Ocean Current Turbine Specifications for the NC Region

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Nomenclature

c	Cable Capacitance [$\mu F/km$]	ℓ_{TC}	Length of Trunk Cable [km]
cc	Cost per km of Cable Supply [$\$/km$]	N_c	Number of Parallel Circuits
CC	Total Cable Cost [M$]	N_{Vess}	Number of O&M Vessels Required
$CAPEX^{OC}$	Total Capital Expenditures for the Ocean Current Technology [M$]	OPC	Onshore plant cost [M$]
$CAPEX^{TL}$	Total Capital Expenditures for the Transmission Line [M$]	$OPEX^{OC}$	Total Operating Expenditures for the Ocean Current Technology [M$/Year]
$CCont$	Contingency Cost [M$]	$OPEX^{TL}$	Total Operating Expenditures for the Transmission Line [M$/Year]
$CCons$	Cost of Consumables [M$/Year]	$OPPC$	Platform and Plant Costs [M$]
$CDev$	Development Cost [M$]	N_T	Number of Turbines
$CEnv$	Environmental Costs [M$/Year]	$p_E(E_i)$	Probability Mass Function of the Line Active Flow
$CInf$	Infrastructure Cost [M$]	P_{Max}	Maximum Feasible Active Power Flow [MW]
$CInsu$	Insurance Cost [M$/Year]	Q_c	Total Reactive Power Produced by the Line [$MVar$]
$CInst$	Installation Cost [M$]	QC_{AC}	Cost of Reactive Power Compensation Cost [M$]
$CIPM$	Integration and Profit Margin Cost [M$]	r	Cable Resistance [Ω/km]
$CMarOp$	Marine Operation Cost [M$/Year]	S^c	Rated Power of the Cables [MVA]
CMF	Mooring and Foundation Cost [M$]	S_{TL}	Rated Power of the Transmission Line [MVA]
$CPTO$	Power Take-off Cost [M$]	$S_{T[L/M]}$	Rated Power of the Low to Medium Voltage Transformer [MVA]
$CRepl$	Cost for Replacement Parts [M$/Year]	S_{34kV}	Rated Power for 34kV Cable [MVA]
CSC	Structural Components Cost [M$]	TC^{TL}	Annualized Cost of the Transmission System [M$/Year]
$CShOp$	Shore Operations Cost [M$/Year]	Th_{Year}	Average Number of Hours in a Year [h]
D_{SL}	Distance of the Energy Collection Point to the Shore [km]	$TOEL$	Total Yearly Energy Losses [$MWh/Year$]
E_i	ith Line Active Flow [MW]	TRL^{OFF}	Offshore Terminal Losses [MW]
f	Grid Frequency [Hz]	TRL^{ON}	Onshore Terminal Losses [MW]
l	Cable Inductance [mH/km]	$V_{N(AC)}$	Line-to-Line Voltage [kV]
ℓ_{ML}	Total Length of the Mooring Lines [km]	$V_{N(DC)}$	Line-to-Ground Voltage [kV]
ℓ_{34kV}	Length of the 34kV Circuit [km]	Y'	Shunt Admittance [$1/\Omega$]
LC	Energy Losses on the Cables [MW]	Z'	Series Impedance [Ω]
$LCOE^{TL}$	Levelized Cost of the Transmission System [$\$/MWh$]	η^T	Efficiency of Terminal System
FCR	Fixed Charge Rate	γ	Propagation Constant [km^{-1}]
G	Set of Possible Active Power Flows		

*Throughout this work, when necessary, the following conversion rates were used: €1= $1.12; £1= $1.31

Introduction

This document describes the cost breakdown structure for the ocean current technology used in the work "Diversifying Investments in NC Offshore Renewable Energy Technologies". We divide this document into three main sections. The first section gives relevant information about the region investigated and detail important aspects that will further influence the cost of the project, the second section evaluates the economics of HVAC and HVDC transmission considering the peculiarities of the region studied, and the third section detail the capital and operating expenditures for the remaining components of the ocean current energy project. Our cost structure is heavily based on the reference [1] and [2], but incorporate a few changes justified next.

In the ocean current project developed by the Sandia National Laboratories [1], it was used as reference site a region on the southeast coast of Florida which has its own peculiarities such as current speed, seafloor depth, and distance of the deployment site from the shore. These characteristics heavily influence the project of the current turbine and transmission system. This way, in order to use the project structure and data of [1] as a base for a new deployment in a different location, it is important to consider possible adjustments in the characteristics of the turbine and transmission system as well as its consequences in the project CAPEX and OPEX.

Our analysis assumes possible changes in the rotor diameter in order to accommodate variations in the current speed of the new region studied as well as the consequences of this change in the cost structure of other components of the project. The distance of the site location is also considered together with its consequences in the collection and transmission system, and a variable seafloor depth is analyzed together with its consequences in the mooring cost.

1. Region Investigated & Major Project Modifications

For the region analyzed it was considered as a feasible site location any site that is between 100m to 2500m depth, the minimum value of 100m guarantee a safe operation of the turbine in accordance with [1], and the maximum value of 2500m is due to anchoring depth limits [3].

Figure 1 shows the average speed in each feasible site location from 2009 to 2014, Figure 2 shows the minimum distance from shore from each site location, and Figure 3 shows a histogram of the current speed in the site locations with 10% higher average speeds (410 site locations), in Figure 3 we considered the data in daily discretization in order to identify variations of the current speed during time.

For the site locations with 10% higher average speeds, the most frequent current speed is around 1.1 m/s, about 35% lower than the most frequent current speed considered for the southeast coast of Florida in [1]. Also, based on Figure 2 it is possible to notice that the distances from shore are much larger than the 30km originally considered by [1] in the definition of the transmission system.

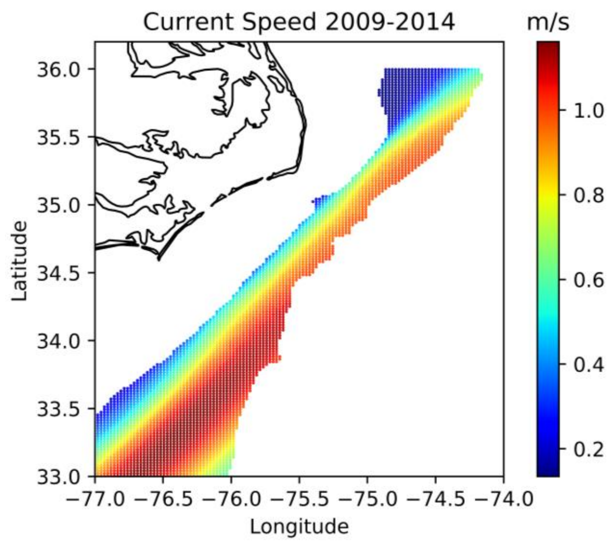

Figure 1: Average Current Speeds in the NC Region from 2009 to 2014

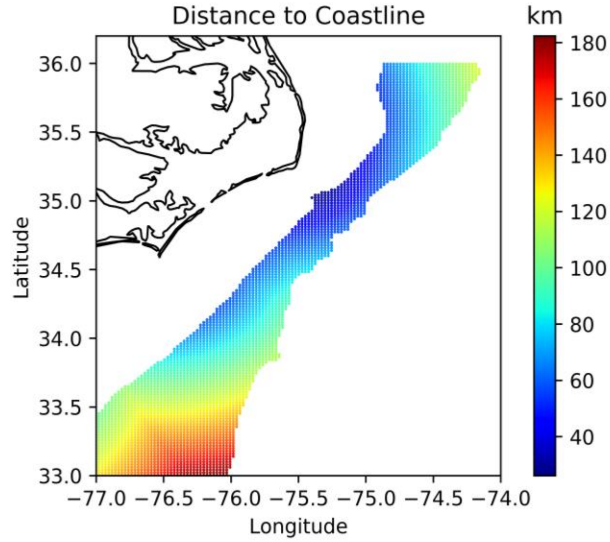

Figure 2: Distance from the Closest Coastline Point for Each Feasible Site Location

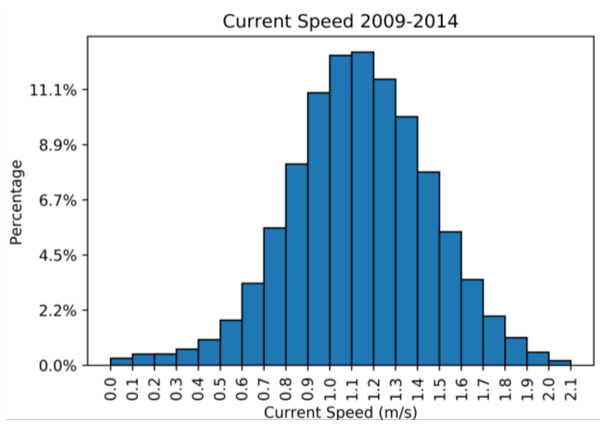

Figure 3: Histogram of The Current Speeds in The 10% Best Site Locations (> 1.1 m/s) from 2009-2014 in Daily Discretization

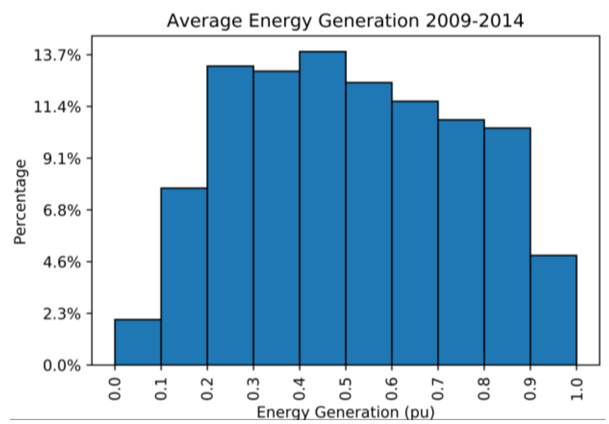

Figure 4: Histogram of The Daily Average Energy Generated for Site Locations of Figure 3

For the original ocean current project carried by SANDIA [1] a current speed of 1.1 m/s would correspond to 27% of the rated capacity for a 4MW turbine, leading to a high underutilization of several mechanical and electrical components. To accommodate the project characteristics to better suit the North Carolina region, we propose an increase in the rotor diameter from 33m (original value) to 45m, in this new configuration the turbine would be at 50% of its rated capacity when operating under a current of 1.1 m/s and would be at its rated capacity when operating at 1.4m/s. Figure 4 shows a histogram of the daily average energy generation in per-unit (1pu = 4MW) for the site locations of Figure 3 considering the modifications in the rotor diameter.

Another important modification made in the original SANDIA model is the incorporation of a 0.6/34kV transformer in each 4MW unit. We decided on the use of this transformer because it is a very usual rating used for offshore wind energy being available at competitive prices [4].

Finally, regarding the transmission system, both HVAC and HVDC options are investigated since for the site locations closer from the shore the HVAC system may be a competitive option when compared to the HVDC, traditionally known to be more economical for large transmission distances (60~80km) [5].

It is not objective of this work to carry out a mechanical and structural analysis of for the new turbine that we are proposing, but rather to generate reasonable cost estimates in order to evaluate the economics of this new technology in the North Carolina region.

2. The Economics of HVAC and HVDC Offshore Transmission

The HVAC transmission has been for a long time the major technology used for transmitting energy from offshore platforms. However, with the recent increase of renewable energy penetration with the deployment of large scale wind energy projects in larger distances from the shore the HVDC systems started to being used more frequently showing not only lower costs for longer transmission projects but also other benefits in terms of system operation and stability [6].

Due to the high values of capacitance in the submarine transmission lines, the values of reactive power flow increases very fast in HVAC systems, raising the need for reactive power compensation and eventually increase in the cross-section and number of cables. On the other hand, the HVDC systems do not transport reactive power and can be operated in longer distances with a lower number of cables and smaller cross-sections.

In order to evaluate the economics of HVAC and HVDC systems for different cable lengths, we decided for the deployment of a transmission line with the capacity of serving 50 devices, 4MW each (200MW). We understand that it is very unlikely for an emerging technology, such as the one analyzed here, to be deployed at high power ratings, but traditionally, HVDC offshore transmission lines are deployed above 200MVA [7] making it easier to perform cost assessments at this power rating.

For the HVAC system, the line is going to be operated at 132kV in order to minimize the flow of reactive power and allow the modeling of longer lines. For the HVDC system, we decided to use a ± 150kV line.

2.1. Modeling of HVAC and HVDC Transmission Systems

Figures 5 and 6 illustrate the major components of the HVAC and HVDC systems considered in this work.

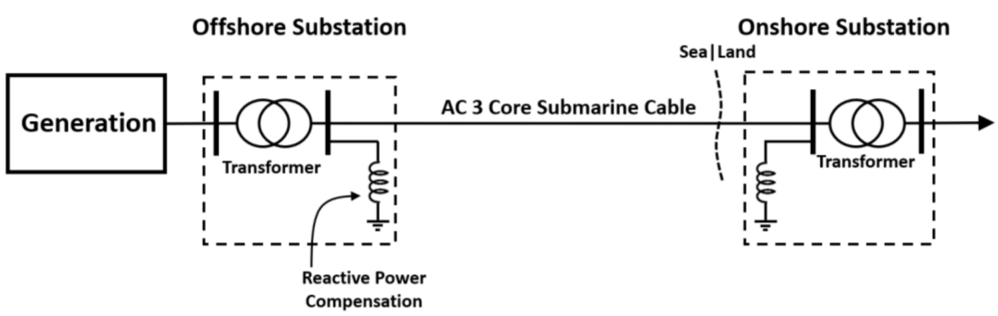

Figure 5: HVAC Transmission System

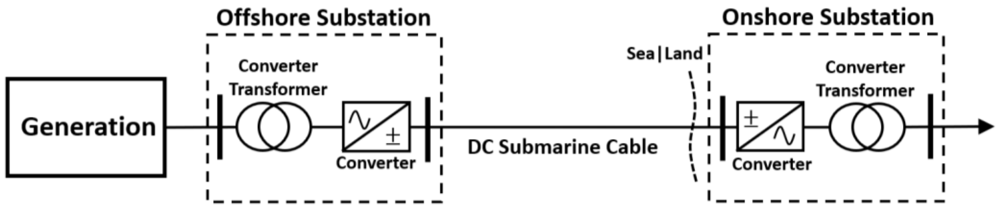

Figure 6: HVDC Transmission System

A submarine HVAC transmission line can be modeled by its π-equivalent circuit as in Figure 7 [8], where Y' is the equivalent shunt admittance, and Z' is the equivalent series impedance. These parameters can be determined by (1-3).

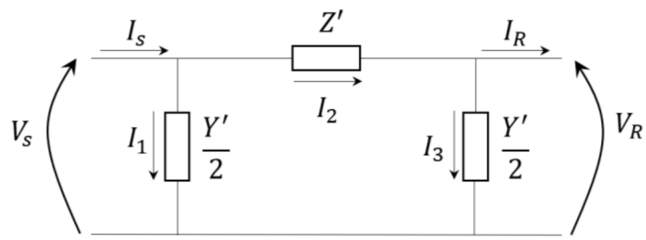

Figure 7: $\boldsymbol{\pi}$-Equivalent Circuit of a Transmission Line

$$\gamma = \sqrt{(r + j\,2\pi f l)(j\,2\pi f c)} \tag{1}$$

$$\frac{Y'}{2} = j\frac{2\pi f c\,\ell_{TC}}{2}\left[\frac{\tanh\left(\frac{\gamma\,\ell_{TC}}{2}\right)}{\frac{\gamma\,\ell_{TC}}{2}}\right] \tag{2}$$

$$Z' = (r + j\,2\pi f l)\,\ell_{TC}\left[\frac{\sinh(\gamma\,\ell_{TC})}{\gamma\,\ell_{TC}}\right] \tag{3}$$

With the formulation above the total reactive power (Q_c) produced by the line can be determined by (4), where $Im\{\cdot\}$ is the imaginary component of the admittance Y'. In order to increase the active power capacity of the cable, an option is to do a reactive power compensation such that in each extreme of the line is placed an inductive reactance capable of providing half of Q_c. For this new compensated system, the maximum amount of active power that can be injected in the line is computed in (5).

$$Q_c = V_{N(AC)}^2\,Im\{Y'\} \tag{4}$$

$$P_{Max} = \sqrt{(S_{AC}^c)^2 - \left(\frac{Q_c}{2}\right)^2} \tag{5}$$

Table I shows typical parameters for the AC cables investigated, the ABB XLPE submarine cables catalog was used as reference and information not provided in [9] such as cable resistance and cost, is estimated from other sources. Estimations for the cable resistance are based on [2] [10] [11], and cost estimates are based on the reference [12]. Table I also provides information on the maximum cable length considering a transmission line with 2 cables of the same cross-section serving a 200MW generation, in full reactive power compensation.

Table I: Parameters of the HVAC Cables

3-core XLPE (132kV AC)	Current Capacity $[A]$	Power Capacity $[MVA]$	Electrical Resistance $[\Omega/km]$	Capacitance $[\mu F/km]$	Inductance $[mH/km]$	Cable Cost [$/m]	[1]Maximum Cable Length $[km]$
300 mm^2	530	121.2	0.079	0.16	0.42	427	137
400 mm^2	590	134.9	0.065	0.18	0.40	524	150
500 mm^2	655	149.8	0.049	0.20	0.38	631	165
630 mm^2	715	163.5	0.039	0.21	0.37	736	181
800 mm^2	775	177.2	0.032	0.23	0.36	845	187
1000 mm^2	825	188.7	0.027	0.25	0.35	942	188

At a DC transmission, there is no inductive or capacitive effect thus the system can be represented by a purely resistive component [13]. Table II presents information regarding the HVDC cable investigated. The electrical parameters were obtained from [14] and the cost estimates were obtained from [15]. An HVDC line with two singe core cables of $300mm^2$ at $\pm 150kV$ has a maximum power limit of 199MW due to current capacity constraints. At this limit, the line can safely serve a system of 50 generators (4MW each) when we consider possible losses in the converters and diversification in the generation profile across different site locations.

Table 2: Table II: Parameters of the HVDC Cable

3-core XLPE (150kV DC)	Current Capacity $[A]$	Electrical Resistance $[\Omega/km]$	Cable Cost- Set of 2 DC Single-Core [$/m]
300 mm^2	662	0.0601	232 [$/m]

The next section details the economics of offshore HVAC and HVDC system in terms of its capital and operational cost. This information will further be an important tool to better understand the transmission options for the ocean current technology in the North Carolina region.

2.2. Cost Breakdown Structure: CAPEX and OPEX

The capital costs (CAPEX) for the HVAC system (Eq. 6-10) can be divided into platform and plant costs ($OPPC_{AC}$), onshore plant cost (OPC_{AC}), cost for reactive power compensation (QC_{AC}), and cable cost (CC_{AC}). A few points are important to mention regarding these equations: equation (6) considers a single transformer per plant; equation (8) considers that the reactive power is compensated equally in each terminal of the line; equation (9) considers the costs for cable landing and installation from [1] and cable cost supply from [12]. Also, regarding the cable cost, it was considered a set of two 3-core cables ($N_c = 2$) in the HVAC circuit, since with the largest cross section (1000 mm^2) [9] a single 3-core cable would be able to transport at maximum 189MVA. For more information regarding the HVAC cables investigated please refer to Table I.

Offshore Platform & Plant Cost [2] $$OPPC_{AC} = 6.55 + 0.0472 \cdot S_{TL} \text{ [M\$]} \quad (6)$$

Onshore Plant Cost [5] $$OPC_{AC} = 0.03434\, {S_{TL}}^{0.7513} \text{ [M\$]} \quad (7)$$

[1] Considering 2 circuits with the same cross section serving a 200MW generation system, in full reactive power compensation.

Cost for Reactive Power Compensation [2]	$QC_{AC} = 0.0262 \cdot Q_c$ [M\$]	(8)
Cable Cost [1], [12]	$CC_{AC} = N_c \cdot cc_{AC} \cdot \ell_{TC} + 0.221 \cdot D_{SL} + 4.245 \cdot 10^{-3}\, S_{TL}$ $+0.629$ [M\$]	(9)
CAPEX	$CAPEX_{AC}^{TL} = OPPC_{AC} + OPC_{AC} + QC_{AC} + CC_{AC}$ [M\$]	(10)

The capital costs structure of the HVDC transmission line is presented in (11-14). Equation (11) considers a single converter per plant, and equation (13) considers the costs for cable landing and installation from [1] and cable cost supply from [15]. Additionally, equation (13) considers a set of two DC single core cables ($N_c = 1$).

Offshore Platform & Plant Cost [2]	$OPPC_{DC} = 32.75 + 0.07205\, S_{TL}$ [M\$]	(11)
Onshore Plant Cost [5]	$OPC_{DC} = 0.1067\, S_{TL}$ [M\$]	(12)
Cable Cost & Installation [1] [15]	$CC_{DC} = N_c \cdot cc_{DC} \cdot \ell_{TC} + 0.221 \cdot D_{SL} + 4.245 \cdot 10^{-3}\, S_{TL}$ $+0.629$ [M\$]	(13)
CAPEX	$CAPEX_{DC}^{TL} = OPPC_{DC} + OPC_{DC} + CC_{DC}$ [M\$]	(14)

Finally, the operational expenditures will be approximated as 2.5% of the CapEx for both AC and DC systems (15), this percentage was estimated based on [16], and [2].

After properly defining the capital and operational costs, the annualized cost of transmission can be computed as in (16), where FCR is a fixed charge rate used to account for the cost of financing the capital. In this work, FCR is assumed to be equal to 11.3% as done in [1].

OPEX	$OPEX^{TL} = 0.025 \cdot CAPEX^{TL}$ [M\$/Year]	(15)
Annualized Transmission Costs	$TC^{TL} = FCR \cdot CAPEX^{TL} + \; OPEX^{TL}$ [M\$/Year]	(16)

Figures 8 and 9 show the CAPEX breakdown structure for the HVAC and HVDC systems in terms of the distance of the platform location from the shore. For these figures, the total cable length was considered as 1.2 times the distance from shore as done in [1]. The black dashed line in Figure 8 and 9 represent respectively the CAPEX values of the HVDC and HVAC systems, the equations of these lines are presented in (17-18). Also, the breakeven distance of both technologies considering only the CAPEX is 65km.

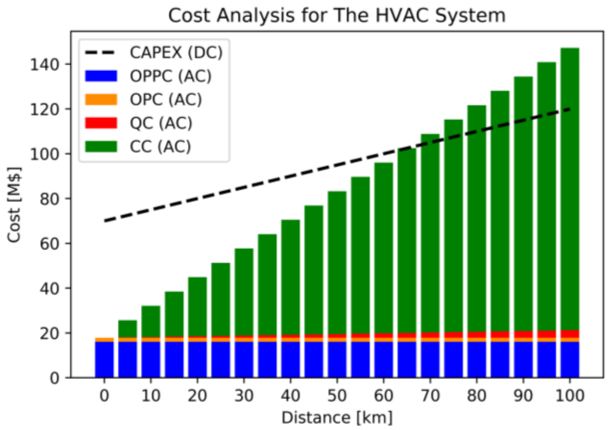

Figure 8: Capital Expenditures for the HVAC system

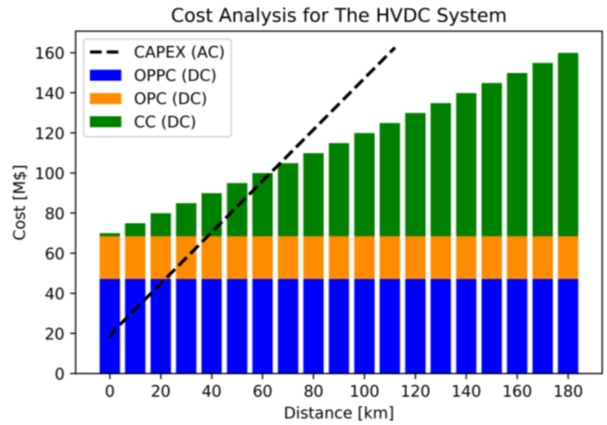

Figure 9: Capital Expenditures for the HVDC system

CAPEX HVAC $$CAPEX_{AC}^{TL} = 19.31 + 1.28\, D_{SL}\ [M\$] \tag{17}$$

CAPEX HVDC $$CAPEX_{DC}^{TL} = 69.98 + 0.50\, D_{SL}\ [M\$] \tag{18}$$

2.3. Energy Losses

The estimation of the energy losses is an important step in the definition of the most adequate transmission system since the efficiency of the HVAC and HVDC systems tends to vary significantly depending on the distances analyzed [5].

The total energy losses in the transmission system (23) can be divided into offshore terminal losses (19), losses on the submarine cables (20-21), and onshore terminal losses (22) [2], [5]. For the HVAC system the terminal losses are mainly due to the transformer efficiency (η_T^{AC}) here considered equal to 99.4% as in [2], whereas for the HVDC the terminal losses are due to the efficiency of the converter system (η_T^{DC}), estimated here in 98.2% [5].

With respect to the nomenclature used in equations (19-22), $p_E(E_i)$ refers to the probability mass function of the active power flows circulating in the line (E_i), estimated from Figure 4, G is the set of all possible active power flows (E_i) and Th_{Year} is the average number of hours in a year (8766 h).

Offshore Terminal losses (AC/DC) $$TRL^{OFF} = (1-\eta_T)\sum_{E_i \in G} 200\, E_i\, p_E(E_i)\ \ [\text{MW}] \tag{19}$$

[2]Losses on the Cables (AC) $$LC_{AC} = \sum_{E_i \in G} 3\left[\frac{200\, E_i\, \eta_T^{AC}}{\sqrt{3}\, V_{N(AC)}\, N_c}\right]^2 p_E(E_i)\, N_c\, r_{AC}\, \ell_{TC}\ \ [\text{MW}] \tag{20}$$

Losses on the Cables (DC) $$LC_{DC} = \sum_{E_i \in G} 2\left[\frac{200\, E_i\, \eta_T^{DC}}{2\, N_c\, V_{N(DC)}}\right]^2 p_E(E_i)\, N_c\, r_{DC}\, \ell_{TC}\ [\text{MW}] \tag{21}$$

Onshore Terminal Losses (AC/DC) $$TRL^{ON} = (1-\eta_T)\sum_{E_i \in G}(200\, E_i\, \eta_T - LC_i)\, p_E(E_i)\ [\text{MW}] \tag{22}$$

[2] This equation is an approximation and considers the line impedances as a concentrated parameter instead of the more complex distributed parameter model.

Total Yearly Energy Losses (AC/DC)	$TOEL = Th_{Year}\,(TRL^{OFF} + LC + TRL^{ON})$ [MWh/Year]	(23)

Figure 10 shows the efficiency of the HVAC and HVDC systems as a function of the distance from the shore, the equations for these lines are presented in (24) and (25).

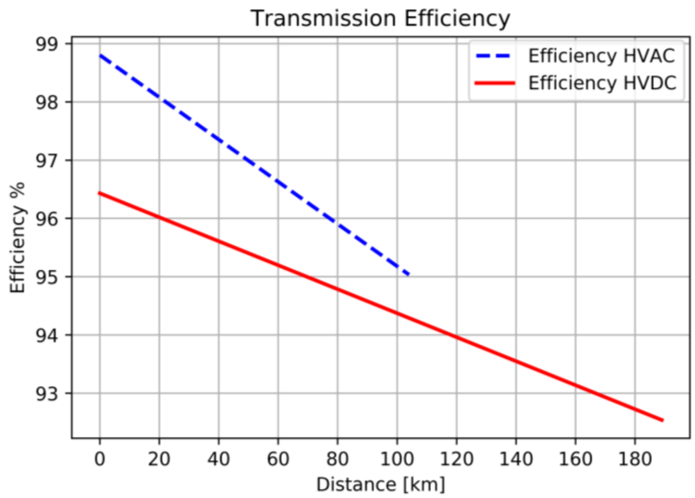

Figure 10: Efficiency of the HVAC and HVDC Transmission Systems

Efficiency HVAC	$\eta_{AC}^{TL} = -0.0362\,D_{SL} + 98.804$ [%]	(24)
Efficiency HVDC	$\eta_{DC}^{TL} = -0.0206\,D_{SL} + 96.432$ [%]	(25)

2.4. Levelized Cost of the Transmission System

With the results from Section 2.2 and 2.3, it is possible to compute the transmission cost component of the levelized cost of energy (26). This metric allows us to value the cost of the transmission system per MWh generated and has been used extensively in the energy sector.

Levelized Cost for the Transmission System	$LCOE^{TL} = \dfrac{TC^{TL}}{\sum_{i\in G} 200\,E_i\,p_E(E_i) - TOEL}$ [\$/MWh]	(26)

Figure 11 shows the values of levelized cost for each transmission technology as a function of the distance from the shore (D_{SL}). In this case, the breakeven distance happens at 66km from the shore for a transmission cost of 18.89 [\$/MWh].

Based on the previous results, for this project, any platform location with a distance larger than 66km from the shore will be operated using HVDC transmission lines, and platforms with distances smaller than 66km from the shore will be operated using HVAC. Figure 12 illustrates the regions covered by each transmission technology.

Levelized Cost for the AC Transmission	$LCOE_{AC}^{TL} = 0.1644\,D_{SL} + 7.998$ [\$/MWh]	(27)
Levelized Cost for the DC Transmission	$LCOE_{DC}^{TL} = 0.0456\,D_{SL} + 15.868$ [\$/MWh]	(28)

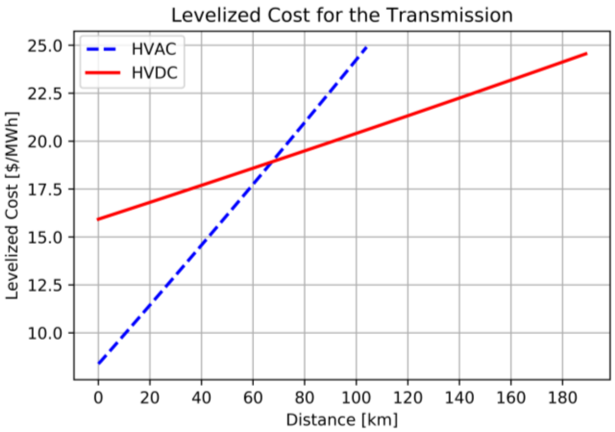

Figure 11: Levelized Cost of the Transmission System

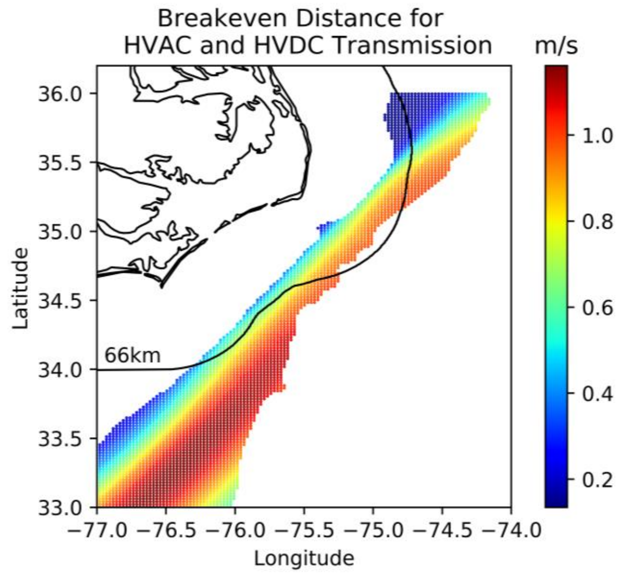

Figure 12: Best Transmission Technology Based on Site Location

3. The Economies of Ocean Current Technology

This section details the cost structure (CAPEX and OPEX) for the ocean current technology. The transmission cost from Section 2 is not incorporated in any cost component detailed here.

3.1. Capital Expenditures

The CAPEX for the ocean current technology considering a given number of turbines ($\boldsymbol{N_T}$) can be determined by (29). Following the structure of [1], the CAPEX is divided into development, infrastructure, mooring/foundation, device structural components, power take-off, subsystem integration & profit margin, installation, and contingency.

CAPEX
$$\begin{aligned} CAPEX^{OC} &= 10.37\,\mathrm{ln}(4\,N_T + 3.7) + 33\,N_{Vess} \\ &+0.5919\,\ell_{34kV} + 0.3784\,\ell_{ML} - 28.2698 \cdot 10^{-3}\,{N_T}^2 \\ &+24.0429\,\,N_T + 7.639 \cdot 10^{-3}\,N_T\,D_{SL} + 20.0773 \cdot 10^{-3}\,D_{SL} \\ &+25.468\ [\mathrm{M\$}] \end{aligned} \tag{29}$$

CAPEX for $N_T = 50$
$$\begin{aligned} CAPEX^{OC} &= 0.5919\,\ell_{34kV} + 0.3784\,\ell_{ML} + 0.4021\,D_{SL} \\ &+1278.06\ [\mathrm{M\$}] \end{aligned} \tag{30}$$

3.1.1. Development

The development costs include siting & scoping, pre- and post-installation studies, NEPA document preparation, monitoring, and studying plans, site assessment, design and engineering. For these costs, it was assumed the same cost structure from [1] and the cost function approximation of [17] was used.

Development Cost:
$$CDev = -13.5643 + 10.37\,\mathrm{ln}(4\,N_T + 3.7)\ [\mathrm{M\$}] \tag{31}$$

3.1.2. Infrastructure

The infrastructure costs include the subsea cables, terminations and connectors, and a dedicated O&M vessel.

Following the assumptions of [1] the cost of terminations and connections is going to be assumed as 10% of the cable cost and the O&M vessel cost is estimated in 30 million per vessel, where each vessel can maintain a maximum of 40 devices.

For the 34kV cable, we decided for the use of a $630mm^2$ three core copper conductor from ABB [9]. At 34kV this cable has a capacity of 42MVA, being able to connect at maximum ten 4MVA turbines to the offshore substation where the energy is finally transmitted to the shore. For this cable, a cost estimate was made using equation (32) from [12]. In (32) S_{34kV} stands for the rated power of the cable in MVA.

34kV Cable Cost per m: $$-39.52 + 89.79 \cdot \exp(0.04\, S_{34kV}) = 395\ [\$/\mathrm{m}] \tag{32}$$

Finally, the infrastructure cost can be determined by (33), where ℓ_{34kV} is the length of the 34kV circuit, and N_{Vess} is the number of O&M vessels required.

Infrastructure Cost: $$CInf = 0.4245\, \ell_{34kV} + 30\, N_{Vess}\ [\mathrm{M}\$] \tag{33}$$

3.1.3. Mooring and Foundation

Based on [1] the cost of mooring lines and chain are estimated as in (34), where ℓ_{ML} is the total length of the mooring lines. For the costs of anchors and connecting hardware, a linear regression was performed using the cost breakdown structure of [1], leading to (35). Finally, the mooring and foundation cost are determined as in (36).

Mooring Lines & Chain: $$1.1915\, N_T + 0.344\, \ell_{ML}\ [\mathrm{M}\$] \tag{34}$$

Anchors & Connecting Hardware: $$0.3402\, N_T + 0.4344\ [\mathrm{M}\$] \tag{35}$$

Mooring & Foundation: $$CMF = 1.5317\, N_T + 0.344\, \ell_{ML} + 0.4034\ [\mathrm{M}\$] \tag{36}$$

3.1.4. Structural Components

The structural components include wings, nacelles, fairing, device access (railings, ladders, etc), and buoyancy tank. To accommodate the new rotor diameter of 45m still keeping 8% of the rotor diameter as the distance between blades an increase of 23% in the wing length would be necessary. The wing corresponds to about 69% of the total weight and 65% of the total cost for the structural components in [1], that said, the structural components of the for the modified model are approximated as 123% of the costs estimated in [1], leading to (37).

Structural Components Cost: $$CSC = 1.23 \cdot (-3.879 \cdot 10^{-3}\, {N_T}^2 + 5.0876\, N_T + 5.613)\ [\mathrm{M}\$] \tag{37}$$

3.1.5. Power Take-Off

The power take-off components include generator, gearbox and driveshaft, hydraulic system, frequency converter, step-up transformer, riser cable, seals, controls system, bearings & linear guides, assembly, rotors, mounting, and a set of other individual costs.

For the cost of low to medium voltage transformers from 0.1 to 3MVA, the reference [12] derive equation (38) using data from values of different sources, where $S_{T[L/M]}$ is the rated power of the transformer in MVA. We extrapolate this equation using the derivate of (38) in 3MVA in order to estimate the cost of a 4MVA 0.6/34kV transformer (39).

Transformer Cost LV-MV (0.1-3MVA)	$0.06496\left(S_{T[L/M]}\right)^{0.6329} + 7.307 \cdot 10^{-3}$ [M$]	(38)
Transformer Cost 0.6/34kV (4MVA)	$[0.06496 \cdot 3^{0.6329} + 7.307 \cdot 10^{-3}] + 0.027468 = 0.165$ [M$]	(39)

The cost for the rotor is going to be estimated as [3]136% of the original value reported by [1] (40), and the other costs are assumed to not vary significantly with the modification in the rotor diameter (41). Finally, the total power take-off cost is determined as (42).

Rotor Cost	$1.36 \cdot \left(-1.519 \cdot 10^{-3}\, {N_T}^2 + 0.65743\, N_T + 1.3181\right)$[M$]	(40)
Remaining PTO Costs	$-16.721 \cdot 10^{-3}\, {N_T}^2 + 11.337\, N_T + 14.27$ [M$]	(41)
Total PTO Costs	$CPTO = -18.787 \cdot 10^{-3} {N_T}^2 + 12.3961\, N_T + 16.0626$ [M$]	(42)

3.1.6. Subsystem Integration & Profit Margin

As in [1], we considered the costs of subsystem integration (e.g. grid connection) and profit margin as 10% of the power take-off and structural components.

Subsystem Integration & Profit Margin	$CIPM = 0.1 \cdot (CPTO + CSC)$[M$]	(43)

3.1.7. Installation

The installation costs include transport of equipment to the staging site, mooring installation, offshore cable installation (34kV cable), device installation, and commissioning.

Using the cost structure provided by [1] we estimate the installation cost by adjusting the number of days required to perform each task based on the new distance of the site locations from the shore. For example, in the original project [1] the estimated time spent in transit to perform the mooring installation is 5 days for one device, this estimate was made for a distance of 30km thus based on the new distance of our site locations (e.g. 90km) the new number of days spent in transit is 15 days.

The formulas used in the calculus of the installation cost are presented in (44-49) where D_{SL} is the distance of the energy collection point (offshore platform) to the shore in km.

Transport Cost to Staging Site	$2.448 \cdot 10^{-3}\, N_T\, D_{SL}$ [M$]	(44)
Mooring Installation	$(2.269\, N_T + 18.2521) \cdot 10^{-3}\, D_{SL} + 0.8036\, N_T + 1.38913$ [M$]	(45)

[3] Correspondent to 36% in the rotor length

Offshore Cable Installation ($N_T \geq 10$)	$0.11357\ \ell_{34kV} + 7.3414$ [M$]	(46)
Device Installation	$(0.40095\ + 2.2275 \cdot 10^{-3}\ D_{SL})\ N_T$ [M$]	(47)
Device Commissioning	$0.066825\ N_T$ [M$]	(48)
Total Installation Cost ($N_T \geq 10$)	$CInst = 1.271375\ N_T + 6.9445 \cdot 10^{-3}\ N_T\ D_{SL} + 18.2521 \cdot 10^{-3}\ D_{SL} + 0.11357\ \ell_{34kV} + 8.73053$ [M$]	(49)

3.1.8. Contingency

The contingency cost is considered as 10% of the infrastructure, mooring, structural components, power take-off, integration & profit margin, and installation costs.

Contingency Cost:	$CCont = 0.1(CInf + CMF + CSC + CPTO + CIPM + CInst\ )$ [M$]	(50)

3.2. Operational Expenditures

The OPEX is divided into insurance, environmental & regulatory compliance, marine operations, shoreside operations, replacement parts and consumables. In this section, all cost estimates are based on [1].

The insurance cost (51) is assumed as 1% of the CAPEX costs. The environmental and regulatory compliance costs (52) are assumed to not vary significantly with the number of turbines. The cost for marine operations (53) is estimated from [1] by adjusting the number of days required to perform each task based on the new distance of the site locations from the shore as explained in Section 3.1.7. The costs for shore operations (54) are assumed to not vary from the values reported by [1]. The costs for replacement parts (55) are estimated as 0.86% of the power take-off costs. The cost of consumables (56) includes oil, grease and filers, and is assumed to not vary from the values reported by [1]. Finally, the OPEX value can be estimated by (57)

Insurance:	$CInsu = 0.01\ CAPEX^{OC}$ [M$]	(51)
Environmental & Regulatory Compliance	$CEnv = 2.036$ [M$]	(52)
Marine Operations	$CMarOp = 5.128 \cdot 10^{-6}\ N_T\ (17925 + 150\ D_{SL})$ [M$]	(53)
Shore Operations	$CShOp = 15.555 \cdot 10^{-3} N_T + 0.2205$ [M$]	(54)
Replacement Parts	$CRepl = 0.0086 \cdot CPTO$ [M$]	(55)
Consumables	$CCons = 17.492 \cdot 10^{-3}\ N_T$ [M$]	(56)
OPEX	$OPEX^{OC} = 0.1037\ \ln(4\ N_T + 3.7) + 0.33\ N_{Vess} + 5.919 \cdot 10^{-3}\ \ell_{34kV} + 3.784\ \cdot 10^{-3} \ell_{ML} - 0.4443 \cdot 10^{-3} {N_T}^2 +\ 0.4719\ N_T + 8.4559 \cdot 10^{-4}\ N_T\ D_{SL} + 2.0077 \cdot 10^{-2}\ D_{SL} + 2.6493$ [M$]	(57)
OPEX for $N_T = 50$	$OPEX^{OC} = (5.919\ \ell_{34kV} + 3.784\ \ \ell_{ML}) \cdot 10^{-3} + 6.2357 \cdot 10^{-2}\ D_{SL} + 26.3446$ [M$]	(58)

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