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A decision support tool to assist with lifetime extension of wind turbines

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ABSTRACT

This paper is aimed at analysing the levelised cost of energy (LCOE) of onshore wind turbine generators (WTGs) that are in operation beyond their design lifetime. In order to do so, the LCOE approach is introduced and input parameters are discussed for a UK deployment. In addition, a methodology is presented to support economic lifetime extension and investment decision making at the end of an asset's design lifetime. As part of a case study, a wind farm consisting of six 900 kW WTGs is subjected to different combinations of i) lifetime extension (5–15 years), ii) input assumptions (pessimistic, central, optimistic), and iii) reinvestment types (retrofits). Results indicate that in the central lifetime extension scenario, LCOE estimates of 22.40 £/MWh are achievable.

1. Introduction

Lifetime extension of wind turbines is an industry area that is receiving more and more attention as depicted by standards, recommendations, and academic papers [1–10]. This is mainly because the European wind fleet is ageing [11] as exemplified in Fig. 1 for the UK and the more competitive allocation of governmental subsidies as identified by Rubert et al. [7]. In addition, recent results of a global survey on the development of levelised cost of energy (LCOE) with 166 participants reveal that within an optimistic economic scenario an onshore lifetime extension of 25% is expected, based on an average operational lifetime of 20.7 years [12]. Note that for the offshore fleet, these figures are +25% and 20.3 years, respectively. Based on the industrial attention and the overall observable reduction in onshore subsidies for new investments and repowering, lifetime extension is expected to become an essential part of the wind industry in the future. However, lifetime extendibility is dependent on an asset's unique technical and economic circumstances and thus requires due diligence in both areas.

Although, there are already significant numbers of wind turbines reaching their end of lifetime [11,13], at present there are no papers analysing the economics of lifetime extension and decision making at the end of lifetime. Consequently, in this paper we present the economic metric of LCOE and discuss input variables in Section 2 alongside a proposed application methodology to assist economic lifetime extension decision making. This is followed by a lifetime extension case study presented in Section 3 based on a wind farm with a capacity of 5.4 MW, consisting of six 900 kW rated wind turbine generators (WTGs). Section 4 presents the case study's results while in Section 5 this paper's validation is presented. In Section 6 limitations and future work are discussed and finally in Section 7, findings are concluded.

2. Levelised cost of energy

Levelised cost of energy is an economic metric that enables to compare different competing energy technologies such as gas, coal, nuclear, solar, hydro, and wind. It can also be applied to compare and contrast different investment scenarios. Contrary to other economic metrics such as return of investment (ROI) and internal rate of return (IRR) that take the financial revenue streams into consideration, LCOE determines the cost of energy produced rather than the potential profit of an investment. While there are different and modified LCOE calculation approaches [14–18], this paper's adapted approach is as follows. The net present value (NPV) of lifetime costs accrued of capital and operational expenditure

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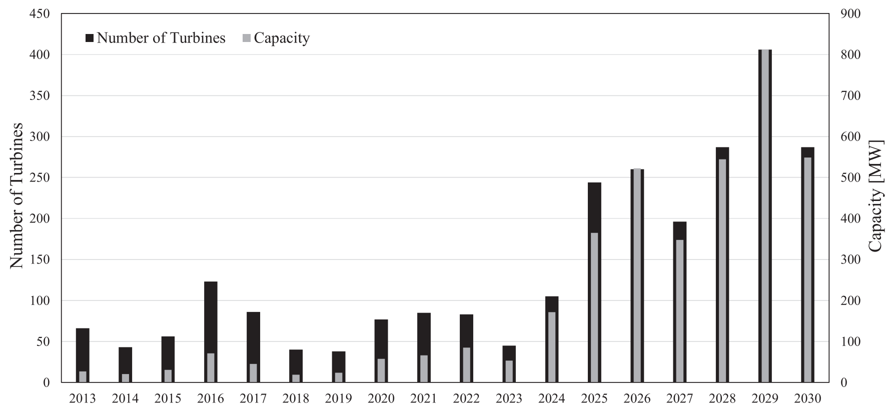

Fig. 1. Onshore capacity reaching end of design lifetime in the UK (20 years) [13].

(CAPEX and OPEX) is estimated for each year, n and summed over the design lifetime as illustrated in Equation (1):

$$NPV_{TotalCost} = \sum_{n=0}^{T} \frac{CAPEX_n + OPEX_n}{(1+i)^n} \tag{1}$$

where T is the design lifetime and i the discount factor. Generated electricity flow is a monetary metric, thus future energy delivery requires discounting as well. This might be counter-intuitive because a specified amount of energy delivered in the future is through discounting worth less quantity at present; however, based on the electricity supply a revenue stream is created and money exchanged. Hence discounting is necessary as illustrated in Equation (2):

$$NPV_{Yield} = \sum_{n=1}^{T} \frac{AEP_n}{(1+i)^n} \tag{2}$$

where AEP_n is the annual energy production of year n.

LCOE is the cost to generate a defined amount of energy; i.e., [£/MWh], hence the NPV of lifetime generation costs defined in Equation (1) is divided by the NPV of the lifetime generated energy defined in Equation (2), thus:

$$LCOE = \frac{NPV_{TotalCost}}{NPV_{Yield}}. \tag{3}$$

Therefore, to determine LCOE for a project, it's lifetime expenditure as well as estimated yield requires evaluation. Within the wind energy industry, different organisations apply different LCOE models; i.e., model varieties originate from different design assumptions such as the CAPEX that can be dealt with as an overnight cost as suggested by the Department of Energy and Climate (DECC) [15], or alternatively as a constant annuity payment as suggested by the National Renewable Energy Laboratory (NREL) [17]. Furthermore, model differences can origin from the discount factor, selection of which requires caution and due diligence. In essence, the discount factor represents a project's risk and thus requires case specific evaluation that is dependent on several factors. For wind energy investments, this includes the investor and investment size, historical data, contracts in place, type of power purchase agreement, the subsidy scheme as well as assumptions in yield estimation and operations and maintenance (O&M) expenditure. Methodologies concerning the applied discount rate may deviate as well; i.e., NREL [17] takes a project's debt-equity ratio and corporate tax rate into consideration by application of the weighted average cost of capital (WACC). On the contrary, less complex models define a hurdle rate aimed at forming a specified project's return as applied by DECC that is set at 10%, although in form of a sensitivity analysis a rate of 7.5% is modelled as well [14,15,19].

Apart from a WTG's input, the output requires analysis as well in order to predict an asset's annual electricity production. If a turbine's physical parameters are known it's energy yield can be estimated by application of a Weibull distribution defined by the shape and scale factor as well as the mean recorded wind speed [20]. The Weibull distribution can thus be modified according to locally recorded environmental conditions. Once the yield for a given period is estimated or known based on a turbine's output, the capacity factor can be calculated. The latter that is defined as the ratio of the actual output of a turbine for a given period and the theoretical output at full capacity.

2.1. Model input parameters

In this Section the detailed LCOE methodology is presented, highlighting how parameters are obtained in order to allow reproduction of the findings presented in Section 4. As illustrated in Equation (3), a LCOE estimation requires two sets of input, a turbine's expected yield and the estimated expenditure over the asset's design lifetime. Within the wind energy sector, LCOE cost parameters are accessible from several sources such as DECC [15,19,21,22], WindEurope [23], Milborrow [24,25], NREL [17], and the International Renewable Energy Agency (IEA) [26], while Miller et al. [27] present a comparison for the US market; however, in agreement with the latter, input parameters deviate significantly (a comparison of OPEX is illustrated in Table 1). This presents challenges to select appropriate model parameters.

Further complexity arises from the time domain, as a wind farm that reaches its end of design life at present experiences current OPEX, while the asset's initial CAPEX was paid for in the past. This modelling challenge is addressed in the proposed lifetime extension methodology in Section 2.2.

2.1.1. Operational expenditure

Operational expenditure covers all occurring activities that are necessary to ensure a safe, reliable, and continuous operation. Costs include administration, land lease, insurance, service and spare parts, power from the grid, as well as miscellaneous items that can vary significantly with an example cost breakdown structure illustrated in Fig. 4 of the Appendix. To allow an impression on the variance in cost estimations, Table 1 presents the cumulated fixed and variable O&M expenditure of different published estimates for a 900 kW wind turbine over 20 years. Overall, a substantial expenditure range is observable which reveals the degree of uncertainty within LCOE calculations. In addition, in Germany there is

Table 1
Comparison of fixed and variable O&M expenditure for a 900 kW wind turbine over 20 years. The turbine is the modelled type of the case study presented in Section 3.

Source	Year	Type	Expenditure
DECC (2017) [19]	2013		
		Fixed	£802,980
		Variable	£198,200
		Total	£1,001,180
ARUP (2015) [28]	2016		
		Fixed	£501,012
		Variable	£206,128
		Total	£707,140
NREL [29]	2015		
		Fixed	$570,960
		Variable	$303,642
		Total	$874,602
Blanco [23]	2009		
		Total	€475,680
IEA [30]	2013		
		Variable	€311,616
Milborrow			
UK [25]	2009	Total	€713,520
[24]	2012	Total	$828,000

evidence that the O&M costs are 10% higher in year 11–20 in comparison to year 1–10 [31]. For a UK deployment, the two most recent LCOE cost parameters are published by DECC in 2013 with a 2017 estimate [19] as well as ARUP in 2016 with a 2015 estimate [28]. As contrasted in Table 2, significant differences are observable.

Both institutions are respected in the field and used for governmental estimations; however, taking the global OPEX expenditure comparison into consideration (Table 1), DECC's fixed cost assumptions appear much higher in comparison. In this paper, 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 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.

2.1.2. Capital expenditure

Wind turbine investment cost can vary substantially, based on the turbine type, size of contract, location, region, commodity prices, demand and supply, as well as the level of subsidies as discussed by Blanco [23]. Furthermore, Wiser and Bolinger [32] identified investments with a greater project size than 5 MW experience a significant reduction in CAPEX. This agrees with DECC's cost assumption threshold. In the central 2017 scenario, DECC's CAPEX is assumed at £1,500,000 per installed MW, including turbine ex. works, civil works, and grid connection. Also, DECC's pre-development costs are taken into account at £100,000 per installed MW. CAPEX and development costs are in agreement with ARUP's 2015 estimate [28]. At present, an onshore WTG's construction is thus likely to cost £1,600,000 per installed MW, resulting in the following CAPEX cost distribution: turbine ex. works £1,136,000, civil works £144,000, grid connection £192,000, and other capital costs £128,000 (site monitoring, permissions, planning costs, transportation, etc.) based on the cost breakdown

Table 2
Difference in UK OPEX assumptions [19,28].

Cost Item	DECC 2017	ARUP 2015
Fixed O&M [£/MW/y]	37,100.00	23,284.00
Variable O&M [£/MWh]	5.00	5.20
Insurance [£/MW/y]	3010.00	1441.00
Connection & system charges [£/MW/y]	4510.00	3109.00

structure published by Blanco [23]. In this paper, the asset's overnight CAPEX is therefore modelled:

$$CAPEX = C_E + C_C + C_G + C_O \tag{5}$$

where C_E is the ex. works expenditure, C_C the civil expenditure, C_G the grid connection expenditure, and C_O other capital costs.

2.1.3. Yield estimation

In order to establish the annual energy production, AEP, of a wind farm, a turbine's power curve requires modelling. As reviewed by Carrillo et al. [33] as well as Lydia et al. [34], there exist different power curve modelling techniques with varying accuracy and complexity. In this paper the static power curve is modelled according to the approximated cubic power curve, $P_S(v)$:

$$P_S(v) = \frac{1}{2}\rho\pi R^2 C_{p,max} v^3 \tag{6}$$

where ρ is the air density ($1.225\ kg/m^3$), R the rotor radius, $C_{p,max}$ the maximum effective power coefficient, and v the instantaneous wind speed. The selected approximation technique offers a reasonable estimate [33] as well as ease of implementation that is suitable for this paper. While a site's inflow conditions are dynamic, the static power curve is further adjusted to account for a 10-min mean wind speed, v_a. As a result, the simulated power curve with respect to mean wind speed, $P_{Sim}(v_a)$ is:

$$P_{Sim}(v_a) = \int_0^\infty P_S(v) P(v, v_a) dv \tag{7}$$

where $P(v, v_a)$ is the mean wind speed probability distribution, assumed as Gaussian in nature, hence characterised by the turbulence intensity parameter, TI and v_a [35].

The annual energy production of a wind farm can therefore be estimated by:

$$AEP = Z(1 - \eta_W) h \eta_A \int_0^\infty P_W(v_a) P_{Sim}(v_a) dv_a \tag{8}$$

where Z is the number of turbines, η_W the factor for wake induced losses (5–15% [36–39]), h the number of hours in a year (8760), η_A the machine availability (95% in agreement with [40]), and $P_w(v_a)$ the Weibull distribution as a function of v_a. Although the long-term wind resource at a site may change over time [41,42], in this paper the annual resource is assumed constant. Further, as determined by Wagner et al. [43], ideally the rotor equivalent wind speed (REWS) shall be calculated that depends on the shear profile of the wind, the modelled hub height, as well as the number of measurement heights. The application of the REWS is further discussed in the case study. As identified by Miller et al. [27], NREL applies a capacity factor of 38%, whereas other estimates are within the range of 18–53%. For a WTG deployment in the UK, on average a capacity factor of 28% is recommended by DECC [14,15]; however, as stated by Sindon [44] and Cannon et al. [41] this parameter is underestimated. The latter based on a study of average, annual capacity factors over the past 33 years in the UK.

2.1.4. Components of lifetime extension analysis

Table 3 presents an overview of the range of activities that are typically considered as state-of-the-art of the end of lifetime analysis in the UK. Results are derived from feedback gathered by Ziegler et al. [11] as well as the additional consultation of experts in

Table 3
Components of lifetime extension analysis in the UK. Derived from Ref. [11] and expert knowledge (Table 7 of the Appendix).

Item	Activity
Visual inspection	Visual inspection of: 1) blades (potentially internal for greater rated turbines), tower, flanges, and drive train
	2) non-destructive testing of bolted connections, and
	3) drive train vibrational analysis (if considered necessary)
Operational analysis	Review of: 1) operational SCADA data,
	2) repair and maintenance log, and
	3) conditioning monitoring data (if available)
Loads analysis	Review of wind inflow conditions (with met. mast if available) and
	compare to initial design assumptions (likely)
	Apply an aero-elastic code e.g. Bladed to redo load analysis of components based on reviewed wind inflow conditions (unlikely at present)
Administration	Consulting and overheads to facilitate LTE

the UK.

In order to qualify as an expert, at least 5 years of experience is required within the industry (the mean consulted industry experience is 18 years) with a track record of LTE exposure as illustrated in Table 7 of the Appendix. In essence, the lifetime extension analysis (LTEA) can be broken down into: i) visual inspection, ii) operational analysis, iii) loads analysis as well as iv) administration. Project specific activities depend on several environmental parameters such as the availability of data, global and local standards, legal requirements as well as an entity's considered best practise [1–3,11]. While in the UK no legal requirements exist for the lifetime extension phase contrary to e.g. Denmark [45] and Germany [46], the presented activities may deviate from project to project. This is reflected in the UK's commonly performed load analysis, that presents substantial cost savings compared to e.g. the use of aero-elastic simulations as required in Germany. On the other hand, there is the example of Denmark where the analysis is legally sufficient based on visual inspections. The lifetime extension capital expenditure, $CAPEX_{LTE}$ is thus modelled as:

$$CAPEX_{LTE} = Z(c_v + c_l) + c_o + c_a + c_{r,r} \tag{9}$$

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.

2.1.5. Other tool parameters

Overall, the LCOE methodology is designed in agreement with DECC's LCOE assumptions, thus inflation in labour expenditure and performance degradation are not considered, whereas decommissioning costs are assumed to be equalised with the turbine's scrap value. The discount rate in the central scenario is conservatively selected at 10%. With regards to the validation of the methodology, a sensitivity analysis was executed by Rubert et al. [7] albeit based on a model with less complexity than presented in this paper. In order to overcome the significant variance in published LCOE parameters, this paper's LCOE estimations are subjected to three scenarios; i.e., a pessimistic, central, and optimistic case.

2.2. Lifetime extension methodology

For the economic lifetime extension assessment, we propose a three-pronged approach aimed at i) evaluation of the development of total lifetime LCOE (design life and lifetime extension), depicted in this report as LCOE, ii) evaluation of solely the LCOE of the extension period (+5–15 years), depicted in this report as $LCOE_2$, and iii) to develop a contingency investment decision model for alternative reinvestment scenarios deviating from this paper's modelling or one-off unexpected repairs and retrofits. The applied LCOE methodology is schematically illustrated in Fig. 2. Throughout the entire model, OPEX and yield parameters are modelled as static cash-flows. The CAPEX is dealt with as an overnight cost for the initial investment in year 0 (Section 2.1.1) as well as for the investment required at the end of design lifetime referred to as $CAPEX_{LTE}$ (see activities presented in Table 3). In addition, the cost of repairs and retrofitting components is budgeted as well if deemed unsafe for continuous operation due to; e.g., wear and tear. Modelling lifetime extension investments as an overnight cost enables treating the extended period as a separate investment since at the end of an asset's lifetime its investment schedule is terminated and the asset is fully written off. In addition, at the lifetime extension stage, the LCOE model breaks down due to severe discounting. Therefore, we propose to economically model the lifetime extension separately as depicted in Fig. 2 with the presented $LCOE_2$ estimation model. Note that the $LCOE_2$ analysis is thus independent of the initial CAPEX in year 0.

If a life extended wind farm is under operation and a severe failure occurs in a WTG or within a cluster of turbines, ideally a rapid management process is required to minimise downtime [69]. Failure modes, their frequency and cost implications are published by a limited amount of sources; however, published data tends to be either generic (no impact breakdown; e.g., in minor, major or replacement) [47] or coarse; i.e., specified on the drive train level, hence lacking a component breakdown [48]. In addition, there exist limited operational experience at the end of design lifetime and beyond [11]. Since access to failure data beyond the design lifetime as well as component replacement data as an outcome of the LTEA is confidentially treated, this presents challenges in sensible

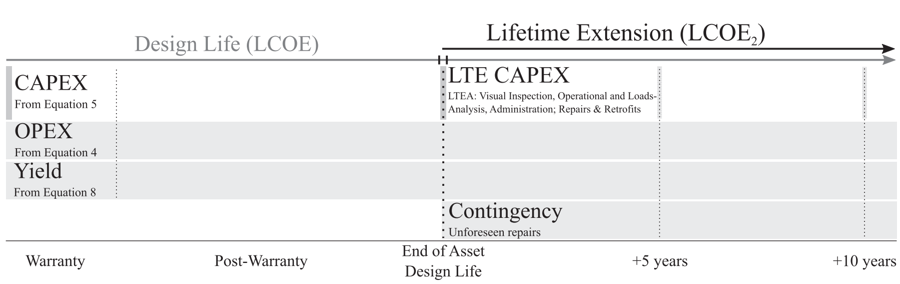

Fig. 2. Schematic overview of lifetime extension LCOE methodology.

modelling. From the point of view of an operator, operating beyond a WTG's design life can therefore result in sudden unexpected cost implications that may or may not require substantial remedial action in subsequent years. If a failure occurs, this generally entails a technical assessment to identify what remedial action is required, paired with a cost estimation for a given failure mode. This can occur because a turbine experienced a failure, or as an outcome of an inspection resulting from the LTEA. Assuming an identified failure can be repaired at a given cost, economic feasibility is not guaranteed and requires further analysis. Given the necessary operational flexibility and challenge to sensibly model failure rates, we propose the application of a contingency based analysis; i.e., a metric on i) how much money is viable to spend on the LTEA (repairs and retrofits) and ii) how much money is viable to spend on top of general O&M expenditure before a certain specified cost threshold is reached in subsequent years. The threshold target may be to maintain the expenditure 10% below a certain guaranteed subsidy per MWh or below the average one-day ahead spot market price in a non-subsidised environment, respectively. Therefore, with the proposed contingency thresholding, an operator can apply the proposed end-of-life decision making support tool to rapidly evaluate a certain situation and determine case specific economic feasibility for a given operational scenario (required expenditure vs. contingency budget). If the cost is below the contingency budget, execution of remedial action is supported and the asset is advised to continue to operate. If, however, the cost is greater than the contingency budget, the remedial action is advised against and instead, decommissioning of the asset is recommended.

3. Lifetime extension case study

Based on findings presented by Ziegler et al. [11], a wind farm rated at 5.4 MW consisting of six 900 kW rated turbines is modelled with a design lifetime of 20 years. This turbine type was selected as its configuration is typical of wind farms approaching their end of design life in the near future. Based on findings by Refs. [7,23], throughout all input parameters, the mean wind speed has the greatest impact on LCOE. Therefore, careful evaluation is required. Sinden [44] extracted historical capacity factors for UK onshore turbines (average 30%), while Cannon et al. [41] extracted more recent historical capacity factors for UK onshore and offshore turbines (average 32.5%). The latter concluding a likely increase due to the inclusion of windier offshore regions. As a result, for this paper's onshore case study, Sinden's modelled WTG power curve (Nordex N80) [44] was replicated, resulting in a mean wind speed of 7.1 m/s scoring a capacity factor of 30% at a hub height of 82.5 m. While the Nordex N80 sits at a higher hub height than the 900 kW modelled WTG, the wind shear log-law was applied (roughness length, $z_0 = 0.03$ - open farmland, few trees and hedges), resulting in a reduction of the average wind speed by 0.25 m/s based on the modelled hub height of 61.5 m [20]. The turbine was further subjected to identify the REWS; however, in agreement with Wagner et al. [43], the impact was observed to be low in magnitude and is thus not taken into consideration. Consequently, 6.85 m/s was applied as the average mean wind speed. This wind speed is also in agreement with the UK's wind atlas [49]. The WTGs' and environmental parameters are further summarised in Table 4. The turbine's maximum effective power coefficient is selected at 0.44 in order to address the design state of the industry in between 1997 and 2000.

Table 5 illustrates the case study's overall input assumption for the central scenario, paired with their estimated range. Each input parameter's highest and lowest estimate[1] serve as an input for the optimistic and pessimistic scenario, respectively. Where possible, parameter ranges were extracted from available research and paired with expert knowledge (Table 7 of the Appendix) to ensure model input parameters appear realistic for a UK based deployment and lifetime extension. Regarding the LTEA, the specified turbine's lifetime is assumed to be extended by either 5, 10, or 15 years under the assumption that O&M costs remain static as modelled over the initial 20 years of operation. In addition, as stated in the DNV GL's lifetime extension guideline, if components are likely to fail in the near future, structural health monitoring (SHM) or component replacement is necessary, thus the following retrofits are modelled:

Table 4
LCOE - Wind turbine parameters.

Parameter	Value
Rotor radius	25.3 [m]
Hub height	61.5 [m]
Cut-in wind speed	3 [m/s]
Cut-out wind speed	25 [m/s]
Turbulence intensity	0.1
$C_{p,max}$	0.44
Mean wind speed	6.85 [m/s]
Weibull shape factor	2
Scale factor (Gamma function)	7.72 [m/s]

- One-off: blades, gearbox, or generator
- Two of: blades, gearbox, or generator
- Replacement of blades, gearbox, and generator.

Cost estimations of retrofits are based on findings presented in Refs. [23,50–52] and estimated as a percentage of WTG's ex. works CAPEX. In the case where multiple sources were available, average percentage figures are applied. Time and rate assumptions were made to the installation expenditure consisting of i) crane mobilisation/demobilisation (Mob/DMob), ii) crane operation, and iii) service personal expenditure that estimates were verified by an expert in the field (Table 7 of the Appendix). For example, in the central scenario the installation cost of a generator replacement is conservatively priced at £10,050 (100t crane Mob/Dmob - £7,500, crane operation - £810, and service personal - £1740).

With regards to the LTEA expenditure, multiple expert cost estimations were gathered, averaged and reverted back to participants for agreement as advised by Yin [55] (except of visual inspection data, secondary data was not available). Overall, little discrepancies in responses were observed. Therefore, inspection costs are assumed at £2150/WTG with the load analysis budgeted at £3500/WTG, respectively. For the modelled wind farm, the operational analysis is estimated at £10,000 and the overall administration expenditure for consultants is included in the mentioned budgets (owner administration is not included in the analysis). The analysis extension period is valid for 5 years until reassessment is required [11]; i.e., for the 15-year lifetime extension estimate, 3 reassessment budgets are modelled (year 20, 25, and 30). For the subsequent LTEAs in year 25 and 30, the cost for the loads and operational analysis is reduced by 50% based on the learning curve of the initial assessment in year 20 (only critical components require loads analysis and operations analysis procedures are established).

4. Results

Results of the LCOE model baseline scenario as well as the $LCOE_2$ estimates for the case study presented in Section 3 are shown in Fig. 3. Complimentary, Fig. 5 of the Appendix presents the life extended LCOE results, while Table 6 illustrates the annual available contingency. Overall, findings are presented for the different model

[1] Wake losses and availability are applied vice-versa.

Table 5
Lifetime extension cost estimations for a wind farm consisting of six 900 kW WTGs.

Parameter	Central	Range	Unit	Source
CAPEX				
Pre-development	100	30–240	£/kW	[14,28]
Construction costs	1500	1100–1800	£/kW	[14,28]
O&M				
Fixed	30,192	22,644–37,740	£/MW/y	[14,28] ±25%
Variable	5.1	3.83–6.38	£/MWh	[14,28] ±25%
Insurance	2226	1669–2782	£/MW/y	[14,28] ±25%
Connection/system charges	3810	2857–4762	£/MW/y	[14,28] ±25%
Other parameters				
Discount rate	10	7.5–12.5	%	[14] & Expert Knowledge
Wake losses	10	5–15	%	[36]
Availability	95	93–97	%	[36,53]
Resulting capacity factor	25.47	23.55–27.45	%	[41,44,54]
CAPEX LTE				
Visual inspection	2150	1613–2688	£/WTG	[11] Expert Knowledge ±25%
Loads Analysis	3500	2625–4375	£/WTG	Expert Knowledge ±25%
Operations Analysis	10,000	7500–12,500	£/Wind Farm	Expert Knowledge ±25%
Spare parts				
3 blades (21% of ex. works)	214,704	151,635–273,745	£/WTG	[23,50–52] ±25%
Gearbox (13% of ex. works)	132,503	93,580–168,941	£/WTG	[23,52] ±25%
Generator (8.2% of ex. works)	84,041	59,380–107,153	£/WTG	[23,52] ±25%
Installation expenditure				
Crane (100 t) Mob/Dmob	7500	5625–9375	£/Wind Farm	Expert Knowledge ±25%
Crane operation	810	608-1013	£/day	Expert Knowledge ±25%
Service personal	58	43.1–71.9	£/h	Expert Knowledge ±25%

combinations of i) lifetime extension (5–15 years), ii) input assumptions (pessimistic, central, optimistic), and iii) reinvestment type. Fig. 3 as well as Fig. 5 are further equipped with defined thresholds (TH) aimed at budgeting the LCOE 10% below the average day-ahead spot-market electricity price of the past 5 years (£39.14 [56]) for life extension scenarios in a subsidy-free environment. A further TH is set under the Renewable Obligation (RO) environment. The latter is aimed at budgeting the LCOE 10% below the RO revenue stream defined by the 2017–2018 buy-out price and day ahead spot-market electricity price (£41.02 + 39.14 [56,57,70]). First and foremost, in the baseline scenario (no lifetime extension), findings result in LCOE estimates of 106.60 £/MWh for the modelled wind farm in the central scenario with an optimistic estimate of 61.81 £/MWh and 166.53 £/MWh for the pessimistic case, respectively. While in the central scenario the LCOE estimate appears higher in relation to other publications [58–61], the optimistic estimate is well in agreement. The higher central estimate is likely caused by multiple modelling differences, namely i) the exclusion of wake losses and availability, ii) the deployment of greater scale turbines as the power scales quadratically with the rotor radius [20], iii) the application of a lower discount factor, iv) different central CAPEX and OPEX assumptions, v) higher wind speeds due to increased hub heights, vi) a higher design lifetime (25 years), and vii) increased power coefficient efficiencies (an old design is essentially modelled).

In the simple life extension case (no repairs, nor retrofits), this paper's proposed $LCOE_2$ methodology, estimates a cost range of 15.87–29.95 £/MWh for a lifetime extension of 5 years with the central case at 22.48 £/MWh (+10 years: 15.78–29.77 £/MWh, 22.34 £/MWh; +15 years: 15.75–29.72 £/MWh, 22.30 £/MWh). These results are paired with significant annual contingency to meet the defined aim to remain 10% below the average day ahead spot-market price as well as ROC revenue respectively, albeit with less contingency (Table 6: shaded area). For the LCOE estimates

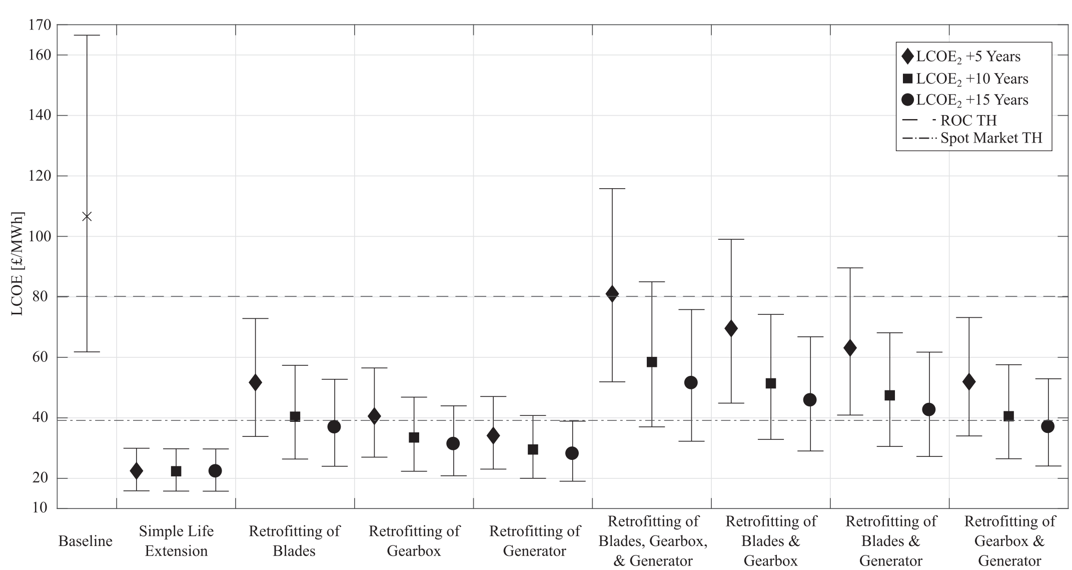

Fig. 3. $LCOE_2$ model results.

Table 6
$LCOE_2$ annual contingency results. N/A: investment is not applicable (cost above set TH).

Scenario	Lifetime Extension [years]	Contingency to maintain $LCOE_2$ 10% below average day-ahead spot market electricity price [£]			Contingency to maintain $LCOE_2$ 10% below RO revenue stream [£]		
		Pessimistic	Central	Optimistic	Pessimistic	Central	Optimistic
Simple Life Extension (no repairs/retrofits)	5	101,312	198,730	299,039	553,593	687,915	826,271
	10	103,254	200,296	300,219	555,535	689,481	827,451
	15	103,832	200,781	300,595	556,114	689,966	827,828
Retrofit of Blades	5	N/A	N/A	68,005	80,625	339,316	595,237
	10	N/A	N/A	164,041	251,362	474,419	691,273
	15	N/A	27,043	194,701	302,222	516,228	721,934
Retrofit of Gearbox	5	N/A	N/A	156,034	260,902	472,176	683,266
	10	N/A	67,200	215,928	367,300	556,385	743,160
	15	N/A	93,259	235,049	398,995	582,444	762,282
Retrofit of Generator	5	N/A	59,696	206,791	365,023	548,881	734,023
	10	N/A	114,522	245,845	434,263	603,706	773,077
	15	2,607	131,488	258,314	454,888	620,673	785,546
Retrofit of Blades, Gearbox, & Generator	5	N/A	N/A	N/A	N/A	N/A	363,065
	10	N/A	N/A	27,192	N/A	258,780	554,424
	15	N/A	N/A	88,286	47,988	342,024	615,518
Retrofit of Blades & Gearbox	5	N/A	N/A	N/A	N/A	126,197	453,622
	10	N/A	N/A	80,569	65,698	342,939	607,801
	15	N/A	N/A	129,793	147,250	410,012	657,025
Retrofit of Blades & Generator	5	N/A	N/A	N/A	N/A	202,901	504,379
	10	N/A	N/A	110,486	132,660	390,260	637,719
	15	N/A	N/A	153,057	203,143	448,240	680,289
Retrofit of Gearbox & Generator	5	N/A	N/A	65,777	77,012	336,403	593,009
	10	N/A	N/A	162,727	249,038	472,622	689,960
	15	N/A	25,592	193,680	300,283	514,776	720,913

presented in Fig. 5, results reveal that in the central scenario, LCOE can be reduced by 4.9% paired with a lifetime extension of 5 years. For an aimed extension strategy of 10 years, the LCOE reduces by 7.7%, whereas in the 15-year extension scenario LCOE reductions within the order of 9.3% are achievable. Overall, economic success is endangered under the RO as well as in a subsidy-free environment, though the derived LCOE metric breaks down as discussed in Section 3, thus its application is not advised. For a single component reinvestment, the central $LCOE_2$ estimates are well below the RO target; however, in the defined subsidy-free case, cost estimations are in close proximity to the defined target (except of retrofit of blades +5 & +10 years and gearbox +5 years). Further, where cost estimations are in close proximity to the set threshold; e.g., a gearbox replacement paired with a lifetime extension strategy of 10 years; caution is required. Here due diligence and risk management activities are necessary, due to a relatively low remaining annual contingency (£67k).

For any two-component reinvestments, all central scenarios are below the RO target where the least cost intensive reinvestment scenario (gearbox and generator) paired with a life extension greater than 15 years is below the defined subsidy-free target. Once again, caution is required as a 15-year extension commitment scores an annual contingency of £26k. Apart from the comparatively low contingency budget, a 15-year lifetime extension strategy is further accompanied by a significant external risk factor (policy changes/spot-market fluctuations). In the unlikely case of retrofitting a wind farm's blades, generator, and gearbox, economic success under the defined thresholding cannot be met in a subsidy-free environment, thus decommissioning is advised in the central scenario. In contrast, economic success can be met under the defined RO target, if subjected to a lifetime extension strategy above 10 years. Apart from a single/combination of gearbox, generator or blade replacement, a WTG can have many different faults or failures with deviating cost implications. For such cases, the presented simple life extension contingency data (Table 6: shaded area) can be compared to an actual cost/failure scenario to support the economic decision making.

5. Validation

According to Mitchell [62] validation is the process of testing whether a model represents a viable and useful alternative means to real experimentation. Further, as argued by Pidd [63], validation is impossible if seen as a comprehensive demonstration that a model is fully correct. With respect to the presented LTE model and case study application, confidentiality and limited experience challenge the degree of ability to validate. In addition, this is the first published attempt aimed at assisting LTE decision making. Hence comparisons to alternative models are beyond the bounds of possible. Lastly, the proposed method is not designed to generate a definite answer to the overall decision making process, it is designed as an economic decision making support tool. Given such challenges, a pragmatic validation approach is selected. This includes i) a model sensitivity analysis (Table 8 of the Appendix), ii) a case study sensitivity analysis (central, optimistic, and pessimistic scenario), and iii) the collection of feedback from industrial experts in the field. For further validation or comparison purposes, all assumptions and input parameters are disclosed for model replication.

6. Limitations and future work

The application of LCOE is always accompanied by a great number of assumptions and generalisations that can be significantly different from project to project. Investment costs are a substantial parameter in determining LCOE; nevertheless, published data covers a great variety; e.g., Blanco [23] estimates the CAPEX range between €869–1680 per kW, whereas this paper's CAPEX ranges between £1130–2040 per kW. Although the derived $LCOE_2$ does not directly depend on a project's initial CAPEX, there is an indirect impact since the cost of spare parts are modelled ex.

works dependent.

Equally, OPEX expenditure can vary based upon multiple parameters with significant modelling deviation as illustrated in Table 1. Additionally, it is also problematic to fully evaluate OPEX expenditures, since there is no accepted standard of what is included in O&M costs and what is excluded. This is challenging, since for example the cost distribution by DECC is defined fundamentally differently to the cost structure presented in Fig. 4. Therefore, different applied methods and cost categorisation approaches can result in deviations of LCOE. With respect to the yield modelling, overall the methodology considers that a 20-year old turbine design is less efficient in power conversion than today's WTGs on the market ($C_{p,max}$: 0.44 vs. 0.49); however, adjustments and developments in i) rotor design or ii) turbine topology (e.g. fixed or variable speed and pitch or stall regulated turbines or drive train topology, i.e. synchronous generators with a gearbox vs. direct drive generator) affect the aerodynamic and drive train efficiency [64]. This will thus impact the extractable power coefficient, C_p that is also dependent on the tip speed ratio, λ and pitch angle, β [20,33]. Therefore, a different drive train topology or rotor design will in return impact an asset's capital and operational expenditure as well as AEP. Furthermore, turbine parameters can slightly deviate such as the cut-in and cut-out wind speed as well as the mean, shape and scale parameter of the locally recorded Weibull distribution. All parameters affect the approximated annual turbine yield derived in Equation (8) and thus LCOE; however, the mean wind speed will have the most significant impact on the overall calculation as highlighted in Section 3 and Table 8 (e.g. Scotland has a higher mean wind speed than England; The UK is windier than southern Europe [49,65,66]). Given that input parameters can vary significantly, enclosed to this paper is a published database allowing users to adjust any combination of the mean wind speed, $C_{p,max}$, turbulence intensity, and Weibull shape factor for the central, optimistic, and pessimistic scenario [67].

The consideration of expert judgement is essential in order to allow a representative state-of-the-art analysis; however, with respect to LTE in the UK, the industry's characteristics are young and confidential making it challenging to collect a representative amount of expert opinions. In order to account for personal bias at least two experts were aimed to take into consideration.

As presented in Section 1, the entire methodology of LCOE may deviate; e.g., NREL applies a different methodology, thus similar parameters result in different LCOE estimations that cannot be compared due to fundamental modelling differences. With the applied capacity factor of 38% by NREL, significantly windier sites and or greater rated turbines are considered in the central scenario compared to the UK (since 2006 the UK's average installed onshore turbine is 2 MW [13,71]).

With regards to the presented results of the case study, it is unlikely yet possible that all WTG require the same component replacement. Therefore, different scenarios are modelled paired with their contingencies, thus researchers, wind turbine operators and investors are able to identify economic boundaries for a given project. In addition, if no reinvestment type appears similar to the presented combinations (e.g. the expenses for a generator rewinding, the purchase of a condition monitoring system or a SCADA/control upgrade), it remains possible to compare the required investment sum to the annual available contingency (Table 6: shaded area).

Lastly, the analysis reveals a proportionality between the extension period and estimated contingency. This is vital, since the available annual contingency can be seen as the likelihood that a set target can be met, thus indicating the risk of an end of lifetime investment; however, a greater extension period also results in a higher uncertainty as identified in Ref. [11], thus in essence the increasing contingency is out-balanced by a greater long-term risk perception. In the UK, this is greatly accompanied with the change to a static RO allocation scheduled in 2027 [68,71] and the non-existent lifetime extension regulation contrary to; e.g., Denmark and Germany.

Future work entails to add further complexity, by taking parameters such as performance degradation, upscaling, inflation, WACC, and end-of-life failure rates into consideration. In addition, the time of reinvestment in this paper is assumed at the end of lifetime; however, this is certainly not the optimised investment time and thus requires further scrutiny. Lastly, repowering and refurbishment decision making synergies of other industries might be explored.

7. Conclusion

Despite the limitations that have been highlighted, this paper provides the reader with a flavour of the complexity and economic boundaries of lifetime extension and offers guidance for operators, investors, and academics dealing with the subject of LTEA. The study gives an idea what investment and cost estimates are achievable for different practical scenarios. Based on the outcomes of this research, the application of the derived $LCOE_2$ metric is proposed where the life extended period is modelled as a separate investment in conjunction with the presented contingency methodology.

Overall, the results reveal that significant cost reductions are achievable with an estimated $LCOE_2$ of 15.87–29.95 £/MWh that is shown to be well below the set target within the RO environment and when exposed to a non-subsidised market. Based on this paper's identified LCOE, the more competitive allocation of onshore subsidies, and the termination of the RO in 2017 (grace period until 2019; runs until 2037), we are confident that lifetime extension will play an ever-increasing role in the UK's onshore wind energy market.

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Appendix

As a supplement to this paper, a database is published allowing users to adjust any combination of the mean wind speed, $C_{p,max}$, turbulence intensity, and Weibull shape factor for this paper's central, optimistic, and pessimistic scenario [67].

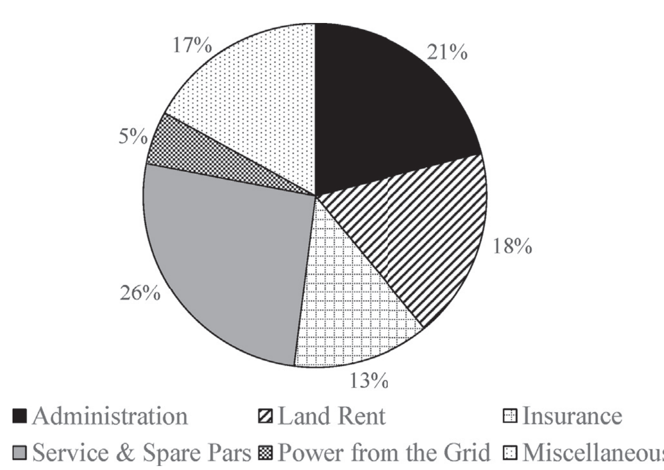

Fig. 4. O&M cost breakdown in % [23].

Table 7
Overview of consulted UK experts.

Generalised job title	Degree	Years of experience in wind energy	Knowledge area	UK LTE exposure
Head of Department	MSc	15	Technical & commercial	Supervised 5 wind farms on LTE
Director	MEng	11	Technical & commercial	Load monitoring campaigns, commercial evaluation
Director	MEng	14	Commercial	Load monitoring compaigns, commercial evaluation
Director	MSc	23	Commercial	Secondhand wind turbines, spare parts
Director	MEng	16	Technical	Supervised 2 wind farms on LTE
Head of Department	PhD	35	Technical & commercial	General commercial project cost
Manager	PhD	10	Commercial	General commercial project cost
Director	MSc	23	Commercial	Commercial project cost

Table 8
Sensitivity of lifetime extension model.

Case [-10%]	Gearbox retrofit [+10 years]		No retrofit [+10 years]	
	$LCOE_2$ [£]	Δ Baseline [%]	$LCOE_2$ [£]	Δ Baseline [%]
Mean wind speed	40.89	22.03	26.83	20.05
OPEX	1.36	−6.42	20.19	−9.62
$C_{p,max}$	35.40	5.66	23.50	5.16
CAPEX (spares)	32.42	−3.24	N/A	N/A
Weibull shape factor	33.14	−1.08	22.12	−0.98
CAPEX LTE	33.42	−0.25	22.26	−0.38

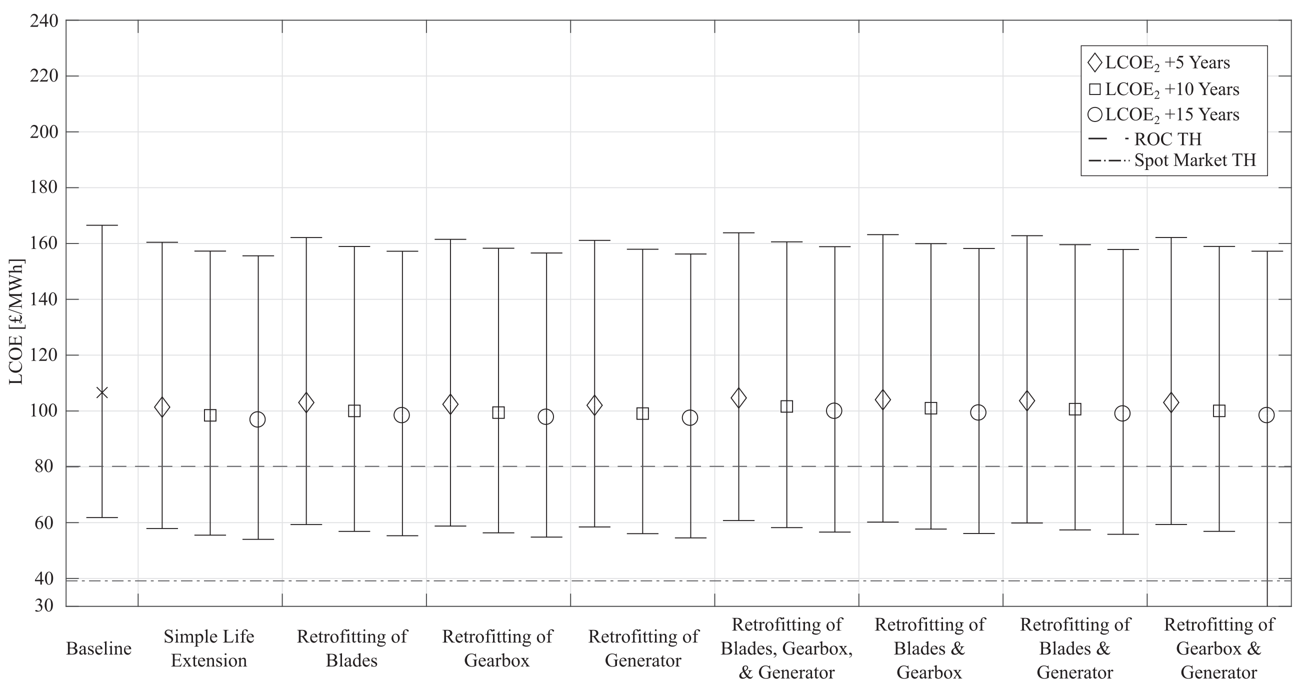

Fig. 5. LCOE model results.

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