

# Assessing the influence of the planned future energy mix on the revenues of offshore energy parks acting on the electricity market in 2030

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## Abstract

With the common goal of reaching commercial viability and utility-scale deployments of wave and tidal projects in mind, it is necessary to consider the potential of earning revenues by participating in the regional and international electricity markets. The expected changes in electricity price will affect renewable energy parks differently based on their power production patterns. While different market and policy mechanisms are being introduced with the aim to soften the impact on power prices it is inevitable that a fully renewable energy system will be driven by peaks and valleys in renewable production. In this study, an updated price model is presented and applied to the Netherlands electricity market of 2030 and 2050 to show how the total installed capacity targets for wind and solar will affect the electricity prices and the potential revenues of offshore and onshore renewable energy parks. While the captured electricity price of solar shows significant seasonality and the captured electricity price of wind is strongly influenced by the large amount of installed wind capacity, the wave technology shows slightly higher capture prices than both other technologies and more constant capture prices over the span of the year - similarly to wind technologies.

## Index Terms

Future price scenarios, capture price, offshore renewable farms

## I. INTRODUCTION

CONSIDERING the long-term plan of renewable energy parks, it is necessary to assess the future electricity market they will operate in. With the rising share of weather dependent renewables in the electricity mix, the electricity price is becoming more volatile and dependent on the availability of few resources. In a renewable electricity system, based predominantly on wind and solar power, the Day Ahead (DA) electricity price will fluctuate considerably based on the weather.

Renewable energy generation parks utilizing other resources which are characterized by strong complementarity to the large-scale installed capacity in the region could benefit from the prices and gain higher revenues compared to large, single-source renewable energy parks. In the case of offshore renewable parks, adding wave and floating solar power to a wind farm would be especially valuable when the overlap of the production profiles of wave and

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Fig. 1. Artist impression of a multi-source offshore renewable energy farm consisting of wind and solar installations studied in the EU-SCORES project.

solar with the wind production profile are modest and, therefore, curtailment of the additional production is low. This can be quantified when assessing a business case or the potential revenue of the offshore park. The design process of a multi-source farm should also incorporate a pricing mechanism that can produce hourly electricity prices based on actual wind, solar and wave conditions. These prices can then be applied to the planned multi-source park in order to justify the share of installed capacities of the technologies included considering the future application of the park. Since offshore multi-source farms will have an expected lifetime of more than 25 years, they will reach the year 2050, in which weather dependent renewable energy will be even more dominant than today. Long-term studies are necessary to quantify the potential influence of different future energy mix scenarios on the revenues of offshore renewable parks.

Multi-source offshore renewable energy farms can play an important role in this emerging renewable energy system. They consist of wind, solar and/or wave power converters connected to the onshore grid with a shared substation and export cable (as shown in Fig. 1). By applying more than one renewable energy generation type in a single farm, the capacity factor of the network connection can be raised. In this way, the overall network connection and grid balancing costs can be reduced. More efficient use is made of the available sea space, if floating solar and/or wave power is added in between the wind turbines. There can also be an integrated service system for the wind, solar and/or wave devices in the farm. The wave farm can serve as a wave barrier for the wind farm, reducing the average wave height in the farm and expanding the weather window for service operations [1]. The first multi-source farms are in the planning, although the investment situation has been deteriorating due to higher supply costs and higher interest rates after the Russian invasion in Ukraine in 2022. Examples of potential future multi-source parks are the combination of wind and solar in the CrossWind consortium by Shell and ENECO for Hollandse Kust Noord and the RWE project Hollandse Kust West VII [2], [3].

In order to assess the financial aspect of the future energy farms, the electricity market needs to be modeled; previously presented methodology [4] is extended and updated and its validation and applicability is presented. The renewable energy production and total demand flows of the entire electricity pricing zone (bidding zone) need to be considered to simulate the future electricity prices of a region. In hourly resolution, the total renewable energy production from wind and solar parks and the total fixed demand in the bidding region are calculated and used to generate the residual load profile. Utilizing the assumption of linear correlation between residual load and electricity price, an hourly price timeseries is simulated. The model introduced is applied to the Netherlands region in a case study. The potential future electricity prices of the Dutch bidding zone in 2030 and 2050 are presented, including the capture prices for the different renewable energy technologies. Furthermore, as the long-term future energy mix plans are uncertain, the potential effects of six variables are quantified through an exploration of the design space of the model.

## II. METHODOLOGY

To study the changes in expected electricity prices in the future energy mix, a previously introduced methodology [4] has been updated to simulate the electricity market behaviour based on the residual load which is defined as the difference between the cumulative electricity produced from renewable energy sources and the demand of the market region. The methodology is based on the linear relation between total residual load and recorded electricity prices observed and studied in historical datasets concluding a linear regression between the two parameters.

The updated model presented in this study follows the main methodology of the previous model. However, instead of utilizing the demand coverage ratio as the parameter that scales the electricity prices linearly, the total residual load is considered to calculate the electricity price. The residual load is a better parameter since the prices are related to the actual electric power in the system and not to the relative powers in the system, as is the case with the demand coverage ratio parameter.

The residual load parameter was first introduced in [5]; they showed that there was a good correlation between the residual load and the DA market price for Germany. In [6], the authors elaborated further on the possibilities of the application of the residual load method to determine the value of electricity in the design of renewable energy systems. While in [7] the effect of adding flexible load (in their case flexible hydrogen electrolyzers) on the electricity prices is presented. The findings show that once high shares of variable renewables are reached, flexible electrolyzers help increase the market share of renewables even further. This means that they disproportionately consume renewable electricity that would otherwise have been curtailed. This leads to a distinct section of the price graph: at high percentages of variable renewables (so at values of the residual load below zero), the demand from the flexible loads will keep the electricity price above zero.

The price model is specifically built to fit future scenarios in which considerable installed capacity of flexible load will be present. In the future, the total demand will be composed of fixed and flexible load also due to strong electrification needs. Negative residual load indicates a surplus of renewable energy generation; this leads to the activation of the flexible load available in the region to absorb the excess electricity and balance the grid. The flexible load will be switched on and off depending on the hourly electricity prices making the demand side of the electricity grid balancing more adaptable to the generation uncertainty. Examples of upcoming flexible loads are electric vehicles, heat pumps and electric boilers in industry.

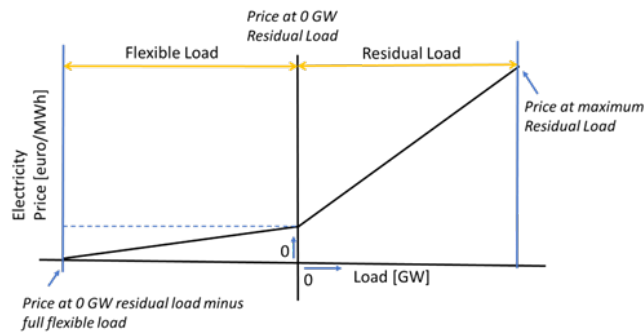


Fig. 2. The Price Model linear regression assumption between DA prices and residual load.

### A. Price Model

The model is used to estimate the DA electricity market in the future. The DA electricity price is set the day before and is based on bids that electricity producers submit based on their forecasted electricity production and their marginal costs. The demand for the next day is forecasted and the electricity price of the next day is fixed based on the production bids and the predicted demand. Once the price is set all parties are obliged to either feed in or take out (depending if they are electricity producers or consumers) the electricity they forecasted. Imbalances caused by forecasting errors need to be solved by trading electricity on more instantaneous markets (such as the Intra Day or aFRR market). These markets are outside of the scope of the model presented. The price model generates a price timeseries with hourly resolution based on the residual load in each timestep. The calculations are based on renewable energy generation timeseries, demand timeseries, and three price-point assumptions. Figure 2 shows the linear regression assumption on which the model is based. While assuming a linear relation between these two parameters is a simplification of the merit order approach used in the electricity market, it has the advantage that simulations can be run rapidly and is dependent on fewer input parameters that can be easily tuned. This approach is validated and the results of it are shown in the subsequent section.

1) *Electricity production*: Initially, the total power generated by renewable energy parks in the region is calculated as an hourly time series. This calculation is based on historical resource data which is used to calculate the power output of for example wind and solar farms. Their power output timeseries is normalized and combined with planned capacities of onshore and offshore wind and onshore PV farms of the region to calculate the cumulative renewable energy production. To increase the accuracy of the renewable energy generation profile of the entire region, a geographical spread of the installed capacity is considered. For each location, the resource timeseries is utilised to calculate the local renewable power production. The renewable electricity production is based on wind and solar production only as they are the largest contributing factors and the technologies planned to be significantly extended in the upcoming years; the model does not include other forms on renewable electricity production such as biofuel or hydro pumps. Furthermore, grid constraints that might cause curtailment of electricity are not included. As the electricity production is based on historical resource data, forecasting errors due to uncertainty of future resource availability are not included in the calculation; as mentioned above the DA market prices are set the day before, thus, using forecasted electricity production to establish the electricity price.

2) *Fixed Electricity Demand*: Similarly, the total demand time series is calculated by using historical demand data and scaling it to fit the future scenario. The total and maximum fixed demand of the future energy scenario is used to define a scaling factor with which the historical demand timeseries is multiplied. By applying a scaling factor to the historical demand for the representation of the future fixed electricity demand, the model assumes a linear increase in fixed energy demand. It does not include any changes to the hourly, daily, or seasonal changes to the fixed electricity demand. Additional electrification of the energy consumption of the studied region is assumed to be included in the electricity demand by adding flexible demand (when residual load is negative) or increase the fixed demand linearly. For consistency, the model considers the historical data for demand and resource of the same period to include correlations between the two timeseries (e.g. colder days in which solar production is low, the demand might be higher due to higher heating consumption). The model does not include storage systems which would affect the demand timeseries as they can store electricity when there is a surplus of production and the electricity prices are low and discharge electricity when demand and prices are high, thus, altering the demand profile.

3) *Residual Load*: The total renewable electricity production and the demand timeseries are used to calculate the total residual load in the energy system. If the residual load is positive, the fixed electricity demand is not met by renewable energy (wind and solar) and additional electricity generation technologies need to be activated. In case of negative residual load, technologies with flexible load will act on the market to absorb the excess of renewable electricity to utilize or feed into the market at a later time. If the residual load is positive, the model does not differentiate between electricity demand met by different non-renewable technologies such as oil, gas, coal, etc.

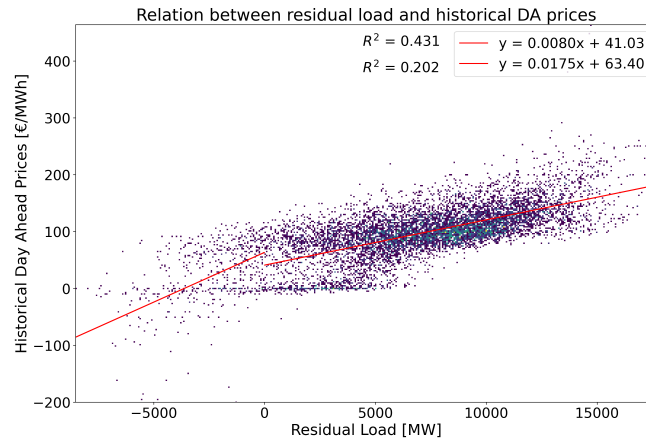


Fig. 3. Linear regression between residual load and DA electricity prices in the Netherlands in 2023. The negative and positive residual load areas are divided into two regression lines as this is the approach taken in the price model.

4) *Electricity Price*: Based on a linear relation between the electricity price and the residual load, a linear price model for the future renewable electricity system is constructed. As depicted in figure 2, three price points need to be assumed in order to define the linear regression between the two variables. The slope in the positive and negative sections of the price model are defined by the three price points and are usually different.

5) *Price Points*: Assumptions need to be made to set up the price model for each scenario; the meaning and thoughtful selection of the input parameters needs to be justified properly and additional sensitivity studies are needed to show their effect on the final metrics. The values that can be used for the capacities of the three points of the price model are often found in reports or scenario documentations, while the price points are taken from expected costs of different technologies. At the maximum residual load price point, the main price drivers are the fuel costs plus the costs of emitting or removing CO<sub>2</sub>. At the EPEX SPOT DA market the fuel based dispatchable plants generally offer to produce at or above their marginal costs. If the price, at the closing of the market, is settled higher than their marginal costs, the renewable energy park operators gain revenues above their marginal costs with which they earn back their CAPEX and other fixed costs and can make a profit. The fuel that is considered for the maximum price point can be natural gas but also bio-fuel, hydrogen or other renewable power based fuels (P2G: Power to Gas). As the model's calculations are based on one fixed price that is applied to this maximum price point; fluctuations in the gas or oil price within the assessed timeframe are not included.

At the lowest point, the maximum installed capacity of flexible load in the energy system is defined. In case residual load surpasses this value, the electricity price becomes negative. The middle point describes the electricity price when renewable energy production and fixed demand are equal and all demand is met by renewable energy. The highest price is defined by the maximum fixed demand capacity and the price for this is based on a simplified merit-order assumption approximating the real market price selection process. Assumptions are made for the prices and capacities for these three points based on reports and future scenario definitions.

Although in the merit-order approach the price for renewable energy generation is typically (close to) 0, flexible load is switched on whenever the prices are below a certain threshold for cost effective operation, thus, the price of renewable electricity is adjusted with this consideration. This depends on the type of flexible load activated (e.g. electricity export, vehicle charging, H<sub>2</sub> production or direct heat production). Furthermore, the installed capacity of flexible load will follow the developments at the supply side of the market. The more solar and wind capacity will be installed, the lower the electricity prices will get and the more flexible load capacity will be added, to profit from the low prices.

6) *Metrics*: Based on the price timeseries multiple metrics can be calculated to assess the electricity market and the value for the different technologies acting on it. The price duration curve can show the prices that can be expected within a year; it presents the prices over the entire year ordered from highest to lowest. The fluctuation and seasonality of the price can be quantified by the coefficient of variance (CoV) on different scales (e.g. hourly, daily, monthly). The capture price of each technology can explain the value of the technology in the energy system and the potential revenues that can be achieved by acting on the market. It is calculated by multiplying the hourly price timeseries with the hourly power production of the specified technology and divided by the total energy generated. This metric can also be depicted per month of the year in order to show potential seasonality effects.

## B. Validation

In order to validate the model, historical data of the Dutch bidding zone of 2023 is used. Figure 3 shows the DA electricity prices and residual load in hourly resolution in 2023. The historical prices and demand are from the EU energy transparency platform ENTSO-E for the bidding zone of the Netherlands [8], while the power

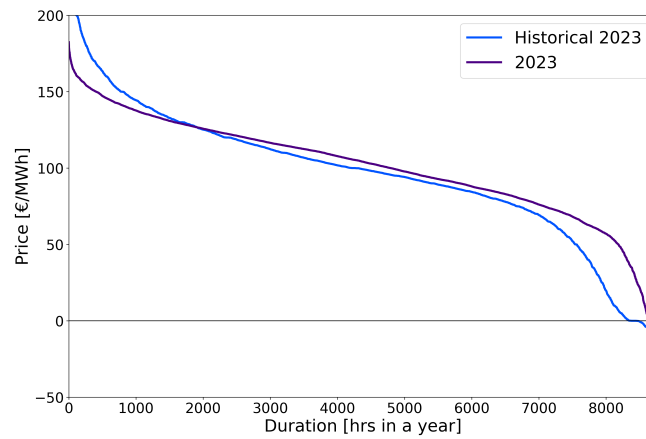


Fig. 4. Price duration curves from historical data and price model simulation for 2023.

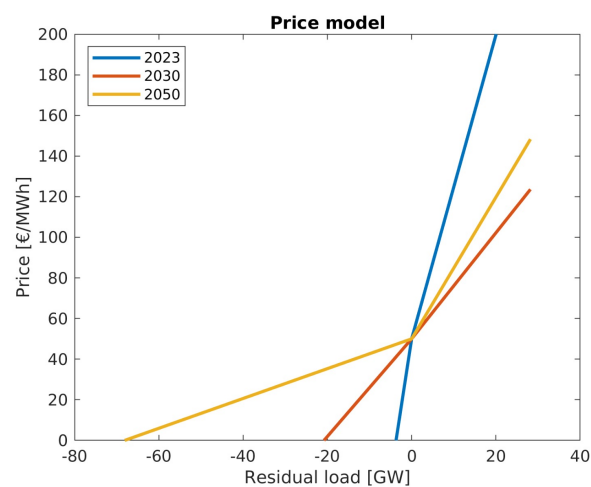


Fig. 5. Applied price points for the two cases and the validation case.

output of renewables is calculated based on historical resource data from the Solcast platform [9]. Within the positive and negative areas of residual load linear regression lines are calculated. An increase of the electricity price with increasing residual load. A linear correlation is appearing between the data points in the positive residual load with an  $R^2$  of 0.431. While for the negative part, the linear correlation is not as evident; this is caused by a lower number of occurrences and the limited amount of flexible load installed in the studied year. There are a large number of external factors influencing the electricity price such as electricity import/export, ambient temperature, etc., that are not parameters considered in this simplified model. However, for the purpose of long-term future scenario assessment and potential revenues of wave, tidal, solar and wind production over a prolonged time window (e.g. one year) the linear relationship is a sufficient approximation to be able to draw conclusions significant for the design process of future renewable energy parks.

Applying the linear regressions extracted from the historical data, the price duration curves of the historical prices and the simulated prices for 2023 can be compared as presented in Figure 4. The selected values for the input parameters of the validation case are included in Table I.

It is worth mentioning that sub-zero prices occur in the current electricity market due to renewable generation plants not having an incentive to decrease their production at these prices and having a fixed subsidized revenue stream per MWh of produced electricity. These price spikes that can be seen in Figure 3 don't influence the general price level, as long as they are incidental.

Furthermore, in 2023 the natural gas price level (52 euro/MWh) was exceptionally high due to the closure of the pipelines from Russia and the scarcity of LNG which leads to a considerably higher price at maximum residual load (200 €/MWh) compared to what will be expected in future scenarios.

In other countries a comparable linear relationship between DA electricity prices and the residual load is emerging, however, in the Netherlands it is currently more pronounced because of the large contribution of solar and wind in the electricity mix.

TABLE I  
INPUT PARAMETERS FOR VALIDATION AND TWO CASE STUDIES

Inputs	NL2023	NL2030	NL2050
<i>Total solar [GW]</i>	23.94	48.3	145.5
<i>onshore [GW]</i>	23.94	48.3	144.5
<i>offshore [GW]</i>	0	0	1
<i>Total wind [GW]</i>	9.89	28.6	64.1
<i>onshore [GW]</i>	6.37	8.6	13.8
<i>offshore [GW]</i>	3.52	20	50.3
<i>Non flexible load [TWh]</i>	109.18	153.48	153.48
<i>Non flexible load [GW]</i>	20.06	28.2	28.2
<i>Flexible load [GW]</i>	3.7	20.8	68.1
<i>Price at max. residual load [€/MWh]</i>	200	123.6	148.3
<i>Price at zero residual load [€/MWh]</i>	50	50	50

### III. SCENARIOS

To present the price model's results, the Dutch bidding zone has been selected to simulate two separate scenarios: the future energy mix and electricity price market of 2030 and 2050 are studied. To define the two scenarios, the II3050 study from Netbeheer Nederland [10] offers detailed insight into the Dutch plans for the energy transition towards 2030 and 2050; it presents three (2030) to four (2050) different scenarios based on possible trajectories. The mean values of these scenarios are used for the initial cases defined here.

In order to calculate the price timeseries and capture prices of the different technologies, the following parameters are defined based on well-researched assumptions: the total installed capacities of onshore and offshore wind and solar power plants; the total flexible and fixed demand of the Dutch region; the price at maximum residual load; and the price at zero residual load. All input parameters are summarized in Table I. The price points defined in this table for each case can be depicted to show the price model of each simulation case (Fig. 5).

- 1) **Total installed capacities of onshore and offshore wind and solar:** The countries around the North Sea are building a renewable electricity system at a remarkable speed. In the Ostend Declaration, the energy ministers of Belgium, Denmark, Germany, France, Ireland, Luxembourg, the Netherlands, Norway and the UK have set targets to install 120 GW of offshore wind in 2030 and 300 GW in 2050 [11]. The Netherlands have set offshore wind targets of 21 GW in 2030 [12] and 70 GW in 2050 [13]. Furthermore, additional plans for offshore floating solar devices were planned in previous years. The installed capacities for renewable energy are based on the average values of the II3050 scenarios as this is a more recent report [10]. A strong increase of especially the installed capacity of wind can be seen. This capacity will mainly be installed offshore (from 20 to 50.3 GW) and less onshore (from 8.6 to 13.8 GW). All planned solar capacity will be installed onshore. As discussed, there is no contractual target for offshore floating solar energy, at this moment, in the Netherlands. However, to understand the value of offshore solar, 1 GW is assumed to be installed by 2050. In these scenarios, there is also no installed capacity for wave and tidal energy. In general, the expected development of wave and tidal power will have no effect on the electricity prices in the Netherlands up to 2050.
- 2) **Total flexible and fixed demand:** The fixed demand increases significantly until 2030 but after that the assumption is that only flexible load will be added to the energy system. Thus, from 2030 to 2050 the flexible load capacity increases by a factor of three due to important electrification efforts.
- 3) **Price at maximum residual load:** The prices for the maximum residual load in 2030 and 2050 are set according to the fuel and CO2 costs. Tennet expects that LNG scarcity will be solved by 2030. The price level for the scenario in the year 2050 is an estimation based upon the fact that by then all CO2 has to be removed.
- 4) **Price at zero residual load:** The price level at zero residual load is kept constant between the two scenarios and is based on the regression line of the 2023 validation case. The most important flexible load in the system in 2023 is the import and export of electricity. The price-effect of adding other flexible loads to the system is not known yet, so there is no information available to set this price level otherwise.

The total power generation of the renewable energy parks in the Netherlands is calculated with historical (2023) hourly resource data for wind and solar taken from the platform Solcast [9]. To approximate more accurately the power production, the Dutch Bidding zone is divided into regions as defined in Figure 6. For each location, the share of the total installed capacity of solar and wind is defined and the power output for each is calculated. The onshore and offshore area of the Netherlands is relatively small compared to other European countries like France and the UK, but still there is an effect of the geographic location on the solar, wind and wave production. This geographic distribution of the renewable generation has a direct influence on the electricity price. The Netherlands

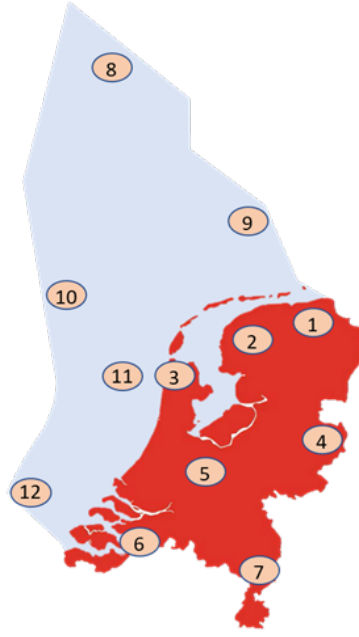


Fig. 6. Geographical spread of onshore and offshore wind and solar generation plants.

TABLE II  
GEOGRAPHICAL SPREAD OF INSTALLED CAPACITIES IN THE DUTCH BIDDING ZONE OVER TWELVE ON(SHORE) AND OFF(SHORE) LOCATIONS

Location Name	Coordinates North	East	Scenario 2030				Scenario 2050			
			Wind On	Off	Solar On	Off	Wind On	Off	Solar On	Off
1 Groningen, Drenthe	53.120	6.580	16.9%		13%		16.9%		13.5%	
2 Friesland	53.220	5.520	9.2%		5%		9.2%		5.1%	
3 Noord Holland	52.930	4.780	10.3%		9%		10.3%		9.5%	
4 Overijssel, East Gelderland	52.270	6.880	3.2%		14%		3.2%		14.0%	
5 Utrecht, West Gelderland, Flevoland	52.100	5.180	31.9%		18%		31.9%		18.3%	
6 West Brabant, Zeeland, South Holland	51.540	4.350	26.1%		22%		26.1%		22.4%	
7 Limburg, East Brabant	51.200	5.770	2.4%		17%		2.4%		17.2%	
8 Northern part of territorial waters	55.399	3.810		0%		0%		50%		0%
9 Ten Noorden Waddeneilanden	54.037	6.042		17%		0%		10%		5%
10 Nederwiek, Lagelander, IJmuiden ver	53.218	3.219		61%		0%		26%		50%
11 Hollandse Kust	52.918	4.150		15%		100%		10%		40%
12 Borssele wind farm	51.998	3.275		8%		0%		4%		5%

has a single DA electricity market, so all the renewable production is aggregated to a total renewable production over the land and sea area. To be able to calculate this total production we have made a simplified geographic spread over the land and sea area, consisting of twelve locations of which seven onshore and five offshore. All the renewable production capacity is concentrated in these 12 locations. The percentages give the distribution of this installed capacity over the land or sea area and are summarized in Table II. Until 2030, these are the planned capacities and locations of the Dutch government. For 2050, an estimation is made for the total installed capacities of offshore wind based on learning curves for offshore wind and where the extra capacities would be installed.

For all offshore locations, additionally, the wave power output was calculated to be able to quantify the captured price and added value for wave energy devices in the future energy mix of the Netherlands. Throughout the 5 offshore locations, the capture factor of the WEC arrays range from 0.35 - 0.20 with the highest capture factor in location 8 (Northern part of territorial waters). The wave resource with which the WEC power output is calculated is taken from ERA5.

#### IV. RESULTS

The two separate cases (2030 and 2050) can be compared with each other but also with the validation scenario of 2023. It is useful to first consider contextual results in order to facilitate the understanding of the price results of the two cases. In Figure 7, the total demand for each year is depicted. The fixed demand increases from 2023 to 2030; while from 2030 to 2050 the fixed demand is constant and the flexible load increases as flexible capacity is installed at a high rate (power capacities considered for the price mode and explaining the maximum possible flexible and fixed demand are summarized in Table I). The flexible electricity demand shows the surplus electricity that was produced by renewables after meeting the fixed demand; it is the sum of all negative residual loads.

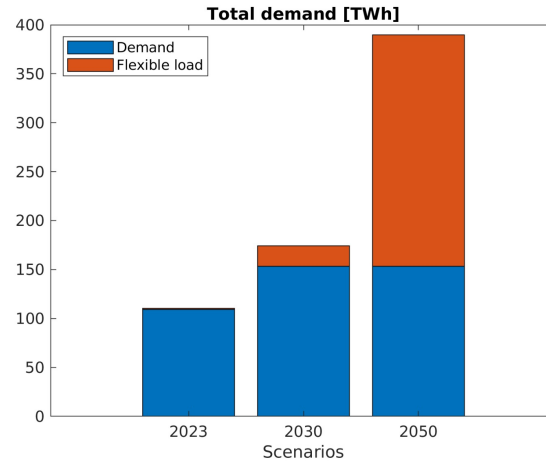


Fig. 7. Fixed demand and flexible load in the two scenarios and the validation case

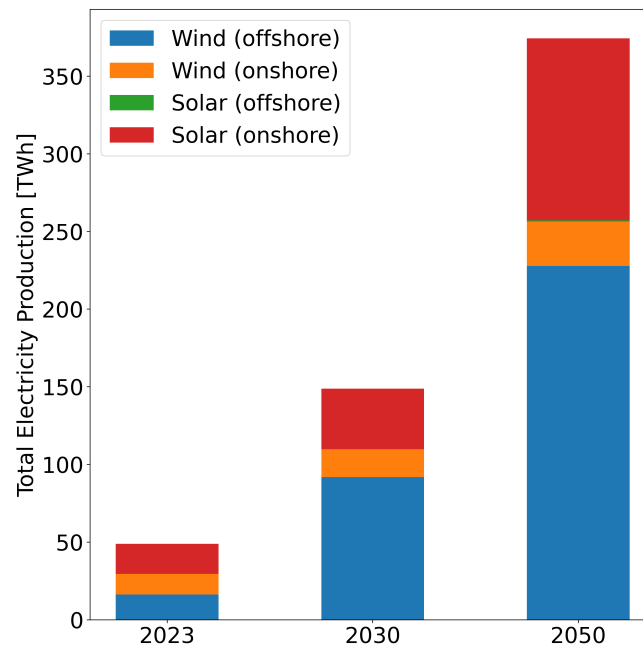


Fig. 8. Total renewable energy production from onshore and offshore wind and solar in the two scenarios and the validation case

When taking a look at the total energy production (Fig. 8), in both future scenarios the offshore wind capacity installed accounts for approximately 25% of the total installed capacity of renewables and it accounts for more than 60% of the total power produced. It is important to compare these shares of total energy produced with the share of installed capacities of the different technologies.

In Table III, the main results of the price simulations are summarized for the two cases and the validation. The mean DA price is shown to explain how the market in total is evolving. An overview can also be gained from Figure 9 in which the price duration curve for the two cases is presented. This is strongly correlated to the price model linear regression defined for the cases (Fig. 5). In 2050, it occurs more frequently that the prices become negative, meaning that although the flexible load capacity increases three-fold from 2030 to 2050 it is still not enough to capture all excess renewable energy generated. In 2030, approximately 60% of the year the demand is not fully met by renewables, thus, the average electricity price is higher than in 2050. Furthermore, less than 25% of the entire year show prices above 50 €/MWh, this means that in the rest of the year, all fixed demand is met by renewable energy generation. The overall market price drops significantly and nearly halves from 2030 to 2050. With increasing installed renewable energy the fluctuation of the electricity price in hourly resolution also increases (as seen from the CoV values); this might also be caused by the stronger dependence on one renewable energy resource in 2050.

The mean capture prices show what average prices per sold energy unit (MWh) the different types of technologies would reach. These are assessed in more detail for the two cases separately to explain potential advantages for specific technologies.

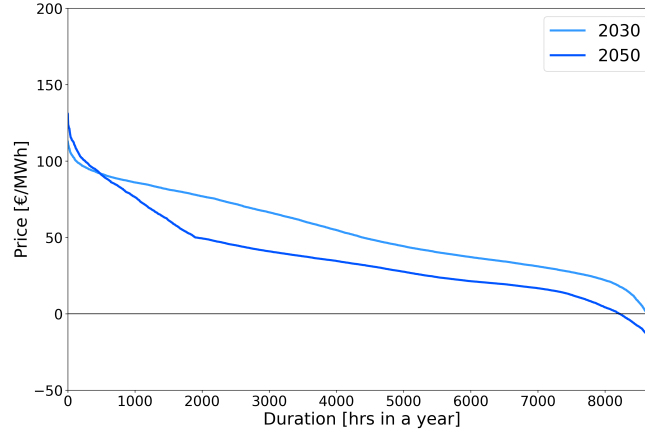


Fig. 9. Price duration curve for the 2030 and 2050 scenarios

TABLE III  
PRICE METRICS FOR VALIDATION AND TWO CASE STUDIES

Outputs	2023	2030	2050
<i>mean DA price [€/MWh]</i>	100.55	53.18	36.41
<i>DA price CoV hourly</i>	0.338	0.474	0.756
<i>mean captured price [€/MWh]</i>			
<i>offshore wind</i>	90.66	39.98	24.67
<i>onshore wind</i>	86.12	37.03	23.61
<i>onshore solar</i>	64.3	34.23	12.27
<i>offshore solar</i>	n/a	n/a	12.10
<i>wave</i>	n/a	42.31	27.00

#### A. NL 2030

With the input assumptions of 2030, the average prices for the different technologies do not differ significantly; approximately 3€/MWh of difference between them can be seen. The difference in capture price between onshore and offshore wind is also worth highlighting as of the total wind capacity installed is mostly deployed offshore, but due to the higher capacity factor of the offshore wind turbines it still reaches a higher captured electricity price. Figure 10 shows the average electricity price per month and the seasonality effects in the capture price per technology for this scenario. Seasonality effects can be seen especially in the captured prices of the solar technology for which prices fluctuate between 25 and 55 €/MWh. Furthermore, the captured price of solar in the month of December is higher than the average market price, but the volumes are very low. Wind shows a smaller peak in captured price during the summer months and offshore wind shows slightly lower captured prices than onshore wind in May and June, but these effects are mostly due to the specific weather in the chosen weather year (2023). It is important to note that the WEC capture prices depicted are for the maximum capacity factor reached (location 8 of the geographical spread) which has an average electricity price of 42.3 €/MWh. WECs appear to be capturing prices more consistently over the entire year. It is noticeable that wind and wave resource are closely linked together as their captured prices show similar trends.

#### B. NL 2050

The average electricity price drops significantly from 2030 to 2050 and the capture prices of the technologies are less dependent on their location (onshore or offshore). While in 2030 no offshore solar was installed, in 2050 a small installed capacity shows that the capture price of onshore and offshore solar is comparable. Similarly to the previous scenario, seasonality affects the captured price of solar significantly more than the one of wind or wave. In comparison to the previous case, in 2050, none of the technologies reach a captured price higher than the average electricity price in any of the seasons. The price of especially solar is that low, that it would attract more installed flexible load than in this simulation anticipated, which would subsequently increase the prices. The captured price of wave is slightly higher than that of (offshore) wind. Offshore wind shows stronger consistency in prices between the seasons; this might be due to the total power production coming predominantly from offshore wind.

#### C. Full factorial simulation

As mentioned above, the scenarios for 2030 and 2050 were taken from average values of different cases defined in the national report [10]. The decision to define scenarios for these long-term goals is motivated by the strong

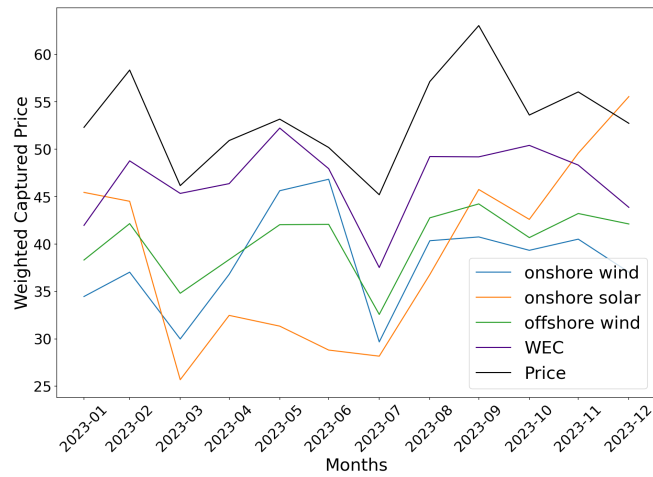


Fig. 10. Capture price per technology in 2030

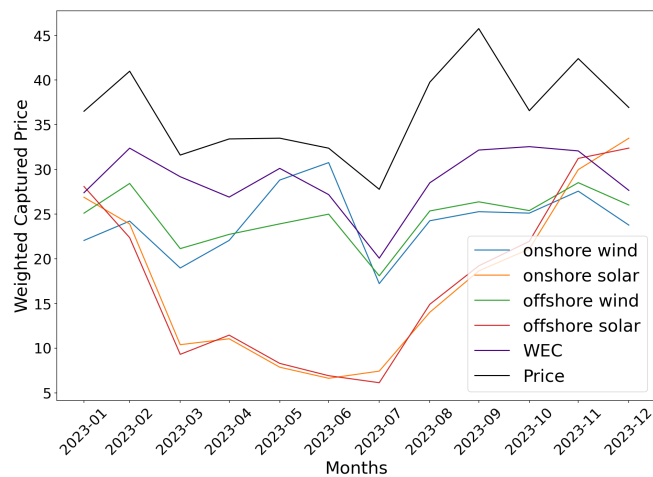


Fig. 11. Capture price per technology in 2050

TABLE IV  
PARAMETER SETTINGS FOR 6-PARAMETER, THREE LEVEL FULL  
FACTORIAL STUDY FOR THE 2030 SCENARIO

Parameters	0.71	Average	1.4
Total solar [GW]	34.5	48.3	67.6
Total wind [GW]	20.4	28.6	40.0
Non flexible load [GW]	20.1	28.2	39.5
Flexible load [GW]	14.9	20.8	29.1
Price at max. residual load [€/MWh]	88.3	123.6	173.1
Price at zero residual load [€/MWh]	35.7	50.0	70.0

influence of political decisions about e.g. taxes and subsidies, and targets and licenses on the energy mix and installation of renewables. The II3050 study deals with this uncertainty by designing 3 to 4 future scenarios in which the input parameters are fixed per scenario, based on a certain common ground like “European Integration” or “Climate Ambition”, but in essence they are all independent variables. For project developers, the most important question will be, under what political policy a potential project could risk generating losses. This will also be the most important question of banks, or other investors and of insurance companies.

By varying all parameters independently, the parameters with stronger include on the electricity market and the expected range of electricity prices based on strong fluctuations in the input parameters can be determined. Table IV shows the main input parameters of the price model and the three level ranges selected for the full factorial study.

A full factorial Design of Experiments (DOE) is defined for the first scenario of 2030. The 0-level values are the mean values of the three scenarios defined by the II3050 report, while the -1 and +1 levels are assumed to be the average value divided and multiplied by 1.4 respectively. This leads to 729 simulation runs to be able

TABLE V  
MINIMUM AND MAXIMUM VALUES BASED ON  
FULL FACTORIAL SIMULATIONS FOR THE 2030  
SCENARIO

Outputs	Min	Max
<i>mean DA price [€/MWh]</i>	11.52	102.62
<i>mean capture price [€/MWh]</i>		
<i>wind</i>	-14.84	92.66
<i>solar</i>	-28.04	88.10

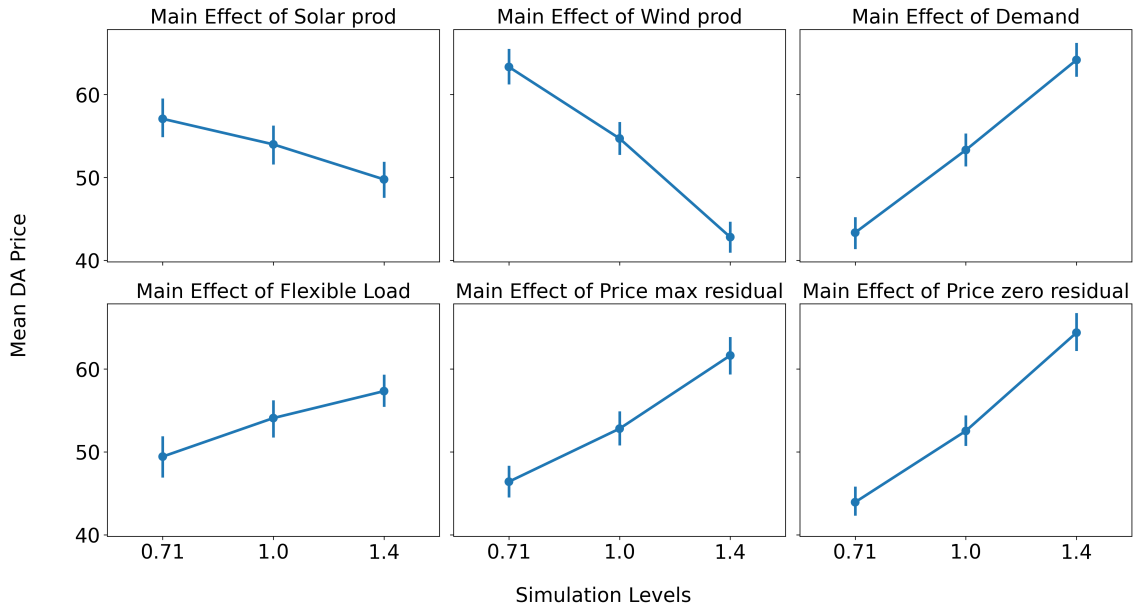


Fig. 12. Main effects of the full factorial results

to explore the entire design space defined by the ranges of these six parameters. The maximum and minimum possible mean price and wind and solar capture prices are summarised in Table V. While the mean market price does not reach negative prices, the capture prices for wind and solar both drop below zero in cases of minimum captured price.

In Figure 12, the main effects of each single parameter being changed independently of the other parameters selection are depicted. As the y-axis is shared by all subsections, it is possible to understand that the price and total fixed demand variables have the strongest influence of the mean DA electricity price.

## V. DISCUSSION

The results presented in this research show a future reality for unsubsidized renewable energy parks. The full factorial study gives an idea as to what could happen in 2030 by exploring the extremes of the design space based on the predefined input parameter ranges. It highlights how influential national and global renewable energy and electrification timelines and goals are in regard to future revenue streams for renewable energy parks.

1) *Production Diversification:* Assessing the future electricity prices shows that focusing on one renewable energy technology alone leads to strong seasonal price fluctuations. During peak production hours price-cannibalization might occur in energy systems with high renewables penetration. Diversifying through the deployment of more and complementary technologies could lead to a steadier electricity price and less need for storage capacity or alternative, non-renewable electricity production. Identifying these potential additional technologies early would incentivize supporting their development and commercialization in order to be deployable in the energy mix as soon as possible. To ensure the profitability and valorisation of renewable energy technologies different system services could be made available to the renewable energy park operators.

With the current offshore renewable energy targets, technologies such as wave and tidal devices will be deployed at a level in which they will act on the electricity market without significantly affecting its behaviour. In the assessed region, wind and wave resources are more correlated than in other regions in which the wave energy potential is significantly higher. Still the wave technology showed slightly higher capture prices than wind. The wave potential along the European Atlantic coasts is exemplary and could deliver supplementary production to solar and wind production [14] in a region in which the electricity market is dominated by solar production. Strong negative correlation to mainstream renewable energy production increases the future value

of the technology significantly. In the above shown case tidal energy has not yet been accounted for; tidal power has the advantage that it is not related to wind and solar power and is fully predictable. In the right regions and considering the future electricity market, it could show promising financial feasibility.

2) *Flexible Demand*: While focusing on increasing the deployment of new renewable energy parks to reach the governmental targets of net zero emissions, it is crucial to remember the demand side as well. Increasing the renewable power generation is useful to meet fixed electricity demands but it also leads to excessive amounts of curtailed electricity, if the energy system is not able to utilize the surplus electricity e.g. by storing and discharging it when required. In the current electricity system, there is hardly any flexible load which leads to negative electricity prices and curtailment of renewable electricity. As visible from the full factorial study, increasing the flexible load capacity will not influence the prices significantly, while, decreasing the fixed demand will decrease the necessity of other electricity generation technologies and decrease the DA market price. However, flexible loads are an essential element in a renewable electricity supply, to accommodate surplus production of solar and wind, as shown in [7].

3) *Business Case*: Current offshore renewable energy parks are planning to be operational for 25-30 years; realistically this means not relying on subsidies or other support schemes for the entirety of the project. Thus, business cases of these future parks need to include the future revenue streams coming from activities on the electricity market. This should be considered in understanding basic and crucial metrics to assess the techno-financial viability of the park to be developed and to analyse potential risks in case of changes in national or European plans and targets for electrification and renewable energy capacities. Furthermore, the assessment of future electricity prices and capture prices could help in shaping realistic and advantageous PPA contracts and potential inclusion of additional activities and markets to increase the estimated revenues. In the EU-SCORES project, the first multi-source offshore energy farms will be demonstrated. The company Oceans of Energy (OOE) will demonstrate a 3 MW offshore floating solar PV plant off the coast of Belgium and the company CorPower will demonstrate an array of four wave energy devices off the coast of Portugal with a total installed capacity of 1.2 MW [15]. The demonstrations will focus on the complementary production profiles of wave and solar co-located offshore wind farms, as well as the electrical integration in the existing and planned infrastructure. OOE and CorPower are supported by 15 partner companies and institutions from nine European countries to study, assess, and demonstrate the scalability of multi-source parks. Furthermore, the project will explore the technical and financial added value of co-location and multi-source farms.

## VI. CONCLUSION

For developers of renewable electricity projects, a reliable calculation of the future revenues is of utmost importance. However, these calculations are influenced by future developments that are hard to predict. Especially because they are influenced by future political decision making. The model presented gives the possibility to assess at a high level the influence of national and international targets on the electricity prices of the future and on the potential value of new renewable energy parks acting on the electricity market. The price model can be applied to any region, bidding zone and power generation plant. It is also possible to study multiple bidding zones to see how interconnections would influence the electricity market. Additional useful information could be gathered by assessing the daily fluctuations in the electricity price to identify patterns of the production and demand profile and understand their effect on the captured prices of specific technologies (e.g. the duck curve). Furthermore, this study highlighted the importance of identifying the extent and influence of uncertainty in the modelled scenarios. This will be considered more thoroughly by extending the timespan of historical data used to calculate the production and demand timeseries of the price model and by including possible randomized errors in the datasets. This will make it possible to give statistically meaningful results and further quantify the effect of uncertainty on the potential future revenues of renewable energy parks.

Wave and tidal energy will have a role in the emerging renewable power system. Electricity prices will be high when there is not much production of wind and solar, thus, making it possible to generate considerable revenues with technologies showing complementarity or being able to store generated power. This is shown in the comparison of the technologies' captured electricity prices.

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