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# A Flexibility-based Approach for the Design and Management of Floating Offshore Wind Farms

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## Abstract

Floating offshore wind farms have become a gateway to reach locations that are technically and economically infeasible to exploit using fixed platforms. However, the high capital investments and the uncertainty associated with the reliability, capacity factor, technology evolution, electricity demand, and regulatory frameworks negatively affect the cost of energy of this approach. Alternative strategies, such as designing for flexibility, have been shown to increase the value of engineering systems subject to highly uncertain environments. In this article, an analysis based on life-cycle costs and Monte-Carlo simulation is used to determine if floating wind farms with flexible installed capacity result in lower costs of energy than traditionally designed wind farms. Flexibility is introduced using an adaptable platform strategy and an over-dimensioned platform strategy. The results show that the adaptable platform strategy has the potential to reduce the cost of energy up to 18% by increasing the energy generation and the lifetime of some components of the wind farm. Nonetheless, the benefits of flexibility depend on new legislation that allows for lifetime extensions and proper flexibility management policies that utilize the potential built into the systems.

*Keywords:* Floating offshore wind generation, Flexibility, Adaptability, Life-cycle analysis, Repowering

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## 1. Introduction

Offshore locations have become a viable option to expand wind energy generation [1, 2] in the last decade. By 2020, the European Wind Energy Association expects to have between 19 and 27 GW installed [3]. However, the costs of building, maintaining, and operating offshore farms are higher than their onshore and close-to-shore counterparts [4, 1] due to the trend of increasing turbine sizes [5] and moving to deeper waters [6, 7, 8, 9] in locations far from shore and difficult access. To facilitate the exploitation of these remote locations, floating platform concepts have been proposed following the example of the oil and gas industry [9]. The main appeal of this concept is that it unlocks locations with water depths greater than 50 m, where bottom-fixed concepts are either technically infeasible or economically unfeasible [1]. However, the capital costs of floating projects can be as large as twice the cost for shallow waters [10]. These additional costs are partially explained by the extra length

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12 of mooring and export cables required [1], but also by the larger turbines deployed [2] and massive  
13 floating platforms. Furthermore, the difficulty to access remote locations increases both operation  
14 and maintenance costs due to the need for high-reliability [11].

15 The expected tendency is that larger and more expensive turbines will be available for farms  
16 located further from shore as the industry keeps developing [12]. For instance, a rapid increment in  
17 rotor diameter and hub height is reported in [5]. These measures are justified for reports such as [13],  
18 where it is stated that increasing the turbine power rating is the technological innovation that has  
19 the highest impact on reducing the energy cost. Other authors [14] report that doubling installed  
20 capacity can reduce the LCOE between 9 and 17%.

21 Going far from shore poses the additional challenges of dealing with extreme meteorological con-  
22 ditions that affect the reliability of the grid, increases maintenance costs, and increases turbines'  
23 downtime [7]. Möller et al [6] also identified larger uncertainties for far from shore scenarios, which  
24 may result in costs underestimation. Further sources of uncertainty related to external social phenom-  
25 ena such as market dynamics, demographic changes, political environment, the evolution of regulatory  
26 frameworks, and the development of new technologies pose additional challenges to the management  
27 and economic viability of offshore projects. These elements portrait a challenging landscape for  
28 offshore floating wind generation: large capital investments and a highly uncertain environment.

29 These conditions establish the need for innovations and alternative design and management  
30 philosophies. The cost reduction effect of increasing installed capacity points towards the imple-  
31 mentation of re-powering and lifetime extension strategies. Large costs are not the only challenge  
32 faced by floating offshore generation; highly uncertain environments also affect the system output,  
33 not only from a technical perspective but also from its perceived competitiveness. If floating offshore  
34 generation is to become a viable source of renewable energy, it needs the tools to deal with a complex  
35 uncertain environment, which requires going beyond re-powering strategies.

36 Different authors [15, 16, 17, 18, 19] have identified flexibility and adaptability as key properties  
37 to have in engineering systems in the face of uncertainty. These authors associate flexibility with  
38 a reduction in the negative impact of uncertainty and even an increased ability to better exploit  
39 new conditions. In the context of engineering systems, flexibility is usually defined as the ability  
40 of a system to be easily modified [20, 21, 22, 23, 24]. The option for future changes is introduced  
41 during the design stage and it is usually coupled with a management policy that suggests when an  
42 adaptation should be executed. In the case of wind turbines, flexibility already exists in different  
43 components in the nacelle that allow to increase the turbine efficiency and control the operating  
44 conditions. However, in this paper we consider flexibility as the option to increase the power rating  
45 of the turbines by installing adaptable floating platforms that enable fast replacements.

46 Although flexibility can be used to achieve re-powering, the concept goes beyond by including  
47 specific design measures to enable fast turbine replacement. Furthermore, the concept does not limit  
48 its applicability to specific time instants but takes proactive measures in the form of management  
49 policies to consider a wide range of external conditions that could motivate an adaptation. However,  
50 flexibility does not address problems encountered in re-powering approaches associated with the

51 financial closure and regulatory compliance of the project.

52 Developing floating offshore wind farms with flexible capacity could potentially increase the service  
53 life and reduce the LCOE. By allowing a fast deployment of larger generators, the wind farm could  
54 take advantage of new technologies to increase the installed capacity with reduced production and  
55 installation costs. A flexible design and management strategy could improve the competitiveness of  
56 operating offshore farms under variable external conditions. For these reasons, this work presents a  
57 parametric analysis to evaluate if flexibility is a valuable property for floating offshore wind farms from  
58 a life-cycle cost perspective. The results show not only that flexibility can be a desirable property, but  
59 also identify the flexibility configurations and management policies that produce the lowest LCOE.

60 This article is organized as follows: section 2 provides a literature review on the concept of  
61 flexibility in the context of engineering systems, section 3 presents the life-cycle cost model used  
62 to determine the costs for the baseline and flexible strategies, section 3.3 explains the simulation  
63 methodology followed to calculate the LCOE for all cases, and section 4 exemplifies the cost model  
64 and simulation methodology in a theoretical farm under multiple scenarios. The results obtained  
65 in this section are used to draw conclusions about the impact of flexibility in the cost of energy of  
66 floating offshore wind farms.

## 67 **2. Literature review: flexibility in engineering systems**

68 The concept of flexibility in engineering systems is not considered to be "academically mature"  
69 [21] because an exact and commonly agreed definition is yet to be proposed. In this work, flexibility  
70 will be understood as defined in [25, 22, 24]: Flexibility is the ability of a system to easily adapt any  
71 of its components. The measurement of the effort is generally given in terms of the resources needed  
72 to perform the change. It is assumed that an initial investment is required to introduce the option.  
73 This additional expenses may come from lengthier design processes and additional materials. It is  
74 expected that the size of the initial investments will limit the scope of the adaptations that can be  
75 performed through flexibility.

76 This description of flexibility can be translated into a numerical representation, which can be  
77 useful to compare different flexible designs for the same system. This study uses the *flexibility vector*  
78 [24] described by Equation 1:

$$\mathbf{f}_i(t) = \left[ \frac{c_{nf,i} - c_{f,i}}{c_{f,i}}, \frac{x_{max,i}(t) - x_i(0)}{x_i(0)} \right] \quad (1)$$

79 This vector describes the flexibility for the design/operational parameter  $i$  using two components:  
80 the first component measures the resources required to perform an adaptation as the ratio between the  
81 unitary cost of modifying  $i$  without flexibility  $c_{nf,i}$  (without being specifically designed to be adapted);  
82 and the unitary cost of performing an adaptation with flexibility  $c_{f,i}$ . The second component measures  
83 the size of the adaptation space as the ratio between the maximum value that  $i$  can take and its initial  
84 value  $x_{max,i}/x_i(0)$ . Following this definition, a system's element  $i$  can increase its flexibility reducing  
85 the adaptation costs or by increasing the adaptation space. The flexibility vector in Equation 1 is

86 defined for a single design or operation parameter of the system. Depending on the system, multiple  
87 flexibility vectors may be needed to describe all adaptation capabilities.

### 88 2.1. Flexibility management policies

89 Designing an engineering system to be flexible is not enough to obtain the reported advantages.  
90 The timing and magnitude of the adaptations need to be properly devised to ensure that the system  
91 response is optimal [20, 26, 25, 27, 23, 24]. These decisions depend both on technical constraints  
92 on the system’s performance and specific demands dictated by stakeholders’ preferences, regulatory  
93 frameworks, and user requirements. These sets of preferences can be modeled using *policies*.

94 Policies are functions that map a set of system states to decisions [27, 28]. The family and specific  
95 parameters of the function allow encapsulating the set of preferences that control the adaptation  
96 process. While in some cases the adaptation policies take complex forms to consider risk preferences,  
97 for many applications a deterministic policy of the form of "if-then" conditionals that trigger an  
98 adaptation process [29] is enough to model a wide range of real-life conditions.

99 The use of policies allows to model the process of managing flexibility as a *sequential decision*  
100 *process* (SDP). The generic SDP model requires an environment and an agent that observes the state  
101  $s(t)$  of the environment at time  $t$  and selects an action  $a(t)$  based on the policy  $\pi$ . At the next time  
102 step, a reward  $r(t)$  is generated by the environment and received by the agent, while a new state  
103  $s(t + 1)$  is reached according to a probabilist model. This model combines random elements with the  
104 sequence of previous states  $s(1 : t)$  and actions  $a(1 : t)$  [30]. Then, the agent observes the new state  
105 and selects a new action  $a(t + 1)$  according to  $\pi$ .

106 In the case of flexible system management and design, the SDP is applied as follows: First, define  
107 the system’s initial design properties  $x(0)$  and  $x_{max}$  (flexibility range of design/operation parameter  
108  $x(t)$ ). Second, define the policy  $\pi$  to guide the adaptation management decisions. Third, during  
109 the operation stage, the conditions defined by the policy are monitored to perform an adaptation if  
110 needed. This results in a sequence of time instants  $\tau_1, \tau_2, \dots$ , and adaptation sizes  $y_{\tau_1}, y_{\tau_2}, \dots$  for  
111 all future adaptations. Figure 1 presents a diagram that synthesizes this design and management  
112 process.

### 113 2.2. Flexibility in offshore floating wind turbines

114 The concept of flexibility can be applied in different ways to floating offshore wind turbines. In this  
115 study two strategies are considered: i) over-dimensioned floating platforms that allow fast installation  
116 of new, larger turbines (Strategy A), and ii) floating platforms that are specifically designed to be  
117 adapted (expanded) when larger turbines are required and available (Strategy B) (see Figure 2).

118 While both strategies accomplish the same objective of allowing fast replacement of the wind  
119 turbines, Strategy B has higher design costs due to research and development activities required to  
120 design adaptable floating platforms. In contrast, production costs are higher for the larger platform  
121 of Strategy A due to its larger size. In both cases, however, the mooring and transmission lines are  
122 over-designed to restrict the adaptations to the platforms only.

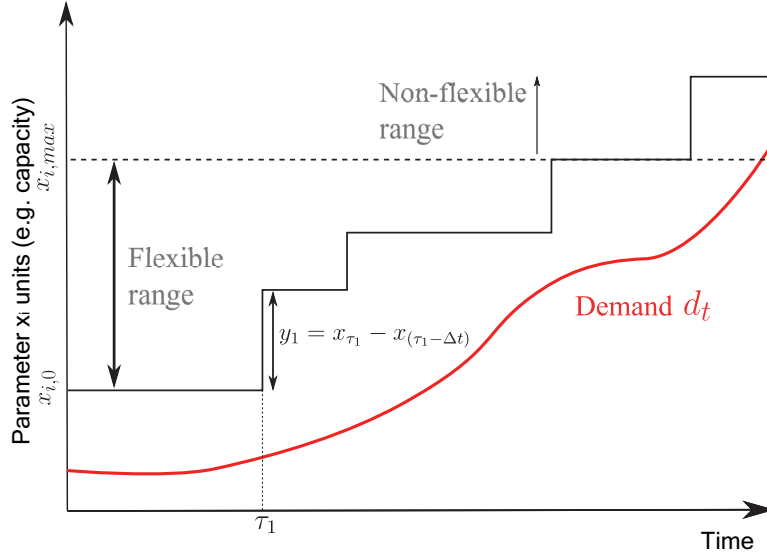


Figure 1: Description of the main elements for flexible designs

123 When an adaptation is performed, there are additional costs for Strategy B due to the necessary  
 124 modifications to the platform. The platform from Strategy A has the advantage of allowing an  
 125 immediate replacement of the turbine. In summary, the difference between strategies is the trade-off  
 126 between initial and future costs. It is important to remark that the details of the design of the  
 127 adaptable platform from Strategy B are beyond the scope of this study.

128 A key element to consider is the type of floating platform. There are three design concepts that  
 129 commonly appear in the literature: i) semi-submersible platforms (SSPs), ii) spar buoys (SBs), and  
 130 iii) tension-leg platforms (TLPs). Each platform type has different draft requirements that affect the  
 131 installation process. While SSPs can be towed from port to the farm site, assembling the turbines with  
 132 the SBs or TLPs and towing them from port is usually not an option due to the draft requirements for  
 133 these platforms. The assembly is usually done in deeper waters using floating cranes before the joint  
 134 turbine and platform can be towed to the site. Furthermore, the SSPs offer a shape more suitable for  
 135 adaptable modular designs. According to [31, 32, 33], SSPs exhibit the lowest LCOE for a wide range  
 136 of farm configurations. Assembly can be completed using only a port crane, which is considerably  
 137 less expensive than using a floating crane. For these reasons, only SSPs are considered in this study.



Figure 2: Flexible strategies for floating platform expansions

### 138 3. Life-cycle cost model

139 The evaluation of the economic performance for the flexible strategies is conducted by estimating  
140 the Life-cycle Cost of Energy (LCOE) and comparing it with a baseline case with no flexibility. The  
141 LCOE is a measure widely used to compare energy generation alternatives by providing an estimation  
142 of the average cost of the energy generated.

143 Estimating these costs for a floating offshore farm is challenging due to the absence of commercial  
144 operating farms and the complexity of the systems [2]. The models proposed in [34, 33, 10] provide  
145 the best guides available. According to these models, the life-cycle costs of offshore wind farms can  
146 be associated with the following stages: i) planning, development, and design; ii) production and  
147 installation; iii) operation; and iv) decommissioning.

148 The planning, development, and design stage costs  $PDD$  represent the cost of activities that  
149 must be completed before the construction phase such as surveys, development of design concepts,  
150 arrangement of legal requirements, and other activities related with project management. These costs  
151 are sometimes reported as a unitary price per unit of installed capacity.

152 The production and material costs,  $PM$ , are defined for each component: turbines, floating  
153 platforms, mooring and anchoring, and electrical systems. Turbines and platforms costs can be  
154 estimated from unitary prices and the capacity of the farm; mooring, anchoring and electrical systems'  
155 costs are estimated from a price per unit of length.

156 Installation costs  $I$  depend mainly on farm component, distance from port, and installation proce-  
157 dure. In particular, the installation procedure determines the fleet composition which is a key element  
158 in the estimation of  $I$ . The next section summarizes the analytical expressions used to estimate these  
159 costs.

160 The operation and maintenance costs,  $OM$ , include transmission charges and maintenance activ-  
161 ities. The transmission charges are usually represented as a constant amount paid to the government  
162 per MWh produced. Maintenance activities can be classified as preventive and corrective. Preventive  
163 maintenance costs are represented as a constant yearly cost, while corrective costs depend on the  
164 failure rate of individual components [11]. Various authors [8, 35, 12] have found empirical models to  
165 calculate these costs as a function of the installed capacity and the distance to shore.

166 In the case of flexible farms, the operation stage must include the adaptation costs  $A$ . For the  
167 flexibility strategies discussed in section 2.2 these costs vary as follows: For Strategy A,  $A$  are the  
168 costs of acquiring and installing the new turbines. For Strategy B,  $A$  includes both acquiring and  
169 installing new turbines and expanding the platforms. The estimation of these costs is detailed in  
170 section 3.2.4.

171 The costs of decommissioning  $D$  include the labor costs, transportation costs, and processing  
172 costs [36]. These costs can be partially offset by recycling most of the raw materials. Empirical  
173 models in the literature [10] have estimated decommissioning costs as a percentage of installation  
174 costs depending on the farm component (turbines, cables, etc.).

175 Once these costs have been determined, the present value is calculated as:

$$PV_C = PPD + PM + I + \sum_{t=1}^T \frac{OM(t) + A(t)}{(1+r)^t} + \frac{D}{(1+r)^T} \quad (2)$$

176 where  $T$  is the planning horizon and  $r$  is the discount rate.

### 177 3.1. LCOE estimation

178 To complete the estimation of the LCOE it is necessary to provide a single value to represent the  
179 energy generated. The total discounted generated energy  $PV_E$  can be calculated using Equation 3.

$$PV_E = \sum_{t=1}^T \frac{E(t)}{(1+r)^t} \quad (3)$$

180 where  $E(t)$  is the energy generated in time step  $t$  in  $MWh$ .

181 The LCOE is then calculated as the ratio between  $PV_C$  (Equation 2) and  $PV_E$ :

$$LCOE = \frac{PV_C}{PV_E} \quad (4)$$

### 182 3.2. Installation and adaptation costs definition

183 As discussed at the start of section 3, installation costs  $I$  and adaptation costs  $A$  depend on farm  
184 location, turbine assembly strategy, and transport fleet composition. The estimation of these costs  
185 is done using analytical expressions to model the specific conditions. The following sections present  
186 the equations adapted from the models published in [2, 33, 10].

187 Due to the large number of parameters, the following naming convention is adopted:  $var_{a,b}$ , where  
188  $var$  can be any variable from Table 1, and  $a, b$  can be physical elements from Table 2 or activities from  
189 Table 3. Subscript  $a$  represent the direct element or activity measured by  $var$  and  $b$  is a complement.  
190 For instance,  $n_{wt,b}$  represents the number of turbines transported per barge, while  $n_{b,wt}$  represents  
191 the number of barges used to transport turbines.

Table 1: Variables' abbreviations

Symbol	Name	Unit	Symbol	Name	Unit
$I$	Installation cost	€	$PM$	Production and materials cost	€
$PPD$	Planning, development and design costs	€	$OM$	Operation and maintenance cost	€
$A$	Adaptation cost	€	$D$	Decommissioning cost	€
$t$	Time	hour	$c$	Unitary cost	€/unit
$d$	Distance	$m$	$s$	Surface	$m^2$
$l$	Length	$m$	$w$	Width	$m$
$v$	Speed	m/s	$n$	Number of elements	-
$k$	Numerical coefficient	-	$R$	Rate of installation	unit/da
$\phi$	Diameter	$m$			



Table 2: Elements abbreviations

Symbol	Name	Symbol	Name
<i>wt</i>	Wind turbine	<i>fp</i>	Floating platform
<i>tug</i>	Tug	<i>b</i>	Barge
<i>pc</i>	Port crane	<i>fc</i>	Floating crane
<i>a</i>	Anchor	<i>ml</i>	Mooring line
<i>AHV</i>	Anchor handling vehicle	<i>CLV</i>	Cable laying vehicle
<i>ca</i>	Cables	<i>aca</i>	Array cables
<i>eca</i>	Export cables	<i>pp</i>	Platform parts
<i>ofs</i>	Offshore substation	<i>ons</i>	Onshore substation
<i>GIS</i>	Gas insulated switchgear	<i>ts</i>	Transformer
<i>dt</i>	Downtime	<i>p</i>	Port
<i>bl</i>	Turbine blade	<i>tw</i>	Turbine tower

Table 3: Activities abbreviations

Symbol	Name	Symbol	Name
<i>is</i>	Installation on site	<i>ip</i>	Installation at port
<i>tr</i>	Transport	<i>sr</i>	Surface rental
<i>ld</i>	Load into vessel	<i>la</i>	Labor
<i>mo</i>	Mobilization of vessel	<i>lf</i>	Lifting
<i>im</i>	Machinery internal movements	<i>sl</i>	Soil preparation
<i>fd</i>	Foundation	<i>pa</i>	Partial assembling

### 192 3.2.1. Wind turbine and floating platform installation costs

193 The first installation costs considered are for the floating platforms  $I_{fp}$ . These costs are estimated  
194 assuming specific assembly and transportation procedures for the wind turbine and its platform.  
195 The assembly procedure of the wind turbine (tower, rotor, nacelle, and blades) is completed at the  
196 port using a crane; then, the full turbine is joined with the floating platform. The joint turbine  
197 and platform are loaded into tug vessels to be towed (wet transportation) to the farm site. This  
198 transportation method is possible due to the low draft of SSPs [10].

199 The described installation procedure results in the following costs: port costs  $I_{p,fp}$  associated with  
200 the storage of turbine and platform components and the use of a port crane to load the assembled  
201 turbine into the vessels; transportation costs  $I_{tr,fp}$  of using tug vessels, and installation costs  $I_{ip,fp}$   
202 associated with the use of the port crane to assemble the turbine and the platform. Therefore, total  
203 installation costs for turbines and platforms are [33]:

$$I_{fp} = I_{p,fp} + I_{tr,fp} + I_{ip,fp} \quad (5)$$

204 Port costs  $I_{p,fp}$  are calculated using the following equation:

$$I_{p,fp} = t_{sr,fp} s_{fp} c_{sr} + n_{wt} t_{ld,fp} c_{pc} \quad (6)$$

205 where  $c_{sr}$  is the cost of port surface rental (€/ $m^2 day$ ),  $n_{wt}$  is the number of wind turbines, and  $c_{pc}$   
 206 is the cost of port crane rental (€/hour). See Appendix A.1 for details on the estimation of these  
 207 values.

208 The transportation costs of the platform  $I_{tr,fp}$  are defined as:

$$I_{tr,fp} = n_{tug,fp} t_{tug,fp} c_{tug} + c_{tug,mo} \quad (7)$$

209 with  $n_{tug,fp}$  the number of tugs used per trip,  $c_{tug}$  the daily cost of the tug vessel (€/day), and  
 210  $c_{tug,mo}$  its mobilization cost (€).

211 The installation cost of the turbine and platform at port is:

$$I_{ip,fp} = \frac{t_{ip,fp}}{24} n_{wt} c_{pc} \quad (8)$$

### 212 3.2.2. Anchoring and mooring installation costs

213 The costs of installing the mooring lines and the anchors  $I_{a\&ml}$  are calculated assuming that an  
 214 Anchor Handling Vehicle (AHV) is used for the task and that both the turbine platforms and the  
 215 substation platforms use the same number of anchors each.

$$I_{a\&ml} = (c_{AHV} + c_{la,a\&ml}) \frac{n_a}{R_{AHV}} \quad (9)$$

216 where  $c_{AHV}$  is the cost of using the AHV (€/day),  $c_{la,a\&ml}$  are labor costs (€/day), and  $R_{AHV}$  is  
 217 the anchor installation rate (per day).

218 The number of anchors  $n_a$  is calculated as:

$$n_a = (n_{wt} + n_{fp,ofs}) n_{ml,fp} \quad (10)$$

219 where  $n_{fp,ofs}$  is the number of floating platforms for the offshore substation, and  $n_{ml,fp}$  is the number  
 220 of mooring lines per platform.

### 221 3.2.3. Electrical systems installation costs

222 The installation costs of electrical systems are divided into installation of cables  $I_{ca}$ , installation of  
 223 offshore substation  $I_{ofs}$ , and installation of onshore substation  $I_{ons}$ . The installation costs of cables  
 224  $I_{ca}$  can be further divided into installation costs of array cables to interconnect the turbines with the  
 225 offshore substation  $I_{aca}$ , export cables that connect the offshore substation with shore  $I_{eca,ofs}$ , and  
 226 onshore export cables  $I_{eca,ons}$  to reach the onshore substation, as shown by Equation 11:

$$I_{ca} = I_{aca} + I_{eca,ofs} + I_{eca,ons} \quad (11)$$

227 The installation costs for the array cables  $I_{aca}$  are calculated considering the use of specialized  
 228 vehicles such as Cable Laying Vessels (CLVs) according to Equation 12 [10]:

$$I_{aca} = \frac{c_{CLV,aca}}{R_{CLV,aca}} l_{aca} \quad (12)$$

229 where  $c_{CLV,aca}$  is the daily cost of the CLV, and  $R_{CLV,aca}$  its installation rate.

230 The total length of array cable  $l_{aca}$  depends on the sea depth, the distance between turbines, and  
231 the position of the offshore substation relative to the turbines.

232 The offshore export cable installation costs  $I_{eca,ofs}$  are calculated similarly, but considering that  
233 the vessel daily cost  $c_{CLV,eca}$  and installation rate  $R_{CLV,eca}$  vary due to the difference in cables used:

$$I_{eca,ofs} = \frac{c_{CLV,eca}}{R_{CLV,eca}} l_{eca,ofs} \quad (13)$$

234 with  $l_{eca,ofs}$  the length of offshore export cable ( $m$ ).

235 The onshore cable installation costs  $I_{eca,ons}$  are calculated as:

$$I_{eca,ons} = c_{eca,ons} l_{eca,ons} \quad (14)$$

236 where  $c_{eca,ons}$  is the unitary price of cable installation ( $\text{€}/m$ ) and  $l_{eca,ons}$  is distance between shore  
237 and the onshore substation ( $m$ ).

238 The installation costs for the offshore substation  $I_{ofs}$  are estimated similarly as in the case of the  
239 wind turbines, considering port costs  $I_{p,ofs}$ , transportation costs  $I_{tr,ofs}$ , and on-site installation costs  
240  $I_{is,ofs}$  [33, 10]:

$$I_{ofs} = I_{p,ofs} + I_{tr,ofs} + I_{is,ofs} \quad (15)$$

241 The port costs  $I_{p,ofs}$  consider the hiring of the port surface to store the transformers and floating  
242 platforms  $s_{ofs}$  until they are loaded to be transported, and the rental of the port crane to load the  
243 parts into the vessels, as shown by Equation 16 [33]:

$$I_{p,ofs} = t_{sr,ofs} s_{ofs} c_{sr} + (n_{ts} + n_{fp,ofs}) (t_{ld,ts} + t_{ld,fp}) c_{pc} \quad (16)$$

244 with  $n_{ts}$  the number of transformers. The expressions to estimate these values are presented in  
245 Appendix A.2.

246 The transportation costs for the offshore substation are calculated as:

$$I_{tr,ofs} = (n_{b,ofs} t_{b,ofs} c_b) + (n_{tug,ofs} t_{tug,ofs} c_{tug}) + c_{b,mo} + c_{tug,mo} \quad (17)$$

247 where  $n_{b,ofs}$  and  $n_{tug,ofs}$  are the number of vessels in the operation.

248 Finally, the installation costs are estimated as:

$$I_{is,ofs} = t_{fc,ofs} c_{fc} + c_{fc,mo} \quad (18)$$

249 with  $c_{fc}$  and  $c_{fc,mo}$  the daily rate and the mobilization cost of the floating crane.

250 The installation costs for the onshore substation  $I_{ons}$  are estimated using Equation 19 [33]:

$$I_{ons} = I_{sl,ons} + I_{fd,ons} + I_{is,ons} \quad (19)$$

251 with  $I_{sl,ons}$  the costs of preparing the soil,  $I_{fd,ons}$  the cost of the foundation, and  $I_{is,ons}$  the cost of  
 252 installation.

#### 253 3.2.4. Adaptation costs

254 The costs of performing an adaptation depend on the flexibility strategy, as described in section  
 255 2.2. For Strategy A, the adaptation costs correspond to the acquisition costs of the new turbines  
 256 plus the installation costs. In this case, the installation procedure differs from the process followed  
 257 during the farm construction. The turbines cannot be fully assembled and towed, and instead, they  
 258 are transported in parts using a barge. Parts of the turbine may be partially assembled at port. The  
 259 installation at sea is conducted using a floating crane to dismount the old turbines and install the  
 260 new devices on the existing platforms. The use of floating cranes comes from the assumption that  
 261 minimizing the adaptation times is the priority. For an alternative objective, a different procedure,  
 262 such as towing the platforms back to port, could be proposed.

263 The costs for this installation procedure can be divided in port costs  $A_p$ , transportation costs  $A_{tr}$ ,  
 264 and installation costs  $A_{is}$ , as described by Equation 20:

$$A = A_p + A_{tr} + A_{is} \quad (20)$$

265 Port costs  $A_p$  consider the rental of storage area at the port and the use of a port crane to load  
 266 the turbine into the transport vessel:

$$A_p = t_{sr,wt} s_{wt} c_{sr} + n_{wt} t_{ld,wt} c_{pc} \quad (21)$$

267 See Appendix A.3 for details on the estimation of these values.

268 The transportation costs  $A_{tr}$  using a barge vessel are defined in Equation 22.

$$A_{tr} = n_{b,wt} t_{b,wt} c_b + c_{mo,b} \quad (22)$$

269 The installation costs  $A_{is}$  are divided between the preassembly costs using the port crane and the  
 270 offshore installation costs using a floating crane, according to Equation 23:

$$A_{is} = t_{fc,wt} c_{fc} + c_{fc,mo} + 24 t_{pc,pa} c_{pc} \quad (23)$$

271 For the case of Strategy B, a slightly different adaptation procedure is followed. This strategy  
 272 requires the transportation and installation of floating platform expansion elements besides the new  
 273 turbines. While Equations 20-23 are valid, a few modifications are needed in the number of lifting  
 274 movements to consider the additional elements that must be loaded, transported, and installed.

275 Specifically,  $n_{li,wt}$  in Equation A.15 and  $n_{li,is}$  in Equation A.18 must be increased by the number of  
 276 platform adaptation parts  $n_{pp}$ . The number of devices transported per barge vessel  $n_{wt,b}$  in Equation

277 A.14 also has to be adjusted to account for the additional space on deck required to place the platform  
 278 parts.

### 279 3.3. Simulation Methodology

280 The purpose of the cost model presented in previous sections is to evaluate the impact of flexibility  
 281 in the economical performance of floating offshore wind farms under uncertain demand, technology  
 282 prices, and capacity factor. For this purpose, a Monte-Carlo simulation procedure, described in Figure  
 283 3, was developed.

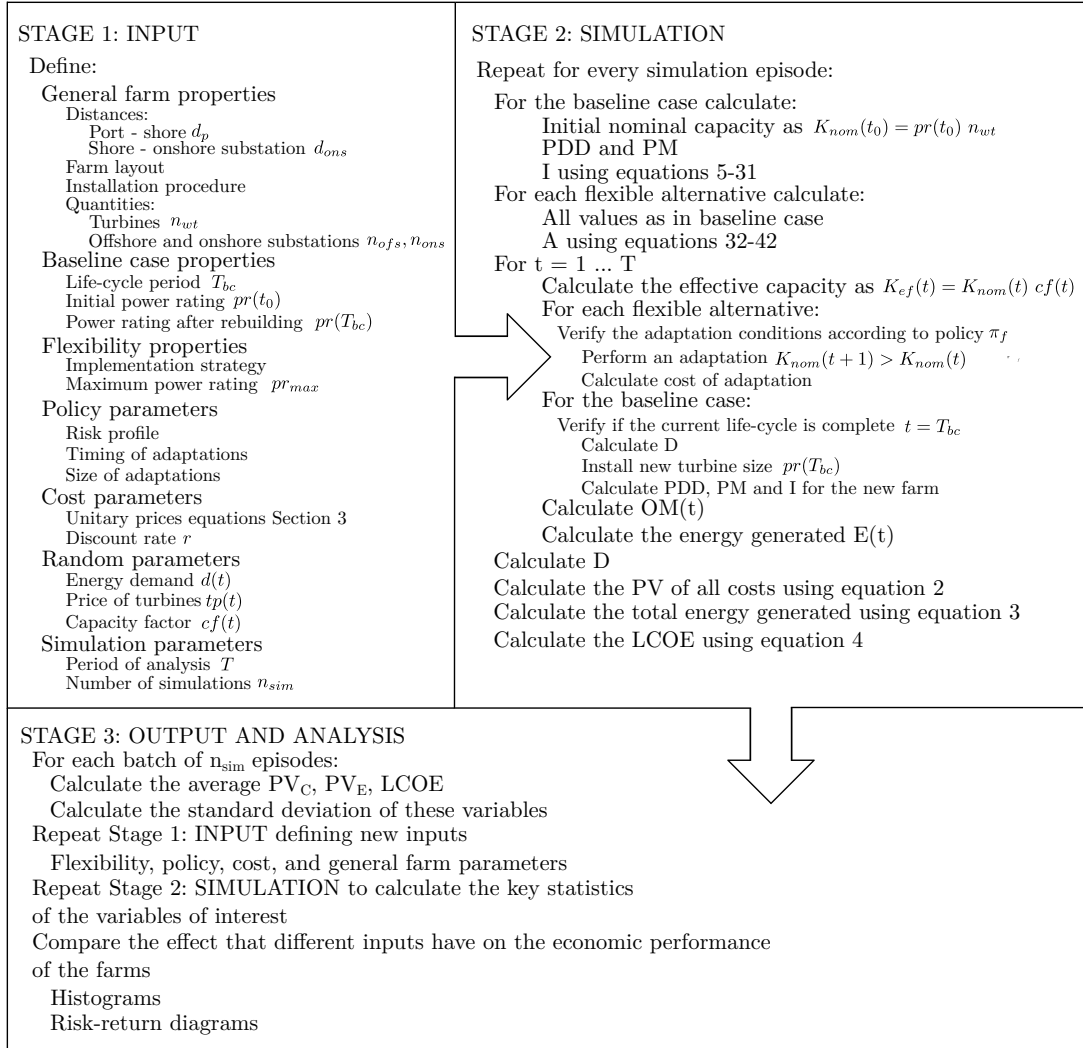


Figure 3: Stage 1: Input

284 The procedure consists of 3 stages: Definition of input parameters, simulation, and output anal-  
 285 ysis. In the first stage, as shown by Figure 3, the parameters that characterize the farm, the costs,  
 286 the random processes and the policy are defined together with the meta-parameters of the simula-  
 287 tion. During the second stage, multiple trajectories of the random processes are simulated, and the  
 288 discounted life-cycle costs and energy generated are calculated for the different system responses. In  
 289 the third stage, the average LCOE is estimated for the batch of data from the second stage and

290 conclusions are drawn by comparing the results for the flexible and baseline cases. This procedure is  
 291 repeated for each farm configuration, flexibility strategy, and flexibility policy to be analyzed.

292 The computational implementation of this methodology can be performed using algorithms of  
 293 order  $O(n)$ . The independence between runs encourages the use of parallel computing to reduce pro-  
 294 cessing times. An implementation in Matlab<sup>®</sup> 2017b using an Intel<sup>®</sup>Core™ i5-5200 2.20GHz processor  
 295 takes 15 seconds in average to run one batch of 1000 simulations.

#### 296 4. Numerical Example

297 The life-cycle cost model presented in section 3 and the simulation procedure presented in section  
 298 3.3 are tested using a generic farm. Five cases are considered: flexible Strategy A (i), B (ii), a baseline  
 299 case (iii), a case with no re-powering (iv), and a re-powering case with no decision flexibility (v). The  
 300 flexible strategies are described in section 2.2. The baseline case represents a wind farm without  
 301 flexibility, which is rebuilt once in the middle of the planning horizon. This includes removing all  
 302 installed components including mooring lines and transmission cables. The case with no re-powering  
 303 is similar to the baseline case but the farm is never rebuilt. The last case also has over-designed  
 304 platforms, as in case (i), but the adaptation is always conducted in the middle of the planning  
 305 horizon. When the the farm is rebuilt or re-powered, the new installed capacity is defined by a  
 306 required demand/capacity ratio.

307 The planning horizon is defined as  $T = 50$  years to allow the comparison of the flexible strategies  
 308 with two life-cycles of cases (iii) and (v), which are assumed equal to 25 years each [36]. Case (iv)  
 309 remains unchanged during the entirety of  $T$ . The farm location is defined at 100 km from shore  
 310 (where the port is also located), but a sensitivity analysis of this parameter is considered. Similarly,  
 311 the initial average sea depth is 100 m but other depths are addressed in the sensitivity analysis. The  
 312 farm has 100 units with identical power rating, arranged in a grid pattern of  $10 \times 10$  units (see Figure  
 313 4). The average distance between units is 7 times the initial turbine diameter. The electrical systems  
 314 are composed of one substation offshore and one onshore. The offshore substation is located in the  
 315 center of the grid (Figure 4), while the onshore substation is located 5 km inland. Wake and electrical  
 316 losses are assumed constant.

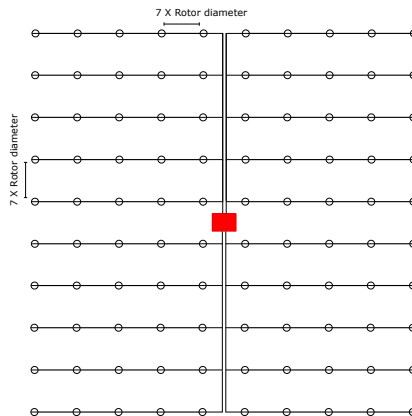


Figure 4: Farm Layout

Table 4: Costs of planning, development, design and production of turbines and platforms

Source and values of various unitary prices					
$PM_{fp}$ (€/MW)	Source [10]				Average
	1 274 900				1 274 900
$PDD$ (€/MW)	Source [1]	Source [2]	Source [8]		Average
	210 000	577 900	280 600		356 167
$PM_{wt}$ (€/MW)	Source[1]	Source[2]	Source[8]	Source [12]	Average
	1 300 000	1 197 468	1 581 342	1 305 600	1 348 602

Table 5: Mooring and anchoring production costs

	Cost component	Value
Mooring	Length per turbine	900 m
	Total length	90 000 m
	Steel density	177 kg/m
	Total steel mass	15 930 000 kg
	Unitary steel mooring price	7.92 €/kg
Anchoring	Anchors per turbine	6
	Anchor weight	3150 kg
	Total anchor mass	1 980 900 kg
	Unitary steel anchoring price	2 €/kg

317 The cost parameters used to calculate the general costs described in section 3 are presented in the  
 318 following section. These cost parameters were obtained from multiple sources in the literature.

#### 319 4.1. Cost estimation

320 The first cost parameters considered are planning, development, and design costs  $PDD$ ; turbine  
 321 production costs  $PM_{wt}$ ; and floating platform production costs  $PM_{fp}$ . These costs are generally  
 322 reported as unitary prices in €/MW or converted using the rate of exchange of the year of the report  
 323 and adjusting it by the inflation of 2019. In this example, these costs are estimated as the average  
 324 unitary price of multiple sources, as shown in Table 4.

325 In contrast, the mooring and anchoring production costs  $PM_a, PM_{ml}$  are estimated using a unitary  
 326 price for the amount of steel required. Therefore, the total costs will depend on the number of anchors  
 327 per turbine, the length of each mooring line, the density of the steel used, and the unitary price of the  
 328 steel. The length of each mooring line is defined as 1.5 the average water depth. It is also assumed  
 329 that 6 mooring lines are used for each wind turbine. Table 5 summarizes these parameters for depths  
 330 of 100 m [10].

331 The production costs of electrical cables  $PM_{aca}, PM_{eca}$  are estimated based on a price per unit

Table 6: Electrical systems costs

Cost component	Value
Unitary price array cables	279 €/m
Unitary price export cables HVDC	336 €/m
Offshore substation	$0.11 \cdot n_{wt} p_r \cdot 1E6$
Onshore substation	0.5 Offshore substation cost

of length for each type of cable. The length of the inter-array cables is calculated using the layout from Figure 4 assuming that the cables are installed on the seabed. At the midpoint of each row of the grid, the cables are directed towards the offshore substation. The production costs of the offshore and onshore substations  $PM_{ofs}, PM_{ons}$  are estimated using an empirical function of the installed capacity found in the literature [10]. Table 6 presents these costs.

Installation costs for all farm components are calculated using the analytical expressions from sections 3.2.4 - 3.2.3 and the parameters in Table 7 [33, 10].

The costs for the adaptation process are divided between production costs and installation costs. Production costs correspond to the costs of new turbines, offshore and onshore substations, and, in the case of Strategy B, the floating platform expansion elements. Turbine costs are calculated using the prices in Table 4 and the stochastic processes from section 4.2. The costs of the substations are estimated using Table 6.

The operation and maintenance costs  $OM$  are generally reported in the literature as a function of both the installed capacity and the farm location. In this study, a linear approximation as a function of the distance to port is considered, for costs ranging between 110 000 and 130 000 €/MW/year. These values were estimated from recent reports in the literature [8, 35, 12].

Finally, the decommissioning costs are estimated as a percentage of installation costs plus an additional charge for site cleaning that depends on the farm area. These percentages depend on the element, as shown in Table 8 [1].

#### 4.2. Stochastic parameters

The simulation process considers the effect from three random processes as described in section 3.3: demand  $\delta(t)$ , technology (turbine) price  $tp(t)$ , and capacity factor  $cf(t)$ . These processes are simulated as time series with shapes and tendencies that follow historical data or predictions reported in the literature. For instance, the demand process is generated according to Equation 24:

$$\delta(t) = \max \{ \beta_1 t + e^{\beta_2 t} \beta_3 \sin(\beta_4 t) t + \beta_5 + B(t) t, 0 \} \quad (24)$$

where  $\beta_1$  to  $\beta_5$  are normally distributed random variables and  $B(t)$  is a Wiener process [37]. The values of these variables used in the example are presented in Table 9. The function  $\delta(t)$  allows to simulate a demand tendencies similar to the curves of the prediction models reported in [38, 39, 40]. While



Table 7: General cost parameters

Parameter	Value	Unit	Parameter	Value	Unit
$I_{fd,ons}$	312 000	€	$n_{fp,tug}, n_{fp,ofs}$	1	platforms
$I_{is,ons}$	63 500	€	$n_{fc,wt}$	1	vessels
$I_{sl,ons}$	660 000	€	$t_{ip}, fp$	3	hours
$c_{AHV}$	48 860	€/day	$n_{li,fp}$	6	lifts
$c_b$	35 000	€/day	$n_{li,ofs}$	4	lifts
$c_{CLV,aca}$	91/000	€/day	$n_{li,wt}$ Strategy A	5	lifts
$c_{CLV,eca}$	114/000	€/day	$n_{li,wt}$ Strategy B	8	lifts
$c_{pc}$	833.33	€/hour	$n_{li,is}$ Strategy A	10	lifts
$c_{fc}$	116 000	€/day	$n_{li,is}$ Strategy B	13	lifts
$c_{eca,ons}$	600	€/m	$n_{li,pa}$ Strategy A&B	2	lifts
$c_{la,a\&ml}$	5 656	€/day	$n_{ml,fp}$	6	mooring lines
$c_{b,mo}$	0	€	$n_{pp}$	3	parts
$c_{fc,mo}$	150 000	€	$n_{ts}$	3	transformers
$c_{tug,mo}$	0	€	$n_{tug,fp}$	2	vessels
$c_{sr}$	0.02	€/m <sup>2</sup> day	$n_{tug,ofs}$	1	vessels
$c_{tug}$	22 502	€/day	$n_{wt}$	100	turbines
$\phi_{bl}$	0.5	m	$R_{CLV,aca}$	150	m/day
$\phi_{tw}$	6	m	$R_{CLV,eca}$	200	m/day
$d_p$	100	km	$R_{AHV}$	7	anchors/day
$k_{dt}$	0.75	-	$r$	3%	-
$l_{bl}$	61.5	m	$t_{im,fc}$	8	hours
$l_{eca,ons}$	5000	m	$t_{li,fp}, t_{li,ofs}, t_{li,ts}, t_{li,wt}$	3	hours
$l_{fp}$	76	m	$t_{li,is}, t_{li,pa}$	3	hours
$l_{GIS}$	4	m	$v_b$	3.6	m/s
$l_{ts}$	6.3	m	$v_{fc}$	3.14	m/s
$n_a$	6	anchors	$v_{tug}$	3.6	m/s
$n_{b,ofs}, n_{b,wt}$	1	vessels	$w_{ts}$	5	m
$n_{ts,b}$	3	transformers	$w_{GIS}$	2.5	m
$n_{wt,b}$ Strategy A	6	turbines	$n_{wt,b}$ Strategy B	4	turbines

359 there is a general linearly increasing tendency, there are local oscillations that simulate medium-  
360 term variability. The addition of the Wiener process allows to model short-term variability, with  
361 uncertainty increasing in time. Figure 5a shows instances of the demand trajectories generated by  
362 Equation 24.

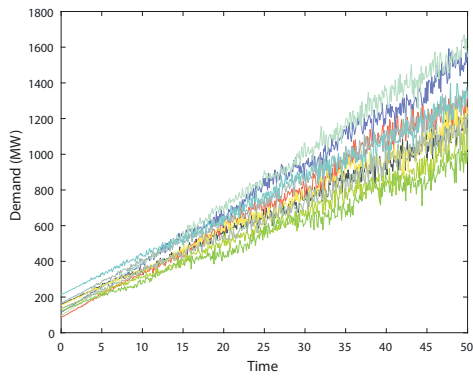
363 Similarly, the technology (turbine) price process is generated using Equation 25:

Table 8: General cost parameters

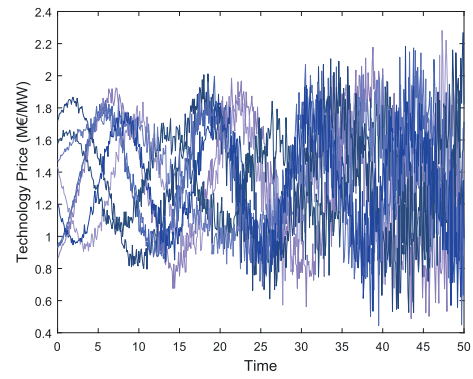
Decommissioning item	Percentage of installation costs / Unitary price
Turbine and platform	70%
Electric cables	10%
Substations	90%
Mooring lines anchoring	90%
Site cleaning	56400 €/km <sup>2</sup> [10]

Table 9: Random demand process parameters

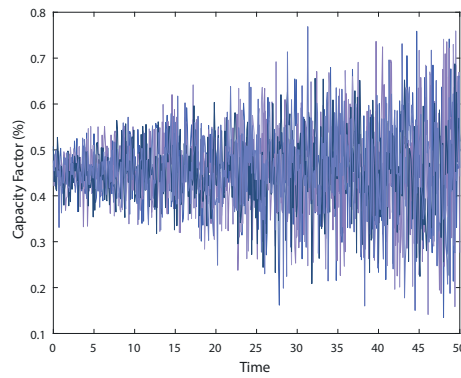
Parameter	Distribution( $\mu, \sigma^2$ )
$\beta_1$	$\mathcal{N}(20, 6)$
$\beta_2$	$\mathcal{N}(-0.02, 0.006)$
$\beta_3$	$\mathcal{N}(10, 3)$
$\beta_4$	$\mathcal{N}(0.5, 0.15)$
$\beta_5$	$\mathcal{N}(150, 45)$



(a) Demand process realizations



(b) Turbine price process realizations



(c) Capacity factor process realizations

Figure 5: Examples of the random processes

$$tp(t) = \max \{ \beta_1 \sin(\beta_2 t + \beta_3) + \beta_4 + B(t) t, 0 \} \quad (25)$$

364 where  $\beta_1, \beta_2$ , are normally distributed random variables,  $\beta_3$  is uniformly distributed, and  $\beta_4$  is a  
365 constant calculated as the average turbine prices reported in Table 4, and  $B(t)$  is a Wiener process.  
366 Table 10 presents the parameters of these variables used in the example. The function represents  
367 an oscillating trajectory according to the historical data shown in [41]. The oscillating behavior is  
368 justified by the variable price of the raw materials, which represent a considerable portion of the total  
369 turbine prices. Figure 5b shows instances of the trajectories generated using Equation 25.

Table 10: Random turbine price process parameters

Parameter	Distribution( $\mu, \sigma^2$ )
$\beta_1$	$\mathcal{N}(400000, 120000)$
$\beta_2$	$\mathcal{N}(0.4, 0.12)$
$\beta_3$	$\mathcal{U}[0, 2\pi]$
$\beta_4$	1348602

370 Finally, the capacity factor, which determines the effective capacity of the farm, is simulated as a  
371 random process according to the following equation:

$$cf(t) = \max \{ \beta_1 \sin(\beta_2 t) t + \beta_3 + B(t) t, 0 \} \quad (26)$$

372 where  $\beta_1, \beta_2$ , are normally distributed random variables,  $\beta_3$  is an average capacity factor, and  $B(t)$   
373 is a Wiener process. Again, the parameters of the variables used in the example are summarized in  
374 Table 11. Function  $cf(t)$  represent a rapidly oscillating tendency between typical values reported in  
375 the literature [42, 43, 44]. The increment in the uncertainty over time is a modeling decision that  
376 attempts to capture the difficulty of predicting for such long time periods. In this case, this variability  
377 may come from the evolution of environmental conditions, technological evolution of the turbines,  
378 and the improvement in the knowledge of the operation. Figure 5c shows instances of capacity factor  
trajectories generated by Equation 26.

Table 11: Random capacity factor process parameters

Parameter	Distribution( $\mu, \sigma^2$ )
$\beta_1$	$\mathcal{N}(5 \times 10^{-4}, 1.5 \times 10^{-4})$
$\beta_2$	$\mathcal{N}(0.7, 0.21)$
$\beta_3$	0.45

379

### 380 4.3. Flexibility policy

381 The flexibility management policy  $\pi_f$  discussed in sections 2.1 and 3.3 can be formulated for this  
382 example using two functions: First, function  $P : \mathbb{R}X\mathbb{R}X\mathbb{R} \rightarrow 0, 1$  maps the triplet  $(\delta(k), tp(k), cf(k))$

383 at time instant  $t = k$  to a value in the interval  $[0, 1]$ . The second function,  $Q : [0, 1] \rightarrow 0, 1$ , takes the  
 384 output of function  $P$  and produces a decision: 1 to perform an adaptation and 0 to do nothing. This  
 385 function requires an input parameter to define this decision threshold, the *adaptation trigger*  $AT$ .

386 Every time an adaptation decision is triggered, a second parameter, the *desired performance after*  
 387 *adaptation*,  $PAA$ , determines the turbine size to be installed based on the ratio demand/effective  
 388 capacity required after an adaptation is completed. This procedure is repeated until the installed  
 389 flexibility is depleted. Adaptations outside the flexibility range are not considered in the example.

#### 390 4.4. Results of simulation scenarios

391 The results presented in this section are the outcome of 1000 simulation episodes generated for a  
 392 single set of wind farm configurations and management policy parameters. For each episode and set  
 393 of parameters an installed capacity profile is obtained, as shown in Figure 6. Each episode consists  
 394 of 501 time steps, which means that the conditions of the decision process are evaluated 10 times per  
 395 year for the simulation period of 50 years.

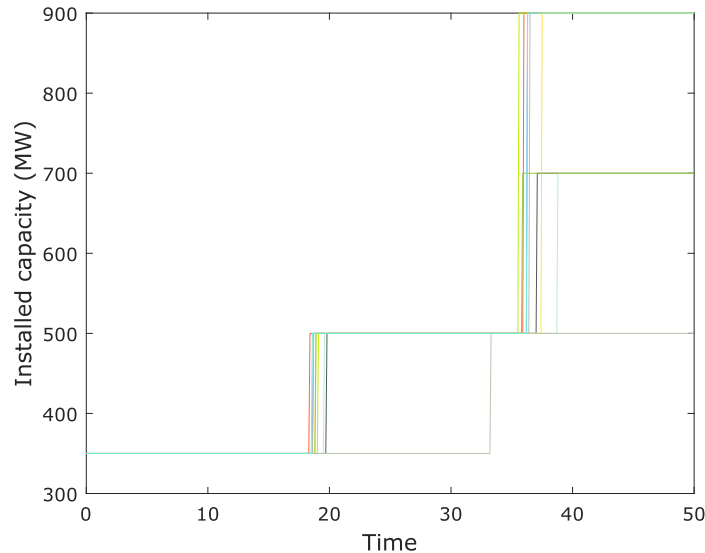


Figure 6: Installed capacity evolution

396 Each capacity profile is paired with a sequence of investments that occur at different time instants.  
 397 For instance, all the initial investments ( $PDD$ ,  $PM$ , and  $I$ ) are assumed as a punctual investment  
 398 occurring at the first time step. In contrast, the operation and maintenance costs  $OM(t)$  are calculated  
 399 as a sequence of investments uniformly distributed over the simulation period. Adaptation costs  $A(t)$   
 400 are punctual investments that occur at variable time steps. Instances of the adaptation costs profiles  
 401 are presented in Figure 7.

402 The profiles presented in Figures 6 and 7 show that the flexible strategies result in adaptations  
 403 every  $\sim 18$  years, in contrast with the single reconstruction in year 25 for the baseline case. This  
 404 adaptation frequency and the magnitude of the increments are the result of the policy defined (section  
 405 4.3) and the available flexibility.

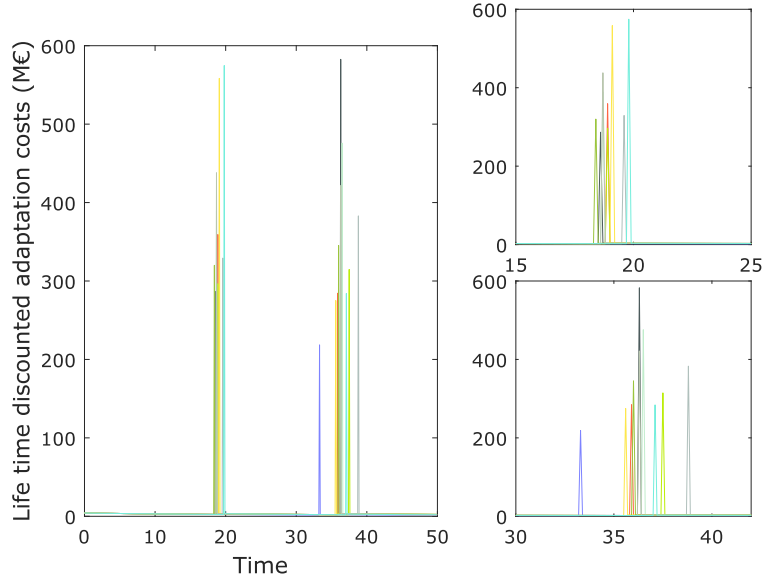


Figure 7: Evolution of discounted adaptation costs

406 The sensitivity analyses presented in the following sections explore the effect that various param-  
 407 eters related to the implementation of flexibility in floating wind farms have on the LCOE.

#### 408 4.4.1. Size of flexibility space

409 The first analysis evaluates the impact of the flexibility range on the LCOE. The flexibility range  
 410 of Equation 1 corresponds to the maximum turbine power rating allowed by the floating platform  
 411 designs, following either Strategy A or B. The initial power rating is assumed as 8 MW for both  
 412 flexible strategies and the baseline case. The maximum turbine power rating allowed by flexibility  
 413 can be [10 12 15 18 20] MW. When a maximum power rating larger than 8MW is selected, the system  
 414 has access to all intermediate sizes. All sizes are available to rebuild the baseline case at  $t = 25$  years  
 415 while case (v) has the same limit as Strategy A.

416 Figure 8 shows the average LCOE as a function of the flexibility range. The average LCOE values  
 417 vary between 65 and 95 €/MWh, which is similar to the values described in the most recent technical  
 418 reports [43, 44]. It can be observed that the lowest LCOE is produced by the unchangeable system  
 419 (case (iv)) followed by Strategy B and the baseline case. This suggests that the cost of replacing the  
 420 turbines is too large and is not compensated by the additional energy produced. However, case (iv)  
 421 provides a bound rather than a realistic alternative because it may be too optimistic to assume that  
 422 a wind farm can operate for 50 years without at least one major replacement.

423 Figure 8 also shows that both flexible strategies and re-powering case (v) result in lower LCOE  
 424 compared with the baseline case for maximum power ratings up to 15 MW. Beyond that point,  
 425 implementing flexibility using Strategy A becomes overly expensive, while Strategy B slowly loses its  
 426 advantage over the baseline case. The difference in slopes between Strategy A and B shows the large  
 427 impact that expensive flexibility-introduction measures have on the overall economical performance of  
 428 the farm. Strategy B is competitive because it can take advantage of low turbine prices, as Strategy A,  
 429 with a lower initial investment. Case (v) follows the same trajectory as Strategy A, but the difference

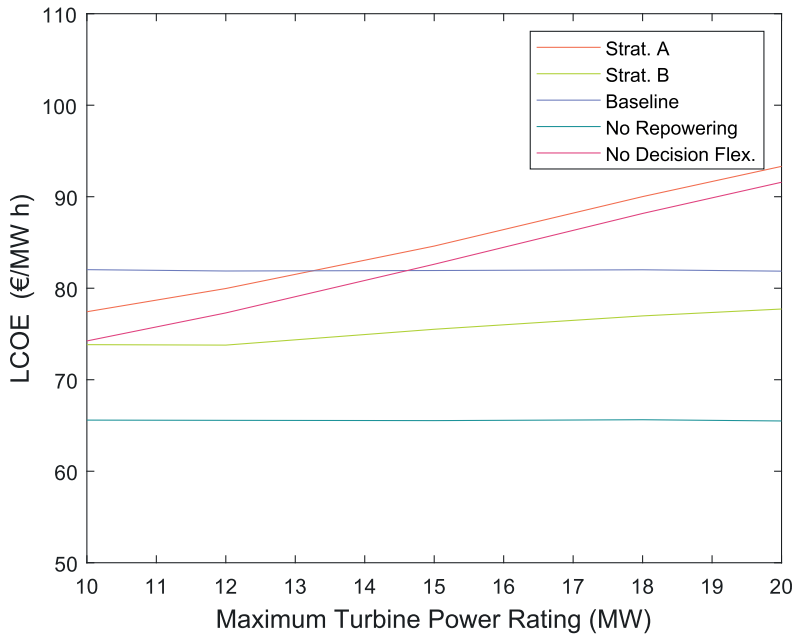


Figure 8: Average LCOE for variable maximum flexible range

430 in the adaptation timing creates a small gap due to discounting.

431 Besides the increased cost, the flexible strategies suffer from stagnation in the energy generated,  
 432 as shown in Figure 9. This figure shows that the flexible strategies are able to generate more energy  
 433 than all the other options, but the asymptotic behavior observed in both strategies suggests that  
 434 the external conditions are not sufficient to justify the investments required for the largest flexibility  
 435 ranges, and this is reflected in the larger LCOE. This highlights the fact that the value offered by  
 436 flexibility not only depends on the design properties but also on the management policy and the  
 437 external conditions.

#### 438 4.4.2. Policy parameters

439 The results from the previous experiment offered a glimpse of the importance of the flexibility  
 440 management policy. For this analysis, the management policy is defined as described in section 4.3,  
 441 using two parameters: the adaptation trigger  $AT$  and the desired performance after adaptation  $PAA$ .  
 442 The first parameter influences the timing of the adaptations while the second parameter affects the  
 443 magnitude of the change. An  $AT$  close to 1 represents an insensitive policy that requires extreme  
 444 conditions to decide to perform an adaptation. A  $PAA$  close to 1 represents a policy that prefers  
 445 large adaptations, as much as the installed flexibility allows it.

446 Figure 10 shows the LCOE as a function of the  $AT$  for turbines with maximum power rating  
 447 of 20 MW and initial power rating of 8 MW. Increasing  $AT$  decreases the LCOE for both flexible  
 448 strategies, while cases (iii)-(v) are unaffected. Larger  $AT$  result in systems that are adapted less  
 449 frequently by increasing the tolerance to external changes. This results in lower adaptation costs, but  
 450 also in less energy produced, as can be observed in the energy curve from Figure 11. The sharper  
 451 fall experienced by both flexible strategies between  $AT = 0.35$  and  $AT = 0.4$  suggests that for lower

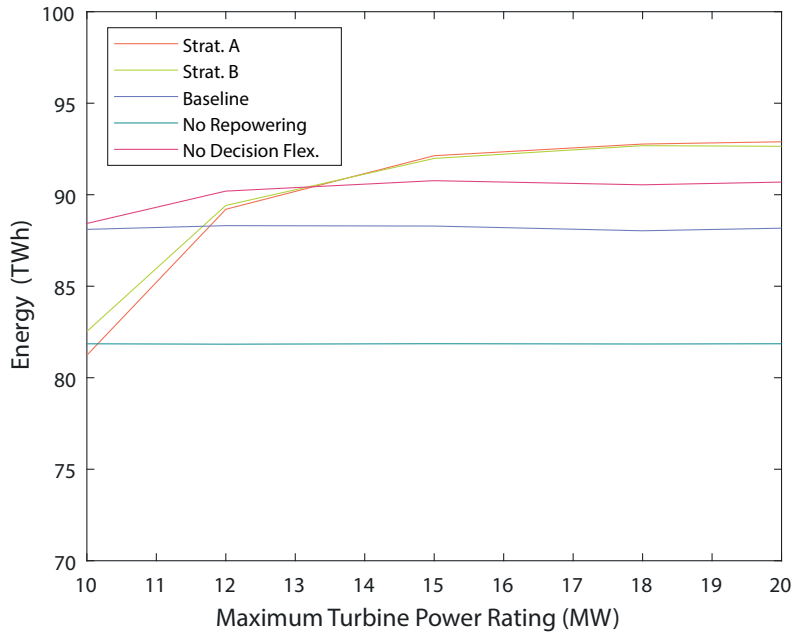


Figure 9: Average discounted energy generated for variable maximum flexible range

452 values the system is sensitive enough to demand an additional adaptation.

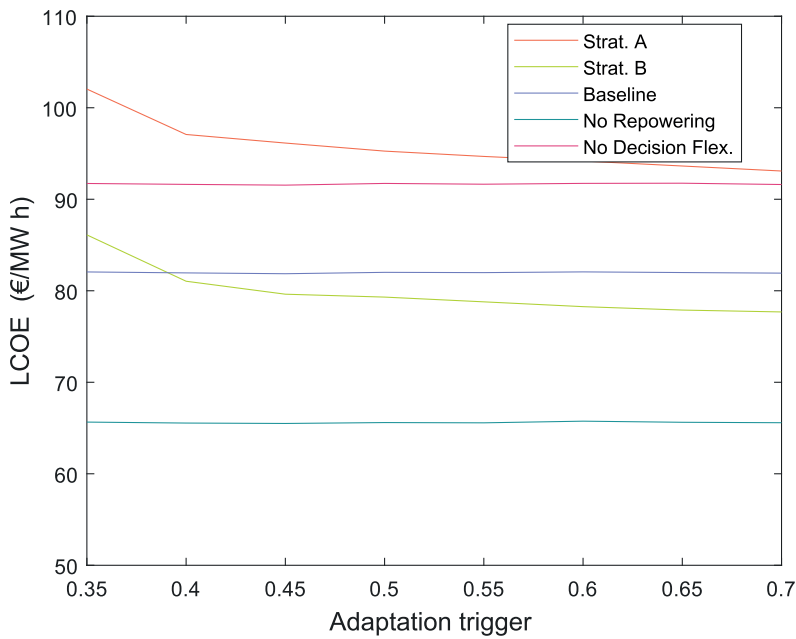


Figure 10: Average LCOE for variable  $AT$

453 The  $PAA$  has a smaller impact on the LCOE for the flexible strategies (see Figure 12). This  
 454 parameter also affects the baseline case and re-powering case ( $v$ ) because it defines the new size  
 455 when the system is rebuilt, re-powered, or adapted. Increasing the  $PAA$  results in larger and more  
 456 expensive adaptations, increasing in consequence energy generation as shown by Figure 13. However,  
 457 the small change in the LCOE suggests that the considerable increment in energy generated barely

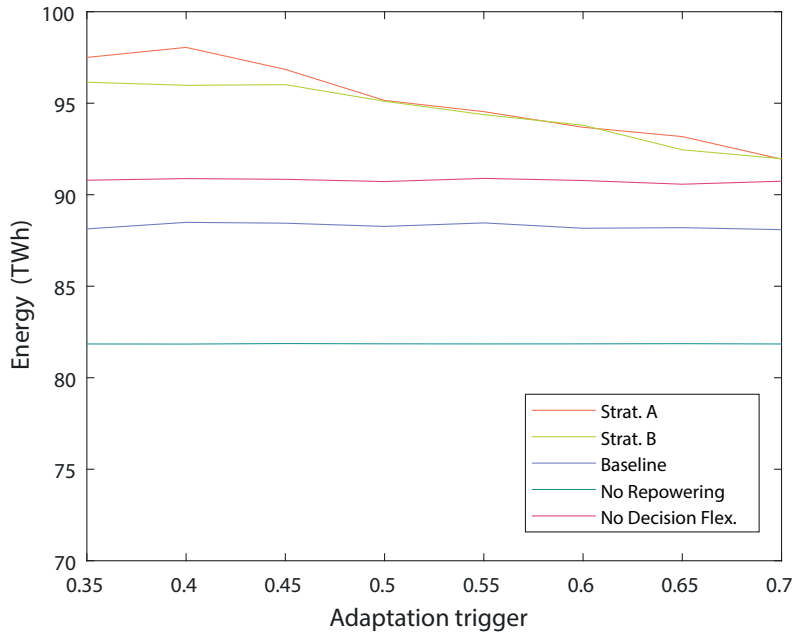


Figure 11: Average discounted energy generated for variable  $AT$

458 offsets the extra costs of adding and using flexibility.

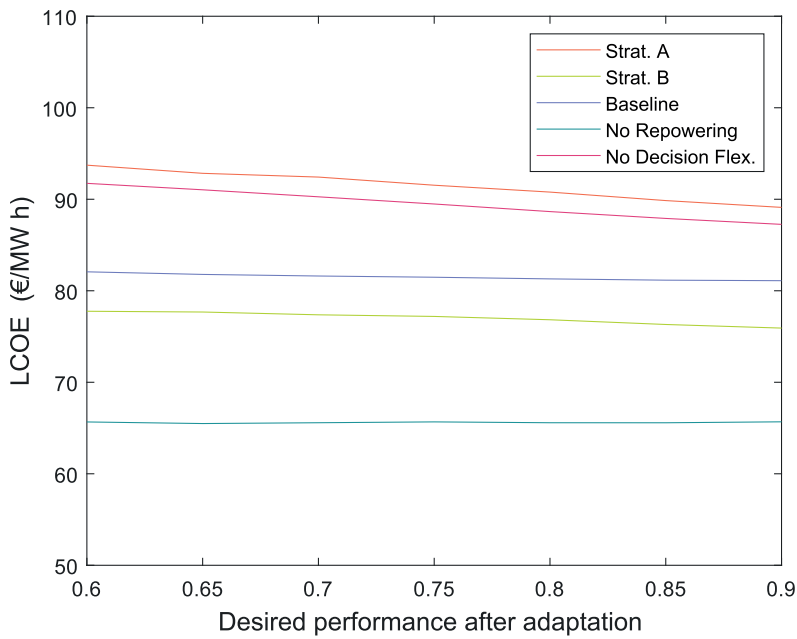


Figure 12: Average LCOE for variable  $PAA$

459 *4.4.3. Initial design*

460 To explore in more detail the design space, in this section the initial turbine power rating is  
 461 variable taking values between 6 and 18 MW, while the maximum power rating is kept at 20 MW.  
 462 Figure 14 shows how the average LCOE changes for all cases by increasing the initial design. It is



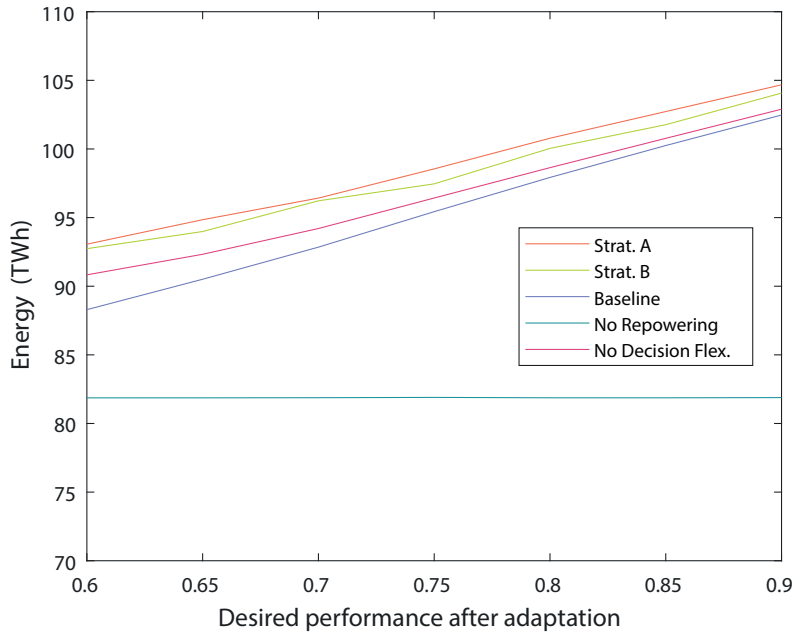


Figure 13: Average discounted energy generated for variable  $PAA$

463 interesting to observe that both flexible strategies converge to the same point, approaching the no  
 464 re-powering case (iv). In contrast, the baseline case remains almost constant. By increasing the initial  
 465 design, the flexible strategies may not require adaptations, behaving as case (iv). Cases (iii) and (v)  
 466 are always modified, but the costs in case (iii) are larger.

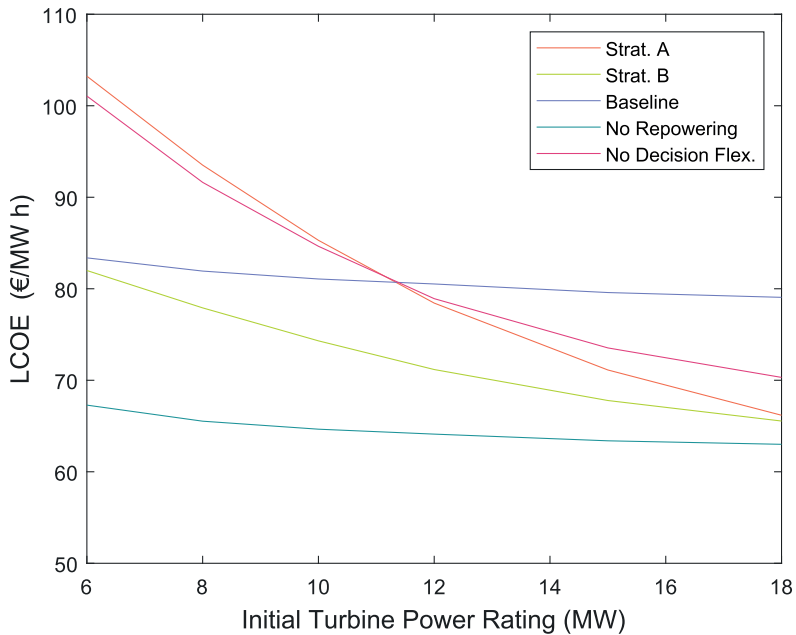


Figure 14: Average LCOE for variable initial turbine rating

467 These results are in line with previous reports (e.g. [13]) that establish that the most impactful  
 468 way to reduce the LCOE in offshore wind is to increase the turbine power rating. Nonetheless, this

469 policy is not definitive as the capital costs can be prohibitive for many projects, even if there is a  
 470 considerable reduction in LCOE.

#### 471 4.4.4. Distance from port

472 In this section, the effect of flexibility on the LCOE is evaluated considering the distance between  
 473 port and the farm  $d_p$ . It is assumed that the port is located at the nearest shore, and that the water  
 474 depth increases linearly with the distance from shore. The flexible strategies have a maximum power  
 475 rating of 20MW.

476 Previous studies showed the correlation between LCOE, water depth, and distance from shore, due  
 477 to larger mooring and export cable costs [1, 5]. Distance also increases installation and adaptation  
 478 costs,  $OM$  costs, and decommissioning costs. Figure 15 shows the LCOE curve for the following set  
 479 of distances: [20, 30, 40, 50, 100, 150, 200] km. The flexible strategies exhibit an 6% increment when  
 480 going from 50 to 100 km, and an increment of 12% when going from 100 km to 200 km, which is  
 481 similar to the 11% increment by doubling the distance reported in [2].

482 The baseline case seems to grow faster than Strategy B up to 150 km. While the adaptation costs  
 483 are slightly affected by the increment in transportation costs, the mooring and electric cables costs  
 484 have a considerable impact on the costs of rebuilding the farm in the baseline case.

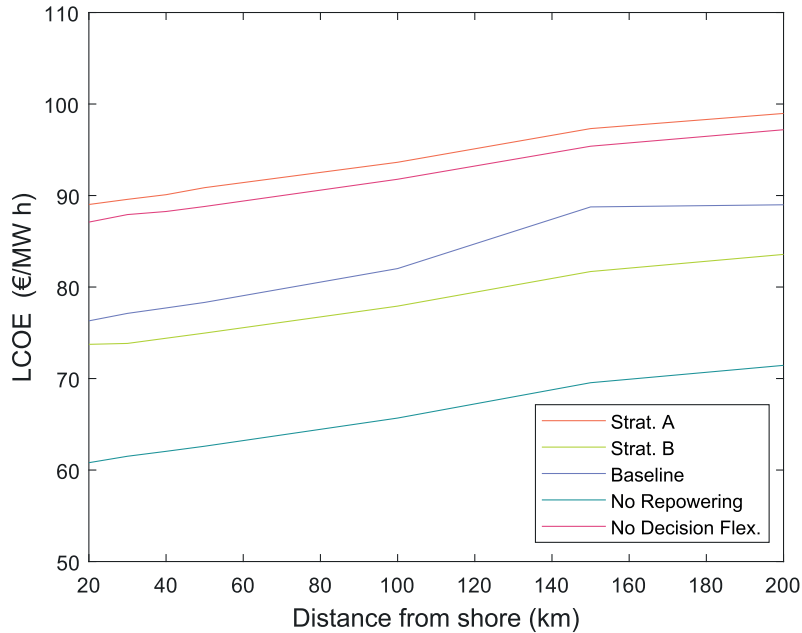


Figure 15: Average LCOE for variable farm location

#### 485 4.4.5. Discount rate

486 To conclude the parametric analysis, this section compares the effect of the discount rate on the  
 487 average LCOE. In all the previous analyses a value of 3% was used considering the long time horizon  
 488 [45]. Nonetheless, it is of interest to observe how the discount rate affects the economical performance  
 489 of the alternatives.

490 Figure 16 presents the average LCOE of the 5 scenarios for discount rates between 3% and 10%.  
 491 Strategy A and the re-powering case exhibit the largest increment in LCOE (2X) due to their relatively  
 492 large capital costs and the less valuable discounted energy. From 5%, Strategy B becomes more  
 493 expensive than the baseline case as the future benefits of flexibility becomes less and less valuable in  
 494 comparison with the initial investment required to add flexibility.

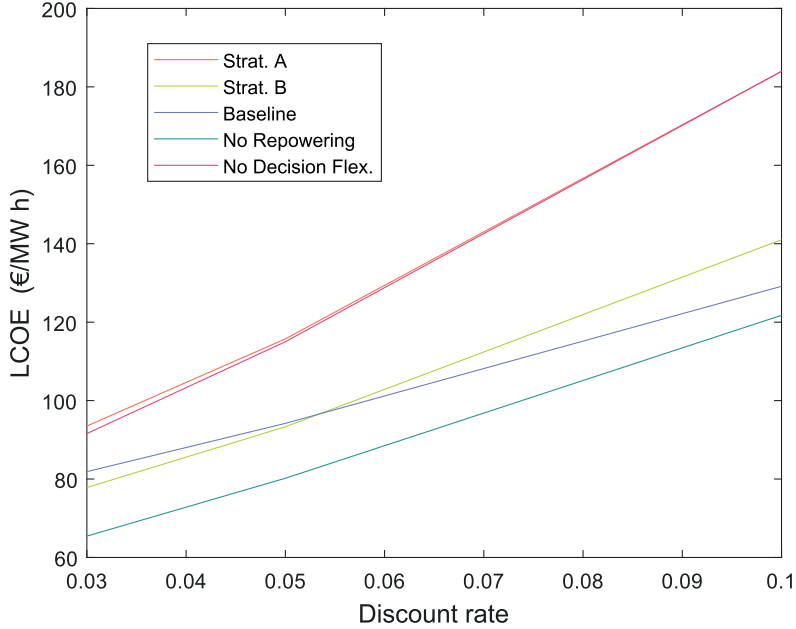


Figure 16: Average LCOE for variable discount rate

#### 495 4.4.6. Comparison of flexible strategies and management policies in the Risk- Return space

496 The previous comparisons between flexibility ranges and management policies can be summarized  
 497 in the risk-return space. The risk-return space is used in financial applications to compare portfolios  
 498 [46]. This tool can be adapted to evaluate the performance of real assets. In this case, the return  
 499 is replaced by the average LCOE and the risk by the standard deviation of 1000 simulations of the  
 500 same wind farm configuration and management policy. The result is Figure 17 where each point  
 501 corresponds to one of the five scenarios with the wind farm located 100 km from shore/port, with  
 502 initial turbine power rating between 6 and 18 MW, with maximum power rating between 8 MW and  
 503 20 MW, managed with *AT* between 0.35 and 0.75 and *PPA* between 0.5 and 0.9.

504 Different marker sizes are used to represent the initial power rating. A clear pattern is detected  
 505 where the smallest designs produce the worst results in all cases. These points are also associated  
 506 with large flexibility spaces (larger costs). This effect is stronger for Strategy A and re-powering  
 507 case (v) due to the larger initial investments. As observed previously, the baseline case and the  
 508 unchangeable case (iv) exhibit a far less volatile behavior, with a clear layering given by the initial  
 509 sizes. For Strategy B, even the less desirable combinations are better than those of Strategy A, due  
 510 to the smaller initial costs. It is interesting to observe that the best configurations of both flexible  
 511 strategies outperform the best baseline designs. This highlights the importance of finding the optimal

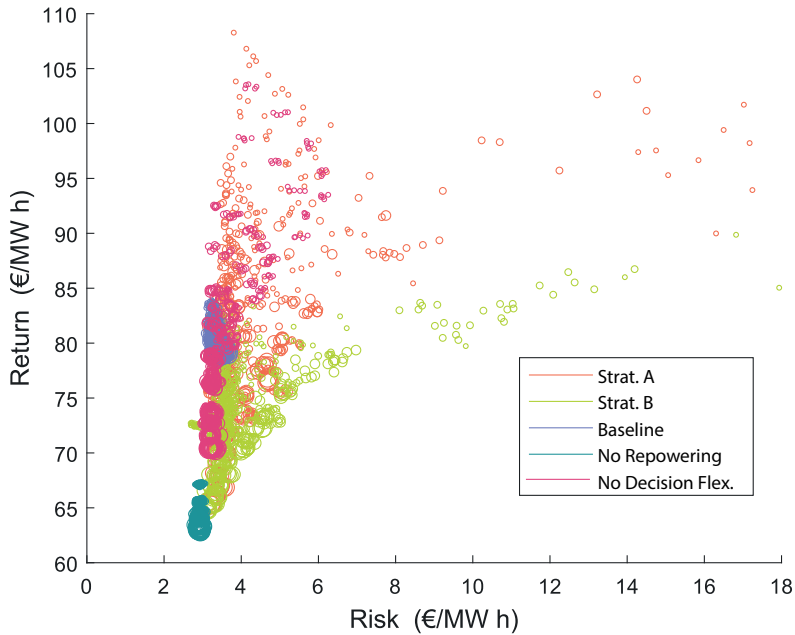


Figure 17: Risk-return space for different farm configurations and management policies

512 policy for each design. The optimal configurations correspond to large initial power ratings (15 - 18  
 513 MW), enough flexibility for one or two adaptations, and large  $AT$ .

514 These results are consistent with previous studies that suggest that large power rating turbines  
 515 have a high impact on reducing energy cost [14, 13, 5]. While this measure increases turbine and  
 516 platforms capital costs, other costs remain the same or change slightly, and the increment in energy  
 517 produced is significant. However, the optimal configurations in Figure 17 are not an option right now  
 518 due to technical limitations, even if large turbines ( $> 12$  MW) are under development. It is also not  
 519 clear how the platform production costs would scale for such massive turbine sizes.

## 520 5. Conclusions

521 This paper proposed a methodology for modeling the life cycle performance and estimating the  
 522 associated costs of flexible solutions for offshore wind turbines. The methodology is a Monte-Carlo  
 523 based approach to model the response of flexible policies and design strategies to the dynamics of  
 524 external processes. These processes are modeled as time series that represent uncertain parameters  
 525 such as demand, capacity factor, and turbine production prices. A life-cycle cost model is used to  
 526 measure the performance of flexible strategies. Two flexible design strategies were analyzed: over-  
 527 dimensioned platforms and adaptable platforms, both subject to variable flexibility management  
 528 policies described as functions of the external processes.

529 In general terms, the results showed that flexibility implemented through the adaptable platform  
 530 strategy (B) can potentially be a desirable property to have in the wind farm, helping to achieve  
 531 reductions in LCOE between 12 and 18% in the best cases, compared with traditionally designed  
 532 floating wind farms, for operational periods of 50 years. These benefits are partially derived from

533 the ability of the flexible alternatives to better react to new contexts, which usually results in more  
534 energy produced at lower investments.

535 The cost reduction can be partially explained by the weight that production and material costs  
536 have on the total costs and, therefore, on the LCOE. By introducing flexibility to the farms, their  
537 life-cycle can be prolonged without incurring in all the initial investments required to rebuild at the  
538 end of the life-cycle while maintaining the option to deploy changes (new technologies) at a low cost.

539 However, flexibility not always results in cost reductions, as shown by the results of the over-  
540 dimensioned platform strategy. This strategy did not show any difference with a re-powering strategy  
541 at fixed times. When the investments required to introduce flexibility into the system are too large, the  
542 benefits may not be enough to compensate for the additional flexibility costs. Implementing flexibility  
543 requires to consider the initial investments, the future adaptation costs, the flexibility management  
544 policy, and the expected evolution of the context.

545 Flexibility and other lifetime extension strategies, such are re-powering, have the potential to be  
546 significant cost-reducing measures, under favorable legal frameworks. Additional research to measure  
547 not only the effect on lifetime costs but on the sustainability in general of floating offshore farms is  
548 required to understand the broad impact of flexibility. Further work is also required to explore the  
549 formulation of improved flexibility management policies.

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554 **7. References**

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## 674 **Appendix A. Detailed Equations**

### 675 *Appendix A.1. Installation of turbines and platforms*

676 The rental time of storage surface for the floating platforms  $t_{sr,fp}$  (*days*) is calculated as:

$$t_{sr,fp} = \frac{t_{ip,fp} n_{wt}}{24} + t_{tug,fp} \quad (\text{A.1})$$

677 The assembling time of platforms at port  $t_{ip,fp}$  is calculated as:

$$t_{ip,fp} = n_{li,fp} t_{li,fp} \quad (\text{A.2})$$

678 where  $n_{li,fp}$  is the number of lifting movements to assemble turbine and platform, and  $t_{li,fp}$  is the  
679 time required for one lifting movement (*hours*).

680 The usage time of the tug vessels  $t_{tug,fp}$  is calculated (*days*) as:

$$t_{tug,fp} = \left( n_{fp,tug} t_{ld,fp} + \frac{2}{3600} \frac{d_p}{v_{tug}} \right) \frac{n_{wt}}{n_{fp,tug}} \frac{1}{24} \frac{1}{k_{dt}} \quad (\text{A.3})$$

681 with  $n_{fp,tug}$  the number of platforms towed per trip,  $v_{tug}$  the speed of the tug vessel ( $m/s$ ),  $d_p$  the  
 682 distance between port and farm ( $m$ ), and  $k_{dt}$  a downtime coefficient.

683 The rented surface at port  $s_{fp}$  is defined as:

$$s_{fp} = n_{wt} l_{fp} \sqrt{l_{fp}^2 - \left(\frac{l_{fp}}{2}\right)^2} \quad (\text{A.4})$$

684 where  $l_{fp}$  is the platform length.

### 685 *Appendix A.2. Installation of electrical systems*

686 The rental time of port surface  $t_{sr,ofs}$  (*days*) is calculated assuming that: i) a barge is used to  
 687 transport the transformers to the offshore site, ii) a tug is used to tow the floating platform, and iii)  
 688 a floating crane is used to assemble the substation *in situ* [10]. The parameter  $t_{sr,ofs}$  is defined as  
 689 the sum [33]:

$$t_{sr,ofs} = t_{b,ofs} + t_{tug,ofs} + t_{fc,ofs} \quad (\text{A.5})$$

690 The barge usage time  $t_{b,so}$  (*days*) is calculated as:

$$t_{b,ofs} = \left( \frac{2}{3600} \frac{d_p}{v_b} + n_{ts,b} t_{ld,ts} \right) \frac{n_{ts}}{24 k_{dt}} \quad (\text{A.6})$$

691 with  $v_b$  the speed of the barge vessel ( $m/s$ ),  $n_{ts,b}$  the number of transformers transported in one  
 692 barge, and  $n_{ofs}$  the number of offshore substations.

693 The time to load one transformer  $t_{ld,ts}$  is calculated as:

$$t_{ld,ts} = n_{li,ts} t_{li,ts} \quad (\text{A.7})$$

694 where  $n_{li,ts}$  is the number of liftings to load one transformer and  $t_{li,ts}$  the time required (*hours*).

695 The tug usage time  $t_{tug,ofs}$  is calculated as:

$$t_{tug,ofs} = \left( \frac{2}{3600} \frac{d_p}{v_{tug}} + n_{fp,ofs} t_{ld,fp} \right) \frac{n_{ofs}}{24 k_{dt}} \quad (\text{A.8})$$

696 The time to load the substation platforms  $t_{ld,fp}$  is calculated as:

$$t_{ld,fp} = n_{li,fp} t_{li,fp} \quad (\text{A.9})$$

697 The floating crane usage time  $t_{fc,ofs}$  is calculated as:

$$t_{fc,ofs} = \left( \frac{2}{3600} \frac{d_p}{v_{fc}} + t_{is,ofs} + t_{im,fc} \right) \frac{n_{ofs}}{24 k_{dt}} \quad (\text{A.10})$$

698 with  $v_{fc}$  the speed of the floating crane ( $m/s$ ) and  $t_{is,ofs}$  the time between internal movement of the  
 699 floating crane (*hours*).

700 The installation time of the offshore substation  $t_{is,ofs}$  is calculated as:

$$t_{is,ofs} = n_{li,ofs} t_{li,ofs} \quad (\text{A.11})$$

701 The port surface  $s_{ofs}$  is defined as [33]:

$$s_{ofs} = n_{ts}(l_{ts} w_{ts} + l_{GIS} w_{GIS})(1 + 1.5) \quad (\text{A.12})$$

702 with  $l_{ts}, w_{ts}$  the transformers' dimensions and  $l_{GIS}, w_{GIS}$  the GIS dimensions ( $m$ ).

703 *Appendix A.3. Estimation of adaptation costs*

704 The rental time in *days* for the new turbines  $t_{sr,wt}$  is calculated as:

$$t_{sr,wt} = t_{b,wt} + t_{pc,pa} + t_{fc,wt} \quad (\text{A.13})$$

705 The barge usage time  $t_{b,wt}$  is calculated as:

$$t_{b,wt} = \left( \frac{2}{3600} \frac{d_p}{v_b} + n_{wt,b} t_{ld,wt} \right) \frac{n_{wt}}{n_{wt,b}} \frac{1}{24 k_{dt}} \quad (\text{A.14})$$

706 with  $n_{wt,b}$  the number of turbines transported per barge.

707 The time required to load a preassembled turbine into the vessel at port  $t_{ld,wt}$  is:

$$t_{ld,wt} = n_{li,wt} t_{li,wt} \quad (\text{A.15})$$

708 The port crane usage time for preassembly  $t_{pc,pa}$  is calculated as:

$$t_{pc,pa} = \frac{n_{wt}}{24} (n_{li,pa} t_{li,pa}) \quad (\text{A.16})$$

709 The floating crane usage time  $t_{fc,wt}$  in *days* is calculated as:

$$t_{fc,wt} = (t_{is,wt} + t_{im,fc}) \frac{n_{wt}}{24 k_{dt}} \quad (\text{A.17})$$

710 The on-site installation time of the turbines  $t_{is,wt}$  is calculated according to Equation A.18:

$$t_{is,wt} = n_{li,is} t_{li,is} \quad (\text{A.18})$$

711 The rented surface at port  $s_{wt}$  is based on the space required to store the turbines and is calculated  
712 as [33]:

$$s_{wt} = 3 n_{wt} l_{bl} \phi_{bl} + 3 n_{wt} \pi \left( \frac{\phi_{tw}}{2} \right)^2 \quad (\text{A.19})$$

713 where  $l_{bl}$  is the length of the blades, and  $\phi_{bl}, \phi_{tw}$  are the diameters of the blades and the tower.