Costs, Performance and Investment Returns for Wind Power

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1. ***Introduction***. In this presentation I will cover two topics. The first is to provide a brief summary of the key results of the analysis of the time profile of capital and operating costs for wind farms and their performance as they age. I will focus particularly on offshore wind since this will dominate investment decisions over the next decade. The second topic is to answer a key question: if my results of my analysis are correct, how will this affect the expected returns on wind projects built in the 2020s?

2. I would like to put my work in context. The results that I will discuss are based on data obtained from (i) company accounts for wind farm SPVs filed over the last 15 years as well as (ii) a comprehensive database on wind turbine performance compiled by the Danish Energy Agency going back nearly 20 years. The details of the data and my analysis are given in papers that have been published by the Renewable Energy Foundation and which can be downloaded from its website[1].

3. I should emphasise that I rely upon actual, documented, data on costs and performance. Too much in the renewables business is based on undocumented and often speculative assertions about the future. Even the smallest degree of scepticism and investigation shows that ex-ante claims and ex-post reality often differ by large margins. Think of the claims about the prospective costs of HS2 and compare that with the reality as the bills came to be paid. That kind of optimism bias is endemic in the renewables sector. The Winner's Curse is alive and kicking for anyone involved in auctions for development rights, CfD contracts, etc.

4. One of the sad consequences of the current climate is that anyone who questions the official consensus is dismissed as being a heretic or driven by malign motives. I suggest that you might consider a couple of questions. If my findings are so clearly wrong, why have those with a contrary view not produced convincing rebuttals based on real evidence rather than speculative projections? The published responses up to now have amounted to qualifications relating to points that I had highlighted from the outset as being uncertain. I do not claim that my results will not be modified in the light of further evidence, but even if my identification of trends based on current data is only 50%, even 25%, correct there are still important implications for investment decisions. There can be no certainty about what actual costs and performance will be 10 or 20 years from now. But is it really prudent to adopt Dr. Pangloss's view that we live in the best of all possible worlds?

5. ***Capex costs***. I will start by considering capital costs. Figure 1 shows an idealised version of the oft-claimed decline in average capex costs for new technologies or products due to learning and

[1] https://www.ref.org.uk/ref-blog/365-wind-power-economics-rhetoric-and-reality

economies of scale. The lower curve shows a cost reduction of 15% per doubling in cumulative capacity. This is at the top end of the range of plausible values, leading to a cost reduction of more than 60% in 7 generations. The lower decline of 5% per doubling is much closer to long run experience. Bear in mind that capex may only be a small part of the story.

6. Figures 2 & 3 show the empirically observed evolution of capex costs for onshore and offshore wind. In both cases there has been a significant increase in the average capex cost per MW as the amount of installed capacity has increased. Note that the capex cost figures for offshore wind include the cost of the offshore transmission system.

7. There are two points to note about offshore wind. First, offshore wind is a pan-European industry with the major operators having projects spread over North-West Europe. Hence, I have used installed offshore capacity in Europe as my capacity variable. Second, the outlier with a very high capex cost per MW is the Hywind floating turbine project. Capex costs for floating turbines are typically 50% to 100% more expensive than for turbines fixed to the sea bed. Hence, floating turbines will not offset the higher costs incurred by the necessity of moving to deeper and more distant offshore locations. Even leaving out the Hywind project, actual offshore capex costs have increased by 15% for each doubling in capacity.

8. There is no convincing evidence that actual – as contrasted to projected – capital costs are falling at anything like the rate that is assumed by BEIS in the UK or various international agencies. But there is worse to come.

9. ***Opex costs***. Trends in capex costs are interesting but they are not where the real story lies. The key issue is the expected economic life of wind farm assets. Under the Renewables Obligation a wind farm was a bond-like asset for 20 years with revenue risk primarily determined by wind conditions and yield performance over time. The period of relatively secure – and high – levels of revenue has been shortened to 15 years under the CfD regime and is even shorter for wind farms underwritten by power purchase agreements (PPAs) for a fixed volume of sales of the type offered in Denmark and other countries in NW Europe. As a consequence, the expected economic life of a wind farm may be much shorter than the physical life of the assets if opex costs exceed expected market prices once the period of subsidised or guaranteed prices has expired. If the cost of capital is below 5% this may have a large impact on the expected project return, especially for equity investors.

10. Figure 4 summarises the evolution of average opex costs in real terms including transmission costs for typical offshore projects. This is based on an analysis of nearly 1,000 data points spread over 15 years and allows for water depth, Offshore Transmission Owner (OFTO) status and other factors. The Blue line shows the opex costs in £000 per MW of capacity per year at 2018 prices for a shallow water project commissioned in 2008 with transmission owned and operated by the wind farm. The Grey line shows the costs in the same units for a deep water project commissioned in 2018 with transmission transferred to an OFTO.

11. Converting these opex costs to £ per MWh using an expected load factor of 35% for the 2008 project and 50% for the 2018 project we get opex costs at age 1 of £16 per MWh for the 2008

shallow water project and £44 per MWh for the 2018 deep water project. The data indicates that these costs have increased at between 5.5-6% per year as the wind farms age. By age 12 the opex cost for the 2008 shallow water project will be £30 per MWh and it will be £82 per MWh for the 2018 deep water project. There is a similar pattern for onshore wind farms, but it is more useful to focus on offshore wind as this is central to the whole Net Zero strategy. It is important to note that the base level of opex costs for each new project has been increasing over time at a rate that is only a little lower than the effect of age on opex costs.

12. In the period 2015-20 the average real market price of power (at 2018 prices) weighted by offshore wind output was £42 per MWh and the annual averages were less than £50 per MWh in every year apart from 2018, when the average was £57 per MWh. Without intervention the real market price for offshore wind output will certainly fall as (i) the amount of generation capacity and (ii) the capacity of interconnector with Europe increases. The real power market price in NW Europe is significantly lower than that in Great Britain. Hence, a merchant generator cannot expect to earn more than £40 per MWh in future unless there is some fundamental change in market arrangements and a realistic price forecast might be as low as £30 per MWh.

13. These figures have profound implications for both existing offshore wind farms and new projects.

    a. It is very unlikely that existing offshore wind farms will be financially viable as merchant generators at such levels of opex costs once their current CfD contracts expire unless there is a large increase in the future level of power market prices. In real terms power market prices would have to be at least double – and probably closer to three times – their current level to give a viable future for existing wind farms after their initial 15 year CfD contracts. That raises two questions: (i) How would such a change come about? (ii) Would any government withstand the political discontent associated with high electricity prices in the past?

    b. The prospects for new offshore wind farms with CfD contracts at 2012-13 strike prices of less than £75 per MWh are dire unless they can repeal history and achieve much lower levels of opex costs than actual experience suggests is plausible. Triton Knoll is the marginal case with projected opex costs that are likely to exceed CfD revenues between year 12 and year 14 of operation. New projects with CfD strike prices of about £40 per MWh are pure gambles on a belief that the future will be completely different from the past. Without such a discontinuity the projects will not cover their opex costs, let alone recover initial capex costs. As Damon Runyon observed, that is not the way to bet!

14. ***Load factors***. This analysis assumes that the expected load factor for offshore wind farms will remain constant for 20 or more years when adjusted for variations in wind conditions. Unfortunately, detailed analysis of the performance of wind turbines in Denmark suggests that the assumption is empirically incorrect. It is the case that the original generation of smaller wind turbines – with capacities of less than 1 MW – experienced only a very small decline in performance. Unfortunately, the reliability of larger turbines – and especially offshore turbines –

has been much worse and this has a critical impact on the expected load factor of wind farms as the turbines age.

15. The issue of differences in reliability is highlighted in Figure 5 which shows standard failure curves for the time to turbine failure from either the beginning of operation or since the most recent failure. A failure is defined as monthly output that is less than 50% of its peers adjusted for turbine size and wind conditions, an outcome that is well outside normal variation. Approximately 50% of offshore turbines experience such failures within 5 years. Some turbine failures can be fixed quickly and cheaply but, in many cases, an extended period of low output and expensive repairs are required.

16. The failure analysis shows clearly that larger turbines – greater than 2 MW onshore and all offshore turbines – have been less reliable than small turbines. In addition, the data also suggest that there is a pattern by which a step change in turbine capacity – e.g. moving from 0.5 MW to 2 MW - leads to lower reliability for 5 or even 10 years, after which new turbines in the size category become more reliable. This pattern is consistent with engineering experience for other large pieces of equipment but it has worrying implications when turbine manufacturers are reducing the time period between new turbine generations. The transition from 0.5 MW to 2 MW turbines took 15-20 years. However, there was a shift to 6-10 MW turbines for offshore use in first half of the 2010s and now manufacturers are focusing on 15+ MW turbines. The compression of the period between turbine generations may exacerbate the reliability problems that accompany the introduction of each new turbine generation. Investors should keep this matter under close observation.

17. Turbine failures – and other kinds of systemic degradation – underpin the decline in the expected load factor for wind farms as they age. The problem for observers and analysts is that the decline in performance is not a smooth process, spread evenly over time. Once initial problems are sorted out, many turbines will operate at a consistent level for many years before experiencing minor or major breakdowns. A general pattern of performance decline can only be examining data for a large sample of turbines over many months or years after adjusting for variations in wind speeds and other factors.

18. Figure 6 shows the results obtained from an analysis of offshore wind farms in Denmark for the decade 2010-19. The reason for focusing on this decade is that the small number of offshore wind farms built in the early 2000s experienced a lot of operational problems, especially with offshore transmission, which took up to 5 years to sort out. Hence, the later period offers a larger and more representative sample of experience. The figure is based on output data for nearly 50,000 turbine-months but the data is clustered at 26 wind farms for which common factors linked to location and operational practices apply. This limits the detailed inferences that can be made from the data.

19. The figure shows the decline in performance for 5 year age categories. After adjusting for wind speed, output in the age category 6-10 years is about 10% lower than that for age category 1-5 years. Output for age category 11-15 years is about 20% below that for age category 1-5 years,

while turbines more than 15 years old have an output that is less than 50% of the expected output in the early years of the wind farm. An alternative way of expressing this pattern is that after 5 years of full operation – i.e. excluding the initial year – expected output declines at about 2.8% per year up to age 15. The sharp decline in the typical load factor after age 15 may be the consequence of commercial decisions about how much should be spent on the maintenance and repair of turbines when wind farms reach the stage of operating as merchant generators after the expiry of guaranteed or subsidized prices.

20. ***Operating margin***. In the remainder of this webinar I will focus on the risks faced by investors implied by the large gap between current evidence about the costs and performance of offshore wind and the optimistic projections that dominate both rhetoric and policy. I will do this by examining a simple investment model based on the operating margin earned by a generic offshore wind farm that is planned for completion in the period 2021-25. All money values are expressed at 2018 prices. To represent the optimistic projections I have used the figures for 2025 projects contained in BEIS 2020 report on generating costs – the Industry assumptions - while the Alternative assumptions are based on my work reported above. I would emphasise that I do not use levelised costs as these are profoundly misleading when there is uncertainty about parameters which affect the economic life of generating assets.

21. For the analysis I distinguish between "systemic" risk and "parametric" risk. Systemic risk covers things like annual variations in wind speed and, thus, output or future power market prices or annual maintenance costs. Such risks should be considered in any investment decision, but their consequences may be magnified when core assumptions built into the revenue and cost projections are uncertain. It is this latter uncertainty that I refer to as parametric risk because it affects the operating margins that will be earned when the project is aged 5, 10, 15, … years.

22. For reasons of convenience – and perhaps gilding the lily – the Industry/BEIS assumptions use constant values for the load factor and O&M costs over the life of the wind farm. In contrast, every engineer knows that wear and tear for generating and electrical plant results in declining availability and increasing maintenance as assets age. We may be certain that the effects of wear and tear are unavoidable without knowing exactly how large they will be – i.e. it is likely to be greater than zero but it may not be as bad as my analysis of actual experience to date suggests. Thus, my analysis of parametric risk allows for key parameters to be drawn from triangular distributions that are bounded by the Official assumptions and my estimates of the parameter values.

23. I can provide fuller details of the risk models on request, but Figure 7 summarises the key results. The blue and green lines show the median values of the operating margin from age 1 to age 20 for the Industry assumptions (red) and my Alternative (assumptions). The Industry assumptions are based on a 15 year CfD contract at a price of £75 per MWh (at 2018 prices) and a constant wind-adjusted load factor. The operating margin falls at age 15 as the CfD contract expires and the wind farm operates as a merchant generator with a mean market price of £40 per MWh. The Alternative assumption allow for the increase in opex costs and the decline in the mean load factor over time. Note that the median operating margin goes negative at age 10 and

is highly negative from age 15 onwards. Under these assumptions the economic life of the wind farm is clearly no more than 15 years.

24. The middle (purple) line in Figure 7 shows the median operating margin for the Full Risk model in which both systemic and parametric risks are taken into account. The error bars show the range between the 5th and 95th percentiles of the operating margin at each age. These highlight the conclusion that the uncertainty about the financial performance of offshore wind projects is high relative to the median return that might be expected. In the Full Risk model the median operating margin is negative from age 15 onwards, implying that the expected economic life of the project is 15 years or the length of the CfD contract.

25. As the final element in the analysis the projections of the distributions of the operating margin are translated into investment returns using a distribution of capex costs spanning the range from the Industry/BEIS estimates to my Alternative estimates. For simplicity I have used a pre-tax cost of capital of 4%. This is lower than the figure of 6.3% used by BEIS which seems to be on the high side. I have not tried to model tax and financial considerations in order to focus on the underlying returns of offshore projects.

26. The key indicators of investment returns are shown in Table 1. They highlight the huge gap between the viability under different assumptions. Under the Industry/BEIS assumptions, offshore wind assets have an economic life of at least 25 years while the median payback period is 11 years and the net return (after allowing for the cost of capital) at the end of the 15 year life of the CfD contract is nearly £1 million per MW. In this scenario the CfD contract price could be as low as £65 per MWh (at 2018 prices) with a better than 50% chance of achieving a positive net return within the first 15 years.

27. Note, however, any CfD contract price that is significantly lower than £65 is a pure gamble on post-CfD power market prices even under the most optimistic assumptions about costs and operating performance. Any investor contemplating participation in any of the CfD Allocation Round 3 (AR3) projects – i.e. Dogger Bank, Seagreen and Sofia – should be aware that these projects can only be financially viable if there is a very large change in the structure of the power market and the level of prices by 2035 or shortly after. Without such a change these projects will incur huge losses. For AR2 projects, Hornsea 2 and Moray East have a chance of breaking even in the best of all possible worlds, but they are likely to incur substantial losses in more reasonable scenarios. Triton Knoll might be viable but the public information that is available indicates levels of actual capex and opex costs which are considerably higher than the levels to break even.

28. Unfortunately, adopting the Industry/BEIS assumptions for the purpose of assessing investment returns involves a reliance on magical thinking that makes belief in fairies and Santa Claus seem entirely rational. Not only is it necessary to believe that well-established trends will be abruptly reversed, but also that both capex and opex costs will fall by 30-50% within less than 5 years for projects that will be in deeper water and further from land. You may think that my analysis based on capex, opex and operating assumptions derived from actual evidence for the last 15 years is too pessimistic. In that case, look at the 95th percentile investment returns for the model

that allows for parametric uncertainty. The economic life of offshore assets is only 15 years, the payback period of 999 years means that the original investment is never recovered for a cost of capital of 4%, and the net return after 15 years is a loss of £547,000 per MW of capacity for a CfD price of £75 per MWh. With a CfD price of about £66 per MWh at 2018 prices for Hornsea 2 the 95th percentile net loss after 15 years is more than £1.8 billion. The AR3 projects remind one of the description of ocean yacht racing as a way of getting wet and cold while tearing up pound notes – except that we should update this by referring to €1,000 euro notes.

29. ***Conclusion***. I would like to finish with what you may regard as a war story. For about a decade from the late 1980s I spent much of my time working with policymakers in Eastern Europe and the Former Soviet Union on adapting to the economic collapse of the socialist bloc. In intellectual terms the issues were hugely interesting, but in human terms the experience was awful because of the impact of the economic disruption on tens of millions of lives. This collapse was not, as often thought, simply the consequence of 50 or more years of socialist policy. The biggest contributing factor was the way the Soviet Union and satellite countries had responded – or not responded - to the oil price shock of the 1970s and the subsequent collapse of the 1980s.

30. Underlying the whole problem was a consistent denial of economic reality by policymakers, industrial managers and many academics. They refused to deal with the way in which markets had changed in a world of volatile energy costs, instead relying upon large scale investment and new technologies in an attempt to buy their way out of the need for economic and institutional change. In addition, they had no understanding of how to implement new technology within existing operations and institutions. The result was a huge amount of extremely expensive but completely uncompetitive industrial plant and infrastructure. Eventually the costs of this strategy of denying reality brought down the whole economic system, causing massive social dislocation and pain.

31. I can see many elements of the same story in European and US responses to climate change and the economic shock caused by the pandemic. There is the same belief in the magical properties of new technology and massive capital expenditure. Equally, there is a complete refusal to acknowledge or address the practical engineering and operational reasons why much of what is proposed cannot be implemented without huge costs and, probably, public discontent. Finally, we have the usual penumbra of industrial and academic fellow-travellers who tell policymakers what they want to hear while expecting to obtain large benefits from exercising their control of privileged access to resources. Think of National Grid as Gazprom with wires and glossy PR.

32. The point is that anyone with open eyes and a critical intelligence could see by the early 1980s that the Soviet response to the oil price shock and its aftermath was not sustainable. Even Mikhail Gorbachev acknowledged this by the mid-1980s. The problem was that the system could not be changed quickly enough and the outcome was an unprecedented disaster.

33. The question for investors today is how current policies, which are equally unsustainable, will fail and what will be the nature of the resulting mess. It is the usual story: do you want to pick up

pennies in front of the road roller and at some random date get squashed? If not, how do you insure against the inevitable collapse of unsustainable policies and magical thinking?

Figure 1 - Idealised projection of capex cost trends for new technologies

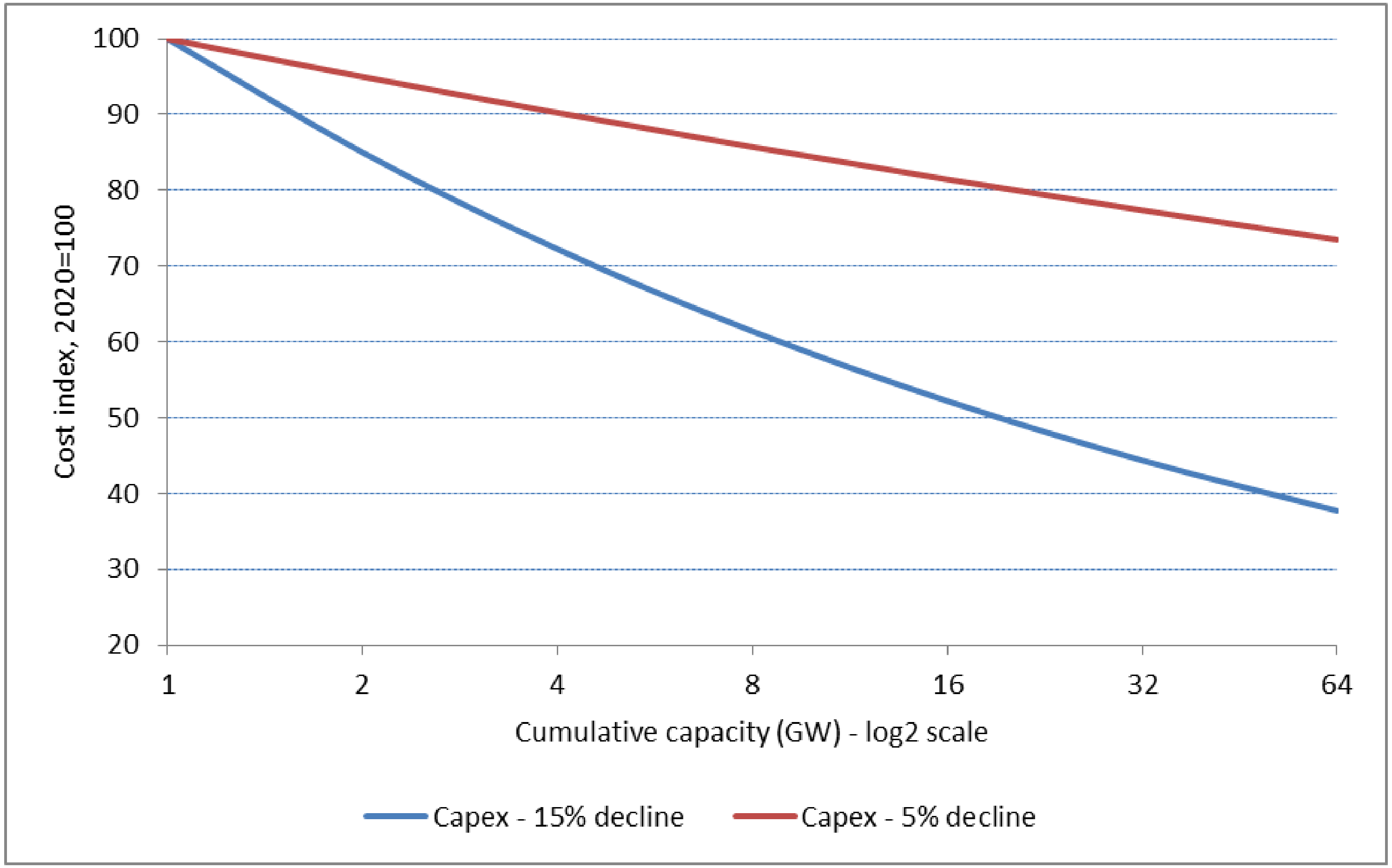

Figure 2 - UK onshore wind: actual capex cost vs installed capacity (£ million per MW at 2018 prices)

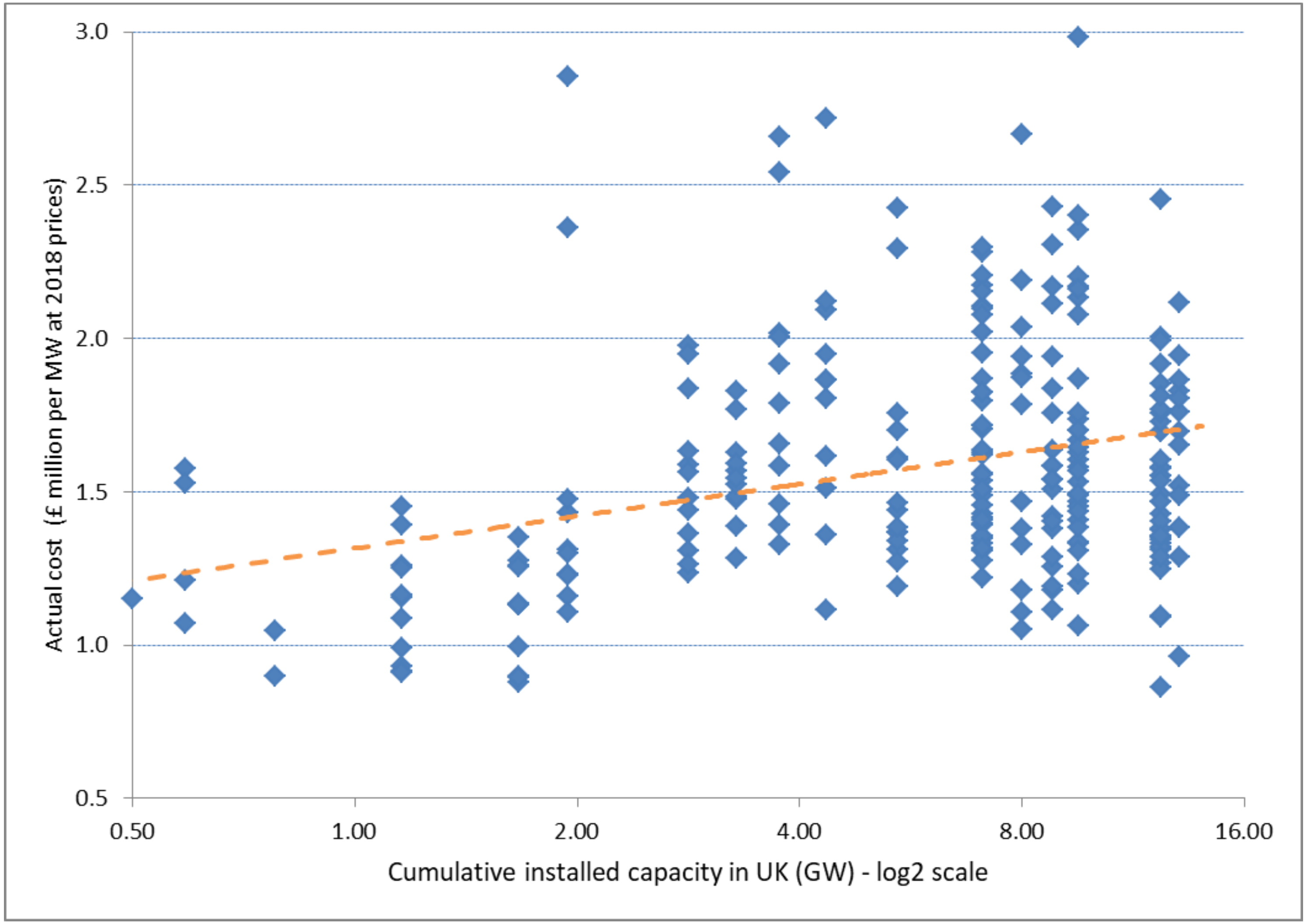

Figure 3 - UK offshore wind: actual capex cost vs installed capacity in Europe (£ million per MW at 2018 prices)

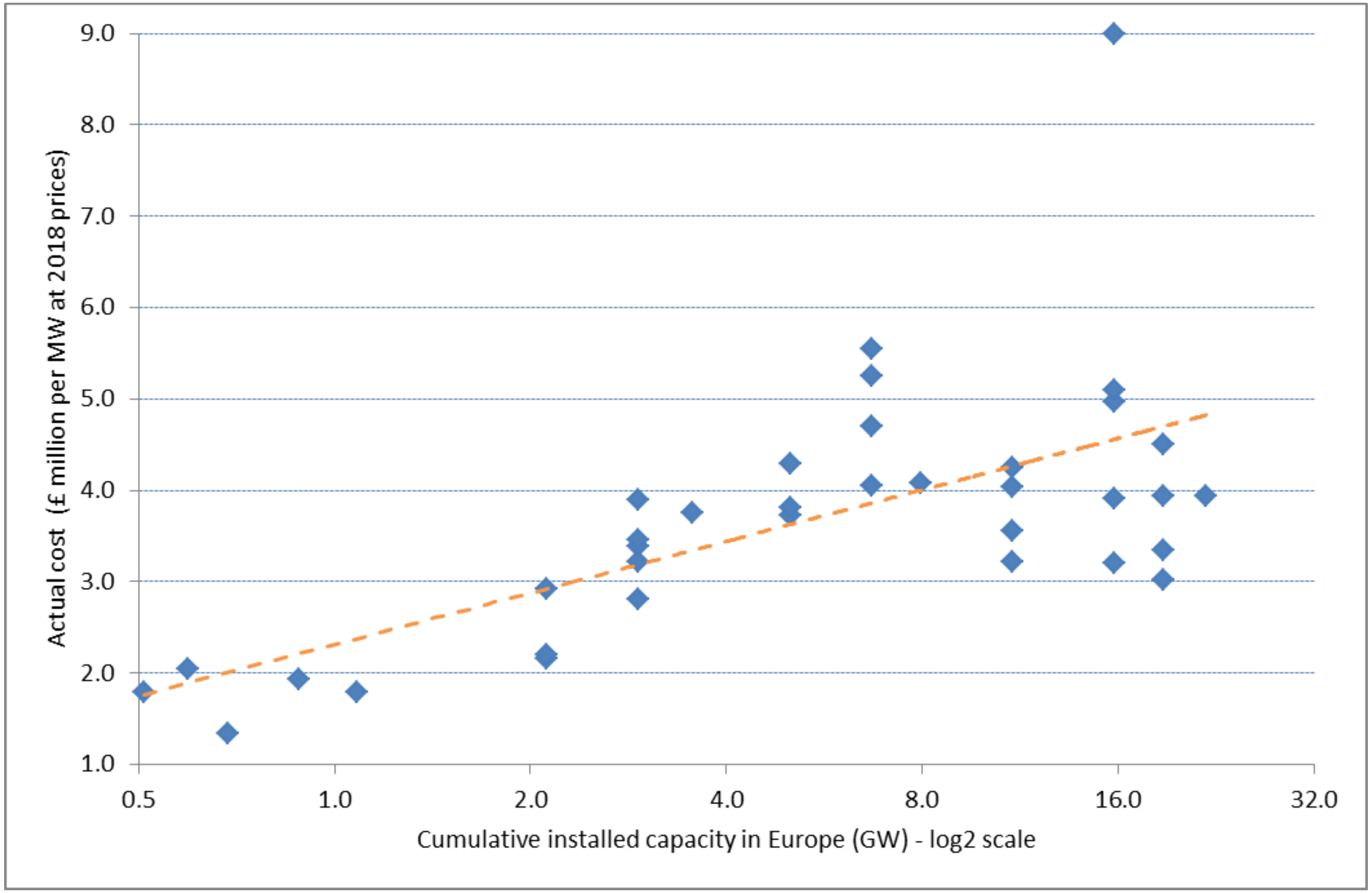

Figure 4 - UK offshore wind: average opex costs vs year of service (£000 per MW at 2018 prices)

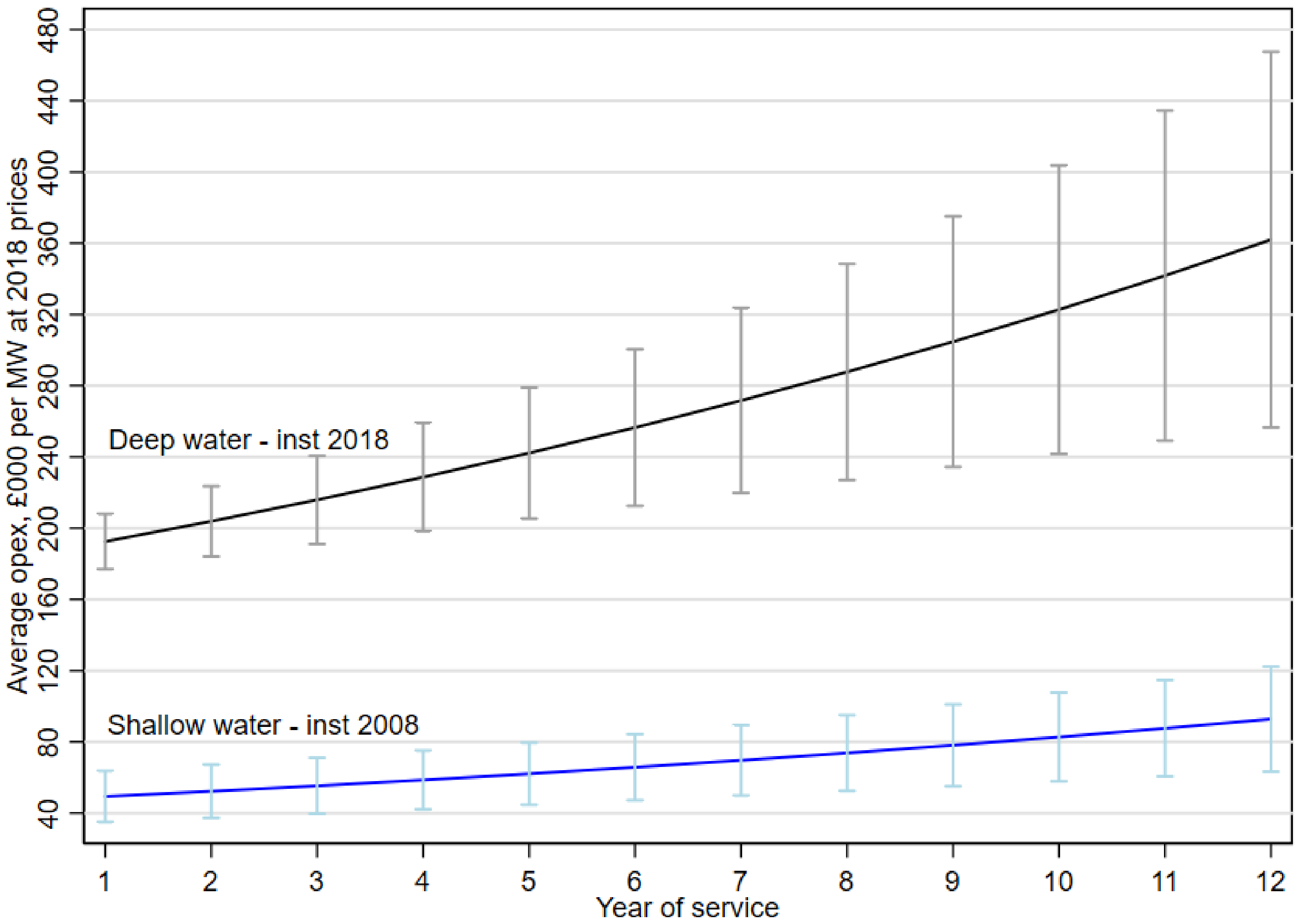

Figure 5 – Failure curves for wind turbines in Denmark

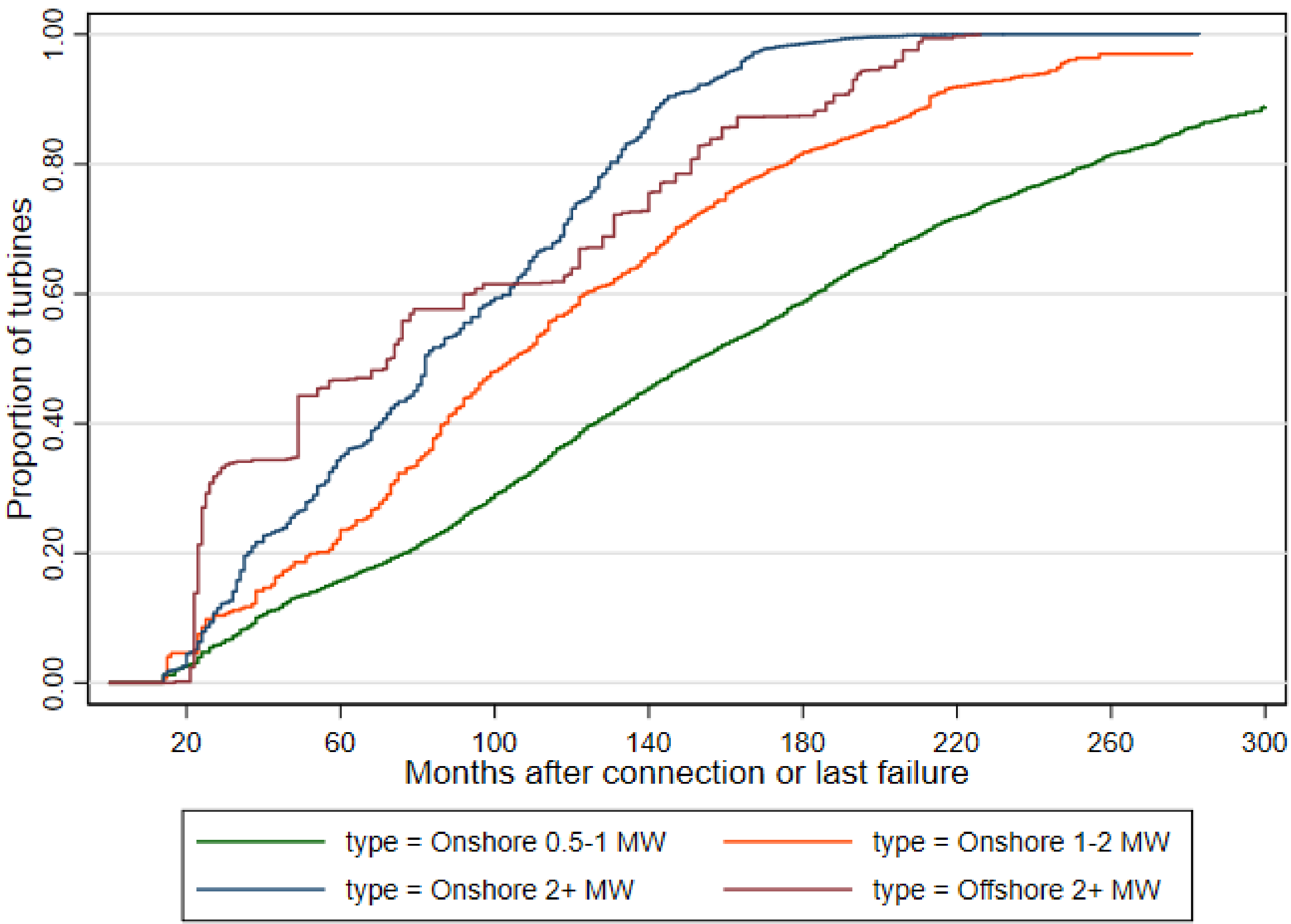

Figure 6 – Performance decline for offshore wind turbines in Denmark, 2010-19

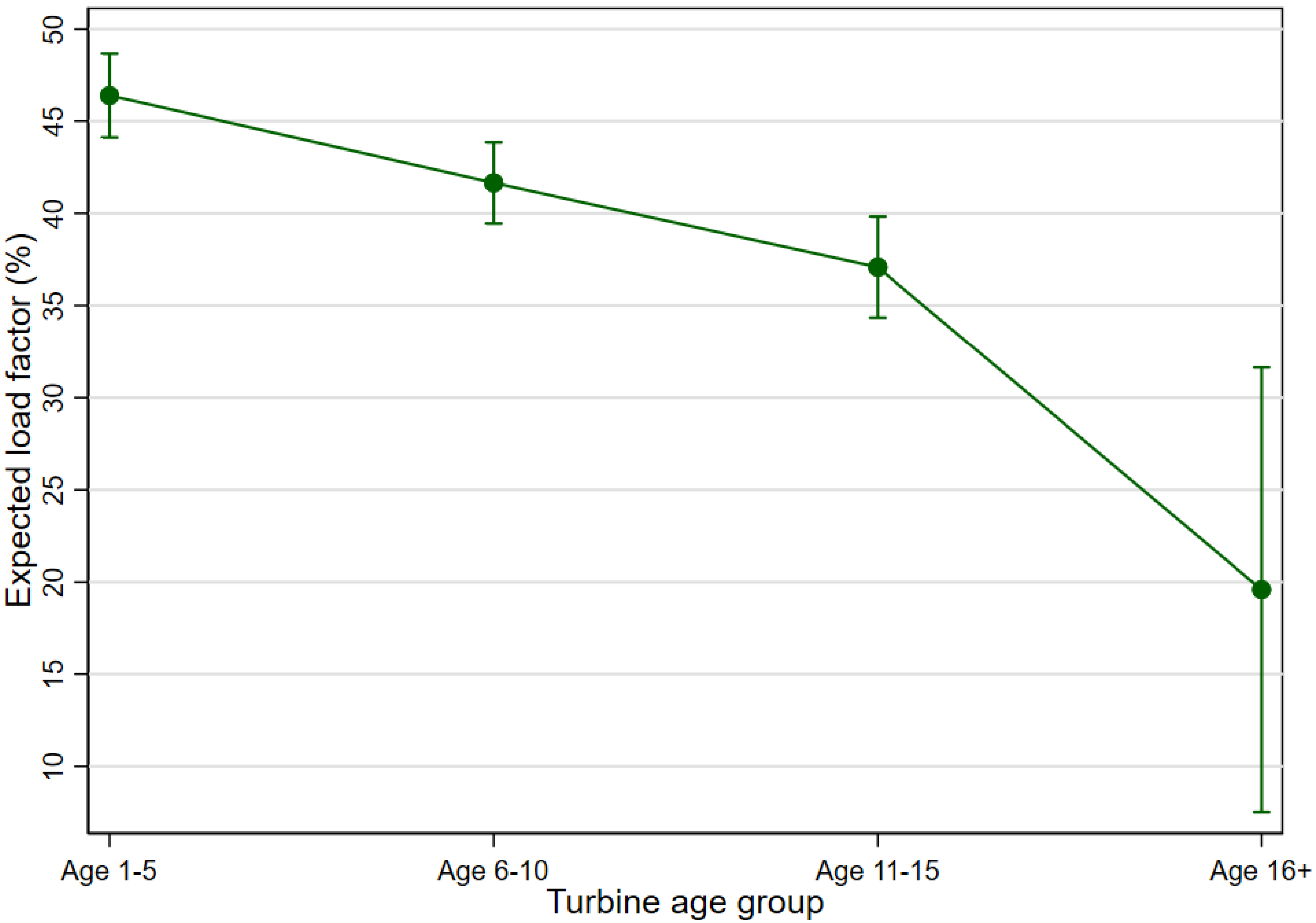

Figure 7 – Operating margin for offshore wind under alternative assumptions (£000 per MW at 2018 prices)

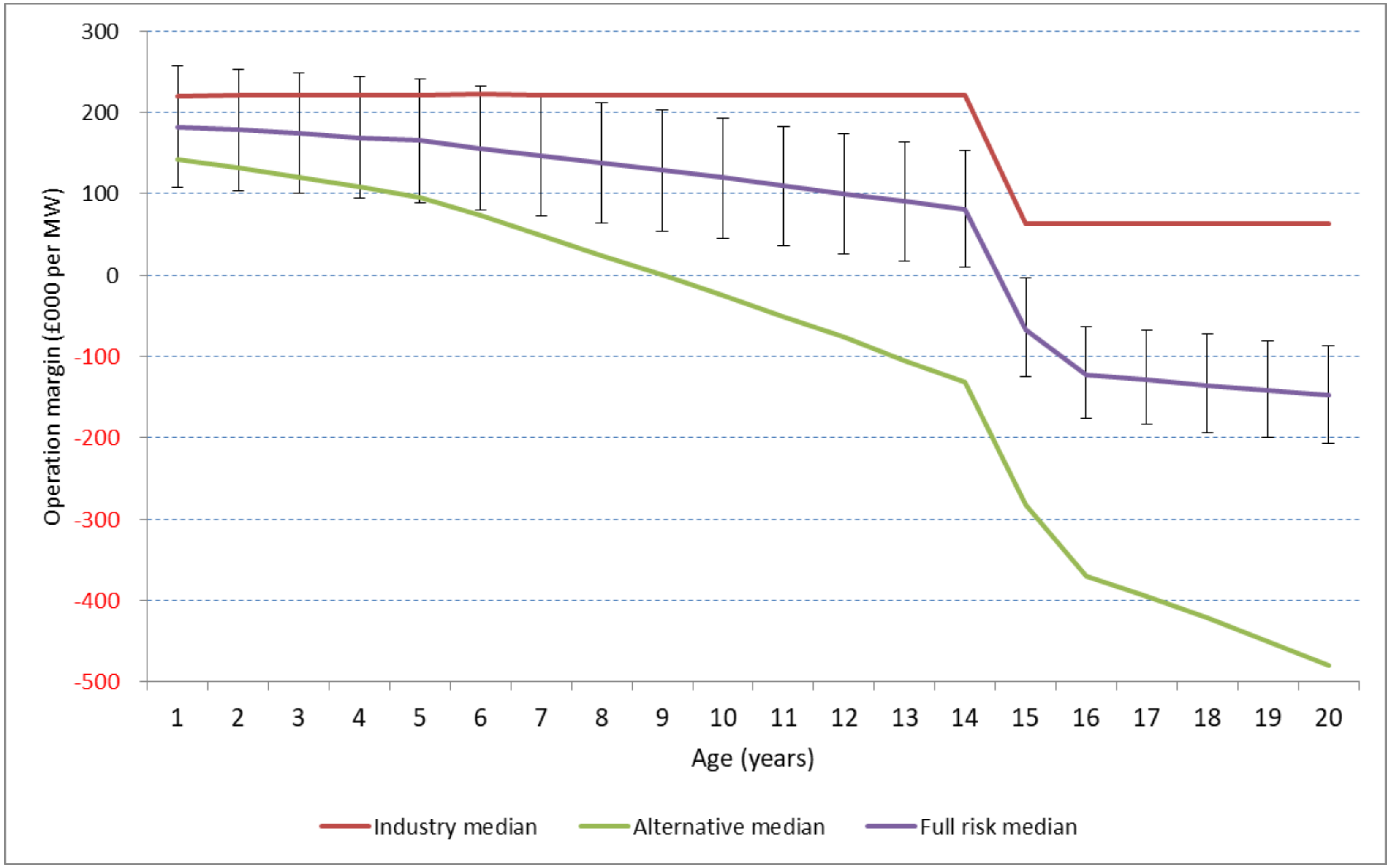

Table 1 – Indicators of investment return under alternative assumptions

	Economic life years	Payback period years	Net return in year 15 £000 per MW
Industry - median	25	11	970
Alternative - median	10	999	-4,372
Full risk - 5th percentile	14	999	-2,511
Full risk - median	15	999	-1,514
Full risk - 95th percentile	15	999	-547

Notes: (a) Risk analysis based on a CfD price of £75 per MWh at 2018 prices.
(b) A payback period of 999 years means that the original investment is never recovered.