Therefore, we inspected all critical points, which could be performed. No cracks or corrosion were noticed after visual NDT.

3.1.4 Yaw system

Consist of yaw-ring, bearing, brake-grips, brake-pads and all relevant bolts according to different system designs. No major problems are noticed. However, in general more focus is needed on wear and tear on the brake-pads.

3.1.5 Tower

All inspected towers were welded cylindrical towers and bolted together through flanges.

i. Therefore we performed visual NDT on welding's. No cracks were found in any of the welding's.
ii. A number of bolts in the flanges were controlled. The methods were performed by use of mechanical measurements and electronic (US sensor) measurements of the elongation. Results were good and showed that bolts were tightened to a satisfying result. The corrosion protection on bolts are most of the times hot galvanized. In addition, bolts called DELTA bolts were used. It is a chemical resistant topcoat. It protects the product against sore impact and improves the cathodic protection. In general, the protection-system works satisfying.

3.1.6 Foundation.

All foundations were inspected visual. More than 90% of the foundation is below ground, which means limited access! In one foundation, we found corrosion on foundation bolts. All other bolts were visual NDT inspected. No critical bolt-connections or welding's were found.

3.1.7 Condition in general

Quality of service *(IPS, OEM, Operator)*

i. **IPS (Independent Service Provider)**.
   In one wind turbine, we found inadequate performed service and maintenance. This has resulted in a high amount of dirt mixed with grease and oil. In addition, wear and tear parts that should be renewed were noticed.

ii. **OEM (original equipment manufacturer)** the quality of the service was of a satisfying quality.

iii. **Operator and owner.** The quality of the service was of a very high quality.

iv. **Rotor blade condition.** Blades inspections show that erosion on leading edge need further focus. The bigger wind turbines/blades the bigger problem. There are different design repairs and solutions. None of these solutions shows satisfying results. Almost all blades show erosion. Therefore, these blade-repairs need to be performed in a higher quality and method

The visual inspections in the project have focused on the structural elements in the windturbines. No remarks were found regarding to the structural elements. Even though we have only inspected 8 windturbines in this project the results combined with our experience from our daily work in the field we are convinced that the design-lifetime of 20 years can be extended for windturbines that today are around 20 years old.

3.2 Bolt-tests

a. As shown in the inspection list for tower bolts, blade bolts and blade bearing bolts, the results for these control-measurements are added to this conclusion. The general overview is that all the measured bolts have a satisfying torque. According to the bolt tension list setting values, coming from the OEM manuals (if such still exist) most bolts are in the lower end. The service plans, after the twenty years of design lifetime, must be upgraded in order to have focus on each turbine type. This must be done and informed to all relevant companies that are approved to perform service and maintenance. Furthermore, it is important that there is an ongoing inspection of the bolt corrosion status. In case of doubt, the bolts shall be exchanged.

3.3 Recommendations

The OEM up to 20 years of lifetime makes service plans. These service plans shall be extended to include the next number of years, which will include extra visual inspections of the structural elements. These plans shall be on turbine type level.

3.4 Bolt measurements: Ultrasonic elongation measurement during tightening / loosening of fastener

R&D has been developing a bolt measurement system that makes it possible to determine the pretension in flange bolts, without loosening these. The results are based on a mixture between mechanical and ultrasonic measurements. These two systems don't give the same results when measuring on a tightened bolt. The difference is then used to determine the actual elongation.

An investigation of the influence of the surface finish and shape of the surface has been tested as well, to describe a robust process for the measurement. Some pre measurement actions might be required. These are described as well.

The ultrasonic equipment are manufactured by Dakota Ultrasonics in US, and among other distributed by R&D A/S.

This equipment is tailored to make this kind of measurements, having high accuracy. Here R&D have developed a method, to ensure the quality and accuracy of the measurements. It is a part of the DNV verification we want to get.

3.4.1 Measuring method

The measuring method allows to measure on mounted bolts, and detect the clamping force, without loosening these. The method can be used on most fasteners having solid head and can be used for control on already mounted bolts.

The measurement is made as a combination between ultrasonic and mechanical measurements on the bolts. The system exploits the change of the speed on sound in a loaded bolt, which gives different values measured by ultrasonic speed and mechanical measurements. R&D has developed a customized tool for this kind of measurements, and have through a lot of tests documented the validity of these measurements.

3.4.2 Theoretical background

When a bolt is tightened, it acts like a spring, where the collation between elongation and force is linear. This is generally known and will not be described more intensive in this document.

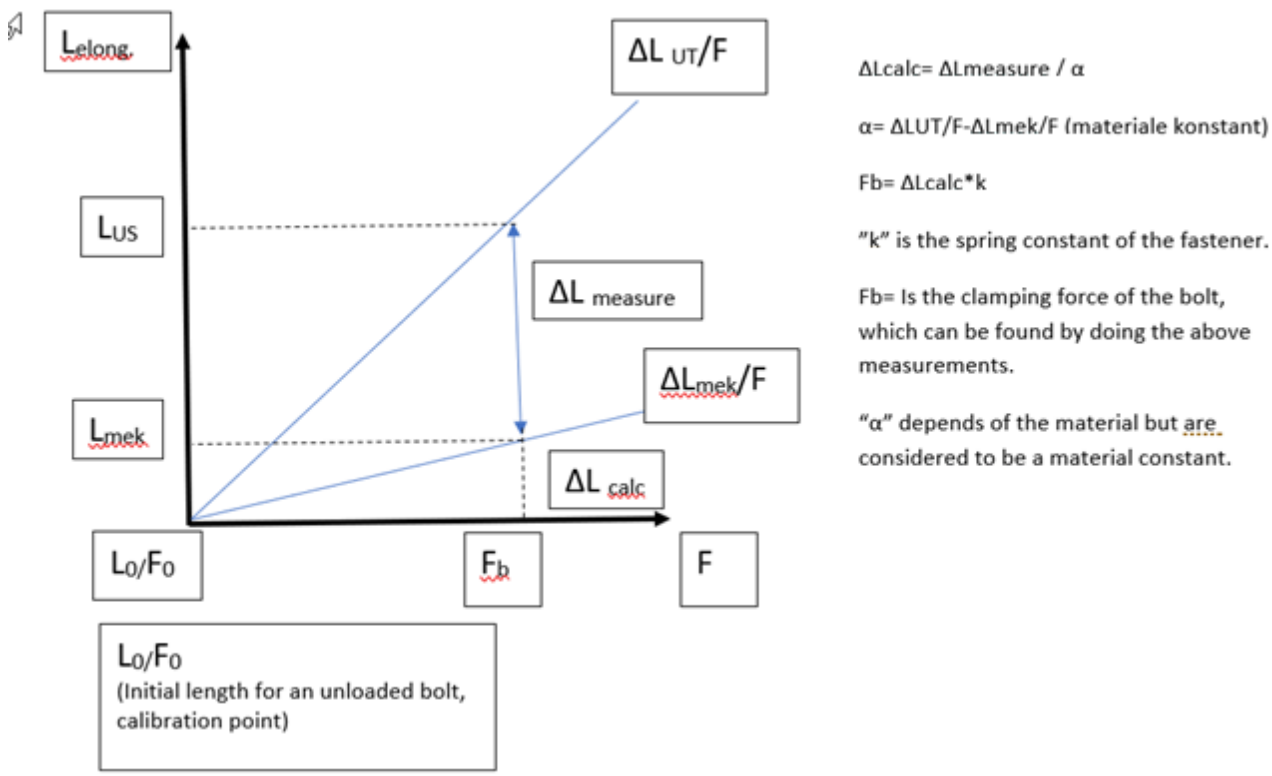
The ultrasonic device is able to detect this elongation, by change in delay of echo "time of flight". Some internal calculations in the device, compensate for the additional changes of delay, caused by temperature and stress level in the bolts. This test is not sensitive for the accurate speed of sound, as it measures the elongation of the bolt, based on a given reference length.
The combi method is working slightly different and are based on length measurement on the bolts using two different measuring systems. The idea is based on the fact that the there are two factors that have influence of a length measurement made by ultrasound:

- The actual elongation
- Stress level in the bolt

If these factors not are compensated, it gives a wrong ultrasonic reading for elongation. The combi method is using these values, which can be calculated into an actual elongation of the bolt.

3.4.3 Measurement description

When measuring the elongation without loosening the bolt, it is important to have access to both end of the bolt. The measurements must be calibrated towards the production batch and dimension on the bolts. This means that a physical length and an ultrasonic length can be measured on a tightened bolt. Then a gap will occur. The size of this gap depends on the stress level in the bolt and may then be used to determine the elongation of the bolt.



The illustration above, describe the principals in the idea. As these results are based on physical length of the bolt, it is important that the system is calibrated, to ensure useable results. A measuring error on 0,5% will have significant influence on the results but this problem is solved during the batch calibration of the measurement system. How we overcome this problem, is described inside this report.

3.4.4 Advanced measurement method description

The advanced method measurement is a benchmarking process, which enable measurements on fasteners that is already mounted. The method is based on ignoring the correction factor built in the ultrasonic device, and combining an ultrasonic length measurement with a mechanical measurement.

The two measurements are different, and by knowing the difference of the measurements, an elongation of the bolt can be determined. The length of some unloaded bolts must be known, as the system needs to be calibrated to a specific batch of bolts. The speed of sound can vary ±1% between different bolt batches, but within the same batch the variation is much less 0,1% or less.

As these measurements are based on the entire length of the bolt, it is very essential to calibrate the system before the measurements are taking place. To improve the accuracy of the measurements, 3 measurements are taken on every bolt. These are evaluated, and the operator will decide whether to accept or re-measure these.

The measurements are made with a customized tool, combining a micro gauge and an ultrasonic measurement in one tool. The tool is equipped with centring pads and magnets, to ensure the position of the measuring points are similar each time. The magnets are added to ensure and maintain the position of the tool, without holding it by hand.

3.4.5 Verification of the Combi method

Several tests have been made to find the right relation, between the ultrasonic measurement and the mechanical measurement.

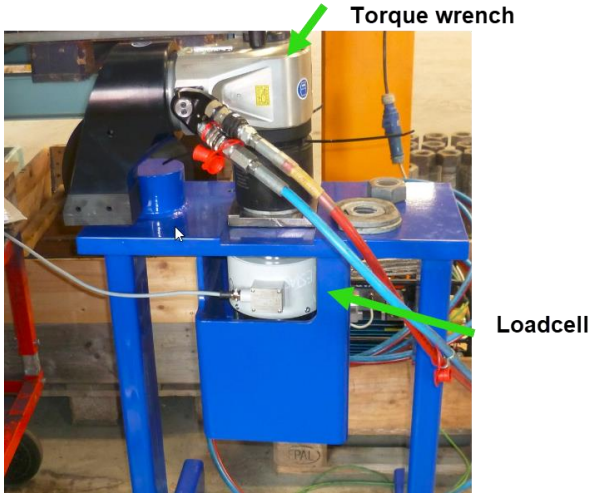
Tests of different length and different sizes of bolts have been made. The calculation factor between the ultrasonic and the mechanical measurement is confirmed.

The most challenging process is to get stabile measurements from the “combi tool” as the measuring positions are “locked” by the alignment tool, and especially getting stabile and equal readings for the ultrasonic part of the tool. However, we have made a procedure, which gives good and stabile readings.

Tests made by R&D, leads to a better precision and accuracy. Bolts within the same production batch, have much less variation in the speed of sound. The measuring error is calculated from the R&D confirmed calculation factor and found to be around 12,7%.

3.4.6 Calculation of the clamping force

R&D has developed a spreadsheet, where the measured elongation is converted into a clamping force. This calculation is based on the formulas in VDI 2230 Blatt 1, but the contribution from the nut and bolthead are slightly changed, to get as good results as possible.



The verification of the results are made through several tests, at torque-tension machines at bolt suppliers and by use of a certified loadcell at R&D and at a costumer workshop. Here the correlation between elongation and clamping force has been tested as well.

Two loadcells are used:

- 2MN loadcell, used for M42-M64
- 500kN loadcell for M16-M36

The loadcell and USB converter are calibrated as a system unit, by Danish Technologic Institute in Aarhus. Look in appendix A.

The calculations are made by use of only a few parameters and does not take into account the different areas at the bolts shaft and the threaded area. Most of the data are selected by drop down boxes in the spreadsheet. In principal only the number of washers, the clamping length and the utilisation are required inputs.

The input area in the spreadsheet is as described below:

Bolt information				
Flance information	R&D			
Bolt size	M56			
Supplier	R&D			
Additional info	HDG			
				Units
Bolt type (HV, ISO 4014, Thread rod)	HV			
Select Bolt size	M56			
Select Bolt Quality	10.9			
Enter global Utilization (0-100%)	70%			
Yield	900			MPa
Max pretension 100%	1827			kN
Nomm pretension	1279			kN
Shaft area	2463			mm^2
Thread stress area	2030			mm^2
Bolthead height	35			mm
Nut height	45			mm
Thickness of std washer	10			mm
Clamping area information				
No of std washers	2		20	mm
Flange thickness	430		430	mm
Clamping length in total			450	mm
Contribution from bolthead end			14	mm
Contribution from nut end			33,55	mm
Calculation clamping length			497,6	mm
Utilisation & elongation				
Nominal elongation 100% prestress		Elongation [mm]	Pre-Stress [kN]	
100% utilisation, (yield point)		1,758	[illegible]	
50% utilisation, (yield point)		[illegible]	913,528	
Max pretension utilisation	130%	1,599	[illegible]	
Normal pretension utilisation	100%	1,230	1279	
Minimum pretension Utilisation	75%	[illegible]	[illegible]	

Additional information

Dropdown menu: Threaded rod, ISO 4014 or HV

Dropdown menu: M16-M64

Dropdown menu: 8.8, 10.9, 12.9

Entering global utilisation, normal between 70-80%

Entering number of standard washers

Entering clampinglength without washers

Entering upper limit

Target value, based on the global utilisation

Entering lower limit

3.5 Verifications made by 3 part (DNV / GL)

3.5.1 Introduction

This test report is based on lab tests performed at DNV-GL facility, in Høvik Norway.

All tests are performed 12-14/6 2019. Two measurement methods are used and will be evaluated.

Standard method:

- Here a reference length of the bolt is measured. Based on this, the elongation of the bolt will be measured when the bolt is being tightened.

Advanced measurement method:

- This test is made to verify that it is possible to estimate an elongation, and by this an clamping force, of a fastener, by combining two different measurement methods. An ultrasonic length measurement and a mechanical length measurement.

The goal for the test is to demonstrate a plausibly standard deviation of max:
5% for Ultrasonic elongation measurement and 10% for a combined measurement.

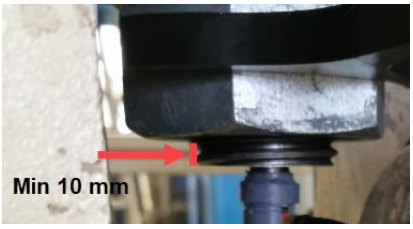
3.5.2. Test setup.

The test is performed at the test lab at DNV facility. The tests are performed at a 200 Tonne tension machine from Instron. The measurement equipment is operated by Flemming Selmer Nielsen, R&D Engineering A/S.

The Instron tension machine is mainly operated by Anette Ripe, DNV GL.

The tensile machine is equipped by some plates, in which the threaded rod is placed for test.

The nuts and washers are mounted in top and bottom, ensuring a thread runout at, atleast 10mm on all the tests.



The tension machine is equipped with 2 measuring probes, which are measuring the mechanical displacement of the tension machine.

Displacement measuring probes on the tension machine

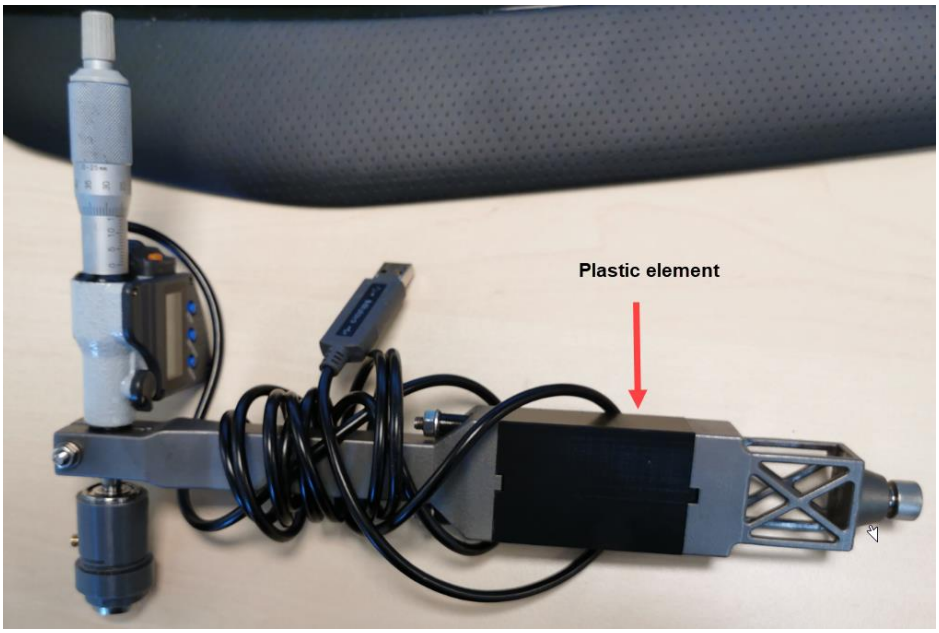
The threaded rod is positioned on the tension machine, and the nuts are tightened by hand.
The clamping length, including washers are measured by a measuring tape, to be able to calculate the pretension of the bolt, based on the elongation.

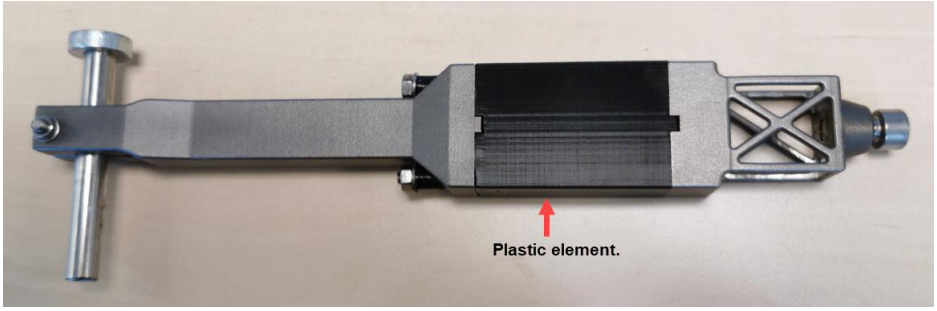
A "0" point calibration of each bolt is made. The procedure is based on the length measured by UT. 3 sets of ultrasonic length measurements are taken, and the average is then used as the setpoint for the micro gauge.

At the same, another reference length is determined by a second ultrasonic device. This measurement is used to measure the elongation achieved at the different utilisation steps at 20%, 40%, 60% and 80% of yield. (For the M64, the max utilisation is 2000kN, corresponding to 74,7%, due to machine limitations).

The measuring tool used for the combined measuring method, consists of a micrometer gauge with a build in UT sensor, enabling to take both measurements simultaneously.

Due to constrains on the tensile machine, the measuring arms are extended by 60 mm.





This extension is made by printed plastic, which is a soft point in the measuring system. Based on this, the measurements are considered to be a bit conservative.

The measuring equipment for ultrasonic measurement, are both made by Dakota Ultrasonics, and handled as a private label by R&D.

The small device, used for measuring elongations only, is a R&D Tension meter 1+, identical to Mini-Max from Dakota Ultrasonics.

The big device, used for the combi measurement, is a R&D MAX II, identical to MAX II from Dakota Ultrasonics.

The combined measurements are taken as an average of 3 measurements. As the results are made in a way that can't be controlled, a quality check of the measurements is needed. The quality check is based on the variance between the 2 x 3 individual measurements. Measurements with more than 4/100 mm difference will be retaken.

3.5.3. Test results.

The test results are summarized on the following page:

Dataplot DNV test								
	COMBI length vs UT length dev				UT elongation			
M24	20%	40%	60%	80%	20%	40%	60%	80%
I	62	8	1,4	7,9	0,808	1,385	2,016	2,914
II*	39,9	19,7	13,2	7,2	0,739	1,324	1,922	2,543
III	18,4	13,5	12,9	10,8	0,729	1,518	1,911	2,549
IV	8,9	0,7	5,6	2,9	0,758	1,568	2,4	3,294
V	13,7	5,9	4,4	3,1	0,746	1,52	2,523	3,396
VI	4,3	0,9	0,5	0,5	0,764	1,561	2,385	3,279
Stdev	22,12986	7,418468	5,53016	3,852272				
	COMBI length vs UT length dev				UT elongation			
M36	20%	40%	60%	80%	20%	40%	60%	80%
I	0,5	0,5	3,8	12,8	0,541	1,13	1,741	2,698
II	0	0,2	4,8	8,9	0,537	1,125	1,714	2,348
III	4,9	2,8	2,3	2	0,552	1,135	1,71	2,359
IV	1,7	0,8	0,1	0,7	0,727	1,527	2,334	3,175
V	1,5	1,2	0,9	0,4	0,732	1,519	2,332	3,186
VI	2,3	1,8	0,7	1	0,713	1,492	2,325	3,171
Stdev	1,725592	0,955859	1,877232	5,249				
	COMBI length vs UT length dev				UT elongation			
M64	20%	40%	60%	80%	20%	40%	60%	80%
I	18	7,4	7,6	4,4	0,525	1,171	1,61	2,054
II	10,5	1,7	0,9	0	0,533	1,061	1,614	2,059
III**	10,4	4,9	13,7	16,3	0,533	1,077	1,613	2,047
IV	15,5	3,3	1,3	1,3	0,726	1,466	2,239	2,802
V	4,5	12,9	8,4	0,7	0,726	1,468	2,259	2,86
VI	4,1	3,2	0,4	0,5	0,75	1,533	2,291	2,9
Stdev	5,6253	4,081013	5,381233	6,28925				

*) elongation measurements retaken

**) difficult to achive right echo

3.5.4. Evaluation of the results

The test results are evaluated for the consistence and accuracy in sets of 3, (one for each dimension and length), and the value are used in the reporting spreadsheet, to get the calculated clamping force, based on the measurements.

M24, length 600 mm

The first 3 samples tested, didn't perform as well.

This is mostly related to the routine, that this is the first test subject, and that everybody should know what to do.

The clamping length (distance between the nuts) is approx. 550mm. The clamping force is based on the elongation of the threaded rod measured by UT.

Measurements based on pure Uitrasonic elongation measurement.							
No of measurements			Measured elongation tension force	Measured elongation tightening*	Calculated force	Actual test force	Deviation on load
	1		0,808	0,808	95	70	36%
	2		1,384	1,384	163	141	16%
	3		2,016	2,016	238	211	13%
M24x600 I	4		2,941	2,941	347	282	23%
	5		0,739	0,739	87	70	25%
	6		1,324	1,324	156	141	11%
	7		1,922	1,922	227	211	8%
M24x600 II	8		2,543	2,543	300	282	6%
	9		0,729	0,729	86	70	23%
	10		1,518	1,518	179	141	27%
	11		1,911	1,911	226	211	7%
M24x600 III	12		2,549	2,549	301	282	7%
						STDEV	10%

The standard deviation of the loads calculated and measured by UT is 10%.

Measurements based on combined measurement.							
No of measurements			Measured elongation tension force	Measured elongation tightening*	Calculated force	Actual test force	Deviation on load
	1		0,494	0,494	58	70	17%
	2		1,504	1,504	178	141	26%
	3		2,044	2,044	241	211	14%
M24x600 I	4		2,723	2,723	321	282	14%
	5		0,528	0,528	62	70	11%
	6		1,106	1,106	131	141	7%
	7		1,698	1,698	200	211	5%
M24x600 II	8		2,371	2,371	280	282	1%
	9		0,615	0,615	73	70	4%
	10		1,755	1,755	207	141	47%
	11		2,192	2,192	259	211	23%
M24x600 III	12		2,307	2,307	272	282	3%
						STDEV	13%

The standard deviation of the loads calculated by use of the combi tool is 13%.

M24 length 800mm

The clamping length (distance between the nuts) is approx. 745mm.

The clamping force is based on the elongation of the threaded rod measured by UT.

Measurements based on pure Uitrasonic elongation measurement.							
No of measurements			Measured elongation tension force	Measured elongation tightening*	Calculated force	Actual test force	Deviation on load
	1		0,758	0,758	67	70	4%
	2		1,568	1,568	138	141	2%
	3		2,4	2,4	212	211	0%
M24x800 IV	4		3,294	3,294	291	282	3%
	5		0,745	0,745	66	70	6%
	6		1,52	1,52	134	141	5%
	7		2,523	2,523	223	211	5%
M24x800 V	8		3,396	3,396	300	282	6%
	9		0,764	0,764	67	70	4%
	10		1,561	1,561	138	141	2%
	11		2,385	2,385	210	211	0%
M24x800 VI	12		3,279	3,279	289	282	3%
						STDEV	2%

The standard deviation of the loads calculated and measured by UT is 2%.

Measurements based on combined measurement.							
No of measurements			Measured elongation tension force	Measured elongation tightening*	Calculated force	Actual test force	Deviation on load
	1		0,832	0,832	73	70	5%
	2		1,557	1,557	137	141	3%
	3		2,541	2,541	224	211	6%
M24x800 IV	4		3,394	3,394	299	282	6%
	5		0,864	0,864	76	70	9%
	6		1,616	1,616	143	141	1%
	7		2,416	2,416	213	211	1%
M24x800 V	8		3,295	3,295	291	282	3%
	9		0,732	0,732	65	70	8%
	10		1,547	1,547	136	141	3%
	11		2,397	2,397	211	211	0%
M24x800 VI	12		3,263	3,263	288	282	2%
						STDEV	3%

The standard deviation of the loads calculated by use of the combi tool is 3%.

M36 length 600mm

The clamping length (distance between the nuts) is approx. 520mm.

The clamping force is based on the elongation of the threaded rod measured by UT.

Measurements based on pure Uitrasonic elongation measurement.							
No of measurements			Measured elongation tension force	Measured elongation tightening*	Calculated force	Actual test force	Deviation on load
	1		0,541	0,541	154	163	6%
	2		1,13	1,13	321	327	2%
	3		1,741	1,741	495	490	1%
M36x600 I	4		2,698	2,698	767	654	17%
	5		0,537	0,537	153	163	6%
	6		1,125	1,125	320	327	2%
	7		1,714	1,714	487	490	1%
M36x600 II	8		2,348	2,348	667	654	2%
	9		0,552	0,552	157	163	4%
	10		1,135	1,135	323	327	1%
	11		1,71	1,71	486	490	1%
M36x600 III	12		2,359	2,359	670	654	3%
						STDEV	5%

The standard deviation of the loads calculated and measured by UT is 5%.

Measurements based on combined measurement.							
No of measurements			Measured elongation tension force	Measured elongation tightening*	Calculated force	Actual test force	Deviation on load
	1		0,539	0,539	153	163	6%
	2		1,124	1,124	319	327	2%
	3		1,811	1,811	515	490	5%
M36x600 I	4		3,095	3,095	880	654	34%
	5		0,537	0,537	153	163	6%
	6		1,122	1,122	319	327	2%
	7		1,78	1,78	506	490	3%
M36x600 II	8		2,578	2,578	733	654	12%
	9		0,58	0,58	165	163	1%
	10		1,168	1,168	332	327	2%
	11		1,75	1,75	497	490	2%
M36x600 III	12		2,406	2,406	684	654	5%
						STDEV	9%

The standard deviation of the loads calculated by use of the combi tool is 9%.

M36 length 800mm

The clamping length (distance between the nuts) is approx. 720mm.

The clamping force is based on the elongation of the threaded rod measured by UT.

Measurements based on pure Uitrasonic elongation measurement.							
No of measurements			Measured elongation tension force	Measured elongation tightening*	Calculated force	Actual test force	Deviation on load
	1		0,727	0,727	152	163	7%
	2		1,527	1,527	320	327	2%
	3		2,334	2,334	489	490	0%
M36x800 IV	4		3,175	3,175	665	654	2%
	5		0,732	0,732	153	163	6%
	6		1,519	1,519	318	327	3%
	7		2,332	2,332	489	490	0%
M36x800 V	8		3,186	3,186	668	654	2%
	9		0,713	0,713	149	163	8%
	10		1,492	1,492	313	327	4%
	11		2,325	2,325	487	490	1%
M36x800 VI	12		3,171	3,171	664	654	2%
						STDEV	3%

The standard deviation of the loads calculated and measured by UT is 3%.

Measurements based on combined measurement.							
No of measurements			Measured elongation tension force	Measured elongation tightening*	Calculated force	Actual test force	Deviation on load
	1		0,74	0,74	155	163	5%
	2		1,54	1,54	323	327	1%
	3		2,331	2,331	488	490	0%
M36x800 IV	4		3,199	3,199	670	654	2%
	5		0,721	0,721	151	163	7%
	6		1,501	1,501	314	327	4%
	7		2,311	2,311	484	490	1%
M36x800 V	8		3,198	3,198	670	654	2%
	9		0,73	0,73	153	163	6%
	10		1,52	1,52	318	327	3%
	11		2,342	2,342	491	490	0%
M36x800 VI	12		3,202	3,202	671	654	3%
						STDEV	2%

The standard deviation of the loads calculated by use of the combi tool is 2%.

M64 length 600 mm

The clamping length (distance between the nuts) is approx. 470mm.

The clamping force is based on the elongation of the threaded rod measured by UT.

Measurements based on pure Uitrasonic elongation measurement.							
No of measurements			Measured elongation tension force	Measured elongation tightening*	Calculated force	Actual test force	Deviation on load
	1		0,525	0,525	510	535	5%
	2		1,071	1,071	1040	1070	3%
	3		1,61	1,61	1564	1606	3%
M64x600 I	4		2,054	2,054	1995	2000	0%
	5		0,533	0,533	518	535	3%
	6		1,061	1,061	1030	1070	4%
	7		1,641	1,641	1594	1606	1%
M64x600 II	8		2,059	2,059	2000	2000	0%
	9		0,533	0,533	518	535	3%
	10		1,077	1,077	1046	1070	2%
	11		1,613	1,613	1567	1606	2%
M64x600 III	12		2,047	2,047	1988	2000	1%
						STDEV	1%

The standard deviation of the loads calculated and measured by UT is 1%.

Measurements based on combined measurement.							
No of measurements			Measured elongation tension force	Measured elongation tightening*	Calculated force	Actual test force	Deviation on load
	1		0,641	0,641	623	535	16%
	2		1,156	1,156	1123	1070	5%
	3		1,742	1,742	1692	1606	5%
M64x600 I	4		2,148	2,148	2086	2000	4%
	5		0,596	0,596	579	535	8%
	6		1,079	1,079	1048	1070	2%
	7		1,627	1,627	1580	1606	2%
M64x600 II	8		2,059	2,059	2000	2000	0%
	9		0,595	0,595	578	535	8%
	10		1,133	1,133	1100	1070	3%
	11		1,869	1,869	1815	1606	13%
M64x600 III	12		2,447	2,447	2377	2000	19%
						STDEV	6%

The standard deviation of the loads calculated by use of the combi tool is 6%.

M64 length 800mm

The clamping length (distance between the nuts) is approx. 680mm.

The clamping force is based on the elongation of the threaded rod measured by UT.

Measurements based on pure Uitrasonic elongation measurement.							
No of measurements			Measured elongation tension force	Measured elongation tightening*	Calculated force	Actual test force	Deviation on load
	1		0,726	0,726	509	535	5%
	2		1,466	1,466	1028	1070	4%
	3		2,239	2,239	1570	1606	2%
M64x800 IV	4		2,802	2,802	1964	2000	2%
	5		0,726	0,726	509	535	5%
	6		1,468	1,468	1029	1070	4%
	7		2,259	2,259	1584	1606	1%
M64x800 V	8		2,86	2,86	2005	2000	0%
	9		0,75	0,75	526	535	2%
	10		1,533	1,533	1075	1070	0%
	11		2,291	2,291	1606	1606	0%
M64x800 VI	12		2,9	2,9	2033	2000	2%
						STDEV	2%

The standard deviation of the loads calculated and measured by UT is 2%.

Measurements based on combined measurement.							
No of measurements			Measured elongation tension force	Measured elongation tightening*	Calculated force	Actual test force	Deviation on load
	1		0,629	0,629	441	535	18%
	2		1,419	1,419	995	1070	7%
	3		2,269	2,269	1591	1606	1%
M64x800 IV	4		2,837	2,837	1989	2000	1%
	5		0,695	0,695	487	535	9%
	6		1,3	1,3	911	1070	15%
	7		2,083	2,083	1460	1606	9%
M64x800 V	8		2,841	2,841	1992	2000	0%
	9		0,721	0,721	505	535	6%
	10		1,486	1,486	1042	1070	3%
	11		2,301	2,301	1613	1606	0%
M64x800 VI	12		2,914	2,914	2043	2000	2%
						STDEV	6%

The standard deviation of the loads calculated by use of the combi tool is 6%.

3.5.5 Summary of results

The standard deviation has been noted for each combination of measurements. The deviations are as percentage of the load applied in the test bench.

They are as follow:

Thread rod size	Ultrasonic based measurement	Ultrasonic combined with mechanical measurement.
M24 x 600	10%	13%
M24 x 800	2%	3%
M36 x 600	5%	9%
M36 x 800	3%	2%
M64 x 600	1%	6%
M64 x 800	2%	6%
Average:	3,8%	6,5%

3.6 Valuable for life time extension approval

The collected data is useful as a part of lifetime evaluation based on the following:

- Fast and reliable measuring without use of a tensioning tool for every bolt
- Determine the level of pretension of the bolts, without disturbing installed connection
- Based on the measurements, the bolted joints can be evaluated, and the correct and most cost-efficient maintenance procedure can be determined.
- If the bolts are approved, reduced maintenance can be implemented, as further check of the bolts can be done by just ultrasonic.
- With the customized tool, a baseline is established, and further changes can check again with a regular and more user-friendly ultrasonic tool.

With ultrasonic it would be possible to ensure a correct flange connection with the use of the normally used hydraulic tools. With bolts approved for further operation, the ultrasonic tool can support with extending their life time while ensuring exact tensioning. Apart from reliability, the tool would also improve health and safety as heavy equipment is not required to the same extend. Further the use of hydraulic tensioning tool would be reduced substantial and thereby a substantial cost, helping life time extension becoming more economically attractable.

3.7 Conclusion

The test results are showing low standard deviations.

Especially the M24x600 test seems to have significant higher deviations than the remaining tests. A part of this might be caused that this is the initial test. The test is still considered as valid and is evaluated together with the other tests. A M24 threaded rod can be problematic to measure on, as the entire rod is threaded. If the ultrasonic hits the side of the threaded rod, the reflection will be reflected in many directions, making it more difficult to get the right measurements. Normally the bolts that are measured on is M36 and above. If the M24x600 measurements are ignored, the average standard deviation for the measurements are:

For UT: 2,6%, for the combined method: 5,75%.

The initial goal is to have a plausibly standard deviation of: 5% for ultrasonic elongation measurement, 10% for a combined measurement. Based on the lab tests, this was achieved.

4. Methods in Existing Standards applicable to Lifetime Extension

Generally, design standards and guidelines provide requirements and recommendations for design of new structures. Examples are the IEC 61400 series for design of wind turbines, the Eurocodes for design of buildings and bridges and the ISO 19900 series for design of offshore structures. However, much more limited information is available on assessment of existing structures, incl. estimation of the remaining lifetime.

In WP3 *Existing Standards on remaining lifetime assessment* information on assessment of existing structures and remaining lifetime in existing standards have been collected with special emphasis on techniques and approaches that can be useful for wind turbines.

The review of requirements and guidelines in the standards had focus on techniques and approaches for:

1) Specification and verification of reliability and safety requirements for cases where life safety is critical.
2) Decision making in cases where life safety is not critical and where economic optimization can be used as basis for assessment of the remaining lifetime.
3) Collection of information on the existing structure and how this can be used to update estimates of the remaining lifetime.

In the following list, an overview is given of the standards and guidelines collected for the review:

- Reliability
    - ISO 2394 (2015): General principles for reliability of structures (ISO2394, 2015)
    - JCSS (2001b): Probabilistic Model Code (JCSS, 2001b)

- Existing structures
    - ISO 13822 (2010): Bases for design of structures – Assessment of existing structures (ISO13822, 2010)
    - NORSOK: Assessment of structural integrity for existing offshore load-bearing structures (NORSOK N-006, 2015)
    - JCSS (2001a): Probabilistic Assessment of Existing Structures (JCSS, 2001a)
    - SIA 269: Existing structures – Bases for examination and interventions (SIA 269)
    - fib Bulletin No. 80: Partial factor methods for existing concrete structures (fib Bulletin No. 80, 2016)
    - *Eurocodes - Assessment and Retrofitting of Existing Structures – General Rules / Actions. Final Document TS, April 2018* (Eurocodes. CEN-TC250-WG2, 2018)
    - VDI6200: Structural safety of buildings – Regular inspections (VDI 6200, 2010)

- Wind turbines

- DNVGL-ST-0262 (2016): Lifetime extension of wind turbines (DNVGL-ST-0262, 2016)
- DNVGL-ST-0126 (2016): Support structures for wind turbines (DNVGL-ST-0126, 2016)
- DNVGL-SE-0263 (2016): Certification of lifetime extension of wind turbines (DNVGL-SE-0263, 2016)
- Bureau Veritas (2017): Guidelines for Wind Turbines Lifetime Extension. Version 0 (Bureau Veritas, 2017).
- NPR 8400: Principles and technical guidance for continued operation of onshore wind turbines (NPR 8400, 2016)
- UL4143: Outline of Investigation for Wind Turbine Generator – Life Time Extension (UL4143, 2016)
- IEC-TS-61400-26: Time based availability for wind turbine generating systems (IEC-TS-61400-26-1, 2011)
- IEC-TS-61400-26-2: Production based availability for wind turbines (IEC-TS-61400-26-2, 2014)
- DS/EN 50308(2005): Wind Turbines – Protective measures – Requirements for design, operation and maintenance (DS/EN 50308, 2005)
- IEC 61400-1 ed. 4: Wind turbines – Design requirements (IEC 61400-1, 2019)

- Offshore structures
  - DNVGL-RP-C210: Probabilistic methods for planning of inspection for fatigue cracks in offshore structures (DNVGL-RP-C210, 2015)
  - DS/EN ISO 19902:2008 + A1:2013: Petroleum and natural gas industries – Fixed steel offshore structures (DS/EN ISO 19902:2008 + A1:2013, 2013)

Based on the review, the following topics of interest were identified:

- Approaches for decision making
- Target reliability level for life extension
- Assessment of existing structures
- Approaches for life extension
- Updating of reliability
- Reliability updating using inspections

4.1 Approaches for decision making

In ISO2394 (ISO2394, 2015) it is written that decisions should be made based on the risks: *"Design and assessment of decisions shall take basis in information concerning their implied risks".*

Basically, there are three approaches/levels for decision making, as given in e.g. ISO2394 (ISO2394, 2015):

- Risk-informed decision making
- Reliability-based decision making
- Semi-probabilistic methods

The risk-informed approach is the most comprehensive analysis, where all direct and indirect costs and other consequences are considered together with their probabilities of occurrence. Here, the costs of improving a structure are considered directly. If fatalities are likely to occur in the event of failure, the risk should be below the acceptance criteria for individual and society risk (ISO2394, 2015) .

For well understood consequence of failure and damage, reliability-based assessment can be used instead of risk-informed. Reliability-based decision making (probabilistic design) requires that a target level for the reliability is set, which can be done using risk-informed methods. The target level will depend on e.g. the consequence of failure, and the relative cost of improving reliability ((ISO2394, 2015); (JCSS, 2001b)). The optimal target reliability level can be found using a risk-informed approach. As the costs of improving the reliability is typically higher for existing structures compared to new structures, the target reliability can be lower. If a reliability model, consistent with the design assumptions is already established, it can be used directly to assess the effect of updated probability distributions on the reliability. However, if this is not the case, this can be difficult.

For categorized and standardized failure modes and uncertainty representation, the semi-probabilistic approach can be applied instead of probabilistic design. The partial safety factor method used in design, is a semi probabilistic method. Here, it is basically ensured that the design load effect (found as a characteristic value multiplied by a partial safety factor) is smaller than the design resistance (found as a characteristic value divided by a partial safety factor). The partial safety factors are generally calibrated using reliability-based methods to reach the target reliability level. For existing structures, the partial safety factors used in design might be too conservative, as 1) more information is generally available leading to reduced uncertainties, and 2) the relative cost of improving reliability is higher for existing structures.

Eurocodes (Eurocodes. CEN-TC250-WG2, 2018) for existing structures provides the same methods for decision making, but here the order is reversed:

- semi-probabilistic methods:
    - partial factor method;
    - assessment value method;
- probabilistic method;
- risk assessment method.

It is stated that, initially, the partial factor method should be used. More advanced methods could be used afterwards:

After the partial factor methods have been utilized, the assessment value methods, probabilistic methods and the risk assessment approach may be used for:

- Overcoming the conservatism of partial factor methods;
- Cases of structural failures with serious consequences;
- Cases of insufficient robustness;
- Evaluating the efficiency of monitoring and maintenance strategies;
- Making fundamental decisions concerning a whole group of structures. (Eurocodes, 2018)

In the partial factor method, both characteristic values and partial factors should be updated based on actual data.

Semi-probabilistic methods can be described in and calibrated for standards in different ways. First, partial safety factors can be calibrated using probabilistic methods for a range of conditions with respect to level of uncertainties and target reliability index (Sørensen & Toft, 2014). As an example, the partial safety factor for stress ranges in IEC61400-1 ed. 4 (IEC 61400-1, 2019) is given directly dependent on the coefficient of variation for stress ranges, as shown in Table 4-1.

Coefficient of variation, V_{Ff} for fatigue stress ranges	15 % to 20 %	20 % to 25 %	25 % to 30 %
γ_{Ff}	1,00	1,10	1,20

Table 4-1: Partial coefficient for fatigue stress ranges as function of coefficient of variation on fatigue stress ranges.

Alternatively, methods can be given to update partial coefficients based on the design value format. It can be formulated as the design (or assessment) value method or the adjusted partial safety factor method. The methods are simple to apply, but there are limits for their validness, and reliability based calibration is the therefore most robust and accurate.

4.2 Target reliability level for life extension

On target performance level the following is stated in (ISO2394, 2015):

- The appropriate degree of reliability shall be judged with due regard to the possible consequences of failure, the associated expense, and the level of efforts and procedures necessary to reduce the risk of failure and damage.

- Some of these requirements shall relate to demands on safety for personnel and environment set by society. Others shall relate to the reliability of the functionality of the structures as specified by the owners.

In Eurocodes (Eurocodes. CEN-TC250-WG2, 2018) the following is stated on the target reliability level:

The performance requirements for an existing structure shall be based on economic criteria and the level of risk to persons acceptable for the client or the relevant national authority. (…)

Target reliability levels, acceptable probabilities of failure and acceptable levels of risk are determined by the relevant national authorities. (…)

The target reliability levels of existing structures can be different from the current code values assumed for new structures. The following aspects motivate the differentiation of target reliability levels between new and existing structures:

- Economic considerations: the relative cost of interventions in existing structures with the aim to increase the reliability level can be very high, whereas the incremental cost of increasing the reliability at the design stage of new structures is generally low;

- Societal considerations: possible resettlement of inhabitants, relocation of activities or loss of public productivity, economic impact and loss of heritage values must be considered in relation to existing structures, whereas such aspects normally do not affect the design of new structures;

- Sustainability considerations: repair or upgrading of existing structures normally enables the choice of the most appropriate materials and implies reduction in the use of resources compared to replacement by new structures or structural elements.

Generally, minimum target reliability levels can be set based on requirements for acceptable human safety (life safety) and target reliability levels can be obtained by economic optimization. An economic optimization may show that it is feasible to use a higher reliability index than the minimum acceptable. Reliability indexes derived based on human safety considerations and economic optimization are presented in the following.

4.2.1 Human safety considerations (life safety)

ISO2394 (ISO2394, 2015) states that "*The fundamental principle of the marginal lifesaving costs for the regulation of life safety applies and is recommended".*

According to the Marginal lifesaving costs (MLSC) principle, the costs associated with saving one additional life should be in balance with the societal willingness to pay for saving one statistical individual (JCSS, 2008). The latter depends on the Life Quality Index (LQI). According to the LQI, the

preference of the society to invest into health and life safety improvements can be described in terms of life expectancy at birth, Gross Domestic Product (GDP) per capita and ratio between working time and leisure time.

The LQI acceptance criterion can be written as:

$$-\frac{dP_f(p)}{dp} \leq \frac{C_1(\gamma_S + \omega)}{G_x \cdot N_F} = K_1$$

where p is the ratio between the expected value of the resistance and the expected value of the load, and P_f is the probability of failure. The constant K_1 is a measure for the relative lifesaving costs, and depends on:

C_1-marginal costs associated with a considered safety measure
γ_S -interest rate
ω -annual rate of obsolescence
G_x -societal willingness to pay for a unitary change in mortality
N_F -expected number of fatalities given structural failure

Based on this, the minimum target reliabilities related to a one year reference period in Table 4-2 can be derived based on the LQI, depending on the relative lifesaving cost. These should be seen as minimum acceptable reliability indexes, when considering life safety.

Relative life-saving costs	Range for K_1 constant	LQI target reliability
Large	$10^{-3} - 10^{-2}$	$\beta = 3{,}1\left(P_f \approx 10^{-3}\right)$
Medium	$10^{-4} - 10^{-3}$	$\beta = 3{,}7\left(P_f \approx 10^{-4}\right)$
Small	$10^{-5} - 10^{-4}$	$\beta = 4{,}2\left(P_f \approx 10^{-5}\right)$

Table 4-2:LQI tentative minimum target reliabilities related to one year reference period as function of relative lifesaving costs (ISO2394, 2015).

4.2.2 Economic optimization

Target values for the reliability index found by economic optimization is given depending on the consequence of structural failure and relative cost of safety measure or equivalently the efficiency of interventions. The target reliability indexes found based on economic optimization can be found in the JCSS (JCSS, 2001b) Probabilistic model code and have been adopted by several standards. The table found in ISO2394 (ISO2394, 2015) is given in Table 4-3 and a similar table is found in SIA269 (SIA 269).

Relative cost of safety measure	Consequences of failure (classes from Table F1)		
	Class 2	Class 3	Class 4
Large	$\beta = 3{,}1\left(P_f \approx 10^{-3}\right)$	$\beta = 3{,}3\left(P_f \approx 5\times10^{-4}\right)$	$\beta = 3{,}7\left(P_f \approx 10^{-4}\right)$
Medium	$\beta = 3{,}7\left(P_f \approx 10^{-4}\right)$	$\beta = 4{,}2\left(P_f \approx 10^{-5}\right)$	$\beta = 4{,}4\left(P_f \approx 5\times10^{-6}\right)$
Small	$\beta = 4{,}2\left(P_f \approx 10^{-5}\right)$	$\beta = 4{,}4\left(P_f \approx 5\times10^{-6}\right)$	$\beta = 4{,}7\left(P_f \approx 10^{-6}\right)$

Table 4-3: Tentative target reliabilities related to one year reference period based on monetary optimization (ISO2394, 2015). Table F.1 mention major wind turbines and unmanned offshore facilities as examples of consequence class 2 structures.

The fib Bulletin No. 80 (Chapter 3) (fib Bulletin No. 80, 2016) outlines the background and motivation for alternative target reliability levels for existing structures (related to one year reference period), following ISO2394 (ISO2394, 1998) and JCSS (JCSS, 2001a). Generally, economic optimization may result in that reliability indices 1.5 lower than for new structures should be acceptable, thus eventually implying that no upgrading is necessary. However, if the structure does not fulfill this level, the upgrade should target a reliability level 0.5 lower than for new structures. For consequence class CC1, a reliability level of 1.8 is therefore acceptable for existing structures, and for CC2, the target level should be 2.3. These values do not consider human safety.

For deteriorating structures (degrading resistance), when human safety criteria can be disregarded, it is recommended to make a full probabilistic analysis, and to verify for an economic optimum for a reference period equal to the remaining working life.

For the target reliability level of existing structures in ISO 13822 (2010), reference is given to ISO2394 (ISO2394, 1998).

In IEC 61400-1 ed. 4 (IEC 61400-1, 2019), the annual target reliability index is set to 3.3, corresponding to an annual probability of failure of 5 10^{-4}. This level is based on the assumptions:

- A systematic reconstruction policy is used (a new wind turbine is erected in case of failure or expiry of lifetime)
- Consequences of a failure are ‘only’ economic (no fatalities and no pollution)
- Wind turbines are designed to a certain wind turbine class, i.e. not all wind turbines are ‘designed to the limit’

Application of this target value assumes that the risk of human lives is negligible in case of failure of a structural element. The reliability level corresponds to minor/moderate consequences of failure and moderate/high cost of safety measure.

4.3 Assessment of existing structures

The standard ISO13822 (ISO13822, 2010) states that the standard is applicable to assessment of any type of existing structure, and an assessment can be initiated under different circumstances, e.g. *an anticipated change in use or extension of design working life*. The introduction states the following points regarding existing structures:

- The ultimate goal is to limit construction intervention to a strict minimum, a goal that is clearly in agreement with the principles of sustainable development.

- The basis for the reliability assessment is contained in the performance requirements for safety and serviceability of ISO 2394. Economic, social and sustainability considerations, however, result in a greater differentiation in structural reliability for the assessment of existing structures than for design of new structures.

The assessment follows the steps shown in the flowchart in Figure 4-1.The principle is that first a preliminary assessment is made, including study of documents and a preliminary inspection. If no clear conclusion on the reliability can be made based on the preliminary assessment, a detailed assessment is recommended. The detailed assessment includes detailed review of documents, detailed inspection and testing, and detailed structural analysis based on updated models. If sufficient reliability cannot be verified, changes must be made to the structure or to the operation of the structure.

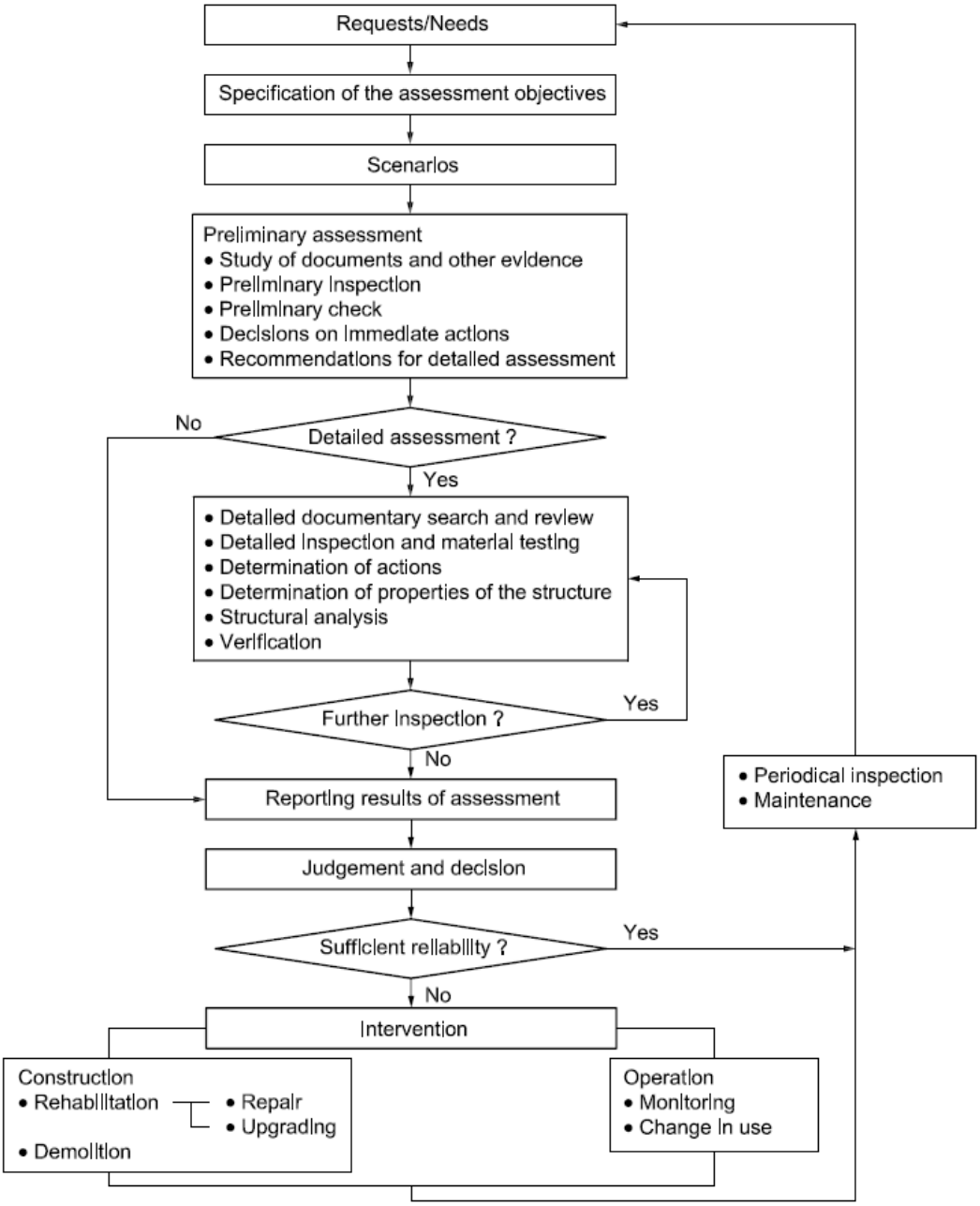


Figure 4-1: Flow chart for assessment of existing structures (ISO13822, 2010), Annex B).

4.4 Approaches for life extension

In the DNV GL service specification of certification of life extension (DNVGL-SE-0263, 2016) four methods for lifetime extension can be applied, which are increasing in complexity:

- Method lifetime extension inspection (Suitable for e.g. a single turbine)
    - (Lifetime extension inspections are performed for all methods)

- Method simplified approach (generic model)
    - Wind measurements for some years are collected
    - Load simulations are performed on a generic model for: a) the IEC wind class and b) the site specific conditions. The results are compared, and remaining useful life (RUL) is estimated

- Method detailed approach (specific model)
    - Site specific data is used for load simulations for the specific OEM model for a few representative turbines in the wind farm
    - The remaining turbines are assessed based on their data and the load simulation results
    - Load measurements can be included

- Method probabilistic approach (reliability approach)
    - The lifetime is assessed using structural reliability methods
    - Load measurements and operational data can be used to update distributions

These four approaches are related to the methods specified in the DNV GL standard on lifetime extension (DNVGL-ST-0262, 2016). The examination consists of an analytical and a practical part, where different approaches are possible:

- Analytical part
    - Simplified approach (generic)
    - Detailed approach (specific)
    - Probabilistic approach

- Practical part
    - General inspection scope
    - Specific inspection scope (based on analytical assessment)

The standard contains explanations on the different approaches, summarized in the following.

The simplified approach can be used, when the design documentation is not available. Load simulations can be made using a generic wind turbine model. Simulations are made for the class used in design (IEC class) and for the data on the site. Thereby, in the simple approach the lifetime is estimated using site specific loads.

The detailed approach require access to original design documentation. The assessment may be performed in two steps: a type-specific part, using the correct wind turbine model and representative environmental conditions, and a site-specific part, comparing the environmental conditions for all turbine locations with the representative conditions used in the type-specific part. If fatigue verification cannot

be made for a component, component exchange, condition monitoring, inspections or update of the controller can be performed.

4.4.1 Probabilistic approach

The probabilistic approach is described on a general level. For example, the following statements are given (DNVGL-ST-0262, 2016):

- Probability distributions may be used to describe the aleatoric and epistemic uncertainty in both the mathematic models and the input parameters to the models. The nature of the uncertainty being described by each distribution in their model set-up shall be clarified by the expert.

- Measurements - both of the turbine response (e.g. component load measurements) and of the local site conditions (e.g. from met-mast and/or SCADA data) – may be used to refine or update probability distributions of key model parameters in the analysis. In all cases, the statistical techniques (e.g. Bayesian updating, optimal estimation etc.) used to characterize the distribution of stochastic parameters for the structural reliability analysis shall be documented.

The steps in a reliability analysis are outlined, and as a first step is mentioned: "Selection of target reliability level". Further, it is mentioned that risk-based inspection methods may be developed.

In the practical part, an inspection should be made to assess the wind turbine with regard to its suitability for lifetime extension. It is stated that the "inspection shall include all load transferring components as well as the control and protection system (see Table 2-1)."

4.5 Updating of reliability

In ISO2394 (ISO2394, 2015), Annex B, two complementary methods for reliability updating are given:

1. Checking performance by proof-loading or using data on past performance of the whole structure
2. Updating distributions for individual variables using Bayesian updating – either event updating or distribution updating.

In annex B, general expressions are given, and in annex C expressions are given for the case with normal distributed variables and unknown mean and standard deviation, with and without prior knowledge. The same is included in Eurocodes annex C (Eurocodes. CEN-TC250-WG2, 2018).

4.6 Planning of inspections for reliability verification

Sufficient reliability can also be verified by the use of probability based inspection planning, as included in the standard DNVGL-RP-C210 (DNVGL-RP-C210, 2015) on Probabilistic methods for planning of

inspection for fatigue cracks in offshore structures. The approach is also described in NORSOK (NORSOK N-006, 2015).

The time to the first inspection can be based on the results from the S-N approach, while assessment of the inspection intervals need to be based on the FM approach in combination with a probability of detection model of the inspection method.

4.7 Conclusions of review

The existing standards on life extension (by DNVGL and NEN) focus on requirements to ensure safe operation. However, in some way this is in contrast to the reliability level set in the IEC standard, as it is assumed that no fatalities will be seen in the case of failure. Instead, the target reliability level is set based on economic optimization, without considering fatalities and pollution. As a consequence, for decisions on life extension for wind turbines, it makes sense to let the decisions be based on a cost-benefit approach, as this will result in economically responsible decisions for the interest of both the owners of the wind turbines and for the society. This might lead to very low optimal reliability levels. Here, health and safety requirements for the technicians could be a limiting factor for pure economic optimization.

Generally, the standards on life extension (DNVGL, NEN) focus on the fatigue limit state. Thus, if there are no sign of deterioration affecting other limit states, it is only necessary to investigate if the fatigue limit state is exceeded. The simple and detailed deterministic approaches in the DNVGL and NEN standard are based on partial safety factors, and life extension can be permitted, if it can be shown using site-specific/operational data that the characteristic load (effect) is smaller than assumed in the design. This could be due to the turbines being designed for an IEC site, not the specific site. But it could also be due to operational data being available to actually give the number of hours of operation in each operational mode, and to give the number of emergency stops etc.

The probabilistic approaches given in the DNVGL and NEN standard, further makes it possible to account for reduced uncertainties on the loading, due to the availability of measurements. A possibility not mentioned in the DNVGL standard, is to develop an approach with adjusted partial factors for fatigue.

For structural components where the design is governed by the fatigue limit state, there are several ways that is can be shown acceptable to extend the lifetime, even if it was originally designed to the limit:

- Lower target reliability acceptable for existing structure
- Lower COV on strengths or loads
- Higher/lower mean value of strengths or loads
- Risk-based inspections used to verify crack size

In a deterministic approach, often only a lower mean value of loads will be considered. However, using the design value format/method a semi-probabilistic approach can be developed, where lower COV and target reliability can be utilized also.

5. SCADA Based Lifetime Prediction

Many wind farms possess multi-year records of operational measurements using the turbine Supervisory Control and Data Acquisition system (SCADA). Such measurements comprise of the 10-minute mean values of individual wind turbine power production, rotor speed, wind speed, wind direction etc. It is also possible for the 10-minute statistics to include minimum, maximum and standard deviations of the measurements. The structural integrity of components depends on the variation in loading they experience in different operating conditions over their lifetime, such as variation in wind turbulence and interaction with the turbine control system. Therefore, if turbine specific measurements can be used to predict the fatigue damage accumulation over time, then, the damage can be compared to the design margins available, as certified for instance with standards such as the IEC 61400-1 (IEC 61400-1, 2019).

When the design basis and specific operational history of the turbines are available, a machine learning approach (Dimitrov & Natarajan, 2019) at the wind farm level can be utilized to estimate the life consumption of the structural components and thereby identify specific wind turbines within the wind farm that are more loaded than others. This allows for planning specific inspection for the most loaded turbines within a wind farm, and thereby where necessary allow for further planning for maintenance. This approach can be directly applied also to wind farms located in a complex terrain. The wind turbulence responsible for fatigue damage can in fact arise both from turbine wakes, but also from local terrain effects, which can be difficult to model in conventional tools.

Re-assessment of the design assumptions is one of the major tasks and important sources of information in assessing the possibility for life extension. As the site-specific environmental conditions are rarely exactly the same as the reference conditions used in turbine design, it is possible that there is some residual fatigue capacity in the primary structures. The design re-assessment requires that the site-specific climatic conditions are determined, and that the load response of the wind turbine can be computed for the full range of environmental conditions experienced at the site. Depending on the information available and the computational approaches used, the amount of uncertainty in the final estimate of remaining life will vary.

The main objective is to use 10-minute average SCADA measurements and an aeroelastic design basis of the turbine to predict the fatigue damage equivalent loads (DEL) on the major structural components of each wind turbine within a wind farm in complex terrain, and to validate the predictions. The main novelty is that no wake model is used to determine the wind and turbulence conditions within the wind farm: the variation in SCADA measurements across the wind farm is taken to contain all information needed to determine the wind turbulence within the farm. The validation of the DEL prediction on each turbine is made by comparing with the SCADA measured standard deviation of power, hence taken as a proxy for loads. Contour maps across the wind farm are made to show the DEL variation across the farm for different operational intervals, thus allowing to identify specific highly loaded wind turbines within the farm.

5.1 Wind Farm Life Consumption Quantification

An aeroelastic design basis of a commercial variable speed pitch controlled wind turbine of 2+ MW capacity is used to simulate dynamic loads on its structures. Ten minute mean SCADA measurements of the power production, rotor speed, wind speed and blade pitch angle from all wind turbines in wind farms situated in complex terrain are used as input to a neural network with 3 hidden layers. The measured 10-minute means are converted to a time series using Principal Component Analysis (PCA) (Natarajan & Verelst, 2012) using the variation of those input values present in the aeroelastic simulations of the same turbine. The output of the neural network is the time series of blade root moments and tower base moments, which is processed to obtain the corresponding DELs.

The neural network predicted loads is first validated with measured loads on a stand alone wind turbine which is instrumented with strain gauges. The validations were made over various measured 10-minute wind conditions and the comparisons were primarily for the blade root and tower base moments. Figure 5-1 provides the validation of the blade root flap moment and tower base resultant moment using the load measurements on a single wind turbine.

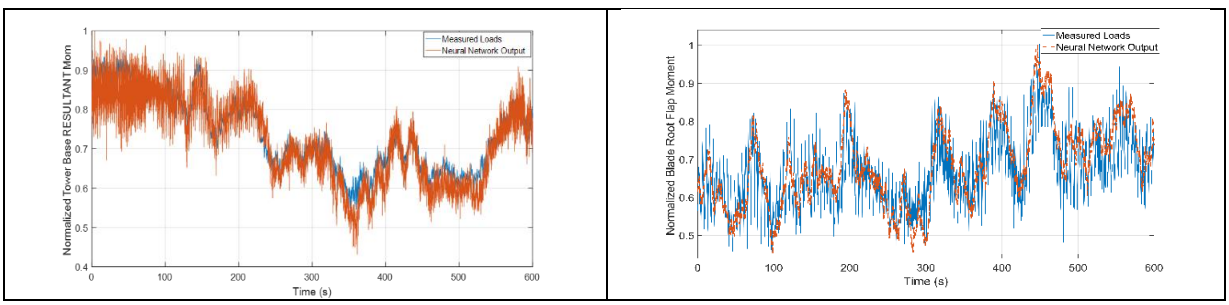


Figure 5-1 : Validation of the predicted neural network loads with measured loads.

The results in Figure 5-1 shows that the neural network predictions satisfactorily reproduce the measured load trends at the blade root and tower base. The blade root flap moment predictions show that the large cycles are captured but not all the small cycles. The neural network is trained using several load simulations with the widely used *Flex5* loads simulation software at different wind turbulence levels used in the IEC 61400-1. Figure 5-2 shows that the neural network satisfactorily re-produces the wind turbulence level outside the training set, given the corresponding mean SCADA input parameters.

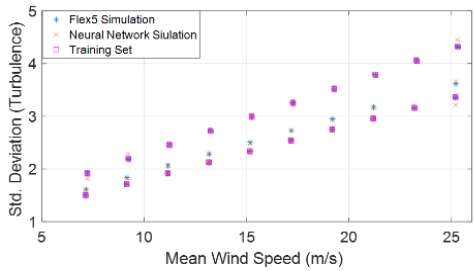


Figure 5-2 : Verification of Neural Network predicted wind turbulence with Flex5 Simulations.

This trained neural network is now utilized to predict the DELs on a wind farm in complex terrain. The site is situated in the United States and features 29 wind turbines of 2+ MW each. Figure 5-3 shows the pictorial details of the complex terrain, and the wind farm layout. Ten minute mean SCADA measurements for all 29 wind turbines over several months are used to predict the DELs on each wind turbine. The predicted DELs across the wind farm are then compared against the measured std. deviation of power, considered indicative of the load distribution within the farm.

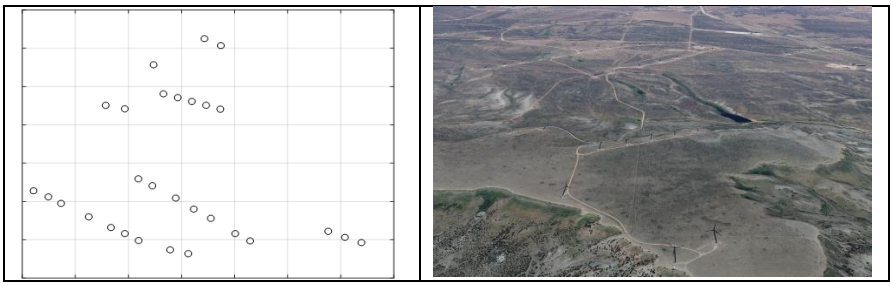


Figure 5-3 : Terrain and layout of the wind farm with 29 wind turbines.

Figure 5-4 displays the comparison with the predicted DEL of the blade root flap moment, the tower base fore aft moment and the measured power std. deviation power over all 29 turbines in the wind farm. As seen in Figure 5-4 the lower two rows and some of the corner turbines to the left are highly loaded in all the plots. The power standard deviations correspond reasonably well with the predicted tower base fore-aft moments.

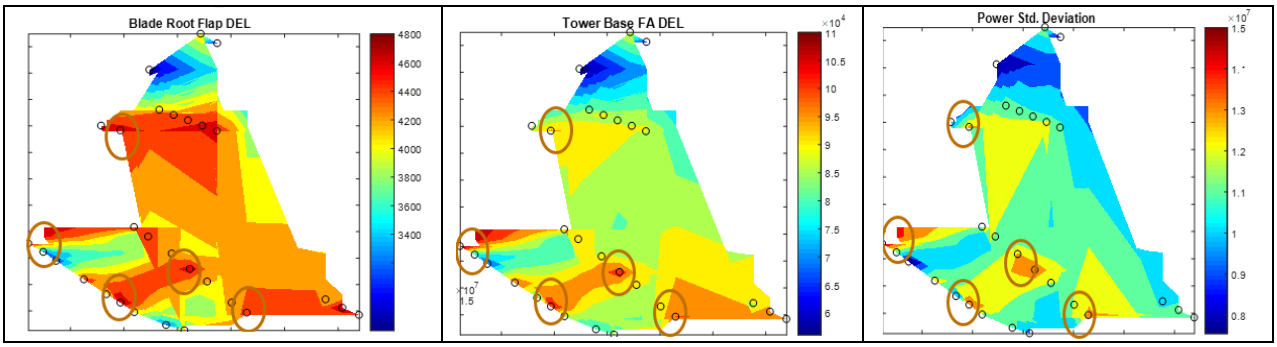


Figure 5-4 : Comparison of predicted neural network DELs with measured power Std. Deviation

A diagram with an overview of the potential approaches to re-assessment of the fatigue lifetime has been prepared (Dimitrov & Natarajan, 2019). For each step of the process several alternatives are given, and normally the uncertainty will increase for the alternatives which use less information or are less specific to the particular site, wind turbine type, and operational history. A specific example of the steps in the procedure has been published (Dimitrov & Natarajan, 2019) and is also shown in the following.

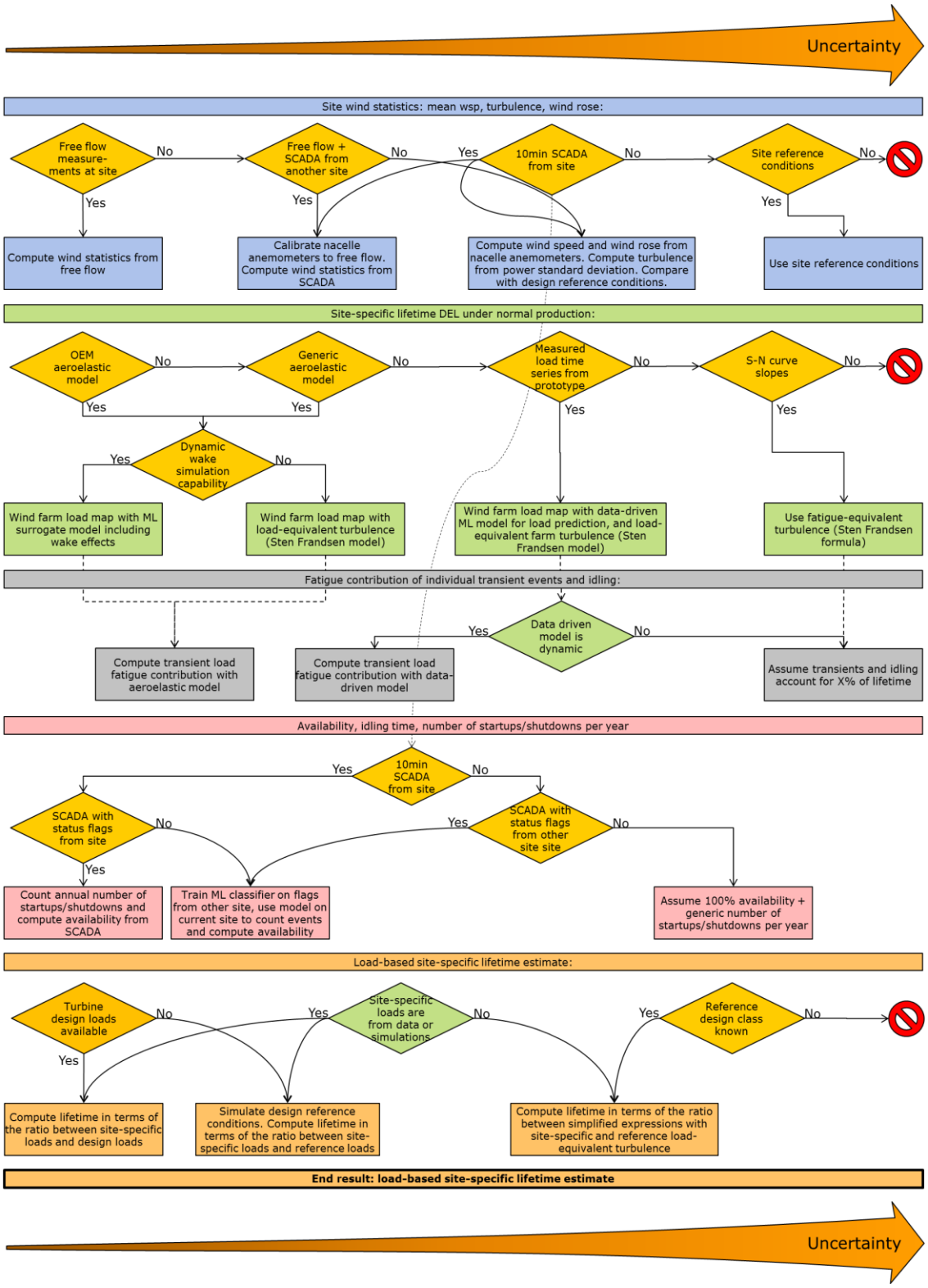


Figure 5-5: Chart describing a procedure for estimating load-based site-specific remaining lifetime, with different process alternatives depending on the type of information available.

5.1.1 Example with lifetime estimation for the Horns Rev 1 wind farm

In this example, the Horns Rev 1 offshore wind farm Figure 5-6 below in western Denmark is considered. It consists of 80 Vestas V80 turbines with 2MW power rating, and has been commissioned in 2001. This example demonstrates a realistic scenario where a few years (but not the entire operating history) of basic SCADA data are available, along with a generic aeroelastic model for a wind turbine which has similar structural properties as the actual turbines, but without having the actual controller algorithms implemented by the OEM. The following data are available:

- Ten-minute SCADA statistics (power, nacelle wind speed and yaw direction, including mean values, standard deviations and status flags) for 3 years;
- Wind speed, turbulence and wind direction at close to hub height (70m) from 3 met masts;
- A generic aeroelastic model of the V80 turbine using the DTU Wind Energy controller.

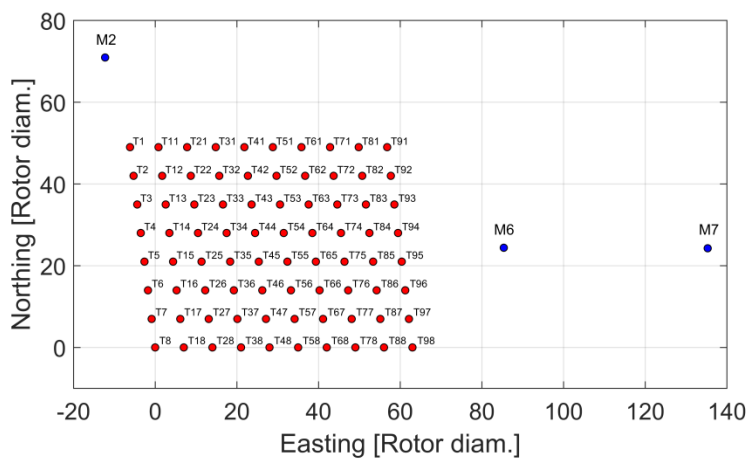


Figure 5-6: Horns Rev 1 wind farm layout and met mast locations.

With this information available, the following considerations are taken:

- As the SCADA records do not cover the full operating history, the SCADA will be used instead to establish the climatic conditions on site. These estimates will be used in a follow-up simulation to compute the lifetime fatigue damage. Since met mast data contemporaneous with the SCADA data are available, the met mast data could be used to calibrate the readings of the nacelle anemometers from SCADA. In principle the met mast data could be directly used to define the site-specific climatic conditions, however most wind farms do not have met masts installed, and therefore a more realistic scenario is to use the SCADA records as climate information source.

- The use of a generic aeroelastic model may mean that the load response is somewhat different than the response of the actual turbine or the model used by the OEM. In order to have a valid

comparison, the design loads for the relevant reference design class (e.g. IEC IA, IIB…) are also evaluated with the generic model, thus allowing for a comparison in relative terms.

- Through the use of the Dynamic Wake Meandering (DWM) model (Larsen, Madsen Aagaard, Thomsen, & Larsen, 2008), it is possible to include the effects of various wake situations into load simulations. Knowing the turbine locations in a wind farm, the wake-induced fatigue damage can be evaluated as function of the relative position between turbines as shown in (Dimitrov N. K., 2019).

As a first step in the analysis, the SCADA data are filtered according to the turbine status and to synchronize the time stamps with the mast data. In order for a given ten-minute period to be considered valid, at least one turbine in an outer row facing the incoming wind direction needs to be available and producing power, and the wind speed and direction readings from the met mast need to be available. This leaves about 150,000 ten-minute periods suitable for analysis.

As the yaw reading of single turbines may be unreliable, a farm-average wind direction is calculated based on the yaw directions of all turbines operating in free wind using the following algorithm:

- For a given 10-minute period, a preliminary average direction is estimated as the median of the yaw angle readings of all operational turbines in the farm;

- The preliminary wind direction combined with the farm geometry is used to estimate which turbines are operating in free wind conditions (no turbines upwind within a ±20deg sector);

- Final wind direction is estimated as the median of valid yaw readings from the turbines operated in free wind conditions.

In the above, the median is preferred instead of the mean, because the mean would be affected by outliers such as erroneous yaw readings. The resulting wind direction has very good correlation with the wind direction obtained from the met mast. A comparison is shown in Figure 5-7(wind direction time series) and Figure 5-8 (wind rose).

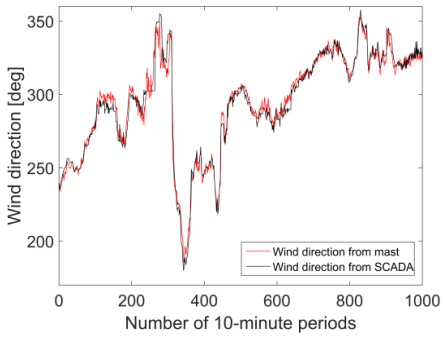


Figure 5-7: Comparison of the wind direction prediction from SCADA data with measurements from met mast.

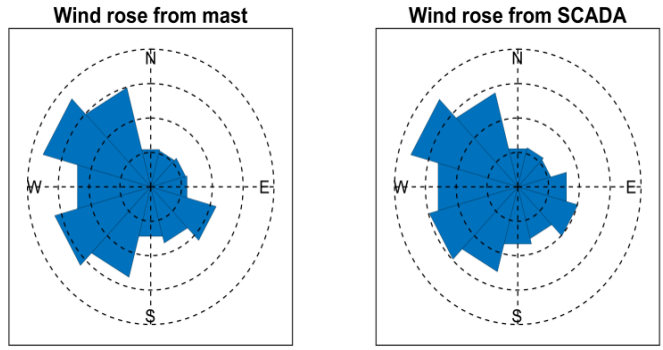


Figure 5-8: Comparison of the wind roses at Horns Rev 1 derived from mast measurements and from SCADA.

Using the same approach as with the wind direction, the free wind speed and turbulence can be estimated as the median of the nacelle wind speed and turbulence recorded by the turbines in free wind conditions. However, nacelle anemometers are placed behind the turbine rotor and their readings are influenced by the induction and the added turbulence. Despite that the wind speeds in the SCADA data are corrected to approximately show the incoming flow speed, the results are not always accurate and the nacelle wind speed readings show a nonlinear behavior with respect to the free wind speed, with a change of slope at around rated wind speed. On Figure 5-9 and Figure 5-10 the raw nacelle wind speed readings are plotted against the readings from M6 (black circles), for a single turbine (T81) and for the average from free-wind turbines, respectively. In order to correct the nonlinearity (mainly visible as change of slope of the lines around rated wind speed), a transfer function is calibrated between the nacelle wind speed reading of a single turbine and the wind speed measured by M6. The transfer function used is a simple ANN regression model with a single hidden layer with 5 neurons and hyperbolic tangent (tanh) activation functions. The transfer function is calibrated for wind turbine 81 which is in the northeast corner of the wind farm. This choice maximizes the availability of data where both the turbine and the met mast are in free wind conditions. The transfer function is then applied on the nacelle wind speed readings of all wind turbines in free wind, and a corrected undisturbed wind speed is estimated.

The corrected data are shown with blue dots on Figure 5-9 and Figure 5-10. Four input variables: nacelle wind speed, nacelle turbulence, mean electrical power, and standard deviation of power are used with a similar one-layer, 10-node ANN model to correct the turbulence (standard deviation of wind speed). The resulting turbulence predictions are shown on Figure 5-11 for a single turbine and on Figure 5-12 for all turbines in free wind. There is significantly more uncertainty than with the wind speed estimation; nevertheless applying the correction noticeably improves the correlation.

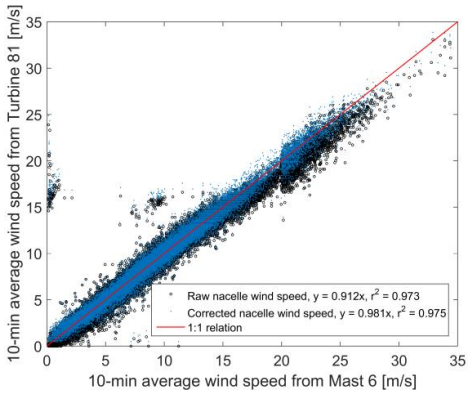


Figure 5-9: Mean wind speed estimation from the nacelle anemometer of a single turbine, compared to data from M6.

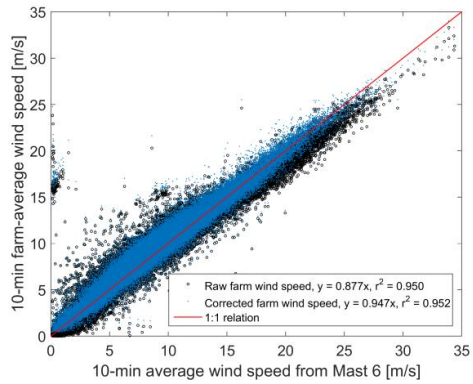


Figure 5-10: Mean wind speed estimation from all wind turbines in free wind conditions, compared to data from M6.

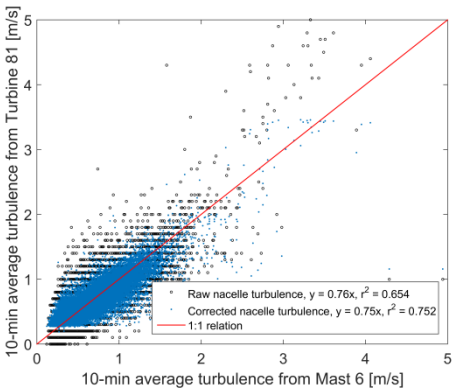


Figure 5-11: Turbulence estimation from the nacelle anemometer of a single turbine, compared to data from M6.

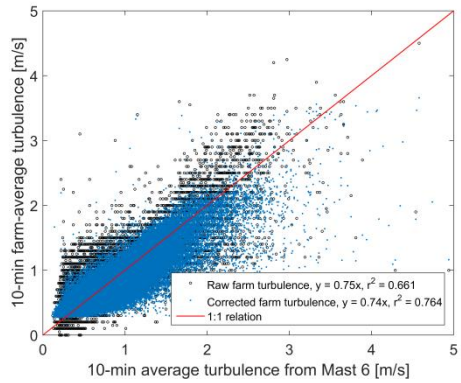


Figure 5-12: Turbulence estimation from all wind turbines in free wind conditions, compared to data from M6.

The SCADA records in existing wind farms usually do not include reliable and extensive load measurements and this is also the case for Horns Rev 1. An alternative is that the loads are determined using an adequate aeroelastic model. The model is used to generate a synthetic data set simulating the turbine behavior under various inflow conditions. In order to create a computationally efficient function which provides continuous mapping between the loads of major components and environmental conditions, a Machine Learning (ML) regression model is trained on the synthetic data set (Dimitrov N. K., 2019).

Although a similar approach can be taken with measured loads (e.g. from turbine prototype), the use of the aeroelastic model is also beneficial as a supplement to measured loads, as it is unlikely that a single load measurement campaign can cover the full range of possible inflow conditions. Another advantage of using an aeroelastic model is that the effect of wake-induced turbulence on loads can be simulated, e.g. by employing the Dynamic Wake Meandering (DWM) model (Larsen, Madsen Aagaard, Thomsen, & Larsen, 2008). In the present study, we use a generic aeroelastic model of the Vestas V80 wind turbine

developed in the Hawc2 aeroelastic simulation software (Larsen & Hansen, 2014) As the OEM-installed turbine controller is confidential, the model features the DTU Wind Energy controller (Hansen & Henriksen, 2013) tuned to reproduce the known power, pitch and rpm curves of the V80 turbine. The model includes a monopile foundation with variable water depth between 7 and 15m.

The model mass and stiffness are tuned so that it reproduces the natural frequencies of the real structure, including the variation of the frequency with water depth. Wake effects are accounted for using the approach described in (Dimitrov N. K., 2019), by introducing three variables describing the relative location of upwind turbines: R_D, the distance in rotor diameters to the closest turbine upwind, θ, the relative angle between the wind direction and the direction of the upwind turbine (or row of turbines), and N_{rows}, the number of turbines upwind in case there is an aligned row of turbines. A random sample of 30,000 combinations of these variables with other external conditions (wind speed, turbulence, wind shear, and water depth) is generated, and aeroelastic load simulations are carried out using Hawc2 and the DWM.

In order to reduce the statistical (realization-to-realization) uncertainty due to using random turbulent realizations, six simulations with random turbulence seeds are carried out for each sample point, resulting in a total of 180,000 simulations. A regression model is trained on the results using an ANN with 3 hidden layers with 24 neurons each, and with tanh activation functions. The process of training the model and its performance are discussed in details in (Dimitrov & Natarajan, 2019). While the large number of simulations in the present case is used to test the convergence of the model training procedure, it was also seen that a smaller number of total simulations – between 10,000 and 30,000 depending on the variable choice – could be sufficient for obtaining a well-working surrogate model.

As there are no load data available, it is not possible to directly validate the load predictions with measurements. However, the same ANN model can be used to predict the power output, and the results can be directly compared to the SCADA records. This prediction is carried out on each individual turbine, and the values are summed to also estimate the total power output of the wind farm. Figure 5-13 shows a comparison of the predicted total power output time series vs. the one recorded from SCADA, while Figure 5-14 shows the correlation between measured and predicted power outputs at individual turbines. Both the total and individual turbine power output predictions show high correlation with measurements. From some differences visible on Figure 5-13 it may be argued that the power curve of the aeroelastic model may not be fully accurate at close to rated wind speeds. This is to some extent expected as the load and power predictions are based on a generic model and not on one provided by the OEM.

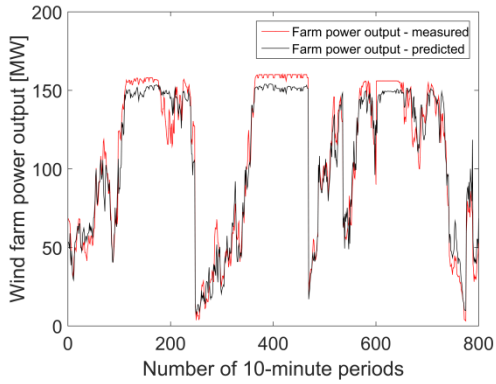


Figure 5-13: Comparison of measured and predicted time series of total electrical output from the Horns Rev 1 wind farm.

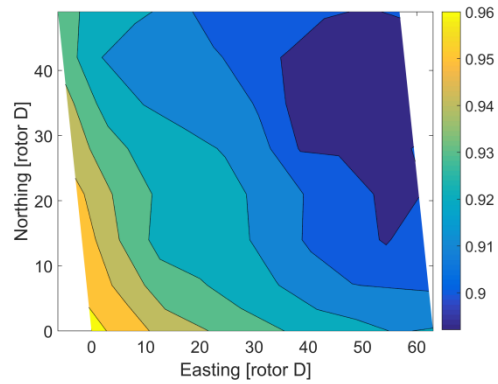


Figure 5-14: Correlation (r-square) between measured and predicted power output at individual turbines.

Damage-equivalent fatigue loads (DEL) are predicted simultaneously with the power predictions, based on the same input data. Based on these results, ten-minute fatigue damage increments are computed for individual turbines, thus establishing their fatigue damage accumulation history. The fatigue damage is computed relative to an assumed 20-year design lifetime under IEC 1A reference conditions. Figure 5-15 shows the estimated damage accumulation history for main shaft torsion, while Figure 5-16 provides a map of the accumulated blade root flapwise fatigue damage over the wind farm based on approximately three years of operation. These estimates are based on directly applying the load prediction model on the free wind time series obtained from SCADA and the accumulated damage corresponds to the time period covered in the data. The lifetime-equivalent loads can be estimated by numerically integrating the load model outputs over the joint distribution of inflow conditions.

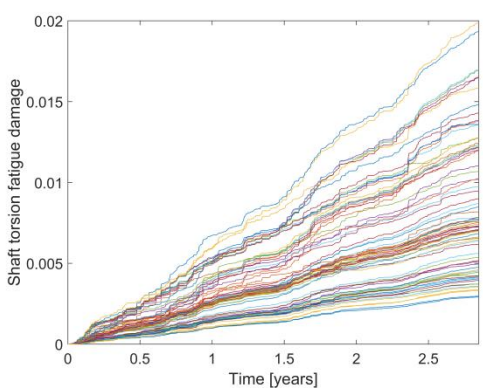


Figure 5-15: Time series of accumulated shaft torsion fatigue damage for all individual turbines in Horns Rev 1.

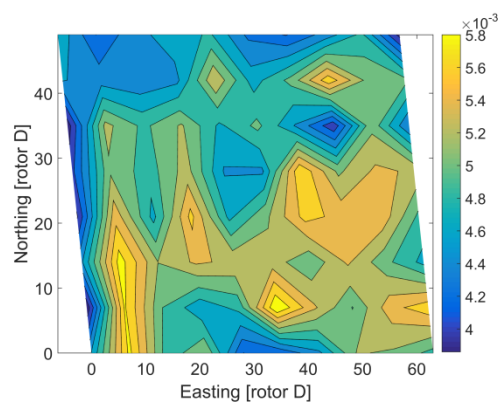


Figure 5-16: Map of blade root flapwise lifetime fatigue damage estimates for all individual turbines in Horns Rev 1.

Finally, Table 5-1 provides a summary of the accuracy of the various ML models presented above. The measures used are the coefficient of determination (R-square), and normalized root mean squared error (NRMSE).

Table 5-1: Overview of the accuracy of the estimations based on SCADA and ML models.

Variable names	R-square	NRMSE
Wind direction	0.973	0.075
Free wind speed	0.952	0.085
Ambient turbulence	0.764	0.256
Individual turbine power output	0.919	0.229
Total wind farm power output	0.956	0.188

5.1.2 Load scaling for life assessment of turbines without available aeroelastic model

The remaining lifetime assessment scenario described above relies on having an aeroelastic model of the specific turbine under consideration. While the model may be generic (e.g. without the OEM controller), it still mirrors many of the features of the specific turbine like rotor size, component masses, natural frequencies, power, rpm and pitch curve. While this is a common scenario, there may also be many situations where no model is available for a particular turbine, and instead we could have access to models of similar turbines. For the purpose of covering such a scenario, a load scaling model was developed in the Lifewind project. The model relies on the following assumptions:

- The wind turbine loads follow a scaling law which can be related to other size-dependent features such as power and rpm curves, rotor diameter, hub height

- The wake effects cause the same relative increase in loads, regardless of turbine size

Based on these assumptions, the scaling model shown schematically on Figure 5-17is built.

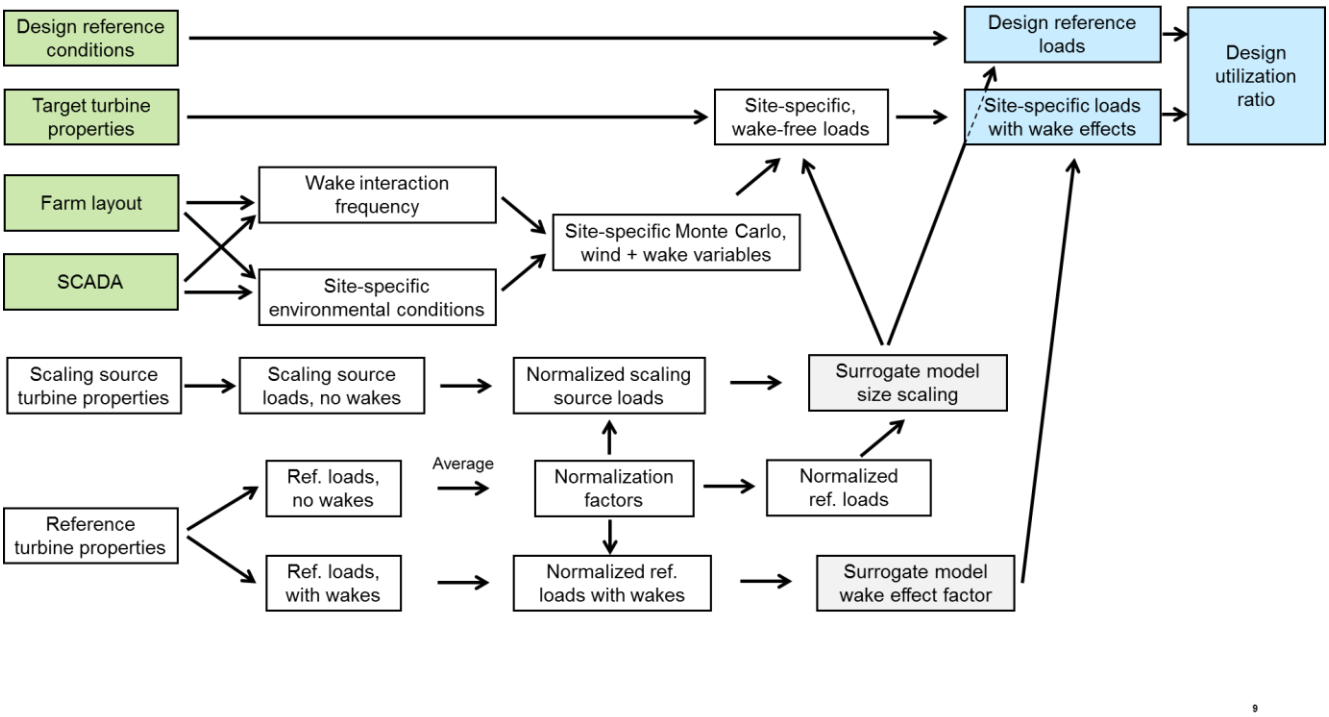


Figure 5-17: Load assessment with scaling models for turbine size and wake effects.

Three ANN-based surrogate models are in the core of the scaling procedure:

- A surrogate model mapping the loads for a "reference" turbine with 80m rotor diameter and 2MW rating (the Vestas V80 with the basic DTU Wind Energy controller (Hansen & Henriksen, 2013)) as function of environmental conditions – wind speed, turbulence, wind shear.

- A surrogate model scaling the loads with respect to the operating characteristics of the wind turbine. Inputs are the rated power, rotor diameter, pitch, rpm and power curves, as well as wind speed, turbulence, and wind shear. Output is the loads for various channels, normalized with respect to the loads of a 2MW wind turbine with 80m rotor diameter under the same combination of wind speed, turbulence and wind shear. The surrogate model is trained by using load simulations in free-wind conditions for two turbine types: a 2.3MW turbine with 93m rotor diameter, and the reference 2.0MW turbine with a 80m rotor diameter. Both turbines are equipped with the DTU Wind Energy controller. As a result it is expected that the scaling works best for turbines with power ratings close to the range used in the model training. On the other hand, it should be possible to expand the useful range of the scaling procedure by training the surrogate model on additional data from turbines with different sizes.

- A surrogate model estimating the change of loads due to the presence of wake effects. The wake-induced load effect is given as the ratio between the wake-affected and wake-free loading

condition. The inputs are the number of turbines upwind of the turbine under consideration, the spacing between these turbines, and the relative angle between the wind direction and the upwind turbine locations. This surrogate model is trained based on the same simulations of the Vestas V80 turbine used in the Horns Rev 1 load and power prediction example discussed above.

For any given turbine, the final load estimate is obtained in three steps:

1. For a given set of environmental conditions (wind speed, turbulence, wind shear) a reference absolute load value under free wind conditions is estimated for a 2MW, 80m rotor diameter turbine.
2. A load-scaling ratio dependent on the properties of the turbine under consideration is computed, and the load estimates from point 1) are multiplied with the estimated scaling ratio
3. If any wake effects are expected, the relative load change due to wakes is computed with the relevant surrogate model, and the loads estimated in point 2) are scaled with the wake-effect ratio.

To illustrate the last step of this procedure, the 10-minute tower base fatigue load accumulation as well as power output are estimated for a turbine with 65m rotor diameter and 1.5MW power rating which is subject to wake effects from neighbouring turbines. Figure 5-18 shows a scatter plot of tower base fore-aft damage-equivalent loads, demonstrating how the wake-induced effects mean "site-specific" loads are higher compared to a reference load case without wakes (IEC class 1B). Under the same conditions, wake-induced wind velocity deficits will result in lower power output than what is seen in free wind, which is shown in Figure 5-19.

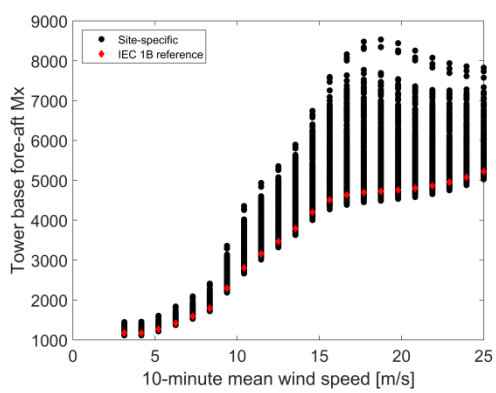


Figure 5-18: Scatter plot of 10-minute tower base load estimates from a load scaling tool taking wake effects into account.

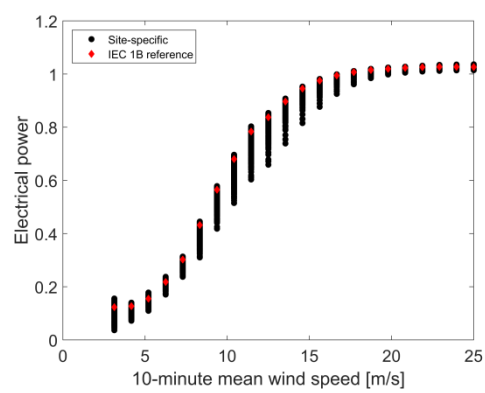


Figure 5-19: Scatter plot of 10-minute power output estimates from a load scaling tool taking wake effects into account.

In a real-world scenario, the above procedure is applied together with the estimation of environmental conditions and remaining lifetime using SCADA which was described earlier. As a result, the lifetime assessment of a turbine of an arbitrary size can be carried out using the following inputs:

- SCADA data for all turbines in a wind farm over several years
- Turbine coordinates
- Turbine operating characteristics: rotor diameter, power curve, rpm curve, pitch curve

An example assessment of remaining useful lifetime based on this procedure is described in Section 6.1 of this report.

5.2 Main Shaft Torsional Damage Identification

In this section, a methodology based on the inverse problem will be developed to estimate the torsional load of a wind turbine drive train main shaft from the SCADA measurements. The procedure to estimate the torsional load based on forward and inverse problems techniques is illustrated in Figure 5-20. For notations, please refer the following subsection. Based on the available inputs, one can choose the appropriate approach for the load estimation. For our study, since only SCADA based measurements are available, the inverse problem technique is adapted for the load estimation. Further, this is system based inverse problem approach as the system output along with mathematical model is going to be used. The problem formulation along with validation are given in subsections 5.2.1 and 5.2.2. Finally, the results are presented in subsection 5.2.3.

5.2.1 Formulation:

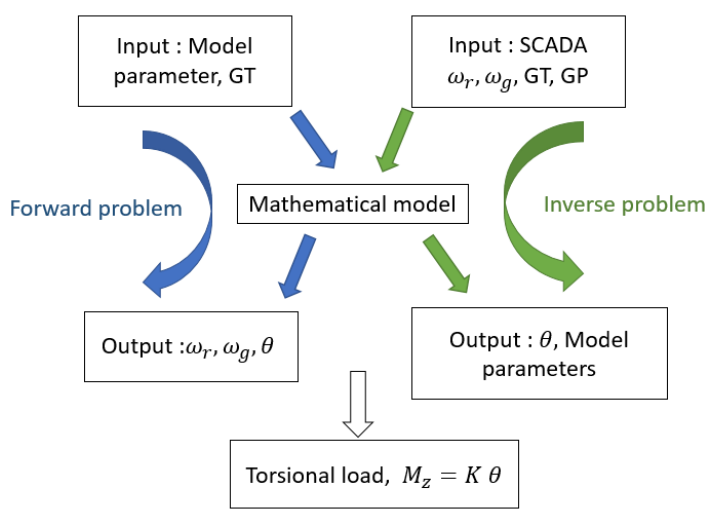


Figure 5-20: Forward and inverse problem.

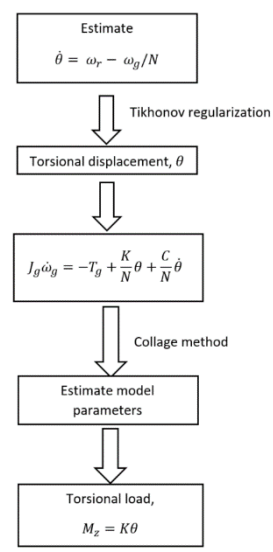


Figure 5-21: Flowchart depicting inverse problem algorithm.

By assuming a two mass model, the drive train dynamics subjected to rotor and generator torques T_r and T_g, respectively, are given by Eqs. (5.1-5.3). It is also assumed that the gearbox is perfectly stiff while transferring deformations on a main shaft. The main shaft is modelled by an inertia free viscously

damped torsional spring. Further, the edgewise flexibility of the blade and the torsional stiffness of the main shaft are modelled in K.

$$J_r\,\dot{\omega}_r = T_r - K\,\theta - C\,\dot{\theta} \qquad (5.1)$$

$$J_g\,\dot{\omega}_g = -T_g + \frac{K}{N}\,\theta + \frac{C}{N}\,\dot{\theta} \qquad (5.2)$$

$$\dot{\theta} = \omega_r - \frac{\omega_g}{N} \qquad (5.3)$$

Here, J_r and J_g are rotor and generator inertias, respectively, ω_r and ω_g are rotor and generator speeds, respectively C is shaft damping coefficient, N is gear ratio and θ is shaft torsional displacement.

In the forward problem approach, given the model parameters and T_r and T_g, Eqs. (5.1-5.3) are solved for ω_r, ω_g and θ. But given only with SCADA measurements, one has to solve Eqs. (5.1-5.3) inversely for θ and model parameters. In general, the available SCADA measurements are $\omega_r, \omega_g, P, \beta, \boldsymbol{U}$. Here, $P, \beta, \boldsymbol{U}$ are, respectively, the generator power, blade pitch angle and wind velocity.

5.2.1.1 Regularisation

With ω_r and ω_g, it is straight forward to use Eq. (5.3) to get $\dot{\theta}$ and by using time integration schemes on $\dot{\theta}$, the shaft torsional displacement (θ) is obtained. Time integration schemes based on time-marching algorithms which are probably the most straightforward and easiest way to obtain the displacement. However, they require initial condition on displacement which are usually unavailable or inaccurate in real situations. Moreover, these time marching algorithms are sensitive to measurement noise which results inadmissible errors in the reconstructed displacement. Particularly, low-frequency spectral components in random noise are amplified during time marching procedures, which severely deteriorate the accuracy of the reconstructed displacement. Also, this inaccurate displacement leads to drastic errors in the system model parameter estimation. Hence, one has to use regularisation techniques to smoothen the reconstructed displacement. Among all the regularisation technique, Tikhonov regularisation has been used widely because of its accuracy and the same has been employed in the present work. The torsional displacement obtained by time integration and Tikhonov regularisation are compared with the actual displacement in Figure 5-22. As seen in the figure, the numerical noise is getting amplified with time and leading to a drift in the displacement, whereas the Tikhonov regularisation matches closely with the actual displacement.

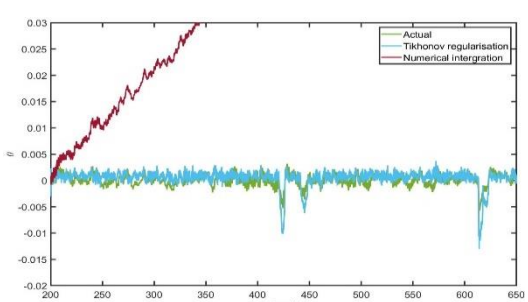


Figure 5-22: Comparison of Tikhonov and time integration displacements with actual displacement.

5.2.1.2 Collage method

Next stop is to estimate the model parameters that are required for the load calculation. Though there are many algorithms available in the literature for the system identification, collage method is used in the present study because of its easy implementation. Collage method is the model based system identification technique which works based on the minimisation problem. For a given initial value ODE, $\dot{x}(t) = f(x,t)$, $x(0) = x_0$ that admits a target solution $x(t)$, the associated Picard integral operator T is given by,

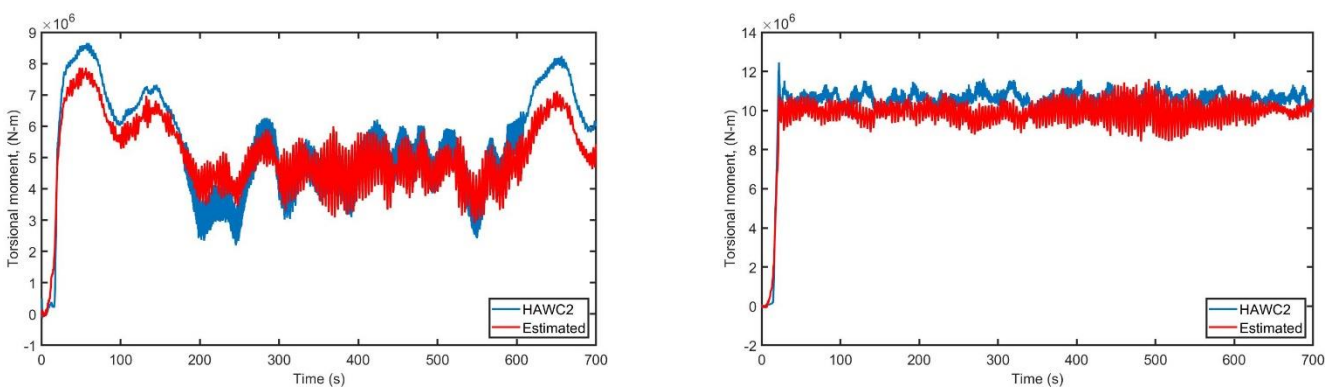
$$(Tx)(t) = x_0 + \int_0^t f\,(u(s), s)\mathrm{d}s.$$

It is important to note that the fixed point of this Picard operator is the unique solution of the given IVP. Accordingly, the collage distance becomes, $(x - Tx)$. Now, minimising the collage distance using least square method yields a set of linear equations in terms of model parameters. By solving these equations, the model parameters are estimated.

When comes to shaft dynamics, since the aerodynamic torque is unavailable, one cannot use the rotor equation (Eq. 5.1) for the parameter estimation. Instead, collage method is applied on generator equation to estimate to estimate the model parameters and together with θ, the shaft torsional loads are estimated as $M_z = K\theta$. The entire procedure of the inverse problem is given as a flow chart in Figure 5-21.

5.2.2 Validation

In order to validate the proposed methodology, torsional loads for the DTU 10 MW wind turbine are obtained by performing aeroelastic simulations in HAWC2 for DLC1.2 load case. For the validation purpose, inputs for the inverse problem are also obtained from HAWC2 simulation instead of SCADA. Torsional loads for two representative wind speeds (8 and 10 m/s) obtained from inverse problem technique are compared with HAWC2 simulation in Figure 5-23.



Wind speed = 8 m/s

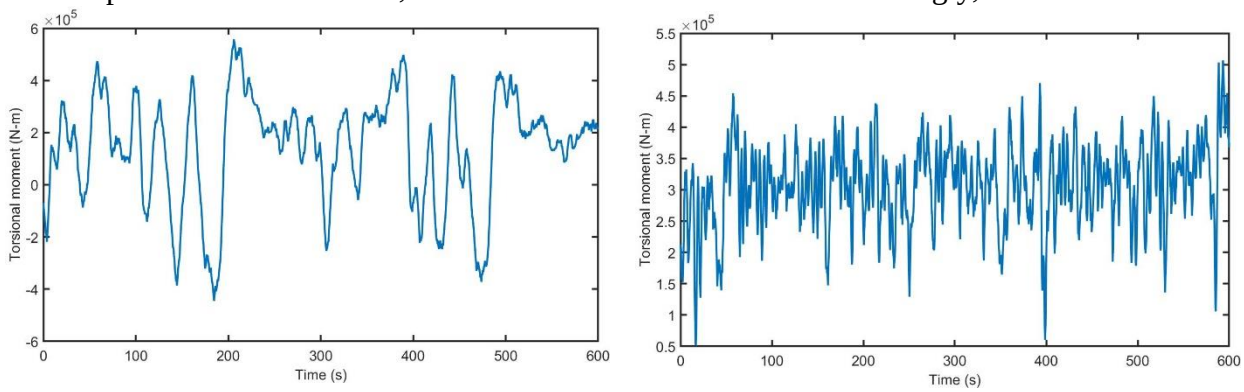
Wind speed = 10 m/s

Figure 5-23: Comparison of torsional loads obtained from proposed method with HAWC2 simulation.

The partial mismatch in the reconstructed torsional load with the HAWC2 load is due to the presence of an extra frequency (0.255 Hz) in the reconstructed load.

5.2.3 Results

Now, using the proposed methodology, the torsional loads for the drive train main shaft are estimated from the SCADA measurements. For this purpose, SCADA measurements of the Vestas V52-850 kW research turbine installed in DTU Risø will be utilized. In particular, measurements taken for the period of January, 2019 consisting of 4459 10-mins simulations are used for this study. Since the interest is on normal operations of the turbine, the measurement data is filtered accordingly, which results in 627 cases.



Wind speed = 8 m/s

Wind speed = 10 m/s

Figure 5-24: Estimated torsional loads obtained from SCADA measurement for two different wind speeds.

From filtered SCADA rotor and generator speeds, the shaft displacement is obtained using Tikhonov regularization, subsequently, the shaft stiffness is obtained by applying the collage method on Eq. (5.2). Then the shaft torsional loads are obtained for all the wind speeds ranging from 4 m/s to 22 m/s. The obtained shaft torsional loads for two representative wind speeds are shown in Figure 5-24. Using these torsional loads, the fatigue damage equivalent loads are calculated using the following equation and the same is shown in the figure below.

$$DEL = \sum_{i=1}^{n} \left(\left(\frac{1}{T}\right) \sum_{k} N_{i,k} S_{i,k}^{m} \right)^{\frac{1}{m}} \qquad (5.4)$$

Here, T is the duration of the load case, $N_{i,k}$ are the number of cycles at load range $S_{i,k}$ determined with rainflow counting and m=9.4 is the Wohler exponent.

5.3 Conclusions

The damage equivalent loads on the blades and tower of all wind turbines located in a wind farm in complex terrain were satisfactorily predicted using neural networks that used the ten minute average SCADA measurements over all turbines as input. The predicted DEL can be used to plan inspections on specific highly loaded wind turbines, and thus assess their fatigue life consumption and eventually evaluate life extension.

Further a method has been proposed to estimate the shaft torsional load from SCADA measurements based on collage method and Tikhonov regularization. The proposed method has been validated with HAWC2 aeroelastic simulations. Upon validation, the shaft torsional loads are estimated from SCADA data of Vestas V52 turbine and torsional DEL is calculated thereafter. Since the calculated DEL is from measurements, it gives the proper estimate about the fatigue life. Also the proposed method do not require any design basis for the load calculation, it is better suited for the estimating the remaining lifetime of older turbines. Also, in principal, this method can be extended to all other wind turbine components.

The major EUDP Lifewind contributions to the load based lifetime assessment have been:

1) Defining and demonstrating a procedure which covers the entire process from data import to a final lifetime estimate
2) Demonstration and validation of a surrogate model-based approach for load and power prediction in wind farms including wake-induced effects.
3) The approach of interpolating load predictions between turbines of different sizes has been explored and shown to provide reasonable output for a modest scaling of turbine sizes.

6. Case Scenarios using developed methods for Lifetime Extension (DTU, Suzlon, European Energy)

6.1 Suzlon – 10 Turbines Site

The life consumption analysis code developed by DTU to estimate the turbines accumulated DEL was tested on a Suzlon site located on extremely complex terrain. The site comprises of 10 turbines, on two lines roughly in the SW-NE direction. The prevailing wind direction at site is from south-east; a large terrain feature is located south-west from the site.

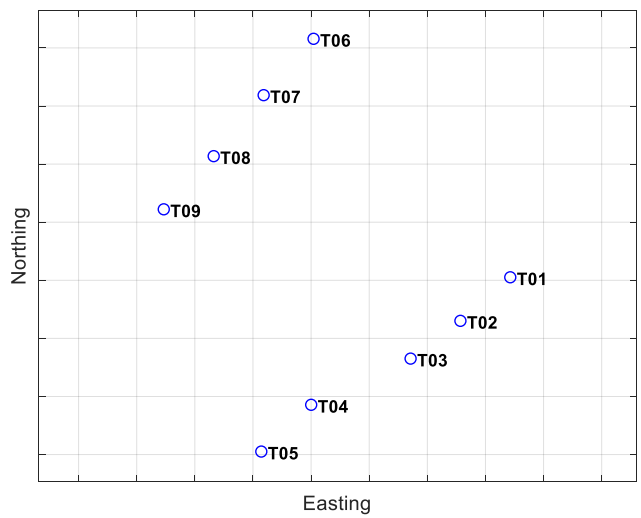


Figure 6-1: Suzlon Site 1. Turbine Layout (coordinates omitted on purpose).

The accumulated DEL estimation is based on two years of SCADA data, consisting for each turbine of 10 minute averages of commonly available sensors: power, rotor speed, pitch angle, nacelle wind speed. The data are filtered beforehand so to exclude any instance where the turbine minimum power in the 10 minute period is below cut-in. In addition, the 10-minute power standard deviation signal is also included in the analysis. The power standard deviation signal is commonly logged by the SCADA system, and often thought to have a good correlation with load variations on the turbine. The first version of the code is modified so to include the power standard deviation as an additional feature considered in the matching of a single data-point to the training set points.

The site wind speed distribution is also estimated from the SCADA data, resulting in a Weibull distribution with scale factor A = 12.0 m/s, and a shape factor k = 4.0. The data used for the wind speed distribution estimation were also pre-filtered to exclude all the non-operational data point, thus probably biasing the estimation towards a higher average wind speed, and less spread distribution.

6.1.1 Synthetic series comparison

Since unfortunately there are no load data available for the turbines, a first check on the algorithm is performed by comparing data available from the SCADA system with the properties of the 10 minute reconstructed ("Synthetic") time series. The signals considered, available both from SCADA and the

reconstructed synthetic series are: average power, wind speed, and pitch angle. In addition, Turbulence Intensity (TI), and Power Standard Deviation are signals that are available both in SCADA and the reconstructed time series, and can be at least indicative of the loads variation, and hence fatigue loads, within the wind farm.

At first, the 10 minute reconstructed ("Synthetic") time series, and the original SCADA Data 10 minutes averages are compared in terms of: power, wind speed and pitch angle. The discretization steps in the training dataset are evident, but a fair agreement is achieved in most of the cases. The distribution of discrepancies is rather symmetric, with the exception of the pitch angle signal.

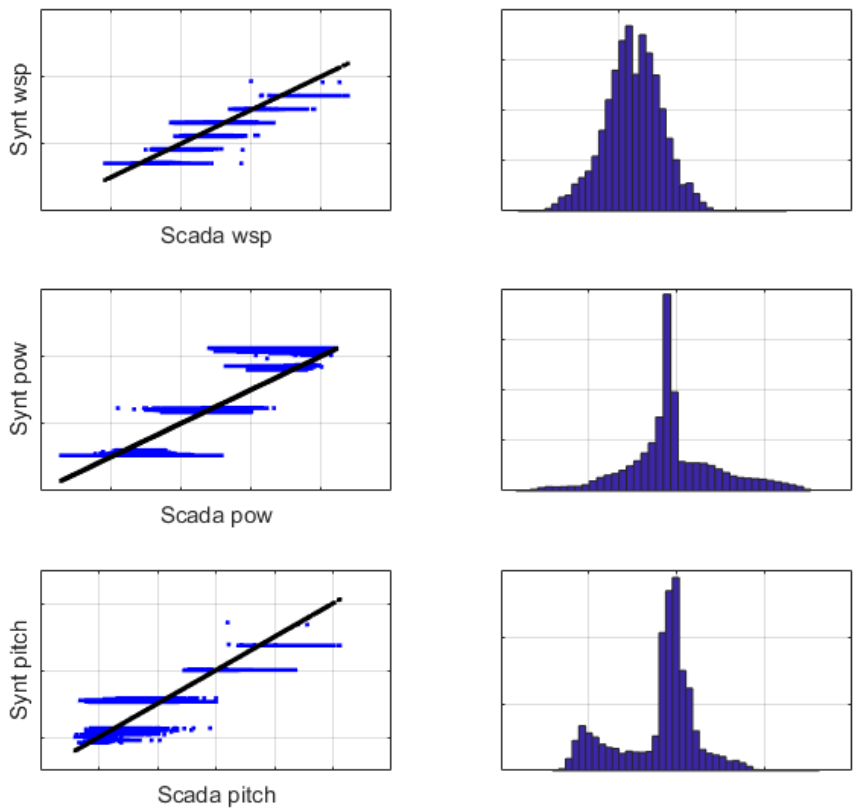


Figure 6-2: Suzlon Site 1. Matching of SCADA average values with the reconstructed time series values (axis values omitted on purpose).

Power variance, and Turbulence Intensity data are summarized in a single "life-time" value for each turbine in the wind farm, by simply performing a weighted average throughout the two years of data, the weight factors given by the Weibull distribution chosen for the site. The average life time values are reported in spatial plots for both the data coming from the SCADA input, and the Synthetic time series.

In the case of the power variance, which is also used to match the SCADA data point to train series, there is a very good agreement between SCADA and synthetic time series. They both indicates larger power variation for turbines placed in the second row, and closer to the south west corner (where the terrain

feature is placed), so that T02 has the lowest variation, and T09 the highest. The range of variations is similar in both cases, somehow smaller for the synthetic series.

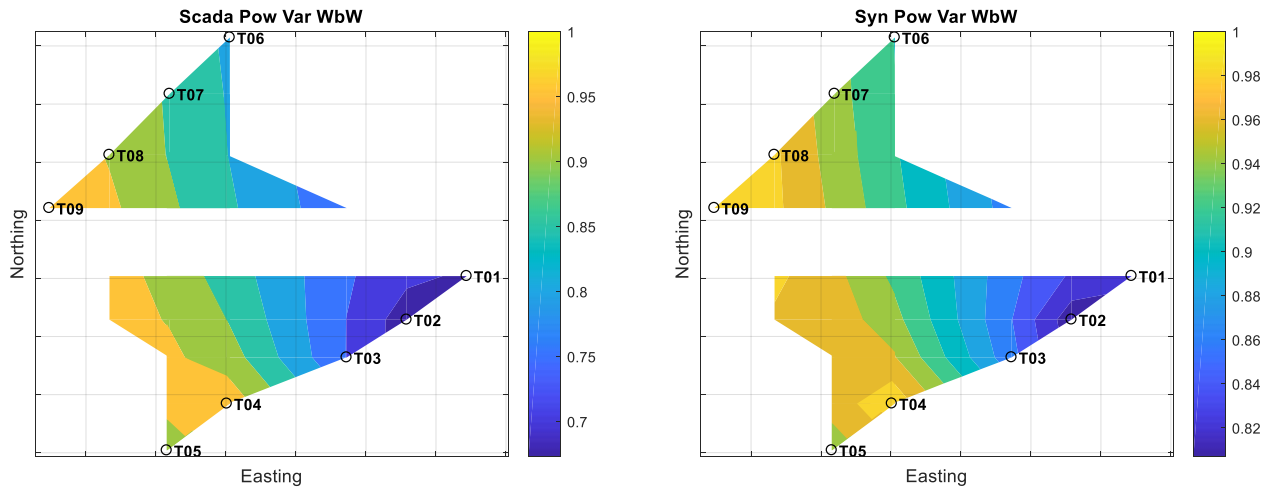


Figure 6-3: Normalized "life-time" weighted Power Variance per turbine, data from SCADA Power Standard Deviation (left), and from Power Standard Deviation in the "synthetic" reconstructed series.

The agreement between SCADA data and the Synthetic regenerated data is less good though for the Turbulence Intensity values. The spatial distribution is different in the two cases, with the SCADA data returning a distribution similar to the power standard deviation one, whereas the synthetic series would indicate higher TI for e.g. turbine T02. The range of variation in the synthetic case is also far smaller than what the SCADA data indicate.

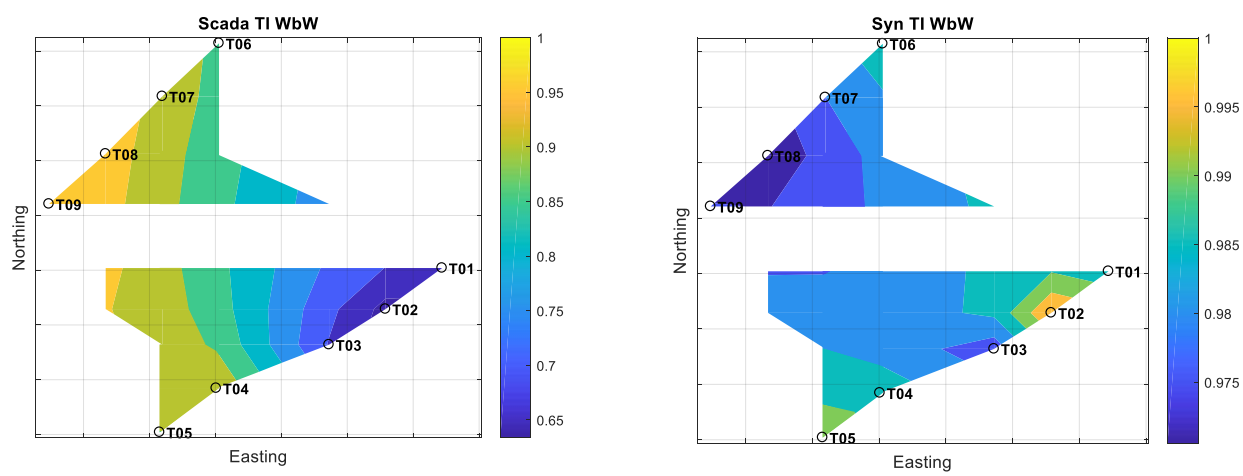


Figure 6-4: Normalized "life-time" weighted turbulence intensity, data from SCADA Turbulence Intensity (left), and from Turbulence Intensity in the "synthetic" reconstructed series (right).

6.1.2 Accumulated fatigue loads distribution

The provided Neural Network model takes then as input the reconstructed time series of wind speed, power, rotor speed and pitch angle, and returns as output 10 minute time series of: blade root flapwise bending moment, tower bottom flange fore-aft (FA) and side-to-side (SS) moments. Each 10 minutes series is then summarized in terms of fatigue Damage Equivalent Loads (DEL). The short term loads are then combined in a "life-time" equivalent DEL that accounts for the site Weibull distribution, and indicates the fatigue damage accumulated by each turbine during the period of time covered by the SCADA data. As in the previous figure, the accumulated DEL can be represented in spatial plots, normalized by the highest loaded turbine, giving thus an indication of which turbines undergo higher loading in the period considered.

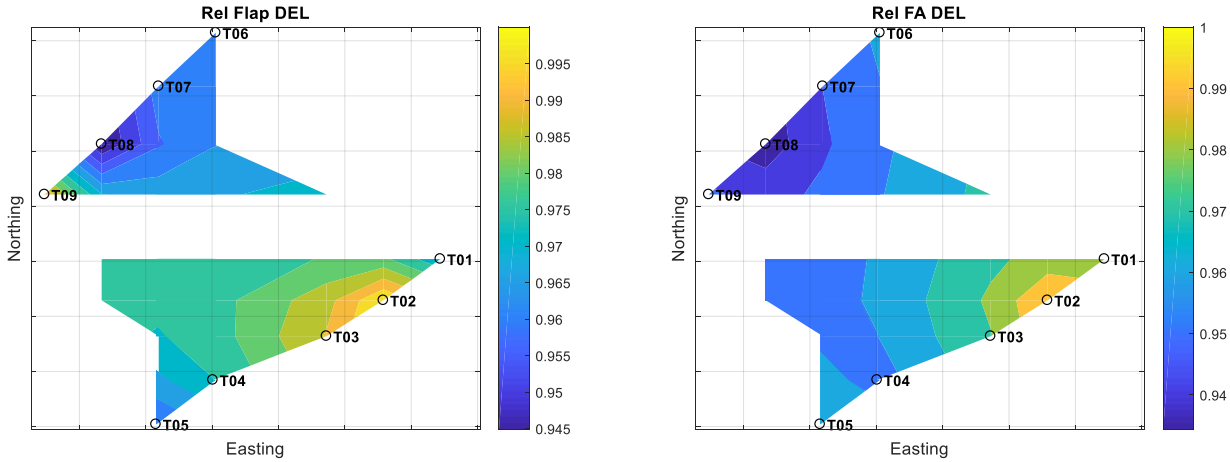


Figure 6-5: Normalized accumulated fatigue Damage Equivalent Loads (DEL) distribution within the wind farm, based on the loads time series returned by the Neural Network model. Blade root flapwise bending moment (left), tower bottom fore-aft moment (right). Tower Side-To-Side moments (not shown) have similar distribution to the tower fore-aft.

The load distribution seems to follow more the synthetic TI distribution, rather than the power variance distribution. The highest loaded turbine appears to be the ones in the first row, closer to T02 at the center, with lower accumulated loading in the second row, around T08.

The discrepancies with the power standard deviation comes somehow as a surprise, hence a closer look is given by plotting the 10 minute short term DEL versus the power standard deviation for each data point considered in the analysis.

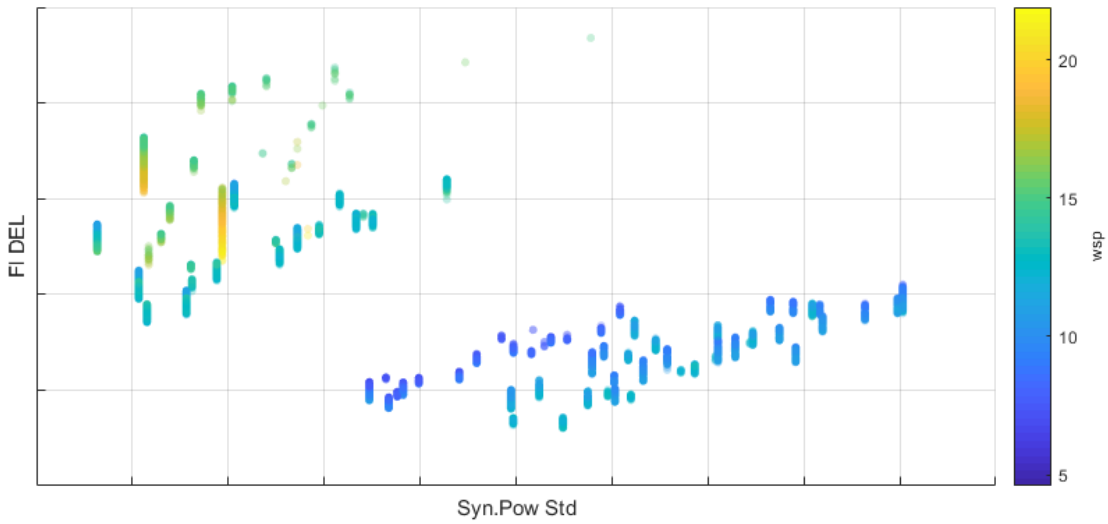


Figure 6-6: Scatter plot of flapwise short-term 10 minute DEL versus the corresponding 10 minute power standard deviation for the reconstructed time series. The colouring of the points indicates the average wind speed during the 10 minute, and seems to outline two clusters of points: at below rated wind speeds (with higher power variance), and above rated (with lower power variance but higher flap loads).

The scatter plot outlines two cluster of points; one corresponds to lower (below rated) wind speeds and features relatively higher power standard deviation, and lower loadings. The other cluster, corresponding to above rated wind speeds, on the contrary appears to have low power standard deviation, but returns higher flap DEL loads. Within each cluster there seems to be instead a positive correlation between power standard deviation and an increase in fatigue loads. Such correlation could explain the particular distribution seen in the reconstructed DEL. As the site wind distribution favours above rated wind speed, the low power standard deviation points could actually yield to higher overall accumulated loading.

Data from the commercially installed wind turbines of the wind farm Krauschwitz, located in Teuchern, Germany was also used to validate the models developed in 5. The wind farm consists of seven Enercon E66-1500kW wind turbines (marked with red circles in Figure 6-7) scattered in a wind field:

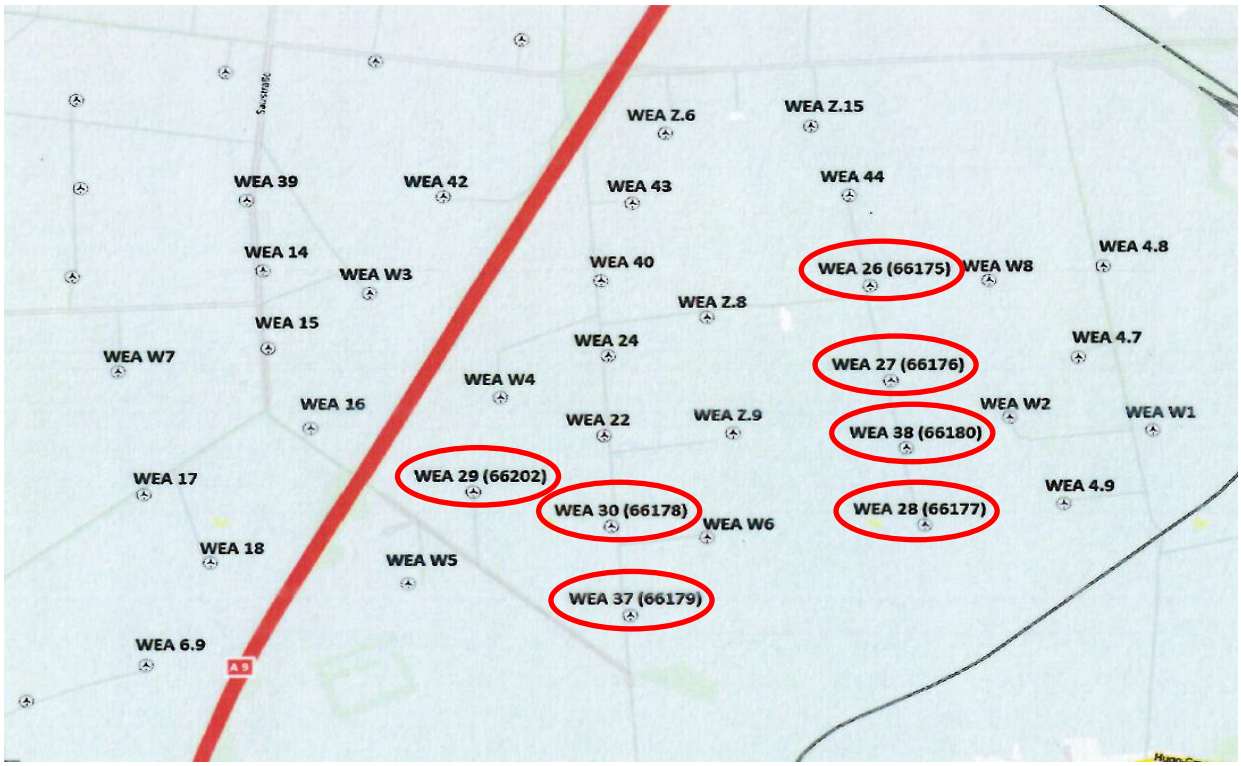


Figure 6-7: Layout of wind farm Krauschwitz (consisting of 7 turbines), located in Teuchern, Germany.

The corresponding coordinates of the 7 wind turbines are given in Table 6-1.

Table 6-1: Wind turbine coordinates of the wind farm Krauschwitz.

Wind turbine number	Longitude	Latitude
WEA 26 (66175)	11°59'02,771"	51°08'13,303"
WEA 27 (66176)	11°59'08,274"	51°07'57,074"
WEA 28 (66177)	11°59'10,760"	51°07'49,343"
WEA 29 (66202)	11°58'07,574"	51°07'52,678"
WEA 30 (66178)	11°58'26,930"	51°07'49,198"
WEA 37 (66179)	11°58'29,433"	51°07'40,255"
WEA 38 (66180)	11°59'05,843"	51°08'03,827"

This wind farm is chosen for the model validation as the turbines reached the end of their design life time of 20 years during the course of this year (2019). Therefore, a life time extension assessment for each of the 7 turbines was performed by *Deutsche WindGuard* (GmbH W. C., 2019) in June 2019. This

assessment is used for comparison throughout the validation of the *Life Extension Model* developed by DTU.

6.2 Assessment of the wind climate at site

European Energy has not been involved in the wind project from time of development but has recently purchased the wind turbines. The original documentation is limited and contains no wind study. However, during the process of repowering other turbines in the area, a number of wind studies were performed this year, e.g. a study undertaken by the German consulting company anemos-jacob (GmbH a.-j. , 2019).
Information from these reports is used to reproduce the wind conditions in the area and the resulting expected annual energy production (AEP).

Figure 6-8 shows the wind index for the region as used by anemos-jacob in order to calculate the AEP. The wind index shows a decrease of the wind resources for the region.

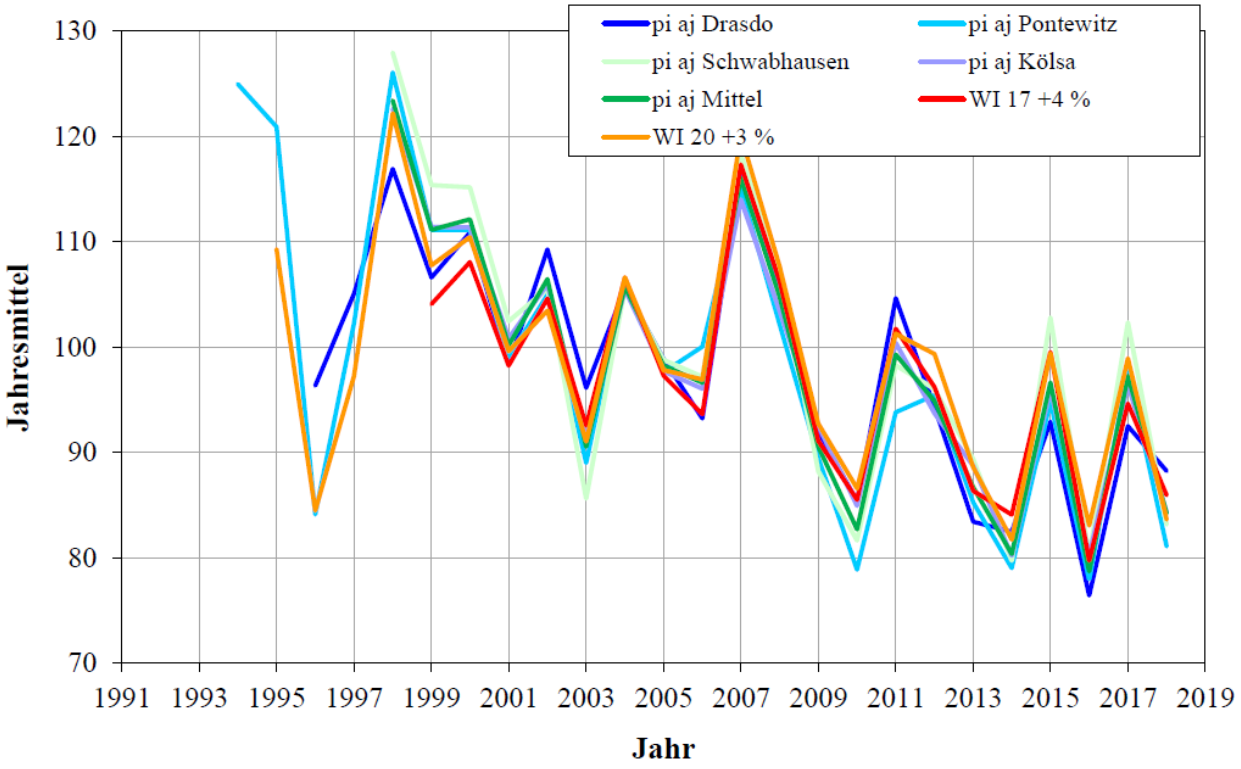


Figure 6-8: Wind index for the region Teuchern in Germany, used by anemos-jacob and the corrected BDB-Index (GmbH a.-j. , 2019).

The Weibull distribution and wind rose for the site are displayed in Figure 6-9 and Figure 6-10.

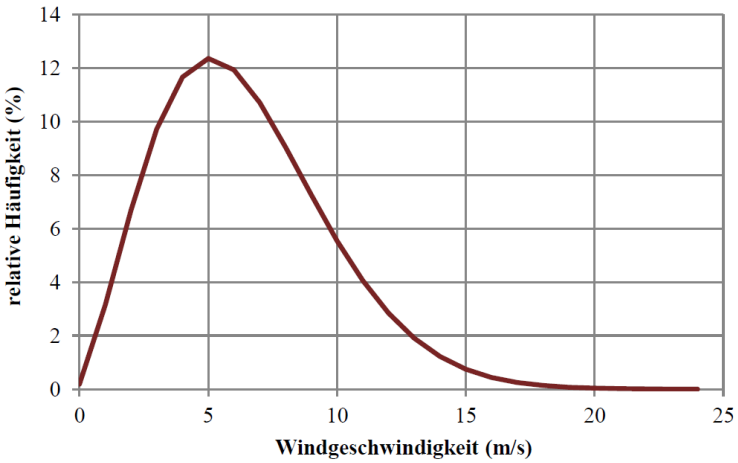


Figure 6-9: Weibull distribution for the area Teuchern in Germany, used by anemos-jacob (a.-j. GmbH, 2019).

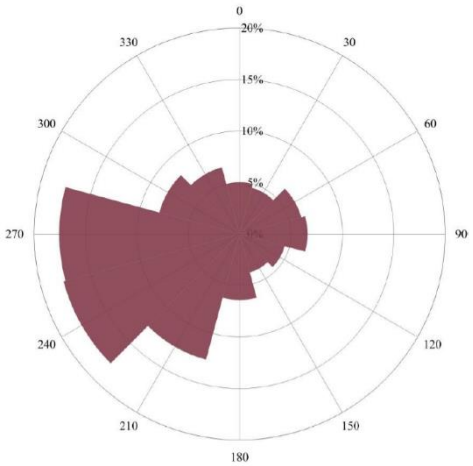


Figure 6-10: Wind rose for the area Teuchern in Germany, used by anemos-jacob (a.-j. GmbH, 2019).

The calculated long term AEP for the turbines of the wind farm Krauschwitz are shown in Table 6-2:

Table 6-2: Estimated Annual Energy Production (AEP) for the wind turbines in Krauschwitz, given by (GmbH a.-j. , 2019).

WTG No. (Serial Number)	AEP [MWh/year]
WTG 26 (66175)	2020
WTG 27 (66176)	2090
WTG 28 (66177)	2090
WTG 30 (66178)	2160
WTG 37 (66179)	2190
WTG 38 (66180)	1900
WTG 29 (66202)	1900

6.3 Wind turbine data

The considered turbines are manufactured by Enercon and were commissioned in Teuchern in 1999. They are equipped with a rotor that has a diameter of 66 m and an installed capacity of 1.5 MW each. All relevant technical wind turbine data is summarized in Table 6-3:

Table 6-3: Wind turbine key data.

Manufacturer	**Enercon**
Type	E-66
Commissioning year	1999
Serial numbers	66175, 66176, 66177, 66178, 66179, 66180, 66202
Rated power	1500 kW
Rotor diameter	66 m
Hub height	66.8 m
Drive train	Direct drive
Cut-in wind speed	3.0 m/s
Rated wind speed	12.5 m/s
Cut-out wind speed	25.0 m/s
Design life time	20 years

The turbine is designed for Wind Zone III (according to the German DiBt-Guideline from 1993) which corresponds to IEC standard Wind Class II. The DiBt-Guideline specifies that turbines are to be designed for a constant turbulence intensity of 0.2 (20 %), independent of wind speed.

The power curve of the turbines which is utilized throughout this analysis is taken from WindPro and displayed in Figure 6-11:

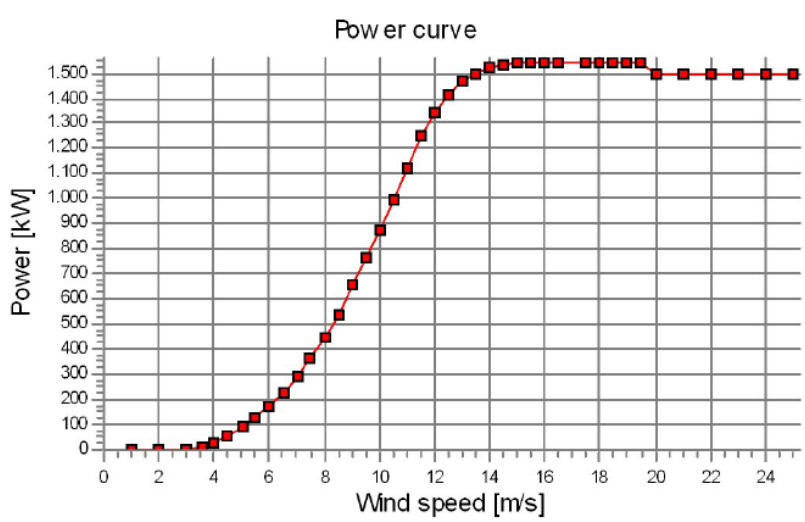


Figure 6-11: Power curve of the wind turbine Enercon E66-1500kW (WindPro).

6.4 Operational data of the wind farm

10-minute SCADA data for all seven turbines is available for the period 03.07.2012-30.09.2019. The yearly production figures for 2013-2018 are shown below:

Table 6-4: Yearly production [kWh] per turbine from 2013-2018.

WTG No. (Serial Number)	2013 [kWh]	2014 [kWh]	2015 [kWh]	2016 [kWh]	2017 [kWh]	2018 [kWh]
WTG 26 (66175)	1.785.436	1.447.931	1.668.503	1.445.742	1.568.872	1.392.397
WTG 27 (66176)	1.854.751	1.570.843	1.828.503	1.533.375	1.775.326	1.502.288
WTG 28 (66177)	1.753.287	1.658.144	1.891.834	1.572.912	1.855.239	1.563.301
WTG 30 (66178)	1.806.329	1.604.707	1.902.286	1.516.881	1.891.537	1.525.993
WTG 37 (66179)	1.914.072	1.705.210	1.985.242	1.623.959	1.910.518	1.585.545
WTG 38 (66180)	1.924.228	1.530.665	1.952.366	1.638.628	1.824.501	1.576.833
WTG 29 (66202)	1.753.314	1.616.090	1.735.319	1.517.817	1.767.829	1.464.465
Sum	**12.791.417**	**11.133.590**	**12.964.053**	**10.849.314**	**12.593.822**	**10.610.822**

The production figures clearly reflect the yearly wind speed fluctuations at site, as shown in Table 6-4. Also the main wind speed fluctuations obtained through the SCADA data in Table 6-5 reflect the same.

Table 6-5: Yearly average wind speed [m/s] per turbine from 2013-2018.

WTG No. (Serial Number)	2013 [m/s]	2014 [m/s]	2015 [m/s]	2016 [m/s]	2017 [m/s]	2018 [m/s]
WTG 26 (66175)	5,1	5,0	5,4	5,1	5,5	5,1
WTG 27 (66176)	5,1	5,0	5,5	5,2	5,5	5,2
WTG 28 (66177)	5,3	5,1	5,5	5,1	5,5	5,3
WTG 30 (66178)	5,4	5,0	5,5	5,1	5,6	5,2

WTG 37 (66179)	5,4	5,0	5,6	5,2	5,6	5,2
WTG 38 (66180)	5,1	4,9	5,5	5,1	5,5	5,2
WTG 29 (66202)	5,2	4,9	5,5	5,1	5,5	5,2
Farm Average	**5,2**	**5,0**	**5,5**	**5,1**	**5,5**	**5,2**

Taking a look at the historical yearly power production of each wind turbine, it can be observed that the turbines did not reach the expected yearly production of around 2000 MWh/year (Table 6-2) as predicted in the wind study performed by anemos-jacob (GmbH a.-j. , 2019). This provides an initial indication that the turbines were not operating as much as anticipated.

The technical availability for the turbines shows that they are technically kept well, as the yearly availability for the last 6 years is above 95%, despite the fact that the turbines have been operating for 20 years.

Table 6-6: Yearly technical availability [%] per turbine from 2013-2018.

WTG No. (Serial Number)	**2013 [%]**	**2014 [%]**	**2015 [%]**	**2016 [%]**	**2017 [%]**	**2018 [%]**
WTG 26 (66175)	99,6	96,7	98,3	99,3	97,8	98,1
WTG 27 (66176)	98,0	98,7	98,6	98,5	98,6	98,2
WTG 28 (66177)	97,5	99,4	99,0	99,5	98,6	99,0
WTG 30 (66178)	99,5	97,4	98,4	99,2	99,0	98,6
WTG 37 (66179)	99,2	98,8	98,1	98,7	95,1	95,6
WTG 38 (66180)	98,5	98,8	97,5	99,4	98,1	97,3
WTG 29 (66202)	99,0	96,9	99,4	98,1	99,0	99,2
Farm Average	**98,8**	**98,1**	**98,5**	**98,9**	**98,1**	**98,0**

6.4.1 Exchange of main components

The only exchange of main components that is known of is a blade exchange between 2006 and 2008, where the blades of all turbines were exchanged by refurbished blades.

Table 6-7: Exchange of blades with refurbished blades.

WTG No. (Serial Number)	Date
WTG 26 (66175)	19-01-2006
WTG 27 (66176)	29-06-2007
WTG 28 (66177)	04-07-2007
WTG 30 (66178)	14-08-2007
WTG 37 (66179)	17-07-2008
WTG 38 (66180)	18-07-2008
WTG 29 (66202)	04-09-2008

6.5 Data processing

The obtained SCADA data for Krauschwitz consists of the following measured parameters:

Table 6-8: Available SCADA data for wind farm Krauschwitz.

Parameter	Unit
Wind speed (min, max, average)	[m/s]
Active power (min, max, average)	[kW]
Power production	[kWh]
Nacelle position	[°]
Rotor speed (min, max, average)	[min^{-1}]

6.5.1 Data filtering

The DTU model requires an *Operational Grid Status* [seconds] (set to 600 seconds if grid was up running fully during the given 10 minute) and a *Power Curve Status* (set to 0 if the turbine is producing according to its given power curve). However, the available SCADA data for Krauschwitz are not containing an *Operational Grid Status* nor *Power Curve Status*. Thus, a simple data filtering method is applied in order to obtain the required status data and thereby discard biased data.

The P*ower Curve Status* is set to 0 if the active power at a given 10-minute time stamp is greater than 0 kW and the difference between the measured minimum and maximum value of the active power is smaller than 800 kW:

$$P_x > 0\ kW \text{ and } P_{x,\ max} - P_{x,min} < 800\ kW$$

The *Operational Grid Status* is set to 600 seconds if the 10-minute active power value of interest, the value prior and the value after are all greater than 0 kW:

$$P_x > 0\ kW \text{ and } P_{x-1} > 0\ kW \text{ and } P_{x+1} > 0\ kW$$

6.5.2 Analysis/verification of the SCADA data for WTG 26 (66175)

The SCADA data for the turbine WTG 26 (66175) has been exported into an Excel sheet in order to verify that the SCADA data is consistent and to apply the above described filters to exclude faulty data sets. The exported data from the SCADA system is obtained for a period from 03.07.2012 until 30.09.2019 giving 375,789 data sets. A number of pivot data tables have been created in order to extract production, wind direction and wind distribution from the Excel data. These tables are presented later in this Section.

6.5.3 Missing data sets

The data set consists of 10-minute mean values for analog parameters and 10-minute counter values. Analyzing the data set reveals that an energy production of 1221 kWh in 10 minute is far from correct. A turbine with a generator of 1500 kW can at most produce 250 kWh in 10 minute. The timestamp shows for example that there is missing a record from 04.07.2012 19:20 which has a consequence for the former and latter 10-minute record. A filter is applied removing records before and after a missing 10-minute data set.

Table 6-9: Missing 10-minute value for the SCADA data set for wind farm Krauschwitz.

Anlage	Seriennr.	Alias	Zeit	Wind Ø [m/s]	Energie prod. [kWh]
1	66175	26	04.07.2012 19:00	4,7	12
1	66175	26	04.07.2012 19:10	4,5	10
1	66175	26	05.07.2012 09:30	3,6	1.221
1	66175	26	05.07.2012 09:40	3,1	0

6.5.4 Average wind speed distributed in Bins

To the data set a column named *Bin* is added taking the integer part of the measured 10-minute average wind speed + 0.5 m/s. The resulting analysis of the data set shows a good correlation between the average wind speeds in the Bins, see Table 6-10.

Table 6-10: Average wind speed distributed in Bins.

Average of Wind Ø [m/s]	Year								
Bin	2012	2013	2014	2015	2016	2017	2018	2019	Grand Total
0	0,2	0,2	0,2	0,2	0,2	0,2	0,2	0,3	0,2
1	1,0	1,0	1,0	1,0	1,0	1,0	1,0	1,0	1,0
2	2,0	2,0	2,0	2,0	2,0	2,0	2,0	2,0	2,0
3	3,0	3,0	3,0	3,0	3,0	3,0	3,0	3,0	3,0
4	4,0	4,0	3,9	4,0	4,0	4,0	4,0	4,0	4,0
5	4,9	4,9	4,9	4,9	4,9	4,9	4,9	4,9	4,9
6	5,9	5,9	5,9	5,9	5,9	5,9	5,9	5,9	5,9
7	6,9	6,9	6,9	6,9	6,9	6,9	6,9	6,9	6,9
8	7,9	7,9	7,9	7,9	7,9	7,9	7,9	7,9	7,9
9	8,9	8,9	8,9	8,9	8,9	8,9	8,9	8,9	8,9
10	9,9	9,9	9,9	9,9	9,9	9,9	9,9	9,9	9,9
11	10,9	10,9	10,9	10,9	10,9	10,9	10,9	10,9	10,9
12	11,9	11,9	11,9	11,9	11,9	11,9	11,9	11,9	11,9
13	12,9	12,9	12,9	12,9	12,9	12,9	12,9	12,9	12,9
14	13,9	13,9	13,9	13,9	13,9	13,9	13,9	13,9	13,9
15	14,9	14,9	14,9	14,9	14,9	14,9	14,9	14,9	14,9
16	15,9	15,9	15,9	15,9	15,9	15,9	15,9	16,0	15,9
17	16,7	16,9	16,9	16,9	16,8	17,0	16,9	16,9	16,9
18	18,0	17,9	17,9	17,9	17,9	18,0	17,9	18,0	17,9
19		19,0	19,0	18,9	19,0	18,8	18,8	18,9	18,9
20		19,7	19,7	19,8	19,7	19,9	19,9	20,0	19,8
21		21,0	20,9	21,1	21,3	20,9	21,1	20,9	21,0
22			21,9	22,0	21,8	22,2	21,7	21,9	21,9
23			23,1	22,9	23,0	22,7	23,0	22,9	22,9
24							24,0	24,0	24,0
25						24,9	25,1	24,8	24,9
26							26,1		26,1
27							27,2	26,8	27,1
28							28,1	28,1	28,1
29							28,6	28,5	28,6
30								30,0	30,0
31							31,2		31,2
Grand Total	**5,1**	**5,2**	**5,0**	**5,4**	**5,1**	**5,5**	**5,1**	**5,3**	**5,2**

6.5.5 Wind direction

Information of the wind direction is taken from the SCADA measurement of the nacelle position (Gondelposition) [°] as shown below. It correlates with the wind rose in Figure 6-10 from the wind resource report (GmbH a.-j. , 2019) as the wind mainly comes from 180-300º.

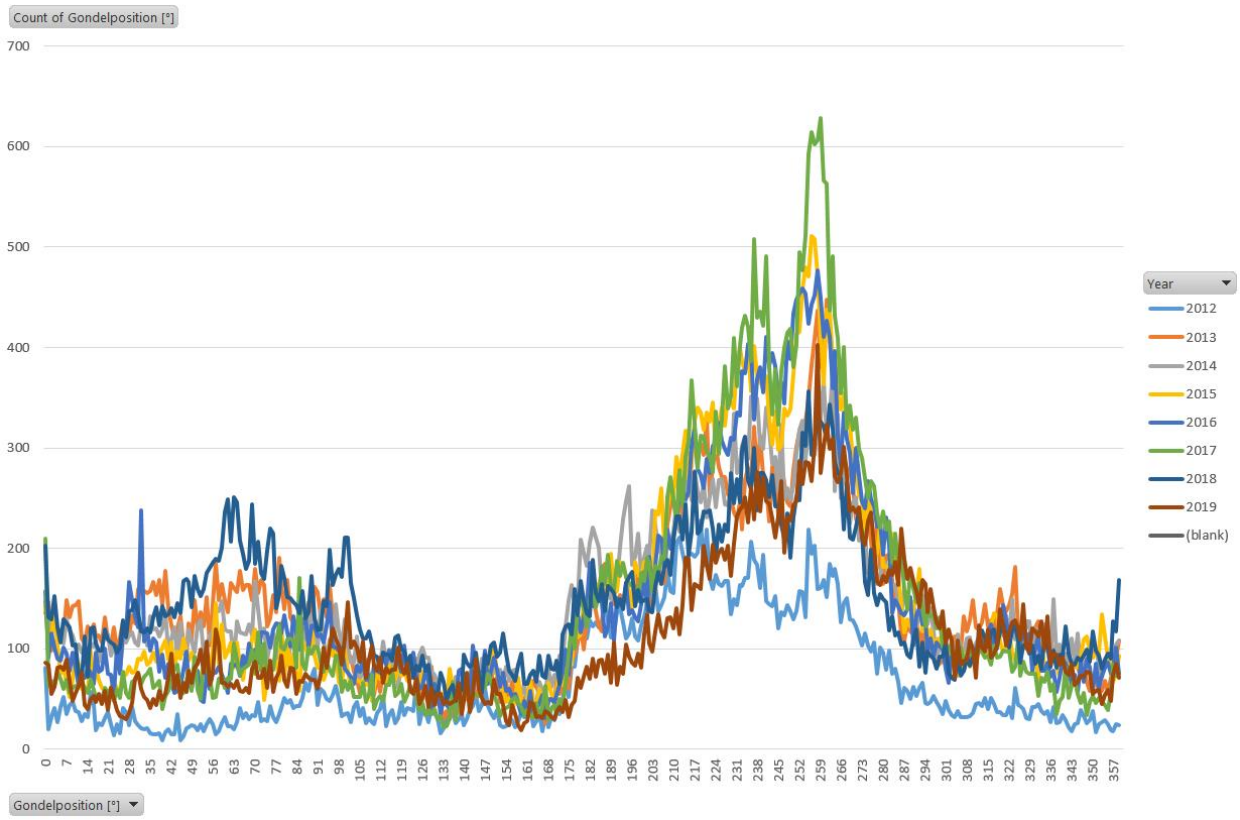


Figure 6-12: Wind direction distribution for the wind farm Krauschwitz in the period 03.07.2012-30.09.2019.

6.5.6 Wind distribution

Figure 6-13 shows a simple count of the data sets in the different wind speed Bins. This simple distribution of wind speeds correlates with the Weibull distribution in Fig. 6-10. (GmbH a.-j. , 2019).

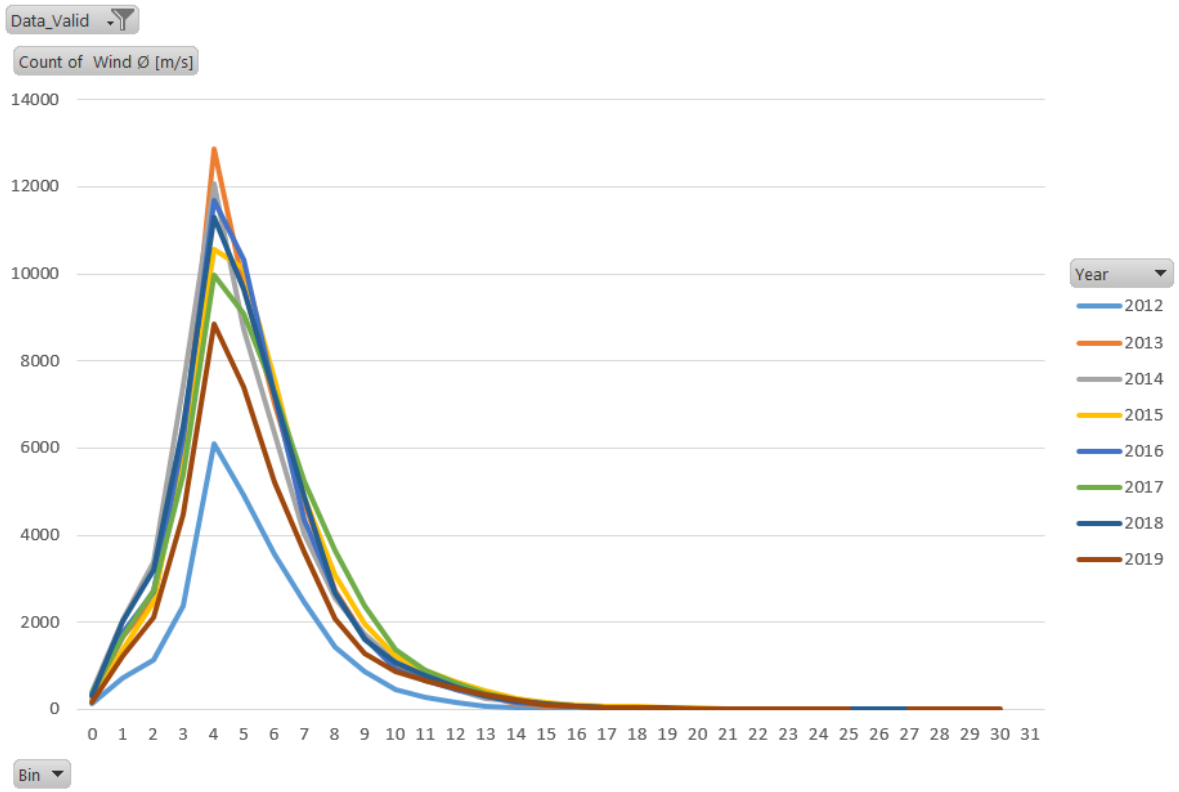


Figure 6-13: Wind speed distribution for the wind farm Krauschwitz in the period 03.07.2012-30.09.2019.

6.5.7 Measured Power Curve

In order to derive a power curve for the given turbine the data is filtered according to *Power Curve Status* (as described in Section 6.5- Figure 6-14 shows the power curve derived from the SCADA data for WTG 26. It is seen that apart from year 2017 and 2019 there is good correlation to the power curve for the Enercon E66-1500kW used by WindPro shown in Figure 6.4 . The reason for the poor power curves in year 2017 and 2019 could be a result of the few data sets for wind speeds above 10 m/s as shown in Figure 6-13.

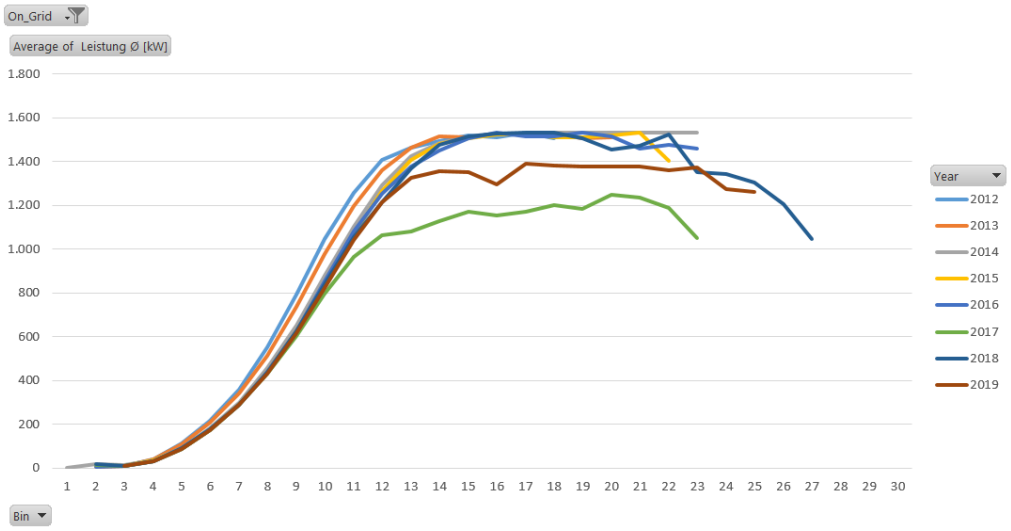


Figure 6-14: SCADA Power curve for WTG 26 (66175) for the wind farm Krauschwitz in the period 03.07.2012-30.09.2019.

The above analysis of the SCADA data demonstrate, that there is a high correlation between the expected wind distributions, power curve and data quality for the turbines in Krauschwitz in order to use the data as input for the *Life Extension Model* without any further filtering.

6.6 Life time extension assessment (Deutsche WindGuard)

In June 2019 *Deutsche WindGuard* (GmbH W. C., 2019) performed a life time extension assessment for each of the seven turbines in Krauschwitz. This assessment is mainly based on the following guidelines and standards:

- DIBt-2012 (Deutsches Institut für Bautechnik) (Bautechnik, 2012)
- DIBt-1993 (Deutsches Institut für Bautechnik) ((DIBt), 1993)
- GL-IV-1-12:2009 (Germanischer Lloyd) (Richtlinien, 2009)
- BWE 2017 (Bundesverband WindEnergie) (Energie, 2017)
- DIN EN 61400-1:2011-08 (Institut für Normung) (e.V., 2011)

The assessment consists of a physical inspection of the turbines and an analytical load assessment through an aero-elastic simulation performed with the software *Bladed*. Throughout the aero-elastic simulation all wind turbines within a radius of *≤10 × Rotor Diameter* are considered for the wake effect simulation. Furthermore, the effective turbulence intensity TI_{eff} is calculated taking the ambient TI and the TI generated by wakes into account. The total life time T of a turbine is then computed by multiplying the life time factor LF by the design life time (20 years in this case):

$$T = LT \cdot 20\ years$$

LT is found by computing the Damage Equivalent Loads (DEL) for the site specific wind conditions DEL_{spec} and for the reference wind conditions DEL_{ref}. Taking a Wöhler Exponent $m = 5$ into account, the LF is computed as follows:

$$LF = \left(\frac{DEL_{ref}}{DEL_{spec}}\right)^{m}.$$

A safety factor of $SF = 1.15$ is taken into account during the analytical simulation.
The assessment results in a total life time for each of the 7 turbines of $T = 35\ years$, meaning an additional life time of 15 years.

6.7 Results

The results generated by the *DTU Life Extension Model* are based on the following data that is fed into the model:

- Farm layout (coordinates of each turbine)
- Filtered SCADA data (according to Section 6.5) for the period 01.01.2013-30.09.2019

- Turbine specific data (hub height, rotor diameter, cut-in and cut-out wind speed, rated wind speed, rated power, power curve, etc.)

Among others, the *Life Extension Model* generates a graph showing the theoretical wind speed distribution considering the Wind Zone/Class the turbine is designed for and a site-specific distribution of the wind speeds taking the measured wind speed of all turbines for the given time frame into account. The graph is displayed in Figure 6-15:

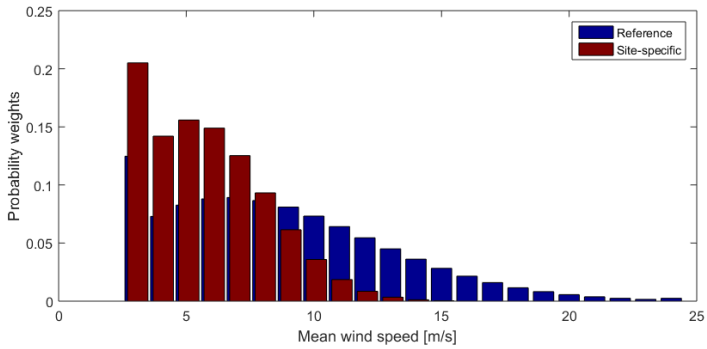


Figure 6-15: Reference and site-specific Weibull distribution of wind speeds (DTU Life Extension Model result).

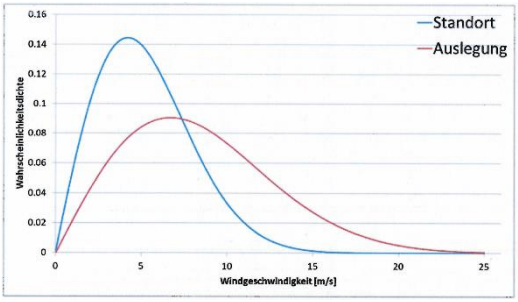


Figure 6-16: Reference ('Auslegung') and site-specific ('Standort') Weibull distribution of wind speeds for WTG 26 (66175) derived by Deutsche WindGuard (GmbH W. C., 2019).

Comparing the Weibull distributions generated by the DTU model with the ones derived in the *Deutsche WindGuard* assessment it can be seen that the reference Weibull distribution ('Auslegung' in Figure 6-16) are corresponding very well. The site specific wind speed distribution of the DTU model displays slightly higher average wind speeds than the *Deutsche WindGuard* assessment.

Moreover, the DTU model provides results in form of relative life time damage equivalent loads (DEL) of the following 8 Load Channels:

- Tower base fore-after, Mx
- Tower-base side-side, My
- Top Tower, Mx
- Top Tower, My
- Yaw moment, Mz
- Main shaft torsion, Mz

- Blade root flapwise, Mx
- Blade root edgewise, My

The site specific DEL are show relative to the reference site DEL for which the turbine is designed. As an example the DEL results for the WTG 26 (66175) are shown in Figure 6-17 below:

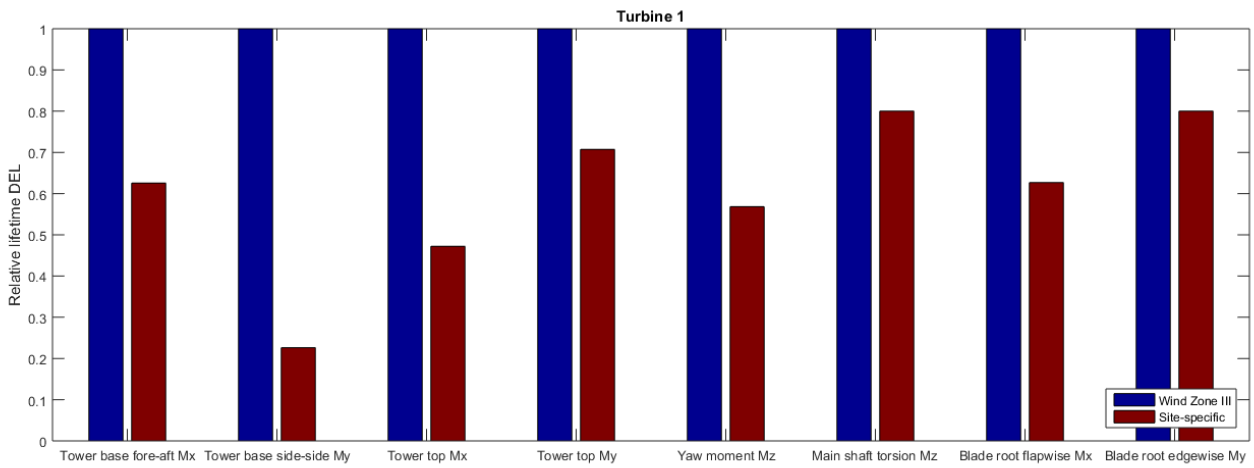


Figure 6-17: Relative damage equivalent loads (DEL) for 8 load channels for WTG 26 (66175) for the reference (Wind Zone III) and the site specific relative DEL.

Figure 6-17 shows that none of the load channels exceed the relative DEL that the turbines were designed for. The limiting load channels are found at the main shaft torsion and the blade root flapwise with relative DEL of around 0.8. Considering a Wöhler Exponent $m = 5$, a total lifetime of approximately 60 years, which is significantly higher than the 35 years resulting from the *Deutsche WindGuard* assessment. However, it has to be noted that no safety factor is taken into account in the DTU model and no physical inspection of the turbines was performed.

Table 6-11 presents the relative DEL for all 7 turbines and all load channels, showing the results with a color code (from green for low DEL, over yellow/orange, to red for high DEL). The results show that the relative DEL variation between turbines for the different load channels is minor.

Table 6-11: Relative DEL for all turbines for 8 load channels.

WTG No. (Serial Number)	Tower base fore-aft *Mx*	Tower base side-side *My*	Top tower *Mx*	Top tower *My*	Yaw moment *Mz*	Main shaft torsion *Mz*	Blade root flapwise *Mx*	Blade root edgewise *My*
WTG 26 (66175)	0.626	0.226	0.472	0.707	0.568	0.800	0.627	0.800
WTG 27 (66176)	0.641	0.227	0.473	0.721	0.570	0.821	0.633	0.800
WTG 28 (66177)	0.635	0.227	0.472	0.716	0.569	0.813	0.631	0.800
WTG 30 (66178)	0.660	0.229	0.475	0.727	0.575	0.836	0.642	0.802
WTG 37 (66179)	0.618	0.226	0.472	0.707	0.568	0.797	0.625	0.800
WTG 38 (66180)	0.609	0.225	0.471	0.701	0.567	0.786	0.621	0.799
WTG 29 (66202)	0.618	0.226	0.471	0.704	0.568	0.796	0.625	0.800

6.9 Conclusion

The tested algorithms allows to get a map of the accumulated loads within the windfarm, with no other information than commonly available SCADA data signals. The accumulated loadings can be considered as a qualitative indication of the relative loading conditions within the wind farm, thus indicating which turbines have been loaded more hard in the considered time period. The information could then be eventually used in prioritizing maintenance operation, or for instance providing a criteria for which turbines would require more detailed observations within the windfarm.

As a result of the analysis performed, it can be concluded that the *Life Extension Model* developed by DTU provides a good indication of loads that a turbine is expected to experience during its life time taking the site specific data and SCADA measurements into account. The results of the model show that the turbines of the wind farm Krauschwitz experience the highest loads at the main shaft torsion and the blade root in edgewise direction. With these load channels as the limiting factors and a Wöhler Exponent of $m = 5$ the remaining life time amounts to 60 years in total. This result might be too optimistic comparing it with the Life Time Extension assessment carried out by *Deutsche WindGuard* (GmbH W. C., 2019), resulting in a total life time of 35 years. However, it has to be kept in mind that (GmbH W. C., 2019) includes a safety factor of 1.15 in the analytical simulation and carried out a physical inspection of the turbines.

The *Deutsche WindGuard* report shows clearly that a lifetime extension assessment always should come along with a physical inspection in order to capture structural damages and to ensure the structural stability. The inspection of the turbines in Krauschwitz reveals several blade damages such as shown in Figure 6-18.

Figure 6-18: Blade damages detected on the turbines in Krauschwitz during physical inspection, as part of the life time extension assessment performed (GmbH W. C., 2019) .

Future work and recommendations

Future work should focus on further validating the load indication given by the algorithm. The application to a wind farm were loading sensor were available would be of particular interest. It would also be interesting to further look into the particular correlation pattern between lower power standard deviation and higher fatigue loading, as this challenges the fairly common assumption that higher power standard deviation would give an approximate indication of a relatively more loaded turbine.

In order to carry out an extensive validation of the model, an analysis with more turbines and different turbine types has to be conducted. It is also recommended to compare the analytically obtained DEL with actual load measurements on turbines. In order to improve the Life Extension Model developed by DTU, surrounding wind farms and their turbines could be included for the wake simulation. Also providing the actual life time in years as an output of the model (considering the corresponding Wöhler Exponent) could be advantageous.

Furthermore, the accessibility and transparency of the model could be improved by including a possibility for the selection of the Wind Zone/Class and by applying a more generic data filtering in order to create more flexibility for the input data. Especially for old turbines it is difficult to obtain substantial SCADA data and an *Operational Grid Status* and *Power Curve Status* might not always be available.

SCADA data is often retrieved in csv files for one year at a time due to the amount of datasets resulting in large files. It should therefore be an option to load a number of csv files into the model.

7. Reliability-based approaches for Life Extension (AAU)

This chapter treats two topics in relation to reliability based approaches for life extension: Reliability level and Reliability-based inspection planning.

7.1 Reliability level

Wind turbines structures are generally designed using the partial safety factor method according to the basic design standard IEC 61400-1 ed. 4 (IEC 61400-1, 2019). Looking into standards for existing structures, it is generally argued that requiring the same reliability level for existing structures as for new structures is not economical. ISO13822 (ISO13822, 2010) states that lower reliabilities for existing structures than for new structures can be justified based on economic, social and sustainability considerations. The main reason for accepting a lower reliability level for existing structures is that it is more expensive to increase the reliability, compared to when the structures were designed.

The DNVGL-SE-0263 (DNVGL-SE-0263, 2016) service specification for certification of life extension (there defined as continued operation beyond the original design life), include four methods for certification: 1) based on inspection alone, 2) and 3) based on semi-probabilistic analytical verification in combination with inspection, and 4) based on probabilistic assessment in combination with inspection. The national regulations decide what is required for life extension in a specific country; in Germany, it is required to assess analytically the structural integrity for the life extension period. In countries where verification of the structural integrity is not required, analyses may still be useful to assess the risk in relation to an investment into life extension and in negotiations with insurance companies. The associated DNVGL-ST-0262 (DNVGL-ST-0262, 2016) standard on life extension elaborate on the methods for analytical assessment. The probabilistic assessment method is described in non-operational terms. They allow for probabilistic analyses, but give only very general guidance on how to do it. The general steps in a reliability analysis is given, and the first step is given as "selection of target reliability level". The straightforward choice for target reliability would be the level given for structural components in new wind turbines in the ed. 4 of the IEC61400-1 standard corresponding to an annual probability of failure equal to$5 \cdot 10^{-4}$. However, the arguments applied for reducing the target reliability level for existing structures also applies to existing wind turbines. The standard IEC61400-28 "Wind energy generation systems – Through life management and life extension of wind power assets" currently under development could include recommendations on selection of target reliability levels to be used in relation to assessment of existing wind turbines. Furthermore, the IEC61400-28 standard could include a set of reduced partial safety factors to be used in semi-probabilistic assessments of existing wind turbines, thus enabling owners to benefit from reduced target reliability without a need for probabilistic methods. Simple tools can be developed for simplified generic estimation of the *assessed fatigue life* (updated "design fatigue life") based on information of the IEC class used in design and the wind conditions on the site, using partial safety factors reduced due to a decreased target reliability. Furthermore, a decrease in uncertainties due to larger amounts of data being available, will lead to lower safety factors being necessary to obtain the same reliability level, as shown in IEC61400-1 ed.4 2019 Annex K and the associated background document (Sørensen & Toft, 2014).

At the design stage, the optimal reliability is found as the reliability level providing the optimal trade off between construction costs and expected failure costs/consequences, i.e. the reliability level minimizing the expected costs. Once the structure is built, the decisions on design cannot be changed. Instead, to

increase the reliability, the structure can be strengthened, or the loads can be reduced. However, it is generally more expensive to make changes at this point in time, compared to making changes at the design state. Only if new information indicate that "status quo" (keep the structure as it is) is not anymore optimal, there could be a good reason for interference. This could for example be that the structure (designed for fatigue) did not become obsolete at the point in time expected at the design state; i.e. life extension or continued operation beyond the original design life is considered. As the probability of fatigue failure increase with time, there may come a time, where the risk of failure (the probability of failure times the costs/consequence of failure) exceeds the benefit of having the structure, and decommissioning will be economically optimal. If the reliability drops below this limit it should be decommissioned or strengthened.

For new turbines, owners are generally investing into an expensive asset, and they will need to be sufficiently sure that the structure is reliable, as they could lose the asset, if it is not. The consequence of failure scale with the price of the asset, and the same target reliability level can be used for all new wind turbines. For existing wind turbines, the situation differ a lot more, and there can be good reasons for differentiation of the requirements to reliability depending on the size of the investments and the failure consequences. Failure consequences can be divided into economic consequences for the owner and societal consequences.

As the societal consequences associated with a collapse of a wind turbine is relatively low, there could be a tendency that economic consequences for the owner dominate the risk for new structures, whereas societal consequences dominate the risk for older existing turbines, unless new investments into life extension is made. Societal consequences include risk of loss of human lives, loss of reputation of the wind industry, and loss of power production. Economic consequences for the owner include costs of demolishment and clean up after failure and lost revenue. Although the owner of the structure is receiving the benefit from existence of the structure, and will pay for upgrading etc. there are possible failure consequences that will affect other stakeholders, and the minimum level of consequences to include should be determined from the point of view of the society. If the risk to the owner is too large for a small owner, he could decide to pay a bigger company to take the risk.

7.1.1 Minimum reliability level for continued operation when no changes are made

The smallest minimum reliability level can be found for the case, when the owner will face no economic consequence in the case of failure. He will face the loss of revenue after failure, but if the structure was decommissioned, he would also not have any income from power production, and the risk of loosing revenue in case of failure, would never drive a decision towards decommissioning. (It should, however, be included as a failure consequence in a design situation, where the decision alternatives are different.) Therefore, the societal consequences are governing the minimum acceptable reliability level.

ISO13822 (ISO13822, 2010) propose a reliability index for the remaining working life as reference period equal to 2.3 for inspectable fatigue, and 3.1 for not inspectable fatigue, without differentiation due to failure consequences. ISO2394 (ISO2394, 2015) propose an annual reliability index of 3.1 for large cost of safety measure, and consequence class 2, which include major wind turbines. If a minimum annual reliability level of 3.1 is used due to the societal consequences, this corresponds on an annual probability of failure of 10^{-3}, which is twice as high as for new wind turbines. It is often argued that the reliability

level for existing structures can be reduced corresponding to one class for the relative safety measure in the table from ISO2394 (ISO2394, 2015) (Steenbergen, Sýkora, Diamantidis, Holický, & Vrouwenvelder, 2015), which generally leads on a reduction of at least a factor two; thus, the proposed reduction to 10^{-3} is conservative compared to this.

For structures, where there is a risk of fatalities in case of collapse, the requirements to human safety often set the absolute lower level for acceptable reliability. For wind turbines located in remote areas, the conditional probability of a person being hit given a structural failure is very low, and requirements for a minimum reliability due to requirements for human safety are not relevant. Instead, the societal risks are loss of reputation for the wind industry and loss of energy production capacity. As the annual probability of fatigue failure is increasing approximately linearly with time (see Figure 7-1), allowing it to grow to a value twice as high, will lead to the annual expected amount of failure for the entire fleet of turbines increasing approximately with a factor of two. Thus, an aggressive increase in the number of failures would not be expected; wind turbines would not start to "collapse all the time".

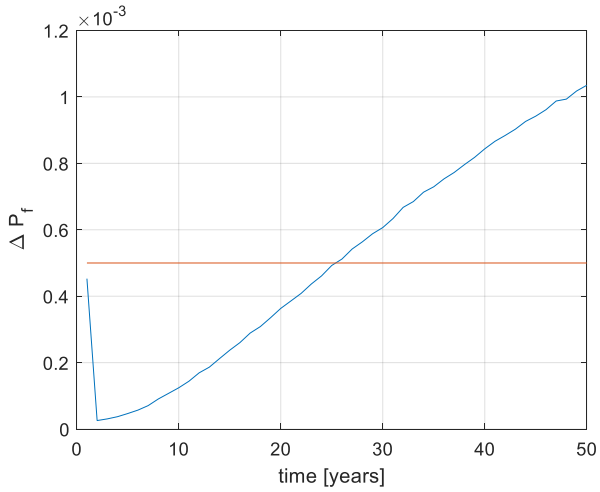


Figure 7-1: Variation of annual probability with time.

7.1.2 Target reliability for life extension

A decrease of the target reliability level for structural components corresponding to an annual failure probability of 10^{-3} is in the previous section assessed acceptable, when no investment is made, and only societal consequences are considered in case of failure. However, if an investment into life extension is made (e.g. change of major components), or there are economic consequences of a failure, an economic assessment should be made to find the optimal target reliability.

Approach for new structures

Following (Rackwitz, 2000) and (Fischer, Viljoen, Köhler, & Faber, 2019), the objective function for structural optimization can be written as:

$$Z(p) = B(p) - C(p) - I(p) - U(p) - M(p) - A(p) - D(p)$$

With decision parameter p, and the net present values of:

- $B(p)$: benefit from the existence of the structure
- $C(p)$: construction costs
- $I(p)$: costs associated with inspection and maintenance
- $U(p)$: costs associated with serviceability failures
- $M(p)$: costs implied with degradation, such as corrosion and fatigue
- $A(p)$: obsolescence costs
- $D(p)$: costs for ultimate limit state failures

It is typically assumed that all other terms than $C(p)$, $A(p)$, and $D(p)$ are independent of the decision parameter p, and the optimal decision parameter can in that case be found by minimizing the expected net present value of these costs:

$$C_T(p) = C(p) + A(p) + D(p)$$

The reliability levels found in ISO2394 (ISO2394, 2015) and shown in Table 4-3: Tentative target reliabilities related to one year reference period based on monetary optimization. Table F.1 mention major wind turbines and unmanned offshore facilities as examples of consequence class 2 structures.
are derived on this basis, originally by (Rackwitz, 2000), and recently documented further by (Fischer, Viljoen, Köhler, & Faber, 2019).

7.1.3 Approach for existing structures

For design of structures, where the decision parameter p relates to the reliability level, the benefit is assumed independent of p, as the structure is assumed to be renewed after failure or obsolescence. Any loss of benefit due to failures are included in the failure cost term. It makes sense to use the renewal theoretical approach, because the renewed structures can be assumed to be designed using the same reliability level, as originally used. For existing structures, the approach is typically different. In (Steenbergen, Sýkora, Diamantidis, Holický, & Vrouwenvelder, 2015), minimum reliability levels and optimal reliability levels for upgrades were derived for existing structures dependent on the length of the remaining service life and the consequences of failure. First, two discrete decision alternatives were considered:

- Accepting the present state (no upgrade): $C_T(p) = D(p)$

- Upgrading the structure: $C_T(p) = C(p) + D(p)$

If the present state is accepted, the only costs considered are the expected failure costs in the remaining life. If an upgrade is made, the costs of the upgrade are considered in addition to the expected failure costs in the remaining life. In case the last option is found optimal, it means that there exist feasible upgrade solutions, and of those the optimal solution is identified. Comparing to the approach for new structures, no obsolescence costs are included here, as the costs of the new structure will not depend on the decision rules for existing structures.

7.1.4 Approach for life extension

As for new structures, no benefits were included in the optimization problem for existing structures described above, because the remaining service life of the structure was the same regardless of whether the present state was accepted or the structure was upgraded, and therefore the benefits were independent of the decision. When considering life extension, the decision options are:

- Decommissioning

- Life extension (e.g. investment in non-structural components and blades)

- Continued operation (without investments)

If deciding upon life extension, there will be a benefit due to the revenue from produced power in the extended life, but if deciding upon decommissioning, there will be no benefit. Therefore, the benefit depends on the decision parameter p and thus cannot be neglected. If neglecting the decommissioning costs, which will be there in both decision alternatives (although at different points in time), the decision problem is to maximize the expected profit in case of life extension. If the expected profit of life extension is negative, decommissioning is the optimal choice. Although life extension projects with a positive expected benefit should be performed from the point of view of the society, an owner might be risk averse, as negative profit could have too large consequences for the liquidity. Here, smaller owners can buy an insurance to make someone else take the risk.

In case of life extension, the profit is calculated as the benefit minus the costs put into life extension, expected failure costs, and operation and maintenance costs including inspections and maintenance of components, land lease, operational costs, etc.:

$$Z(p) = B(p) - C(p) - D(p) - OM(p) \tag{1}$$

The life extension costs $C(p)$ are assumed to be paid at the time the life extension it performed ($t = 0$), and all other costs are discounted to this time. The expected present values are found for the other costs until the time of obsolescence T_ω, which could be equal to the end of the planned extended life. However,

if the planned extended life is long, obsolescence could also happen earlier, or even later, thus it could be considered uncertain. The expected failure costs $D(p)$ are found on basis of the failure consequences H, and the probability density function of the time to failure, $f_T(t;p)$. (Index p is included, as decisions could be made, which affects the time to failure.):

$$D(p) = \int_0^{T_\omega} \exp(-\gamma t)\, H\, f_T(t;p)\, dt$$

The expected benefit is calculated as the discounted benefit, if no failure occur before obsolescence, plus a term considering benefit until failure, if failure happens before obsolescence.

$$B(p) = \int_0^{T_\omega} \int_0^{t} \exp(-\gamma\tau)\ b(\tau)\, d\tau\, f_T(t;p)\, dt + \int_0^{T_\omega} \exp(-\gamma t)\ b(t)\, dt\ \left(1 - F_T(T_\omega;p)\right)$$

Here $F_T(t;p)$ is the cumulative distribution function for the time to failure, and $b(t)$ is the annual benefit at time t.

For O&M costs not ending in case of failure (e.g. due to contracts), the net present value is found as:

$$OM(p) = \int_0^{T_\omega} \exp(-\gamma t)\, C_{OM}\ dt$$

For O&M costs ending in case of failure, an expression similar to the benefit term can be used, of alternatively, instead of letting $b(t)$ denote the annual benefit, it can denote the annual benefit minus annual O&M costs.

Economic consequences of failure due to contracts with insurance, banks, and land owners should be included either through C_{OM} or H.

The density function for time to failure $f_T(t)$ can be calculated using structural reliability methods based on a probabilistic SN model. For the loading occurring prior to the life extension, the loading corresponding to the initial configuration should be used, and if the loads are changed due to upgrades of components or control system, this should be reflected. The density function should be calculated conditioned on survival op until time of life extension, and the distribution should be shifted to have time zero at the time of life extension, to fit with the above expressions.

It is noted that there are the following four cases to consider:

- Continued operation: continued operation beyond the original design life without any changes to the WT
    - The solution when none investments are feasible
    - No (or sufficiently small) economic consequences are associated with a failure
    - Original fatigue calculations are valid

    - The minimum reliability can be reduced to 10^{-3}
    - Continued operation for structural components could be allowed in e.g. 15 years without any verifications of structural reliability

- Continued operation: continued operation beyond the original design life with changes to the control system of the WT that increase loads
    - No (or sufficiently small) economic consequences are associated with a failure
    - Original fatigue calculations are not valid
    - The target reliability can be determined by balancing the increased income with the increased failure probability, and should not be less than corresponding to 10^{-3}
    - It should be verified analytically that the reliability of structural components is above the minimum level in the extended life

- Life extension: continued operation beyond the original design life with major component exchanges to components similar to the original components
    - The risk of structural failure could compromise the feasibility of the investment
    - The original fatigue calculations are still valid, but updated calculations may be made with new knowledge on loads to reduce uncertainties
    - The target reliability can be determined by economic assessment of the feasibility of the investment, and should not be less than corresponding to an annual probability of failure equal to 10^{-3}
    - General recommendations can be derived for the minimum remaining fatigue life based on the target reliability and economic situation

- Life extension: continued operation beyond the original design life with major component upgrades (or component exchanges and upgrades to the control system)
    - The risk of structural failure could compromise the feasibility of the investment
    - The original fatigue calculations are not valid
    - The target reliability can be determined by economic assessment of the feasibility of the investment, and should not be less than corresponding to an annual probability of failure equal to 10^{-3}
    - It should be verified analytically that the reliability of structural components is above the minimum level in the extended life

7.1.5 Example: derivation of minimum reliability level for life extension

Using the probabilistic SN model for fatigue given in (Sørensen & Toft, 2014), the annual reliability index can be found given the design parameter (e.g. proportional to a cross sectional parameter) z. The cumulative probability of failure is first calculated based on Monte Carlo simulations, then the annual probability of failure conditioned on survival is found, and the annual reliability index is found based on

this. Figure 7-2 shows the progression of the annual reliability index with time for various values of the design parameter z. In the design situation, z would be chosen such that the reliability index is higher than 3.3 in the last planned year of operation, e.g. year 20. Generally, the reliability is decreasing with time, but for very low reliabilities, the reliability is increasing with time.

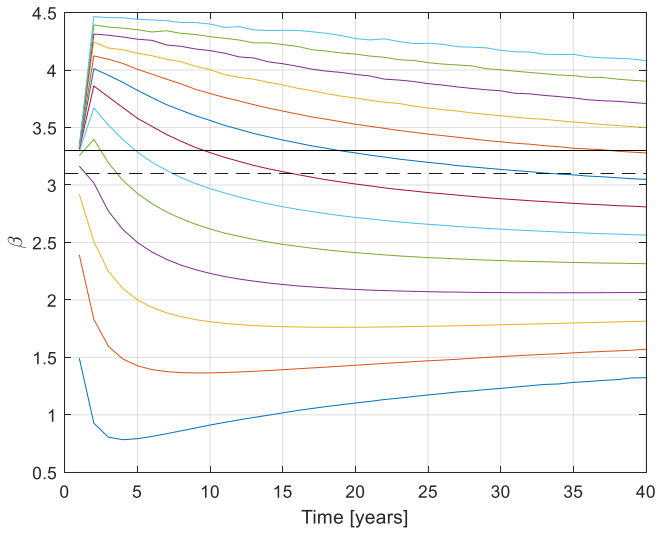


Figure 7-2: Annual reliability index as function of time for various values of the design parameter z. The black line corresponds to β=3.3 and the black dashed line to β=3.1.

For each of the z-values, the profit $Z(p)$ can be calculated using eq. (1) given values of all parameters. If the profit is negative, life extension is infeasible compared to decommissioning, and therefore the minimum acceptable reliability is where the profit is zero. The value of z associated with zero profit is identified using linear interpolation between the z values, and the minimum reliability index is the value in the last year of operation.

To make the results as generic as possible, the costs are set relative to the annual profit (benefit minus operational costs). In general, three types of costs are considered, as high probability of structural failure can make these important. First, if life extension costs are high, failure can be critical as the revenue that should have paid back these costs are not gained. Secondly, if there are large fixed operational costs that will still have to be paid for the extended life also in case of failure. Thirdly, if the failure consequences are high.

The life extension costs are defined through the profit margin calculated without considering the risk of structural failures. For example, a profit margin of 10% means that the life extension costs are 10% lower than the discounted profit considering benefit from revenue and costs to operation in the life extension period. The fixed operational costs are defined as a proportion of the annual profit, and the failure consequences are also defined in relation to the annual profit. Therefore the parameters to be defined to calculate the minimum reliability level are:

- Interest rate

- Profit margin
- Relative failure costs
- Relative fixed operational costs
- Life extension period
- Original planned lifetime

Life extension periods 5, 10, 15, and 20 years are considered, and the original planned lifetime is fixed at 20 years. The base assumptions are: interest rate 0.05, profit margin 0.1, relative failure costs 1, and relative fixed operational costs 0.5. The values are varied, one at a time, while the other are fixed, and the resulting minimum annual reliability indices are shown in Figure 7-3. It is seen that the minimum reliability indices found considering the profitability of life extension compared to decommissioning are generally lower than the proposed value of 3.1 (corresponding to an annual probability of failure equal to 10^{-3}), and therefore this value can in most cases be used for both continued operation and life extension.

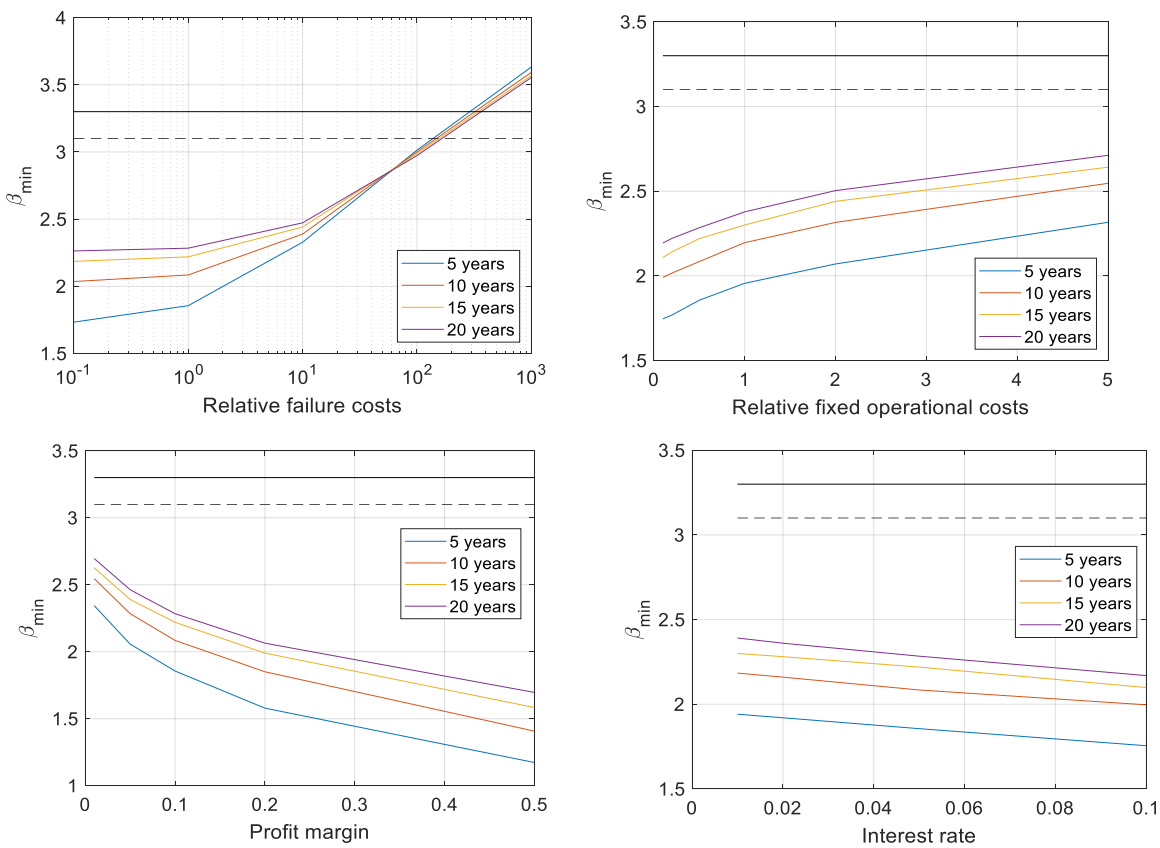


Figure 7-3: Minimum reliability index for varying cost parameters and life extension period.

7.1.6 Discussion of target reliability level

Some people might object that allowing a lower reliability level for assessment of existing structures than for design of new structures, could lead to designers choosing a shorter design life, because it will always be possible to get permission to continue operation afterwards due to lower safety factors for the assessment. Or, they could make changes to the control system to allow for larger fatigue loads, once the turbine is build, and therefore has become an existing turbine. If the owner is subject to all costs, benefits and failure consequences, this should not be a problem, as the rules in the standards should correspond the economically optimal decisions. Thus, if the owner had a wish to allow for increased loading, or planned for operation beyond the chosen design life, it would have been more optimal to make the structure more reliable. If societal consequences are also included, it might be a valid point that owners could attempt to save money in this way. However, choosing a lower reliability could have as a consequence higher insurance premiums, due to the higher risk that the insurance companies would have to bear.

If issues with a specific wind turbine type is detected, this should be considered, as well as observations of cracks and deterioration at inspections. But by decreasing the target reliability to 10^{-3}, the analytical assessment of structural components would allow most turbines to run for an extended life of several years, unless the loads turn out to be much larger than expected. The reason for decommissioning would in most cases be findings at inspections or major failures of mechanical components that would require expensive repairs.

7.2 Reliability verification using inspections

This section presents a procedure for assessment of life extension for welded steel details wind turbine structural exposed to fatigue, e.g. in the tower. It is assumed that the considered structural components are designed to satisfy the requirement in IEC61400-1 (2019) that the annual probability of failure does not exceed $5\ 10^{-4}$. It is noted that the extreme load cases do not need to be considered explicitly in relation to life extension unless there are changes in the environmental conditions compared to the design assumptions, or new information about the materials / resistances are obtained.

As described in previous chapters life extension has been considered and applied in other industries; Here especially offshore structures for oil & gas production is to be mentioned, since reliability-based procedures have been developed for planning of inspections for fatigue critical details. These procedures can be further developed as described below and applied also for fatigue critical details in wind turbines.

The basis for application of a probabilistic / reliability-based methodology for lifetime extension is a probabilistic model for fatigue failure. For welded steel details in wind turbine structures such a probabilistic model can be found in the background document (Sørensen & Toft, 2014) for IEC61400-1 (2019). This probabilistic model is basically linked to the application of SN-curves and Miners rule for verification of fatigue using partial safety factors.

In IEC61400-1 (2019) the partial safety factors for design with respect to fatigue of welded steel details are a material partial safety factor γ_m = 1.25 and a load partial safety factor γ_f as a function on the coefficient of variation of the fatigue load, COV_{load}, see Table 7-1. COV_{load} is obtained from $COV_{load} = \sqrt{COV_{wind}^2 + COV_{SCF}^2}$ where COV_{Wind} (see Table 7-2) is related to the uncertainty of assessment of the fatigue wind load and COV_{SCF} (see Table 7-3) is related to the uncertainty in obtaining the fatigue stress concentration factors, see (Sørensen & Toft, 2014).

Table 7-1: Partial safety factor γ_f for fatigue load (Sørensen & Toft, 2014) for IEC61400-1 (2019).

Coefficient of variation, COV_{load}	0-5 %	5-10 %	10-15 %	15-20 %	20-25 %	25-30 %
γ_f	0,85	0,90	0,95	1,00	1,10	1,20

Table 7-2: COV_{Wind} related to the uncertainty of assessment of the fatigue wind load (Sørensen & Toft, 2014)

COV_{Wind}	Uncertainty is assessment of fatigue wind load
0.10-0.15	More than 2 years of climatic data, corrected with MCP techniques. Wind measurements above and below wind turbine hub height. Flat terrain with low roughness
0.15-0.20	Minimum 1 year of climatic data. Wind measurements at hub height and below. Non-complex site with medium roughness.
0.20-0.25	Less than 1 year of data, not corrected with MCP techniques Wind measurements below hub height. Complex terrain.

Table 7-3: COV_{SCF} related to the uncertainty of assessment of the fatigue wind load (Sørensen & Toft, 2014)

COV_{SCF}	Fatigue critical detail
0.00	Statically determinate systems with simple fatigue critical details (e.g. girth welds) where FEM analyses are performed
0.05	Statically determinate systems with complex fatigue critical details (e.g. multi-planar joints) where FEM analyses are performed
0.10	Statically in-determinate systems with complex fatigue critical details (e.g. doubler plates) where FEM analyses are performed
0.15	2 dimensional tubular joints using SCF parametric equations
0.20	Tubular joints in structures where tubular stiffness is modeled by Local Joint Flexibility (LJF) models and SCF parametric equations are used

The following general procedure can be used for assessment of lifetime extension from year T_L to year T_L^U, see also (Sørensen J. , 2019)

- Update the long-term fatigue load model (Markov matrix) based on measurements (if available)
- Calculate the annual reliability (index) as function of time using the SN-approach using

    - Markov matrix to represent the long-term distribution of stress ranges
    - Stochastic model for fatigue strength for SN-approach, fatigue load and model uncertainties, see (Sørensen & Toft, 2014)

- Calibrate a (1- or) 2-dimensional Fracture Mechanics model to give the same annual reliability (index) as function of time using
    - Same fatigue load as for the reliability assessment using the SN-approach
    - Stochastic model for fracture mechanics model, see (Sørensen & Toft, 2014).

- Consider if a reduced reliability level can be accepted during the lifetime extension following section 7.1. Generally, a reduced reliability level can be argued in higher cost of safety measure for an existing wind turbines compared to a new wind turbine

- Assume that inspections have been performed or are planned with the result that no cracks are detected. If cracks are detected they are assumed to be repaired by grinding (small cracks), welding (medium cracks) or replacement (very large cracks)
- The reliability of inspections are modelled by POD (Probability Of Detection) curves, e.g. the POD-curves for Visual, MPI, EC, … inspections in (DNVGL-RP-C210, 2015).

- Choose / optimize an inspection and repair strategy, i.e. selection of inspection times, inspection methods and repair strategy such that the annual probability of failure does not exceed 5 10^{-4} during the extended lifetime [0, T_L^U]. No-find of cracks are assumed. If cracks are detected and repaired (by grinding, welding or replacement), then a new reliability assessment is necessary

Figure 7-4: Annual reliability index as a function of time (in years) without and with inspections at year 10 and year 20.Figure 7-4 shows an example of a reliability-based planning of required inspections where the original design lifetime was 20 years (designed to an annual reliability index at year 20 equal to 3.3). A decision on lifetime extension until year 25 is made at year 10. Figure 7-4 shows the ‘original’ annual reliability index as a function of time, which is equal to 3.3 at year 20 and decrease to a lower reliability level after year 20. It is seen that if inspections are performed with visual inspection at year 10 and year 20 with ‘no-find’ of cracks, then the lifetime can be extended to year 25 (the read lines show the updated annual reliability index after the inspections).

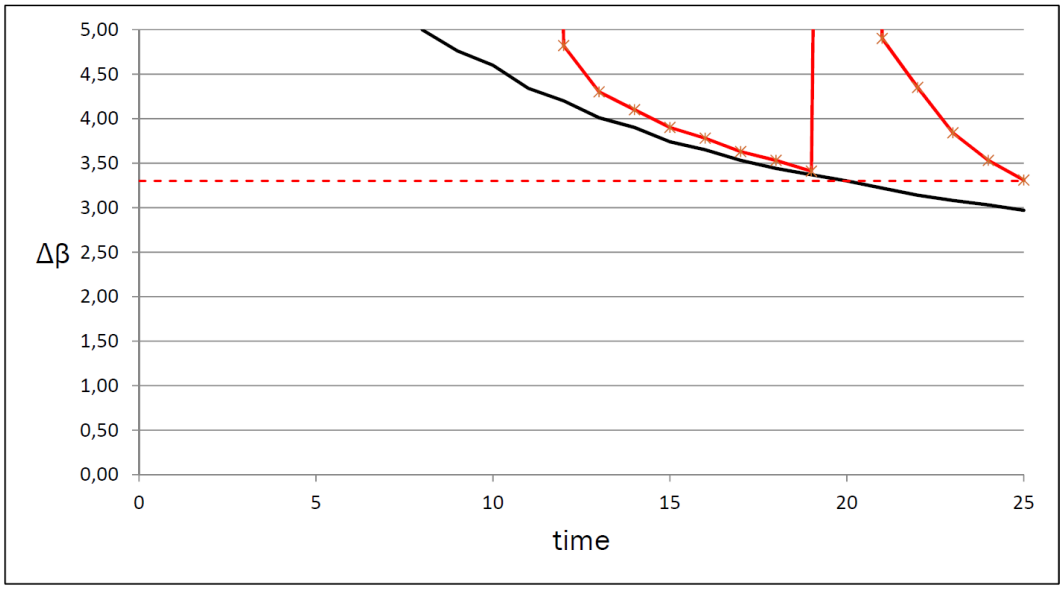


Figure 7-4: Annual reliability index as a function of time (in years) without and with inspections at year 10 and year 20.

In cases where the assumptions made at the design stage are changed, this can be accounted for in assessment of a life extension. One example is that the mean fatigue load is changed due to change in the long-term modelling of the mean wind speed and/or the turbulence. This can easily be accounted for when estimating the fatigue life both sing a deterministic (use of partial safety factors) and a probabilistic approach.

Another example is that the level of uncertainty is different from the design assumption. This could be that data from site assessment shows that COV_{load} is larger than the assumption made when selecting the partial safety factor for design. Table 7-4 shows examples of required inspections considering life extension from 20 to 25 years where the original design was made assuming COV_{load} =15-20% and a load partial safety factor γ_f = 1.0. ΔT_I is the inspection time interval. Three different inspection techniques are considered. The decision is assumed to be made in year 15 and three different levels of updated knowledge on the fatigue load uncertainty COV_{load} are considered. The POD curve for Eddy current follows (DNVGL-RP-C210, 2015), and for close / normal visual inspection it is assumed an exponential POD-curve with mean detectable cracks widths equal to 5mm and 10mm. Figure 7-5 shows an example of updated annual reliability index given an updated COV_{load} = 20-25%, use of close visual inspection and thus required inspections at years 18, 21 and 24.

Table 7-4: Required inspection time intervals for life extension (in years) (Sørensen J. , 2019).

COV_{load}	Eddy current	Close visual	Normal Visual
10-15%	no	no	No
15-20%	20	20 + ΔT_I = 4	20 + ΔT_I = 3
20-25%	18 + ΔT_I =5	18 + ΔT_I = 3	18 + ΔT_I = 2

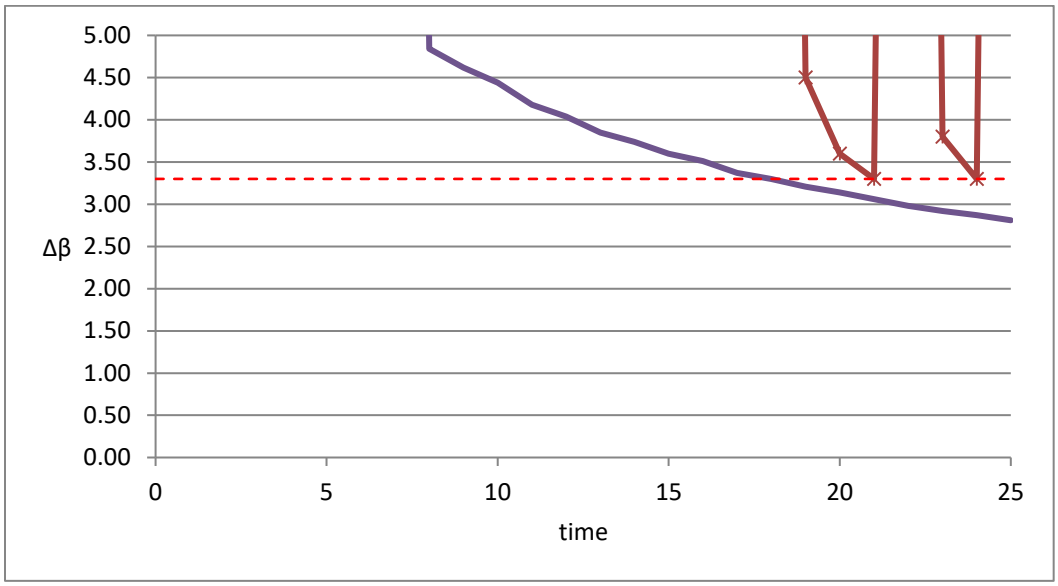


Figure 7-5: Annual reliability index as a function of time (in years) given inspections with updated COV_{load}=20-25%. Inspections are performed at years 18, 21 and 24 (Sørensen J. , 2019).

The probabilistic approach described and illustrated above for planning of inspections, are closely linked to the basis for design for fatigue according to IEC61400-1 (2019), see (Sørensen & Toft, 2014), and can be extended to other fatigue critical details where a minimum reliability level is required.

In cases where no minimum reliability level is required inspections and maintenance / repairs can be planning by use of a risk-based approach where the total expected costs in the remaining lifetime due to inspections, maintenance/repair and potential failure, are minimized. This approach is being used in the EUDP project CORTIR for application on wind turbine blades and requires the same probabilistic modelling as described above, and typically a probabilistic fracture mechanics model calibrated to a SN-curve approach.

8. Summary Recommendation to IEC Standards for Assessment of Lifetime Extension

Based on the multiple project results and findings, a recommended text for the IEC 61400-28 standards is formulated to be concise as follows:

- A plan for inspections should be made for the period of lifetime extension, which includes relevant structural elements. The turbine service plans shall be extended to include the number of years of life extension with relevant updates to the inspection plan. Special focus should be made to:
  - Leading edge erosion of blades.
  - Sufficient tension of bolts at major component interfaces in the primary load path.

- The integrity of the major structures/components in the primary load path upon life extension must be ensured by a combination of loads prediction and inspections.

- For components where a reliability requirement is specified in IEC 61400-1, an assessment of the fatigue life should be made. Various options exist for this:
  - Acceptance of a lower reliability level (annual probability of failure of 0.001) can give additional years based on economic considerations.
  - Load prediction using SCADA data (and other measurements if available).
  - A probabilistic SN approach can be applied to reduce uncertainties on loads.
  - A probabilistic FM approach can be applied to update the reliability using inspections, and a reliability-based inspection plan can be made if needed.

- The turbine structure upon end-of-life should still be safe for operators during de-commissioning.

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