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The Effect of Upscaling and Performance Degradation on Onshore Wind Turbine Lifetime Extension Decision Making

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Abstract. Ever greater rated wind turbine generators (WTGs) are reaching their end of design life in the near future. In addition, first research approaches quantified the impact of long-term performance degradation of WTGs. As a consequence, this work is aimed at discussing and analysing the impact of upscaling and performance degradation on the economics of wind turbine lifetime extension. Findings reveal that the lifetime extension levelised cost of energy ($LCOE_2$) of an 18 MW wind farm comprising of 0.5 MW rated WTGs are within the order of £23.52 per MWh. Alternatively, if the same wind farm consists of fewer 2 or 3 MW WTGs, the $LCOE_2$ reduces to £16.56 or £15.49 per MWh, respectively. Further, findings reveal that an annual performance degradation of 1.6% (0.2%) increases $LCOE_2$ by 34-41% (3.6-4.3%).

1 Introduction

Lifetime extension (LTE) is financially attractive in comparison to new investment and repowering due to the following identified root causes: the ageing of the current European wind fleet as illustrated in Figure 1; the more competitive allocation of onshore subsidies for new investments [1]; the trend of terminating repowering subsidies as observed in Germany, Spain, Denmark, and the UK [2]; the demonstration of competitive lifetime extension levelised cost of energy ($LCOE_2$) [3]; and finally the comparatively little due diligence for the lifetime extension analysis (LTEA) as well as the hard-won, long-term stakeholder relationships with local communities. As a consequence, LTE of wind turbine generators (WTGs) has become a widespread objective within todays' onshore wind energy industry.

As greater rated turbines have been commercially developed and installed in the past, there is an observable trend of greater WTG classes reaching their end of design lifetime as illustrated in Figure 2, depicting the current and future distribution of turbine classes reaching their 20th year of operation. In 2016, the distribution is predominantly composed of WTG below 0.5 MW and to a lesser impact of WTG in between 0.5 and 1 MW; however, this distribution is changing significantly over the next decade with the pre-dominant WTG class shifting towards installations in between 0.5 and 1 MW. Given this observable trend of greater scale turbines reaching their end of design lifetime, this paper is aimed at analysing the development of lifetime extension LCOE with varying turbine classes.

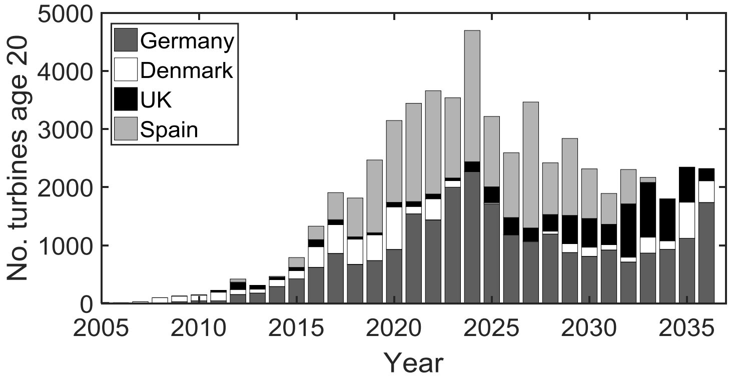

Figure 1: Number of WTGs reaching their 20th year of operation [2].

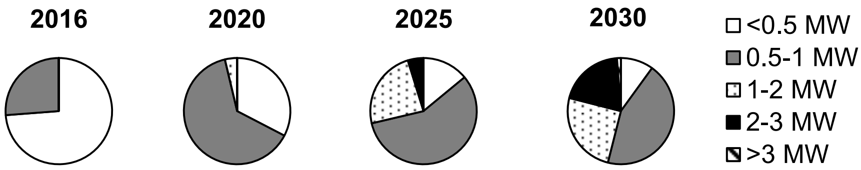

Figure 2: Distribution of WTGs reaching their end of design lifetime (20 years) [2].

Furthermore, performance degradation (PD) can be observed in all different types of machinery, with its effect mostly attributed to wear and tear of components. In 2014, Staffell and Green [4] as well as Wilkinson [5] focused on the long-term impact of PD on WTGs, with initial attempts to quantify its impact on the annual energy production (AEP) over an asset's lifetime. Given this recently published performance degradation, current LCOE models appear to omit this reduction in AEP when estimating project costs [6–9]. Consequently, the origin and effect of PD on LCOE for an asset's design life as well as for the life extended period is placed under scrutiny.

To assess the impact of upscaling and PD on lifetime extension economics, this paper's research methodology is presented in Section 2, followed by the derived model's results in Section 3. Eventually, findings are critically discussed in Section 4 before an overall conclusion is drawn in Section 5.

2 Methodology

Provided an asset has sufficient structural reserves left at the end of design life, economic LTE profitability is not guaranteed and requires thorough analysis. Therefore, based on the technical remaining useful lifetime (RUL) the aimed extension period necessitates a commercial LTEA. While Ziegler et al. [10] analysed the optimal time to switch from lifetime extension to repowering, Rubert et al. [3] developed an economic support tool to assist lifetime extension decision making. The latter is based on a two-pronged approach comprising of i) an LCOE-based decision making methodology at the end of design lifetime in conjunction with ii) a contingency-based methodology for the life-extended period (5-15 years). Based on this proposed methodology, the impact of upscaling and PD is analysed. The applied model is schematically illustrated in Figure 3, in which the authors propose to treat the lifetime extension period as a separate investment by considering the LTE expenditure as an overnight cost consisting of visual inspection, operational and loads analysis, as well as administration. Operational expenditure

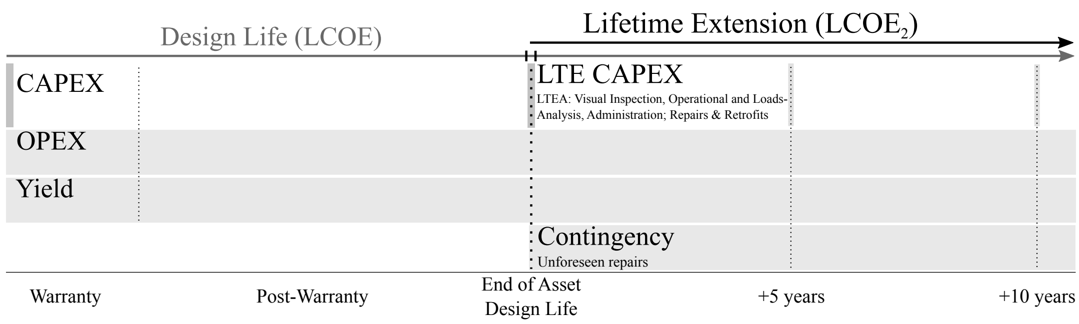

Figure 3: Economic lifetime extension model [3].

(OPEX) is modelled as a fixed annual cost, while inter-annual variability of the wind resource is not modelled. Based on the achievable cost per MWh for a given scenario ($LCOE_2$), an informed decision can be made on extending the life of an asset. Once a decision has been made to extend the lifetime, a contingency framework enables to keep a project within set economic boundaries if unforeseen repairs, retrofits or the installation of condition monitoring systems are necessary. Eventually, at the end of the life extended period; i.e., when the turbine is decommissioned, the remaining contingency fund is converted into a profit.
The model's input data is taken from central assumptions published by Rubert et al. [3]. Although, where necessary input parameters are adjusted to facilitate upscaling and PD scenarios. To allow replication of findings, adjustments to input parameters are discussed in Section 2.1 for upscaling and in Section 2.2 for PD respectively.

2.1 Upscaling

Naturally, as increasingly greater rated turbines have been commercially developed and installed, there is an inevitable fact of greater rated turbine classes reaching their end of design lifetime as illustrated in Figure 2. In order to compare the impact of upscaling of turbines on LTE economics, an 18 MW rated wind farm consisting of different generic turbine classes is modelled. The corresponding blade radii and hub heights are taken from commercially available turbines. If a significant variance in rotor size and hub height was observed at an equal rated power, the mean encountered turbine is modelled, indicated by an [M] besides individual upscaled and downscaled models, indicated by an [S]. Adjusted parameters for some turbine models are summarised in Table 1.

Table 1: Upscaling input parameters of selected 18 MW wind farm configurations. Cost estimates origin from literature [3].

Parameter	500 kW [S]	900 kW [M]	2 MW [M]	3 MW [M]
Turbines	36	20	9	6
Hub Height [m]	46.5	61.5	95.5	121.7
Blade Radius [m]	19.5	25.25	44.6	54.32
$C_{p,max}$	0.44	0.44	0.44	0.48
Wake Losses [%]	10	5.55	2.5	1.66
Wind Speed at Hub Height [m/s]	6.6	6.85	7.25	7.45
Turbulence Intensity	0.1	0.1	0.1	0.1
Weibull Shape Factor	2	2	2	2
Weibull Scale Factor [m/s]	7.44	7.73	8.18	8.41
Resulting Capacity Factor	0.25	0.27	0.37	0.39
Visual Inspection [£/Turbine]	2,150	2,150	2,688	2,688
Loads Analysis [£/Turbine]	3,500	3,500	3,500	3,500
Operational Analysis [£/Wind Farm]	59,400	33,000	15,000	10,000

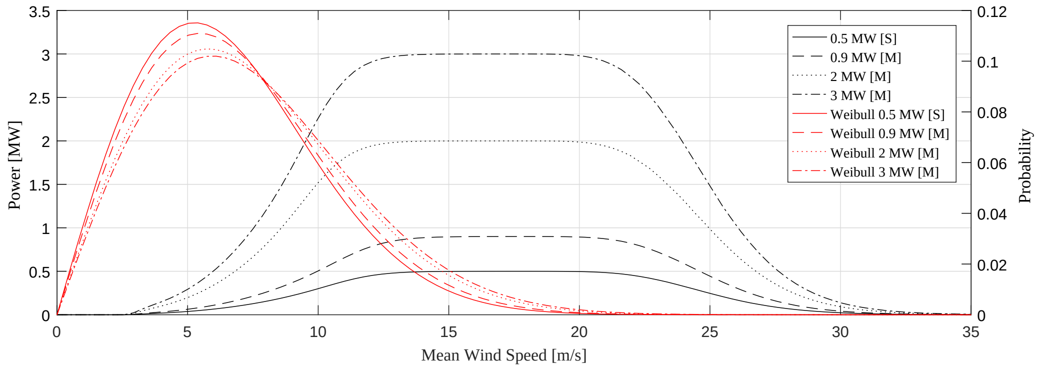

Figure 4: Simulated power curve with respect to the 10-minute mean wind speed, $P_{Sim}(v_a)$ on the left axis and wind speed probability distribution, $P_w(v_a)$ on the right axis.

2.1.1 Yield Modelling

Based on findings from [3], the site's mean wind speed is characterised by 6.85 m/s at a reference hub height of 82.5 m. Due to the natural shear profile of the wind inflow [11], each modelled turbine's mean wind speed at hub height, $U(z)$ varies. Therefore, $U(z)$ is extracted through the wind shear log-law:

$$U(z) = U(z_r)\frac{ln\frac{z}{z_0}}{ln\frac{z_r}{z_0}} \tag{1}$$

where z_r is the reference hub height, $U(z_r)$ the average wind speed at reference hub height, z the modelled turbine hub height (Table 1 and Figure 5a), and z_0 the surface roughness length (assumed as 0.03 m for open farmland, few trees and buildings) [12]. The application of the wind shear log-law assumes neutral atmospheric stability and is designed up to heights of 100 m, with evidence of inaccuracies above [13] and proposed methods to overcome this limitation [14]. The latter method requires empirical knowledge of a site, presenting challenges to adequately address in this paper, thus for simplicity the shear log-law is applied above 100 m. The annual energy production, AEP, of a wind farm is estimated by:

$$AEP = Z(1-\eta_W)h\eta_A\int_0^\infty P_W(v_a)P_{Sim}(v_a)dv_a \tag{2}$$

where Z is the number of turbines, η_W the factor for wake induced losses, h the number of hours in a year (8760), η_A the machine availability (95% in agreement with [15]), $P_w(v_a)$ the Weibull distribution as a function of the 10-minute mean wind speed, v_a, and $P_{Sim}(v_a)$ the simulated power curve as a function of v_a [3]. The detailed yield modelling methodology of $P_{Sim}(v_a)$ can be accessed in the literature [3].

Wake losses depend on multiple factors, such as terrain topology, wind distribution, atmospheric stability, turbine thrust coefficient, C_t, spacing and the array layout [11, 13, 16–18]; however, in this paper the wind farm with the most turbines (36 x 500 kW) is assumed to experience a medium wake loss of 10%. Each of the modelled wind farm wake losses are scaled linearly with the number of turbines deployed in the respective wind farm.

Further, all modelled turbine topologies have the same cut-in/out wind speed while the drive train and rotor efficiency is modelled depending on the encountered efficiencies of turbines deployed in between 1997 and 2000. Figure 4 illustrates the simulated power curve with respect to the 10-minute mean wind speed (underlying standard distribution) as well as the wind speed probability distribution on the right y-axis for the selected turbine generator classes presented in Table 1.

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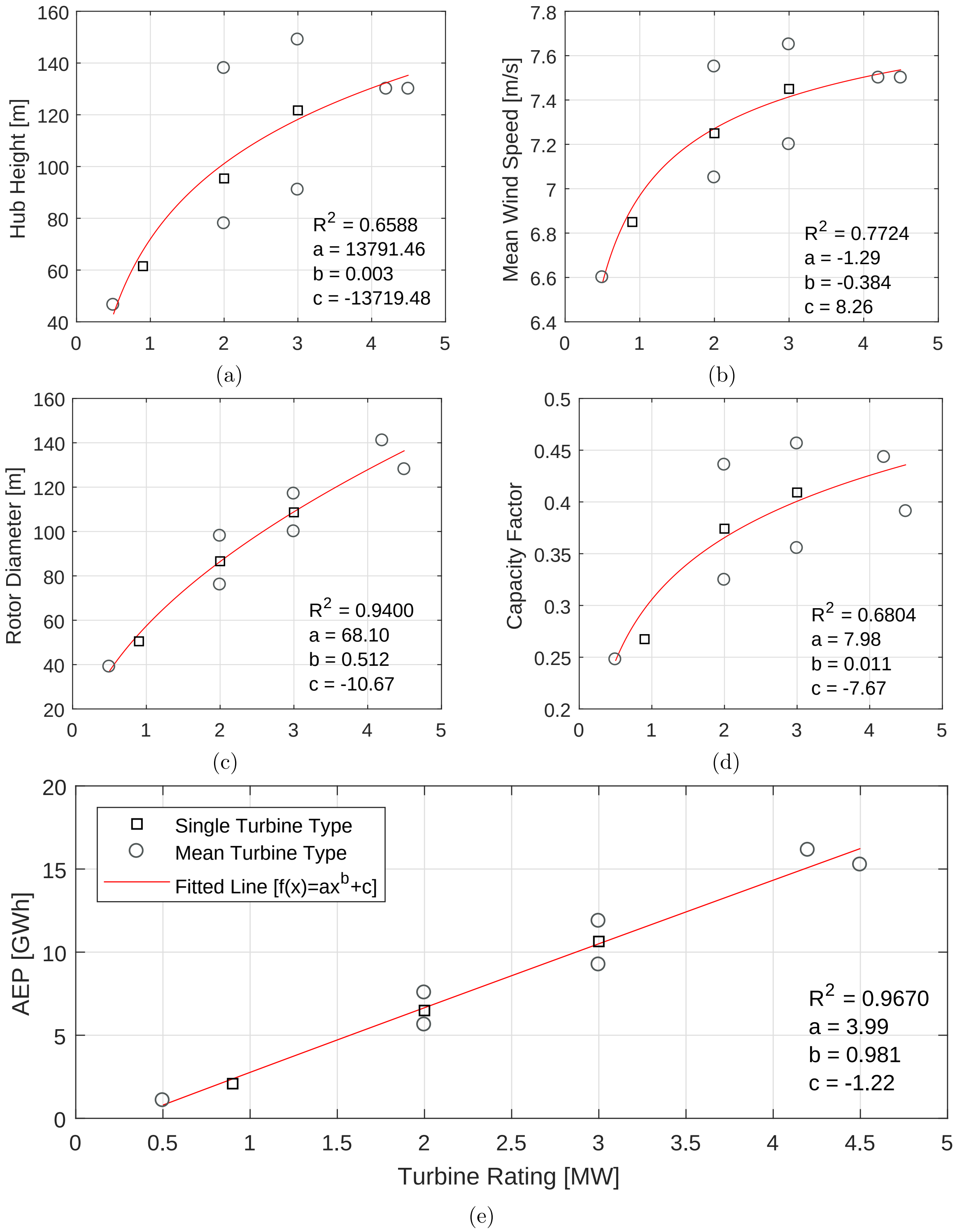

Figure 5: Modelled turbine parameters and their compound effect on capacity factor and AEP. The mean wind speed (b) is derived from the wind shear power law based on the modelled hub height (a), while the annual energy production (e) and hence capacity factor (d) is the result of the mean wind speed (b), rotor diameter (c) as well as the Weibull distribution and modelled power curve (Figure 4). A square displays an average turbine parameter, whereas a dot indicates encountered min/max parameters.

Under the presented modelling parameters, the 0.5 [S], 0.9 [M], 2 [M], and 3 MW [M] turbines achieve a capacity factor of 0.25, 0.27, 0.37, and 0.39 respectively. In addition, Figure 5 illustrates the modelled input parameters of all considered turbine types; i.e., hub height (a), mean wind speed (b), and rotor diameter (c) as well as output parameters, i.e., capacity factor (d) and AEP (e) respectively. The turbine model's annual energy production (AEP) was further compared to [19], giving confidence in the model.

2.1.2 Expenditure Modelling

It is important to highlight that for the life extended period's $\mathrm{LCOE_2}$ estimate, the cost per MWh is dependent on the AEP, OPEX, and lastly by the LTEA's captial expenditure ($\mathrm{CAPEX_{LTE}}$) [3]. Since the initial CAPEX is not considered in the published lifetime extension $\mathrm{LCOE_2}$ framework as illustrated in Figure 3, the derived generation cost is thus independent of an asset's initial investment cost.

With respect to the $\mathrm{CAPEX_{LTE}}$, the cost for visual inspection for a multi-MW turbine is assumed 25% more expensive, since the total inspection area is larger. The expenditure for the loads and operational analysis is assumed to scale linearly with the number of turbines; however, economies of scale and clustering individual turbines into cells certainly reduce costs. Since available cost figures of clustering activities are not available and highly site dependent, for ease of analysis, linearity is assumed. The cost for administration of consultants is included in the other LTEA's budgets, while the owner's administration expenditure is not included in the analysis. $\mathrm{CAPEX_{LTE}}$ is thus modelled as:

$$CAPEX_{LTE} = Z(c_v + c_l) + c_o + c_a + c_{r,r} \tag{3}$$

where c_v is the visual inspection cost per WTG, c_l the loads analysis expenditure per WTG, c_o the operational analysis expenditure, c_a the administration expenditure, and $c_{r,r}$ the cost for necessary repairs and retrofits.

The annual OPEX, $OPEX_n$ is modelled as:

$$OPEX_n = R(C_F + C_I + C_U) + AEP_n\, C_V \tag{4}$$

where R is the asset's rated power, C_F is the fixed operations and maintenance (O&M) expenditure, C_I the insurance cost, C_U the connection and use of system charges, and C_V the variable O&M expenditure. Cost parameters are illustrated in Table 2 that are based on a deployment within the UK [3].

Table 2: Lifetime extension tool parameters [3]. Optimistic and pessimistic parameters are further presented for the supplement database [20].

Parameter	Central	Range	Unit
CAPEX			
Pre-development	100	30-240	£/kW
Construction costs	1,500	1,100-1,800	£/kW
O&M			
Fixed	30,192	22,644-37,740	£/MW/y
Variable	5.1	3.83-6.38	£/MWh
Insurance	2,226	1,669-2,782	£/MW/y
Connection/system charges	3,810	2,857-4,762	£/MW/y
Other parameters			
Discount rate	10	7.5-12.5	%
$\mathbf{CAPEX_{LTE}}$			
Visual inspection	Table 1	±25%	£/WTG
Loads analysis	3,500	2,625-4,375	£/WTG
Operations analysis	Table 1	±25%	£/Wind Farm

2.1.3 Other Assumptions
In this work inflation in labour expenditure is not considered, whereas decommissioning costs are assumed to be equalised to the turbine's scrap value. The discount rate is selected at 10%.

2.2 Performance Degradation
"Ageing is a fact of life. Its effects are inevitable for all kinds of machinery, reducing the efficiency, output and availability of steam and gas turbines, solar PV modules, batteries and automobiles alike" [4]. Essentially, if ageing effects are observable on a wind turbine, its effects will naturally impact the overall efficiency, thus reducing the AEP and capacity factor while increasing LCOE as published in the literature [1].

In fact, wind turbine performance degradation has different distinct origins when the actual long-term wind resource is not considered or alternatively normalised for. On the one hand, there is wear and tear as well as operational errors (e.g. pitch and yaw misalignment) where the degradation process is characterised by a low rate of change. On the other hand, there is turbine downtime and hence reduced availability caused by broken parts characterised by a high rate of change (failure/sensor activation). The former can have numerous triggers such as leading edge erosion (LEE), fouling, or deformations reducing aerodynamic efficiency [21, 22], reduced system performance in components along the drive train (low and high speed shaft, gearbox, generator due to inadequate lubrification, bearing failures, or gear teeth detachment), power electronics [23] and auxiliary system [24].

When dealing with wind turbine performance degradation, there is no defined standard, i.e. what sources of PD are included and what are excluded from consideration. As mentioned previously, studies have aimed to quantify long-term performance degradation with different methodologies such as based on the UK's renewables obligation certificates (ROC) register [4] or a supervisory control and data acquisition (SCADA) system respectively [5]. Naturally, both approaches have advantages and disadvantages while considering a different combination of PD sources in the analysis, as contrasted in Table 3.

Namely, Staffell and Green's method is essentially a holistic method that is more complicated in its execution and is impacted by the potential inclusion of a bias due to increasing curtailed periods. The latter that is expected with an increasing total wind energy penetration within a

Table 3: Comparison of available PD identification approaches

Approach	**Staffell and Green**	**Wilkinson**
Data source	ROC register	SCADA
Data access	Public	Confidential
Data resolution	Monthly	10 minute (1 second)[1]
Methodology	Wind farm simulation of yield output based on NASA data	Remodelling of power curve from operational data
Complexity	High	Low
Analysis type	Holistic	Specific
Embedded PD sources	Wear and tear, operational errors (pitch and yaw misalignment), curtailment, ancillary services[2], downtime (repairs, maintenance, grid faults, etc.)	Wear and tear, operational errors (pitch and yaw misalignment)
Challenges	Correct for curtailment and ancillary services (identify)	Correct for downtime (identify)[1]
Opportunities	Introduce SCADA or Elexon data	Identify impact of curtailment, downtime, and ancillary services

[1] depends on the system and operational SCADA configuration; [2] low impact at present, expected to increase in the future [25]

network or sub-network [26].

Whereas Wilkinson's approach isolates a turbine's wear and tear as well as operational errors; the method neglects to include a turbine's downtime that impacts the long-term performance. For example, if components fail and require lengthy sourcing or the installation is restricted by weather conditions (especially offshore) a turbine will not produce power for a certain period [27] that is not necessarily extractable of SCADA data (depends on the system and operational configuration).

Consequently, it is impossible to prefer one method over the other, hence depending on the aimed application of a PD metric, one has to differentiate what sources of PD to include and which to exclude. For example, in terms of revenue and economic calculations the holistic approach appears more sensible to apply, because in this application the long-term annual yield matters that is dependent on wind farm availability, wear and tear, operational errors (yaw and pitch misalignment), as well as curtailment. Arguably, the latter factor is an operational restriction characterised by a network's local capacity limits with no direct impact on degradation.

Therefore, a sensible modification to the holistic approach would be to isolate and identify the impact of curtailment for a given wind farm or area separately. This is in essence challenging, because ROC data does not contain curtailment information; however, can be overcome if SCADA data is accessible, or alternatively through the purchase of Elexon's metered generation data [28].

Similarly, for Wilkinson's approach a downtime registry would be required to introduce the impact of repairs, maintenance, grid faults etc. Also, the recorded curtailment periods can be translated into an AEP loss over time caused by de-rating. Consequently, for both methodologies access to more detailed operational data can thus aim to identify and categorise the impact of the different identified sources of performance degradation. Knowledge on the isolated impact of different PD sources can thus help users to apply suitable PD metrics depending on the type of analysis.

With regards to available performance degradation metrics, published data varies with a recorded linear annual degradation of 0.2% as published by Wilkinson [5] with a limited dataset of the first 6 operational years while Staffell and Green's UK fleet approach observed a linear annual performance degradation of 1.6%. As highlighted by Rubert et al. [1], LCOE for the design lifetime can thus increase by up to 12.62% based on a simple model, which impact is significant and under such circumstances, essential to take into consideration.

In terms of implementing long-term performance degradation parameters into the presented economic model, two 18 MW wind farms (20 x 0.9 MW and 9 x 2 MW presented in Section 2.1) were subjected to a varying linear, annual PD. The modelled annual energy production, subjected to performance degradation is thus as follows:

$$AEP_{n,\gamma} = AEP(1 - \frac{\gamma}{100})^n \tag{5}$$

where γ is the annual degradation factor [%] ranging from 0-2, and n is the year.

Overall, the aim was to analyse the impact of PD on LCOE and LCOE_2 and further evaluate if results are projectable on upscaled turbines; i.e., if the cost percentage impact of PD is comparable to greater scale WTG. Concerning the latter, as identified by Bolinger and Wiser, CAPEX undergoes cyclical variations [29] and turbines within the region of 1-3 MW have comparatively equal CAPEX/MW variations [30]. Further, sub 1 MW as well as above 3 MW substantial cost differences can be observed, although comparatively little project data was analysed. Since 900 kW is at the top of the sub 1 MW classification it is financially considered as a 1 MW turbine, hence CAPEX expenditure is comparable to a 2 MW turbine allowing a comparison of LCOE.

3 Results

3.1 Upscaling

Figure 6 presents LCOE_2 estimates for an 18 MW wind farm consisting of different turbine size classifications for a 5-year lifetime extension period (no repairs, reconditioning or retrofits required). In addition, data was fitted to an exponential function in the form of $f(x) = ax^b + c$ scoring an R^2 goodness of fit of 0.85 for the cost estimate and roughly 0.69 for the contingency estimate respectively. Both goodness of fit indicators illustrate the great variance within turbine classes (some turbines have comparatively upscaled rotors, presumably for low wind speed regimes), hence the exponential fit and findings require caution in their application.

Findings reveal that cost reductions are most prominent within the sub-2 MW class, with the rate of change (slope of the function) reducing above. In detail, a wind farm consisting of 36 x 0.5 MW rated turbines paired with a lifetime extension strategy of 5 years can achieve LCOE_2 of around £23.69/MWh. The generation cost reduces to £16.59/MWh for a 2 MW

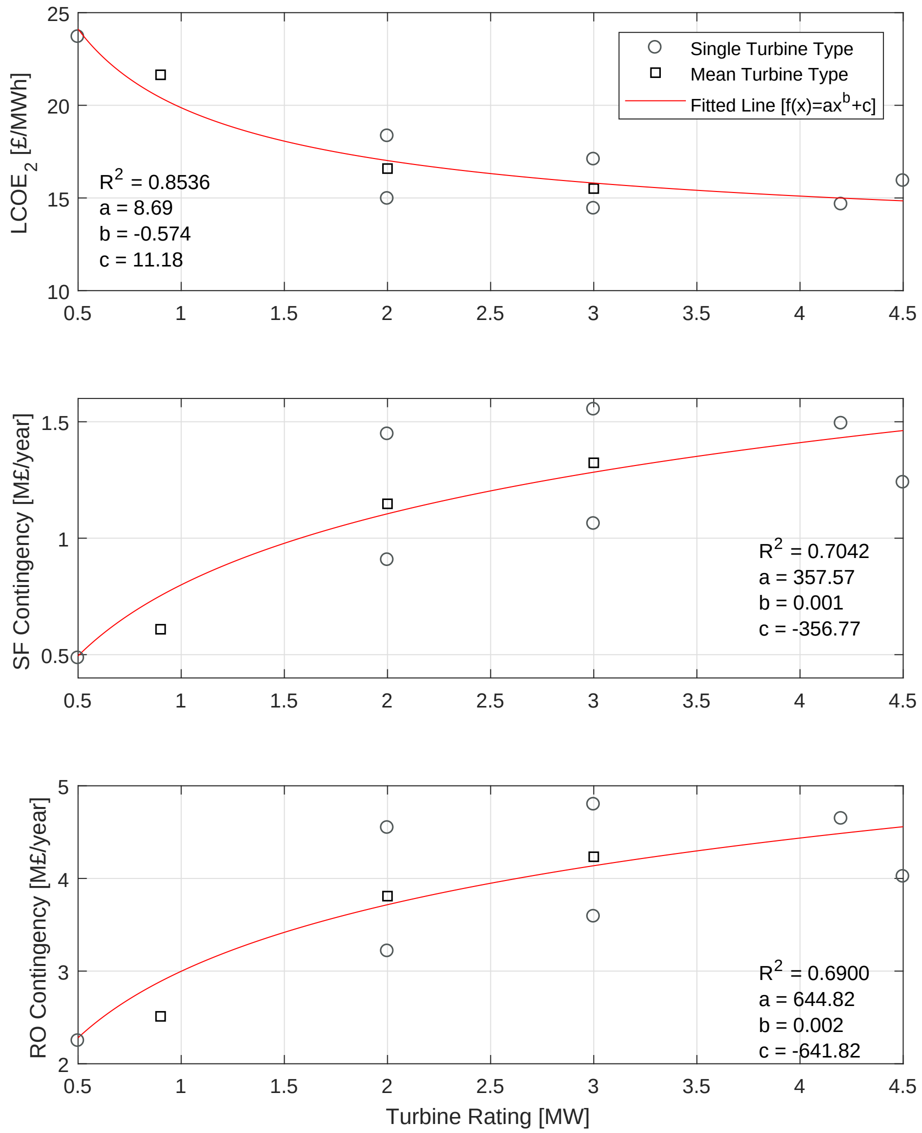

Figure 6: LCOE_2 +5 years upscaling results. This analysis is CAPEX independent. Subsidy-free (SF)/Renewable Obligation (RO).

turbine class, whereas a 3 MW turbine class results in $LCOE_2$ of £15.51/MWh. Within the 4 MW range there are fewer turbines commercially available; however, the Enercon E-141 with a rating of 4.2 MW (a significantly upscaled rotor diameter in this class) scores the lowest price per unit energy; i.e., £14.64/MWh.

The contingency parameter defines the maximum available budget to spend on unexpected repairs and retrofits along the lifetime extension period in order to deliver a specified operating profit [3]. In the applied model this is implemented by a defined maximum cost of energy threshold. The threshold is set in order to achieve a profit of £7.25/MWh∗, thus for the subsidy-free scenario the threshold is set £7.25 below the average day-ahead spot-market electricity price of the past 5 years [31]. For the renewable obligation (RO), the threshold is set £7.25 below the RO revenue stream defined by the 2017-2018 buy-out price and day ahead spot-market electricity price [31, 32]. The applied threshold is therefore £36.24/MWh for the subsidy-free environment and £81.82 for the RO respectively. Equally to the $LCOE_2$ results, the available annual contingency within the RO and subsidy-free framework increases with a significant rate of change below 2 MW, with an observable subsequent slowdown (Figure 6 centre and bottom graph). Besides an increase in contingency, fewer turbines are deployed, resulting in a substantial increase of available contingency per turbine.

3.2 Performance degradation

Figure 7 presents the impact of PD on the economics of lifetime extension for a wind farm consisting of 20 x 0.9 MW WTGs. The figure's x-axis represents an increasing PD corresponding to a percentage drop in AEP with the top graph presenting the impact in percent on the $LCOE_2$

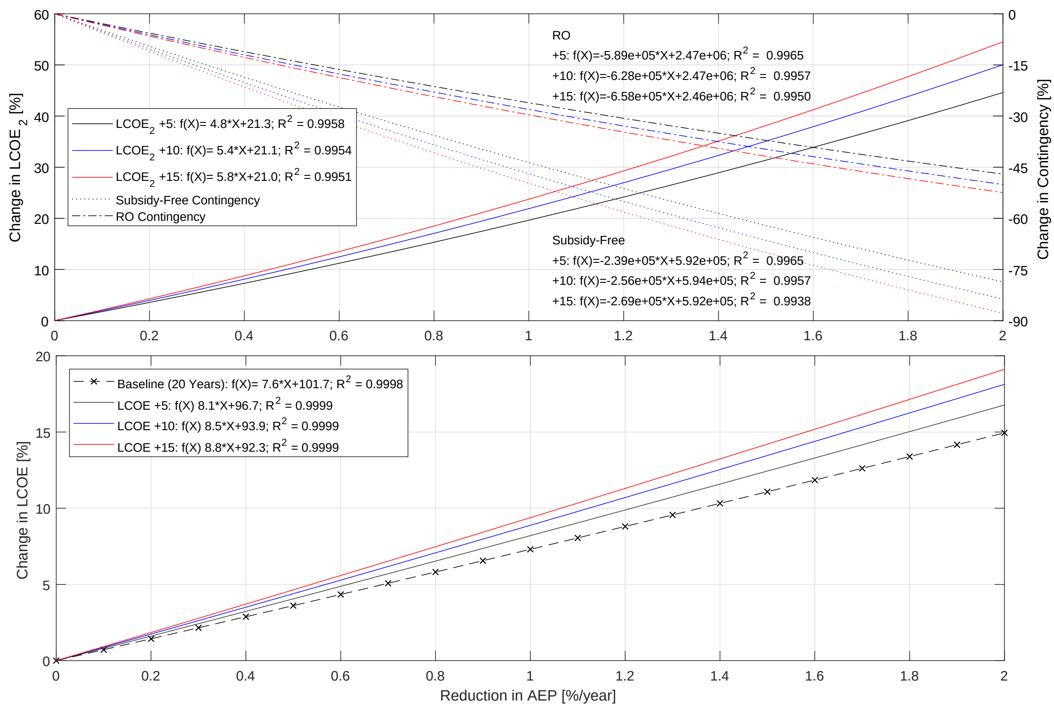

Figure 7: Impact of PD on an 18 MW wind farm consisting of 20 x 900 kW WTGs (LCOE applies CAPEX assumption).

∗This is derived from an assumed ROI of 20% based on a CAPEX of £1.6 million for a 20 year design lifetime, thus a profit of £16,000/MW/Year.

Table 4: Comparison of the impact of PD on LCOE and $LCOE_2$ of a 0.9 MW versus a 2 MW WTG in %.

Turbine Rating [MW]	Annual PD [%]	LCOE Baseline	LCOE +5	LCOE +10	LCOE +15	$LCOE_2$ +5	$LCOE_2$ +10	$LCOE_2$ +15
0.9	0.2	1	2	2	2	4	4	4
2	0.2	1	2	2	2	3	4	4
0.9	1.6	12	13	14	15	34	38	41
2	1.6	12	13	14	15	31	35	38

Table 5: Comparison of the impact of PD on annual contingency of a 0.9 MW versus a 2 MW WTG in %.

Turbine Rating [MW]	Annual PD [%]	SF +5	SF +10	SF +15	RO +5	RO +10	RO +15
0.9	0.2	-10	-10	-11	-6	-6	-7
2	0.2	-7	-8	-8	-5	-6	-6
0.9	1.6	-66	-70	-74	-39	-42	-44
2	1.6	-49	-52	-55	-36	-39	-41

metric on the left y-axis (solid line) for different life extension scenarios. A lifetime extension of 5 years is marked in black, of 10 years in blue, and of 15 years in red. In addition, the top graph presents the impact in percent on the available annual contingency under the RO (dashed line) and subsidy-free environment (dotted line) on the right y-axis. The bottom graph presents the impact of PD on LCOE for the design life of an asset (dashed black line with marker) and design life plus lifetime extension (solid line).

Concerning the latter economic metric, as argued by Rubert et al. [3], the inclusion of design life on a lifetime extension cost metric is advised against (severe discounting, asset is written off, and CAPEX dependency). Nevertheless, for the purpose of integrity results are presented. Overall, findings are further fitted to a linear function to interpolate results.

First of all, based on the applied methodology a reduction in AEP reduces yield and variable OPEX. Therefore, both effects counter-balance each other to a certain degree. However, there is a greater impact on yield, increasing the cost of energy and therefore reducing the annual contingency. Second, the impact of PD on the 20-year design lifetime is in agreement with findings from the simple analysis executed by Rubert et al. [1] with an increase of LCOE of 11.8% (1.4%) if an annual PD of 1.6% (0.2%) is encountered. Third, a comparison of the impact of PD reveals a much greater sensitivity of the $LCOE_2$ methodology (top graph) than the non-advised LCOE approach (bottom graph). In detail, results indicate that an annual PD of 1.6% (0.2%) elevates $LCOE_2$ by 34-41% (3.6-4.3%) contrary to the LCOE metric with an increase of around 13-15% (1.6-1.8%).

With regards to the impact on the available contingency of the aimed lifetime extension period, findings also reveal a significant impact. Overall, an annual PD of 1% reduces the available RO contingency by 28%, whereas in the subsidy-free environment a reduction of 47% is observed.

In addition to Figure 7, Figure 8 of the Appendix presents the impact of PD on an 18 MW wind farm consisting of 9 x 2 MW rated turbines. Findings are further contrasted in terms of the percentage impact on i) cost of energy in Table 4 and ii) contingency in Table 5. Results reveal a comparable impact with regards to LCOE and $LCOE_2$ modelling, whereas minor impact differences are observable for the RO contingency estimates. Substantial differences are observable for the subsidy-free contingency. This is due to the fact that the baseline contingency for the 900 kW turbine is substantially lower than the 2 MW's, relatively to both RO cases.

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4 Discussion and Future Work

This paper's results are aimed at an asset's design life of 20 years, albeit a great share of WTG installations are nowadays designed for 25 or even 30 years of operation [33]. In such instances, upscaling $LCOE_2$ results are still valid since the LTE period is considered as a separate investment case at the end of design lifetime. Further application is however limited as modelling PD, or any conventional LCOE calculation is dependent on the design life, hence the suggested model requires modification. Therefore, LCOE and PD results are only valid for a 20 year design lifetime while $LCOE_2$ estimates are generically applicable.

Overall, the proposed upscaling and PD methodology works well if no component replacement is required. However, in deviating scenarios with component reconditioning or retrofitting, it is challenging to model turbine spare part expenditure (part of the LTEA). This is because an ex works CAPEX distribution as well as CAPEX per installed MW may not develop homogeneously with upscaling (there is evidence that the CAPEX/MW has equal price fluctuations in between 1-3 MW turbines as discussed in Section 2.2). Therefore, due diligence is required in CAPEX modelling. In addition, component replacement installation expenditure requires scrutiny as well, since greater rated cranes are neccessary with substantially higher mobilisation and daily rates. This can be further explored in order to model asset specific requirements. Nevertheless, it is expected that operators and owners will approach LTE from a more strategic point of view (+10-15 years vs. +5 years), especially for greater rated WTGs (2–3 MW) with greater budgets to spend for the LTEA (including component replacements). Given the difficulty in modelling component replacements, the available contingency may be applied to compare the necessary expenditure to the set budget.

Further, modelling PD in combination with component replacement, draws challenges to predict yield improvements (e.g., replacement of eroded blades), besides the ability to identify root causes of performance degradation down to a component level in the first place. To take this further, a turbine drive train has many components, hence sources of PD can vary greatly as highlighted in Section 2.2. Second the impact of PD may or may not be significant nor quantifiable from turbine data (reduction of 0.2% annually [5]); i.e., an annual degradation of less than 1% appears impossible to account to a specific component's output. Nevertheless research activities are executed such as for leading edge erosion by Offshore Renewable Energy Catapult (OREC) whose results suggest that the AEP can be increased by 1.5-2% following a moderate blade erosion repair [34].

With respect to the presented upscaling results, overall the methodology is applied irrespectively of differences in turbine design, hence the power coefficient with respect to the wind speed, $C_p(v)$ might deviate. In addition, a site's environmental conditions can vary significantly impacting the LCOE assessment besides modelling inaccuracies; e.g., due to the application of the log-law above 100 m height. While is it impractical to present the depth of possible modelling combinations, attached to this paper is a database allowing users to identify i) baseline LCOE, ii) baseline + lifetime extension LCOE, as well as iii) the advised $LCOE_2$ estimate for different lifetime extension scenarios (+5-15 years) under varying input parameters. The latter includes to vary i) the turbine rating, ii) the turbine and site parameters (mean wind speed, $C_{p,max}$, turbulence intensity, and Weibull shape factor), and iii) the cost scenario (central, optimistic, and pessimistic – Table 2). The tool is accessible in [20].

The UL 4143 lifetime extension standard "Outline of Investigation for Wind Turbine Generator - Life Time Extension (LTE)" [35, 36] states that individual turbines within a wind farm can be clustered into cells for the LTEA. Naturally, clustering activities decrease the $CAPEX_{LTE}$ of the load and operational analysis as well as administration per turbine. Clustering may or may not be applicable, depending on the site's external and operational conditions, as well as the applied aero elastic simulation model. In addition, the LTEA is dependent on local standards and regulations driving the cost; e.g., in Germany aero-elastic simulations are required whereas in Denmark inpections are sufficient [2]. Therefore, modelled $\mathrm{CAPEX_{LTE}}$ that are presented in Table 1 may deviate significantly and may not be comparable to countries outside the UK. Nevertheless, sensitivities are also modelled and adjustable in the cost scenario tool attached to this paper (Table 2 of the Appendix).

With regards to the lifetime extension period, the set contingency threshold depends on an owner's or operator's operational framework as well as aimed profit margin. Further, the threshold definition is likely dependent on economies of scale; i.e., for greater rated turbines, a lower profit margin per MWh may be acceptable, based on a relatively grater AEP [MWh/MW] (Figure 5e). As a consequence, due diligence is required to evaluate a suitable threshold for a lifetime extended site.

While this paper's model applies an annual linear PD, in reality fluctuations in the rate of change are likely to be observed. Future work, could aim to identify the impact of the different sources of PD over time (Table 3) and model a case study accordingly.

Based on general industrial feedback summarised by Ziegler et al. [2] as well as discussions with operators in the field, we are of the opinion that performance degradation is likely to impact a turbine at a later stage of life than at the beginning (warranty and performance based maintenance contracts are often in place to maintain a specified availability [1]). We further think that an average fleet degradation parameter will be somewhere in between 0.2-1.6 [%/year]. Although, we believe on average, PD lies within the lower band of the given spectrum if the impact of curtailment is identified and compensated for. This is also in agreement with recent findings from Olauson et al. [37], concluding a lifetime energy loss of 6%, which according to this paper's model corresponds to an annual PD of 0.6% over a 20-year design life. Lastly, the degree of performance degradation is highly dependent on an asset's O&M procedures, thus well maintained turbines are likely less impacted by degradation processes.

5 Conclusion

This paper aims to give an overview of the impact of upscaling and PD on the economics of lifetime extension. Results presented are derived from a model with limitations, hence its application requires careful evaluation if actual conditions are comparable to the applied model input. If input data differs significantly, it is possible to replicate the tool and adapt changes according to an asset's unique requirements as this model is limited to central case assumptions. Nevertheless, to overcome this limitation, a tool is provided allowing users to adjust selected input parameters.

In summary, this paper serves as a continuation of an economic lifetime extension decision support tool [3], in order to serve the need to understand the impact of upscaling and PD as well as a combination of both on an asset. Turbine owners and operators can take these findings into consideration when subjecting a wind farm to an economic LTEA, or replicate the tool if input data differs significantly.

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7 Appendix

As a supplement to this paper, a database is published allowing users to adjust any combination of i) the turbine rating, ii) turbine and site parameters (mean wind speed, $C_{p,max}$, turbulence intensity, and Weibull shape factor), and iii) the cost scenario (central, optimistic, and pessimistic) [20].

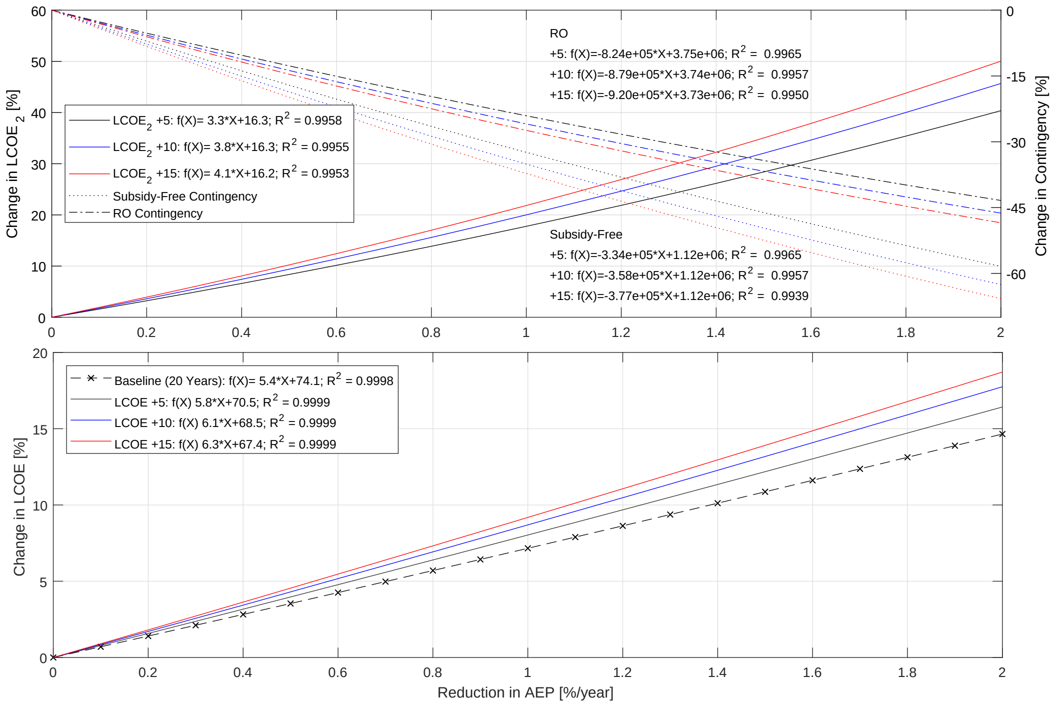

Figure 8: Impact of PD on an 18 MW wind farm consisting of 9 x 2 MW WTGs (LCOE applies CAPEX assumption).

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