Techno-economic assessment of interconnection of offshore wind farms using Hydrogen-based solutions

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Abstract

Hydrogen can fulfil the role of energy storage and even act as an energy carrier, since it has a much higher energetic density than batteries and can be easily stored. Considering that the offshore wind sector is facing significant growth and technical advances, hydrogen has the potential to be combined with offshore wind energy to aid in overcoming disadvantages such as the high installation cost of electrical transmission systems and transmission losses. In this thesis, two hydrogen producing systems were modelled, one with the electrolyzer offshore, the other with the electrolyzer onshore, along with a conventional wind farm. To do so, each component was individually modelled and combined to construct the systems. Furthermore, an hourly optimisation algorithm was developed to control the operation of the systems and a neural network was implemented to forecast day ahead power production and electricity price, so that the regulation costs could be modelled. Using cost projections for 2030 and 2050, the simulations were also performed for those years. Results show that the onshore electrolyzer system is always more economically interesting than the offshore electrolyzer system, mainly due to its ability of purchasing electricity from the grid. This system is profitable in 2020 for a hydrogen price of 6€/kg, in 2030 for 4€/kg and in 2050 for 3€/kg, while the offshore electrolyzer system is only profitable for a hydrogen price of 9€/kg, 5€/kg and 3€/kg in 2020, 2030 and 2050, respectively. The conventional wind farm is never economically viable in any of the simulated years.
Keywords: green hydrogen; offshore wind; techno-economic analysis; water electrolysis; grid integration; hourly day ahead forecast;

1. Introduction

1.1. Motivation

Hydrogen is a gas that can be easily produced using electrolysis and has several potential applications, ranging from energy source for transportation to being mixed into the natural gas grid, along with current applications in fuel refining and fertilizer production. Historically, hydrogen production is based on fossil fuels and emits a large amount of CO2, however, in the last decades, significant advances have been made in electrolysis and renewable energy production, making the production of green hydrogen at a reasonable price point possible.

Considering that underwater pipeline installation is cheaper than electrical cables and that transport of a gas in a pipeline suffers much smaller losses ($< 0.1\%$) [1, 2], a case can be made for the production of hydrogen offshore with pipelines to transport it to shore.

1.2. Overview

The thesis offers an overview of the current situation on the subject by highlighting the main features of the technologies used by the different components of the hydrogen production system, as well as an outline of the system configuration options (offshore vs onshore electrolyzer location) and potential uses of hydrogen. The offshore electrolyzer system has the electrolyzer offshore, transporting hydrogen back to shore in a pipeline, while the onshore electrolyzer system has the electrolyzer onshore, transporting all electricity to shore through an electrical cable. The latter system can either generate hydrogen or sell electricity directly to the grid, depending on the market conditions. Moreover, the thesis reviews the main recent research topics related to the subject by performing a thorough literature review, including state-of-the-art reports and journal papers.

The aim is to develop and compare two green hydrogen producing systems with a conventional floating offshore wind farm without hydrogen production, analysing both the technical point of view and also from an economic point of view. Since the thesis focuses on the potential application of these systems in the Iberian Peninsula, the wind farms being used in the hydrogen producing systems as well as the conventional wind farm must be floating wind farms, on account of the deep waters that surround the peninsula.

The simulations are conducted for two locations at different distances to shore so that the effect of placing the wind turbines further out to sea can be analysed. Additionally, using cost projections for the technologies that compose each system, simulations for 2030 and 2050 are also performed.

A neural network is also trained to forecast the day ahead wind power production and electricity prices, since one of the advantages of implementing hydrogen in an offshore wind farm is the added system flexibility. This neural network is a one dimensional Convolutional Neural Network (CNN) that receives the previous 64 hours of data after being pre-processed with Variational Mode Decomposition (VMD) to forecast the 24 hours of the following day. VMD is a technique where the initial signal is divided into several signals of different frequencies, enhancing the neural network's ability at detecting patterns.

Furthermore, the historic Iberian Electricity Market (MIBEL) prices and wind speeds off the coast of Galicia, Spain are modelled to simulate how each system would perform in past conditions. Since the operation of these systems isn't linear, an optimisation algorithm for each system is developed to guarantee maximum revenue.

A sensitivity analysis is included, where the effect that any possible deviations from the cost projections will impact the systems can be estimated.

2. State-of-the-art review

2.1. System Components

The hydrogen production system is composed of the offshore wind farm, for electricity production, the electrolyzer, for hydrogen production, the hydrogen storage system and either a pipeline in the offshore electrolyzer system or an electrical cable in the onshore electrolyzer system and conventional wind farm.

2.1.1 Offshore Wind

When analysing fixed bottom wind turbines or floating turbines the main differences are cost and the locations where each technology can be implemented. The fixed bottom is the most used technology by a significant margin, with 24,952 MW installed in Europe, compared to only 62 MW of floating wind installed in Europe at the end of 2020 [3]; thus, it is the most cost-effective solution in offshore wind farms. However, floating wind prices are expected to lower rapidly in the next few years and allow access to much deeper waters; this will be useful in countries that do not have shallow water far from shore.

The report in [4] shows a projection of the Levelized Cost Of Energy (LCOE) of both bottom fixed and floating wind until 2050. The report indicates a current LCOE of 175 €/MWh for floating and 90 €/MWh for fixed bottom technologies. In 2050, these two figures are estimated to converge to 35 €/MWh.

2.1.2 Electrolyzer Technologies

An electrolyzer is a device that receives DC electricity and demineralized water and separates the hydrogen and oxygen atoms from the water molecule through a chemical reaction, generating high purity oxygen and hydrogen. While different technologies for electrolyzers operate in slightly different ways, all have an anode and cathode that are separated by an electrolyte.

Currently, there are two technologies used in commercial applications for the production of hydrogen, Alkaline Electrolyzer (AEL) and Proton Exchange Membrane Electrolyzer (PEMEL). Another technology undergoing intense research and development is Solid Oxide Electrolyzer (SOE), which promise high efficiencies and flexibility, at the cost of high operating temperatures (500 to 1000 °C, varies according to the chemistry) and durability.

AEL are currently the cheapest technology and have the longest lifetime, due in part to being the oldest of the technologies mentioned above [5, 6]. This type of electrolyzer has been used in the industry for roughly 100 years, so while further progress is expected, both PEMEL and SOE development will surely be faster. However, they cannot react as fast to changes in production, maintenance of the alkaline fluid is complex, cannot operate below a certain threshold for safety reasons, take longer to start, and present a rather low current density when compared to PEMEL, around 5 times lower [7].

PEMEL are more recent than AEL and come with several advantages, such as much faster start-up times, higher current densities which lead to smaller electrolyzer footprint, higher hydrogen purity ($\geq$ 99.8%), can operate beyond nominal power, and higher output pressure [5, 6, 7]. When combined with a renewable power source, the ability to easily adjust the power to suit the conditions, including a quick start-up time, are two great features that allow this technology to extract the most out of intermittent power sources.

Despite in recent years PEMEL having made significant progress in higher efficiency, output pressure, ramp up and ramp down times, and CAPEX, they are still considerably more expensive than AEL [6, 8]. The main reason for the high price is the significant amount of platinum needed to build the stack of the electrolyzer.

2.1.3 Hydrogen Storage

Storage of hydrogen is similar to natural gas, with a few key differences, mainly when some metals come in contact with hydrogen can suffer hydrogen embrittlement, which leads to increased degradation and chance of material failure. Another difference to consider is increased leakage, especially in underground natural structures such as aquifers[9]. The main approaches in storing hydrogen are gaseous storage and liquid storage, other approaches like chemical storage exist but only on a much smaller scale so they won't be considered.

Gaseous hydrogen density has a nearly linear relation with pressure[10], so a greater storage pressure leads to a smaller volume needed to store a certain amount of hydrogen gas. However, due to material properties and operational costs, hydrogen is not stored at pressures higher than 100 bar [9], which corresponds to a density of roughly 7.8 kg/m^3 [9].

The second approach consists of storing liquid hydrogen in metal tanks, a process similar to what is widely used for Liquified Natural Gas (LNG). The main advantage is the high density in liquid state of 70 kg/^{3}, almost 10 times the density of hydrogen in a gas state at a pressure of 100 bar. However, the liquefaction of hydrogen is a very energy-intensive process, with anywhere from 6 to 10 kWh of electricity needed to liquefy 1 kg of hydrogen [9, 11].

2.2. System Configuration

There are two possible options for the system configuration related to the location of the electrolyzer. It can be placed offshore, near the wind farm, or onshore, near the existing grid coupling point. PEMELs represent the best choice for the offshore electrolyzer system due to the smaller footprint and easier maintenance [5], which in an offshore scenario means the platform can be smaller and the maintenance trips can be further apart. In order to compare both systems, PEMEL was also used in the onshore electrolyzer system.

Figures 1 and 2 contain the system configuration for the offshore electrolyzer system and the onshore electrolyzer system, respectively.

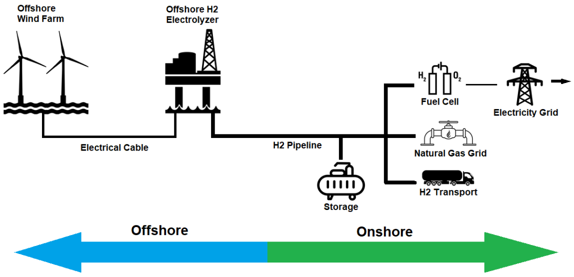

Figure 1: Offshore electrolyzer system

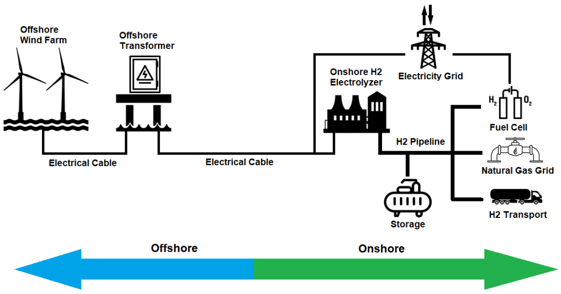

Figure 2: Onshore electrolyzer system

3. Proposed Models

The proposed models are presented in this chapter, starting with a brief overview on how the simulations were conducted, how each component was modelled, how the systems were optimised to maximize revenue and how the economic analysis was performed.

3.1. Simulation Overview

The data regarding the project's location was obtained in http://windatlas.xyz for two locations off the coast of Galicia, Spain. These locations were chosen since they present some of the highest wind speeds close to shore in the Iberian Peninsula. The first location is 25 km off the coast (latitude 43.93, longitude -8.21) and the second is 50 km (latitude 44.14, longitude -8.32).

Regarding the hydrogen producing systems, one crucial factor is sizing the electrolyzer and fuel cell since a larger electrolyzer/fuel cell will result not only in higher revenues but also in higher initial investment and maintenance costs. This sizing should be done as a ratio of the wind farm's nominal power, on account that a higher powered wind farm should be accompanied by a higher powered electrolyzer and vice-versa. The ratio that maximizes Net Present Value (NPV) is denominated as optimal ratio. Considering that the conditions that influence the value of the optimal ratios are hydrogen price, electricity price and wind speed, the ratios must be calculated for every hydrogen price present in the analysis.

The first steps for all three systems are the same: calculating the number of required turbines to achieve the desired nominal power of the wind farm, simulating the wind power production and forecasting day ahead wind power production and electricity prices. From this point onwards, the simulation differs depending on the system. For the onshore electrolyzer system the next steps are: sizing the electrolyzer, fuel cell and desalination unit; sizing the compressor and storage; calculating electrical losses; onshore electrolyzer optimisation.

For the offshore electrolyzer system the next steps are: sizing the electrolyzer, fuel cell and desalination unit; sizing the pipeline; sizing the compressor and storage; calculating hydrogen production; offshore electrolyzer optimisation. Finally, for the conventional wind farm the only necessary step is to calculate the electrical losses.

3.2. Hourly Optimisation

For the onshore electrolyzer system, two optimisation algorithms were developed. The first represents the day ahead operation and uses the forecasts to determine what the electricity bid should be. The second algorithm represents the real time operation and uses the previously placed bid, the real power production and electricity price to determine how to distribute the wind farm's electricity between selling electricity to the grid and producing hydrogen. Since this optimisation isn't trivial and requires calculating a significant amount of variables, the algorithms were implemented as a Mixed-Integer Linear Program (MILP). This method consists of defining an objective function to maximize or minimize, the problem's variables and the constraints between the variables.

This optimisation is done on an hourly basis due to the fact that the actual electricity production is only known in real time, so for every hour of the simulation the day ahead MILP and real time MILP are used. On the other hand, for the offshore electrolyzer system only a real time algorithm was developed, since all electricity sold to the grid is generated in the fuel cell, which can easily be adjusted to match the previous day bid.

3.2.1 Onshore Electrolyzer System

The objective function is the maximization of the revenue at a given hour, defined in expression 1, and the constraints are defined in equations 2 to 6.

$$\text{max revenue} = sp_h^{for} \cdot bid_h + ph \cdot hp_h \tag{1}$$

$$ep_h^{for} = ee_h + bid_h \tag{2}$$

$$hp_h \leq \frac{ee_h}{c_{sp,el} + c_{sp,cp}} + H_{max-p} \cdot (1 - y_{ee}) \tag{3}$$

$$hp_h \leq H_{max-p} \cdot y_{ee} \tag{4}$$

$$ee_h < P_{el_{min}} + P_{el_{max}} \cdot y_{ee} \tag{5}$$

$$ee_h \geq P_{el_{min}} - P_{el_{max}} \cdot (1 - y_{ee}) \tag{6}$$

In the previous equations sp_h^{for} is the forecasted day ahead electricity price at hour h, bid_h is the day ahead market electricity bid at hour h (it can take a negative value when buying electricity from the grid to produce hydrogen is profitable), ph is the price of hydrogen, hp_h is the hydrogen produced at hour h, ep_h^{for} is the forecasted electricity production at hour h, ee_h is the energy fed into the electrolyzer at hour h, y_{ee} is a binary value that is 0 when ee_h is lower than the electrolyzer's minimum operating power and 1 if it's higher, H_{max-p} is the electrolyzer's maximum hydrogen production rate and $P_{el_{max}}$ and $P_{el_{min}}$ are the maximum and minimum powers for which the electrolyzer can produce hydrogen. The range of values each variable can take are defined in equations 7 to 9.

$$0 \leq hp_h \leq H_{max-p} \tag{7}$$

$$0 \leq ee_h \leq P_{el_{max}} \tag{8}$$

$$-P_{el_{max}} \leq bid_h \leq P_{el_{max}} \tag{9}$$

With the electricity bids determined, the final step is to perform the real time optimisation, which uses the actual wind power production and electricity price along with all other relevant information to decide how to operate the system. In order to transform this problem into a MILP, the objective function (equation 10) and the constraints (equations 11 to 29) were defined.

$$\text{max revenue} = sp_h \cdot es_h + ph \cdot (hp_h - hc_h) - RC_h \tag{10}$$

$$es_h = ep_h - ee_h + efc_h \tag{11}$$

$$imb_h = es_h - bid_h \tag{12}$$

$$ss_h = ss_{h-1} + hp_h - hc_h - hs_h \tag{13}$$

$$hp_h \leq \frac{ee_h}{c_{sp,el} + c_{sp,cp}} + H_{max-p} \cdot (1 - y_{ee}) \tag{14}$$

$$hp_h \leq H_{max-p} \cdot y_{ee} \tag{15}$$

$$hs_h \geq ss_h - ss_{res} - ss_{max} \cdot (1 - y_{ss}) \tag{16}$$

$$hs_h \leq ss_{max} \cdot y_{ss} \tag{17}$$

$$\tag{18}$$

$$RC_h \geq imb_h \cdot (sp_h - sp_h^+) - 1000 \cdot P_{Park} \cdot (1 - y_{imb}) \tag{19}$$

$$RC_h \geq imb_h \cdot (sp_h + sp_h^-) - 1000 \cdot P_{Park} \cdot y_{imb} \tag{20}$$

$$efc_h \leq \frac{0.55 \cdot hc_h \cdot h_{LHV}}{1000} + 1000 \cdot P_{fc} \cdot y_{fc} \tag{21}$$

$$efc_h \leq \frac{0.477 \cdot hc_h \cdot h_{LHV}}{1000} + 1000 \cdot P_{fc} \cdot (1 - y_{fc}) \tag{22}$$

$$imb \leq 2 \cdot P_{Park} \cdot y_{imb} \tag{23}$$

$$imb \geq -2 \cdot P_{Park} \cdot (1 - y_{imb}) \tag{24}$$

$$\frac{efc_h}{P_{fc}} \leq 0.63 + y_{fc} \frac{efc_h}{P_{fc}} \geq 0.63 + (1 - y_{fc}) \tag{25}$$

$$ss_h \leq ss_{res} + ss_{max} \cdot y_{ss} \tag{26}$$

$$ss_h \geq ss_{res} - ss_{max} \cdot (1 - y_{ss}) \tag{27}$$

$$ee_h < P_{el_{min}} + P_{el_{max}} \cdot y_{ee} \tag{28}$$

$$ee_h \geq P_{el_{min}} - P_{el_{max}} \cdot (1 - y_{ee}) \tag{29}$$

From the wind and pricing data along with the previously calculated electricity bids, information regarding electricity produced (ep_h), electricity bid (bid_h), electricity price (sp_h), positive imbalance price (sp_h^+) and negative imbalance price (sp_h^-) is already known. These 5 values are fixed for each hour of the simulation, so they are considered constants by the real time optimisation model. The remaining constants have the same value throughout the optimisation, they are hydrogen price (ph), electrolyzer and compressor specific energy consumption ($c_{sp,el}$ and $c_{sp,cp}$), maximum hydrogen production rate (H_{max-p}), hydrogen storage reserve (ss_{res}), maximum hydrogen storage (ss_{max}), wind farm's nominal power (P_{Park}), hydrogen's lower heating value (h_{LHV}), fuel cell's nominal power (P_{fc}) and maximum and minimum powers for which the electrolyzer can produce hydrogen ($P_{el_{max}}$ and $P_{el_{min}}$). The variables are electricity sold at hour h (es_h), hydrogen sold at hour h (hs_h), energy fed into the electrolyzer at hour h (ee_h), electricity produced by the fuel cell at hour h (efc_h), hydrogen produced at hour h (hp_h), hydrogen consumed by the fuel cell at hour h (hc_h), current amount of hydrogen stored at hour h (ss_h), previous amount of hydrogen stored at hour h-1 (ss_{h-1}), electricity imbalance at hour h (imb_h) and regulation costs at hour h (RC_h).

3.3. Economic Model

The economic model uses the results from the technical analysis and evaluates the project from an economic point of view by calculating revenue, expenses and the performance metrics to evaluate each system, along with the levelized cost of the products generated.

The equations to adjust total revenue, total CAPEX and total OPEX according to the rate of return are 30, 31 and 32, respectively, where N is the project's lifetime in years, R_n is the revenue for year n, R_t is the total revenue, I_t is the total investment, I_i is the initial investment in %, a is the rate of return, $OPEX_y$ is the yearly amount spent on OPEX, a_{loan} is the loan's interest rate and N_{loan} is the loan's duration. The yearly revenue R_n is calculated using equation 33, where $R_n^{H_2}$ and R_n^E are the revenues from selling hydrogen and electricity in year n, respectively, and RC_n is the regulation cost in year n. When calculating the total OPEX, the second sum in equation 32 represents the cost of replacing the electrolyzer stack (I_s), which only occurs every N_{stack} years. The number of times the stack is replaced is $\frac{N}{N_{stack}}$ rounded down to an integer. The annuity of the loan can be calculated using equation 34, where an is the annuity.

$$R_t = \sum_{n=1}^{N} \frac{R_n}{(1+a)^n} \quad [€] \tag{30}$$

$$CAPEX_{total} = I_t \cdot I_i + \sum_{n=1}^{N_{loan}} \frac{annuity}{(1+a)^n} \quad [€] \tag{31}$$

$$OPEX_{total} = \sum_{n=1}^{N} \frac{OPEX_y}{(1+a)^n} + \sum_{n=1}^{N/N_{stack}} \frac{I_s}{(1+a)^{n \cdot N_{stack}}} \quad [€] \tag{32}$$

$$R_n = R_n^{H_2} + R_n^E - RC_n \quad [€] \tag{33}$$

$$an = (1 - I_i) \cdot I_t \cdot \frac{a_{loan} \cdot (1 + a_{loan})^{N_{loan}}}{(1 + a_{loan})^{N_{loan}} - 1} [€] \tag{34}$$

To assess the profitability of a project, the two metrics chosen are NPV and Internal Rate of Return (IRR). NPV subtracts all the expenses from the revenue generated throughout the lifetime of the project, properly adjusted according to the project's rate of return, as can be seen in equation 35.

$$NPV = R_t - CAPEX_{total} - OPEX_{total} \quad [€] \tag{35}$$

On the other hand, the IRR (calculated according to equation 36) is the maximum rate of return on the project, providing an estimate on the return on the investment made in the project.

$$IRR = 100 \cdot (a_1 - \frac{(a_2 - a_1) \cdot NPV_1}{NPV_2 - NPV_1}) \quad [\%] \tag{36}$$

The equations to calculate the Levelized Cost Of Hydrogen (LCOH) and LCOE are equation 37 and equation 38, respectively, where H_{2_n} is the amount of hydrogen generated in kg in year n, E_n^g is the total amount of electricity generated in MWh in year n, E_n^p is the total amount of electricity purchased in MWh in year n to produce hydrogen, N is the project's lifetime and a is the project's rate of return.

$$LCOH = \frac{CAPEX_{total} + OPEX_{total} + \frac{E_n^p}{(1+a)^n}}{\sum_{n=1}^{N} \frac{H_{2n}}{(1+a)^n}} \; [€/kg] \quad (37)$$

$$LCOE = \frac{CAPEX_{total} + OPEX_{total}}{\sum_{n=1}^{N} \frac{E_n^g}{(1+a)^n}} \; [€/MWh] \quad (38)$$

4. Results

4.1. Day Ahead Forecasting

The developed neural network is a Convolutional Neural Network (CNN) with data pre-processing using 10 mode VMD. Table 1 contains the Root Mean Square Error (RMSE), Mean Average Error (MAE) and Mean Average Percent Error (MAPE) for the forecast of wind power production for the location 25 km from shore, with table 2 containing the results for the location 50 km from shore. The same metrics for the forecast of day ahead electricity price are presented in table 3.

Table 1: Performance metrics for wind power production forecast 25 km from shore

Model	RMSE [kW]	MAE [kW]	MAPE [%]
VMD-CNN	859	592	33
Baseline	4274	3218	232

Table 2: Performance metrics for wind power production forecast 50 km from shore

Model	RMSE [kW]	MAE [kW]	MAPE [%]
VMD-CNN	665	443	23
Baseline	4323	3242	220

Table 3: Performance metrics for electricity price forecast

Model	RMSE [€/MWh]	MAE [€/MWh]	MAPE [%]
VMD-CNN	3.19	2.31	6
Baseline	8.54	5.88	18

4.2. Optimal Ratios

To calculate the optimal ratios, every ratio from 0 to 100% in increments of 5% is tested for both the electrolyzer and fuel cell as well as for every hydrogen price considered. Regarding the fuel cell, it was concluded that its operation is almost never viable. Nonetheless, a minimum fuel cell ratio of 5% was selected so that the fuel cell's operation could be analysed. The optimal electrolyzer ratios can be seen in table 4.

Table 4: Electrolyzer's optimal ratios for the location 25 km from shore

System	Hydrogen Price [€/kg]	Year		
		2020	2030	2050
Offshore Elec.	2	60%	90%	90%
	4	90%	90%	95%
	6	90%	95%	95%
Onshore Elec.	2	5%	5%	5%
	4	100%	100%	100%
	6	100%	100%	100%

4.3. LCOH

The LCOH curve for the offshore electrolyzer and onshore electrolyzer systems are presented in figures 3 and figure 4, respectively.

A ratio of 95% was chosen in the offshore electrolyzer system (the difference in LCOH if the ratio is 90% is under 0,5%). For the onshore electrolyzer system, a ratio of 100% was chosen since it is the most common optimal ratio.

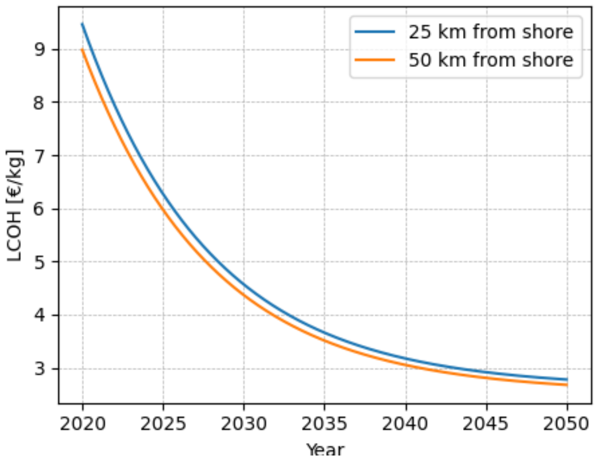

Figure 3: LCOH of the offshore electrolyzer system

The LCOH for the offshore electrolyzer system (figure 3) follows a similar trend to the one observed in the conventional wind farm's LCOE, only with an even more substantial reduction throughout the years considered in the simulation. It drops by 34% from 2020 to 2025, by a further 18% from 2025 to 2030 and in the final 20 years from 2030 to 2050 it drops another 18.5%.

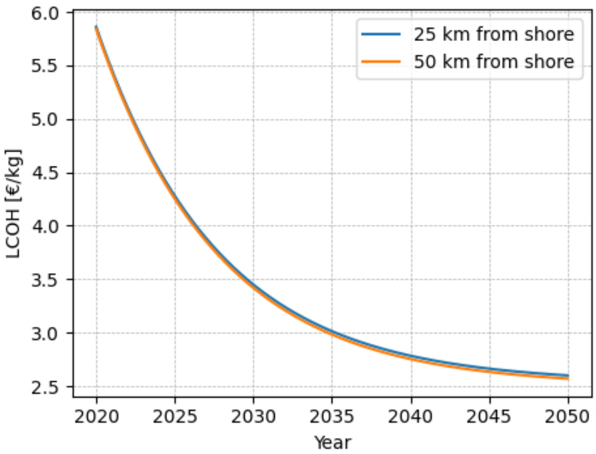

Figure 4: LCOH of the onshore electrolyzer system

Regarding the onshore electrolyzer system, its LCOH is always lower than the offshore electrolyzer system, mainly due to its ability to purchase electricity from the grid. Therefore, the electricity isn't necessarily generated by renewable resources and the hydrogen produced by this system can't be denominated as green hydrogen. The LCOH difference between the systems is over 3 €/kg in 2020, however in 2030 and 2050 this difference lowers to roughly 1 €/kg and 0.20 €/kg, respectively.

4.4. Economic Assessment

The economic assessment of the three systems for different hydrogen prices can be seen in table 5 for the location 25 km from shore.

The first remark to make is that the onshore electrolyzer system is always more economically interesting than the offshore electrolyzer system, mainly due to its ability to purchase electricity. Even though the results only show positive NPV for higher hydrogen prices or in future years, the conventional wind farm in these locations also yields a negative NPV in all simulated years, indicating that floating offshore wind farms are still relatively expensive to build and might not be profitable in the coming years in the Iberian Peninsula. It should be noted that cost projections are far from certain and small variations greatly impact the economic assessment of future years (as is detailed in chapter 4.5).

4.5. Sensitivity Analysis

The parameters that were changed are capacity factor, rate of return and CAPEX. Starting with the offshore wind farm's capacity factor, in [4] a capacity factor of 54% was used in 2030. In the end, the lower capacity factor was set at 34.98% and the higher capacity factor was set at 53.18% (as a reminder, the capacity factor in the techno-economic analysis is 44.1%).

The results from the sensitivity analysis for the LCOH and NPV of the offshore electrolyzer system in 2030 for the location closest to shore can be seen in figures 5 and 6, respectively.

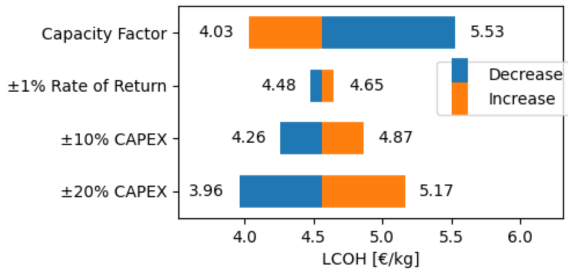

Figure 5: Sensitivity analysis for the LCOH of the offshore electrolyzer system in 2030 for the location 25 km from shore

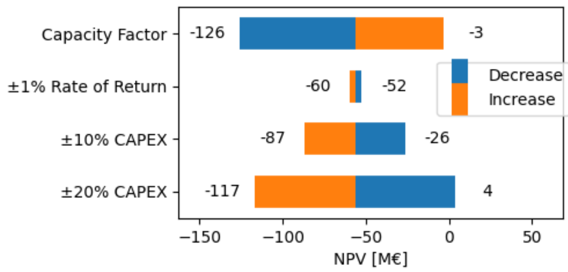

Figure 6: Sensitivity analysis for the NPV of the offshore electrolyzer system in 2030 for the location 25 km from shore

As can be seen, even increasing the capacity factor by 20% leads to a slightly negative NPV in the offshore electrolyzer system for a hydrogen price of 4 €/kg, while a 20% reduction in CAPEX has a similar effect. Looking at the LCOH for the offshore electrolyzer system, the biggest reduction is 14.8% if the CAPEX drops by 20%, achieving a value lower than in a scenario where the capacity factor increases by 20%.

The results from the sensitivity analysis for the LCOH and NPV of the onshore electrolyzer system in 2030 for the location closest to shore can be seen in figures 7 and 8, respectively.

Table 5: Economic assessment for the location 25 km from shore

System	Hydrogen Price [€/kg]	NPV [€]			IRR [%]		
		2020	2030	2050	2020	2030	2050
Offshore Electrolyzer	2	-651M	-256M	-82.3M	-	-	-
	4	-486M	-56M	129M	-	0.58	31.24
	6	-309M	145M	340M	-	24.61	72.08
Onshore Electrolyzer	2	-489M	-157M	-33M	-	-	0.89
	4	-374M	119M	325M	-	22.05	67.41
	6	22.6M	571M	796M	8.51	77.72	155
Conventional Wind Farm	-	-474M	-152M	-31M	-	-	1.22

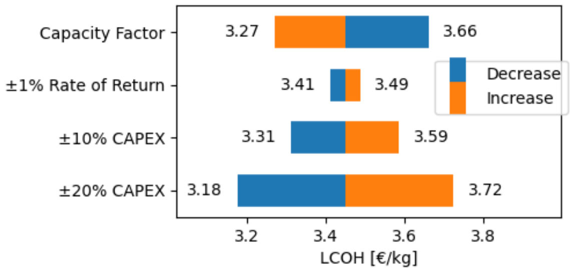

Figure 7: Sensitivity analysis for the LCOH of the onshore electrolyzer system in 2030 for the location 25 km from shore

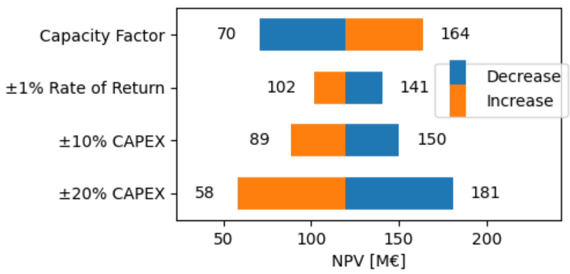

Figure 8: Sensitivity analysis for the NPV of the onshore electrolyzer system in 2030 for the location 25 km from shore

Regarding the onshore electrolyzer system, for both a 10% and 20% variation in CAPEX, there is a significant change in the overall profitability of the system. Comparing the scenario where CAPEX rises by 20% to the scenario where CAPEX drops by 20%, despite there being an appreciable difference in LCOH, the NPV is three times higher in the latter scenario.

5. Conclusions

In this thesis, a techno-economic analysis on two hydrogen producing systems and a floating offshore wind farm without hydrogen production was performed. In order to perform the simulations, each component was individually modelled and combined to construct the systems. Furthermore, an hourly optimisation algorithm and neural networks to forecast day ahead electricity price and offshore wind power production were also implemented.

The offshore electrolyzer system for the location 25 km from shore has an LCOH of 9.46 €/kg, 4.57 €/kg and 2.78 €/kg for 2020, 2030 and 2050, with the location 50 km from shore having slightly lower LCOH. This system is only economically viable for high hydrogen prices, mainly owing to the high investment cost in constructing a floating offshore wind farm. In 2030 for the location 25 km from shore, a hydrogen price of 4 €/kg yields a NPV of -56 M€ and a hydrogen price of 5 €/kg yields an NPV of 44 M€ (IRR is 12.19%). For the same location in 2050, a hydrogen price of 2 €/kg leads to an NPV of -82.3 M€ and a hydrogen price of 3 €/kg leads to an NPV of 23 M€ (IRR is 11.22%).

For the onshore electrolyzer system, its ability to purchase electricity helps the system to achieve a lower LCOH of 5.86 €/kg, 3.45 €/kg and 2.6 €/kg for 2020, 2030 and 2050, respectively, for the location 25 km from shore. At this location, in 2030 for a hydrogen price of 3 €/kg the project has an NPV of -95.3 M€ and for a hydrogen price of 4€/kg, the NPV is 119 M€ (with an IRR of 22.05%). In 2050, a hydrogen price of 2 €/kg results in a NPV of -33 M€ and a hydrogen price of 3 €/kg results in a NPV of 96 M€ (IRR is 24.43%).

The lower LCOH of the onshore electrolyzer system translates to this system always being more economically interesting than the offshore electrolyzer system, however, there is an important distinction that separates them. While the energy source of the offshore electrolyzer system is only the renewable energy generated in the offshore wind farm, the onshore electrolyzer system also purchases electricity from the grid, so its energy source might not be 100% renewable as the source of its electricity can't be determined. Thus, only the hydrogen produced by the offshore electrolyzer system can be denominated as green hydrogen.

Acronyms

AEL	Alkaline Electrolyzer
CNN	Convolutional Neural Network
IRR	Internal Rate of Return
LCOE	Levelized Cost Of Energy
LCOH	Levelized Cost Of Hydrogen
LNG	Liquified Natural Gas
MAE	Mean Average Error
MAPE	Mean Average Percent Error
MIBEL	Iberian Electricity Market
MILP	Mixed-Integer Linear Program
NPV	Net Present Value
PEMEL	Proton Exchange Membrane Electrolyzer
RMSE	Root Mean Square Error
SOE	Solid Oxide Electrolyzer
VMD	Variational Mode Decomposition

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