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TNO report**TNO 2020 R12096 | Final report****DEVELOPING A LONG LASTING
OFFSHORE WIND BUSINESS CASE
IN THE ENERGY TRANSITION BY 2050**

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Management summary

The European offshore wind energy ambition is to become a key source by 2030 and to meet more than 50% of power demand by 2050. This requires to increase the capacity from current 22 GW to 450 GW in the North Sea. However, the very high share of electricity production from offshore wind is increasing the stochastic nature of the power system and creating large uncertainties for the wind business investments and decision making.

This study provides insights for a long-lasting offshore wind business case under the Dutch decarbonized pathways (NECP and TRANSFORM scenarios), understanding its potential and suggesting the optimal realization of such a market by converting part of the electricity into green hydrogen as an interesting prospect.

The main results of future Dutch power system modelling show that future electricity price fluctuations are most sensitive to large-scale wind and solar energy integration, demand for electricity and flexibility and EU-ETS-CO₂ prices. Such combination increases future electricity prices with higher volatility and risk exposure. Beyond 2030 the dependency between prices and such market drivers is even stronger to achieve climate neutral system.

The offshore wind business is vulnerable to those changes. Currently offshore wind profit relies on subsidies scheme but the era of zero-subsidies has arrived. It will need to look into other markets to increase the net profit. With respect to power to hydrogen technology, there is still a need for further research into multi objective optimisation to maximise both offshore wind profits and electrolyser utilisation. The necessity for balancing both the offshore wind profits and the electrolyser capacity/utilisation will be a necessary problem to be solved for an efficient future energy system. Sizing the electrolyser allows a higher utilization rate, this parameter is important when modelling the LCOH, as they are strongly dependent. Furthermore it has been observed that the LCOE is the value prevalently impacting the profits, both because it affects the utilization rate of the electrolyser, as selling to SPOT market is preferred when the LCOE is lower, and for the natural effect of the lower the costs to produce the same product, higher the profits.

1 Introduction

Offshore wind is a large-scale renewable energy technology that is poised to play a dominant role in the energy system: it will become a key source of power by 2030 and will meet more than 50% of power demand by 2050, according to European Commission's (EC) estimates [1], [2]. The EU Strategy on Offshore Renewable Energy [3] proposes to increase Europe's offshore wind capacity from its current level of 12 GW to at least 60 GW by 2030 and to 300 GW by 2050.

The very high share of electricity production from variable renewable energy sources (vRES), mainly from wind but also from solar PV, is increasing the stochastic nature of the power system and creating large uncertainties for the wind business investments and decision making. The large scale deployment vRES require a full adaptation from system, end-user and business perspective, and the conversion of electricity to hydrogen is an interesting prospect [4]. However, it is still unclear how all this can be fit in without endangering the stability of the network and what are the technical and economic impacts and implications of integrating hydrogen with offshore wind.

Additionally, dropping technology costs and increased market integration make RES investments increasingly competitive and lead to a progressive phase-out of financial support mechanisms. In a decarbonised power sector with a high share of vRES generation, price volatility will be much more important than today, which incorporates a price risk for RES investments but also for other production or storage technologies. This risk may translate into an increased risk premium which prevents actual investments despite a per se profitability of the projects.

This study aims to shed further light on the impact of a future RES energy market while considering the aforementioned uncertainties. Specifically, this study provides insights for a long-lasting offshore wind business case, understanding its potential and suggesting the optimal realization of such a market by converting part of the electricity into green hydrogen. The research questions postulated are:

- Will offshore wind business case in the market conditions of 2030 and 2050 be profitable considering the expected LCOE reduction?
- Which market mechanisms and incentives may be required for a long-lasting offshore wind business case?
- What will be the techno-economic conditions for offshore wind businesses to obtain higher profit by either selling energy in the power market or for green hydrogen?
- Which will be the optimum electrolyser boundary conditions to host future offshore wind deployment?

Energy and power system models, are widely used tools able to address these issues, yet the emergence of intermittent RES-E and new market mechanisms have required modellers to adapt both the methodology and the datasets used. Stochastic optimisation using a multitude of scenarios is one example for a methodological improvement found in many recent studies. This study used the TNO ESM and PSM tools¹ and the national scenarios by 2030 [1] and 2050 [5] to address the research questions.

¹ <https://energy.nl/en/category/themes/energy-modelling/>

This report includes a general description of the power market introducing the main effects of the large-scale RES integration on the power system (Section 2).

Section 3 illustrates current market conditions and trends in the Netherlands with a focus on offshore wind business.

The analysis of the market mechanism for a long-lasting offshore business case are investigated in Section 4. Firstly, the national scenarios within the timeframes selected (2030 and 2050) and the main features of the models used are introduced, then, the inputs and results of the modelling are included, presenting the sensitivity analysis and measuring their impact on the business case for offshore wind by 2050.

Section 5 of the report includes a P2X business case: offshore wind is coupled with electrolyser to produce green hydrogen. The results shed light on the optimum conditions of the integrated system and the incentives required to increase the offshore wind revenue.

2 Power market in the Energy Transition

The equilibrium between demand and supply is determined at wholesale markets, where a pool of power generators bid their production and are awarded a contract until the demand is met. Different markets exist at different time scales. Here, the focus is on the day-ahead market; it is the most representative of electricity prices.

The functioning of the market is illustrated via the merit order curve where every asset places a bid for a given capacity and at a specific price, (which equals in theory its variable production costs, driven by the asset technology) [6]. The order of entrance in the merit order curve is as follow: firstly, there are some must-run power plants (e.g. Combined Heat and Power (CHP) units) operating at minimum load supplying energy to the electricity market. After these must-run plants, RES enter with near-zero production costs; then, fossil-fuelled assets, nuclear plants and biomass, which convert energy from an input fuel into power. As such, their variable costs depend on the fuel price, technology characteristics (e.g. conversion efficiencies), operational costs and the European Union Emission Trading System (EU-ETS) of CO₂ price. Thus, low variable costs technologies will generally run most of the year at their maximum capacity, and high variable costs assets will mostly operate only for short periods in the year to supply peak demand. At every time-step, the most expensive running asset sets the market price. Besides the electricity demand, the merit order mechanism also includes flexible assets, which act as additional energy demand sources in the electricity market. These are batteries, hybrid boilers, industrial boilers and electrolyzers (for production of hydrogen). Flexible assets are activated depending on the exceedance of supply over demand and when it is most profitable for them to store electricity. As variable renewable generation, storage and assets availabilities as well as demand levels fluctuate, so does the merit order structure and thus power market prices.

The market drivers are changing and the merit order is also changing during the Energy Transition with the high share of RES penetration (Figure 1)². The main current market drivers and the future expected ones are illustrated in Table 1.

Table 1 Market drivers changing in the Energy Transition

Current market drivers on day-ahead price formation	Factors changing during the Energy Transition
Fossil fuel costs	Energy mix (capacity and costs), hydrogen production at zero marginal cost
EU ETS CO ₂ prices	Increasing gas and CO ₂ prices
RES deployment	Increasing RES share
Nuclear and coal decommissioning	No coal, no nuclear
Demand flexibility	Higher demand, electrification (batteries, electrolyzers, hybrid boilers, industrial heat pumps,...)
Interconnection capacity	Higher cross border physical Flows (net exports / imports of each country with the neighbour).
Market setup	Energy trading volume shifts across different channels (PPA/cleared, spot (APX) or exchanged future). Future trends on subsidies schemes (SDE+) feed-in and premium tariffs

² The above explanation considers perfect market functioning based on marginal prices and is as such represented in the EYE model.

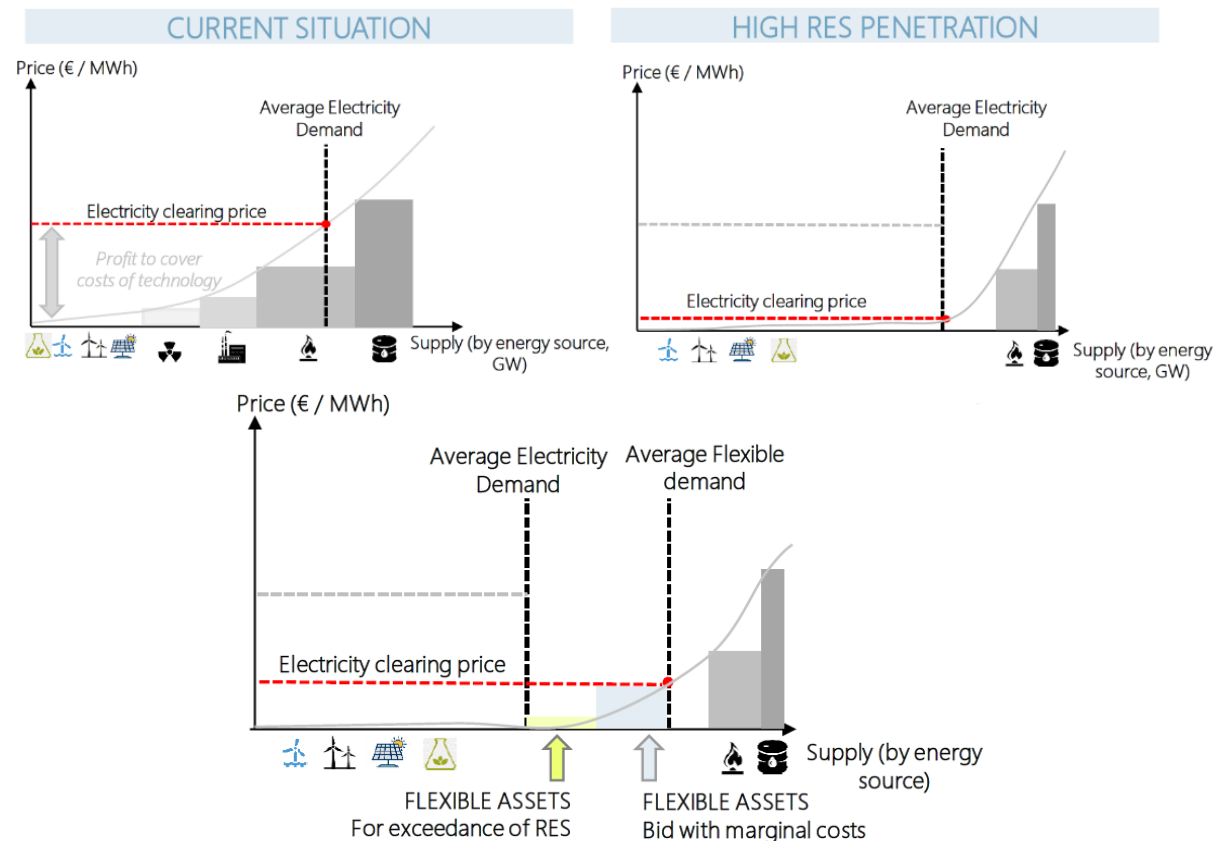


Figure 1 Merit order: impact of RES share in the wholesale market and bidding strategy including flexible assets.

3 Dutch market conditions and offshore wind

Offshore wind energy development has been driven by government support schemes³ so far (Figure 2); however, recent cost reductions raise the prospect of offshore wind power becoming cheaper than conventional power generation. This implies that policymakers have managed to design auctions that fairly reflect the actual costs of developing offshore wind farms, and that the specific auction design is not particularly influential on the outcome. Recent projects in the Netherlands have moved towards becoming subsidy-free. Wind farm developers bid 0 €/MWh and will pay land lease fees, indicating that offshore wind farms are at the point where they are likely to pay money back into the system [7]. A harmonization of the auction results from neighbouring countries based on their design features, to show that offshore wind power generation can be considered commercially competitive in mature markets can be found in [7].

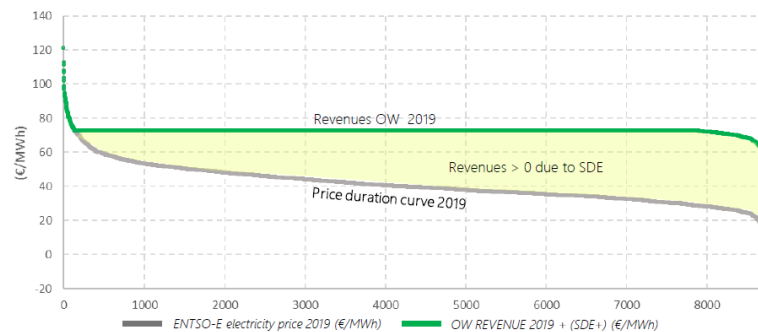


Figure 2 Price duration curve and tender bids for 2019 in the Netherlands, Borssele I, II.

Based on the European quarterly electricity market reports⁴, the Netherlands shows a decrease in trading activities (10% less) in 2019, due to an increase in long-term contracts and a reduction in Over-The-Counter deals and spot exchanges. During the Q1-2020 a particular mechanism [ARENH](#) increased trading activities which allowed alternative suppliers to purchase electricity from the dominant player in the market at a fixed price of 42 €/MWh. In general 10-30% of the total energy generated is traded in the spot market, 40%-60% is in PPA and 10-20% in futures/forwards. From Q2-2019 the market behaviour has changed and seen PPA contracts increase, spot trading decrease and zero subsidies on offshore wind projects.

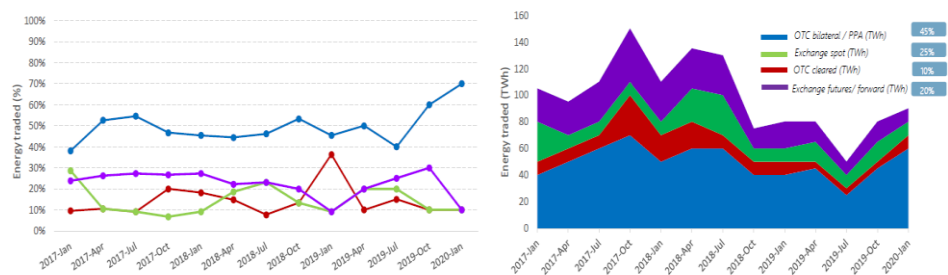


Figure 3 Dutch electricity market trends and volumes shifted across different channels.

³ The subsidy is a feed-in-premium scheme based on Stimulation of Sustainable Energy Production (SDE+) tender aiming to incentivise companies and (non-profit) organizations to produce renewable energy in the Netherlands. Offshore wind electricity is subject to a cap, the difference between this cap and the electricity market price equals the compensation and revenue provided by these SDE+.

⁴ https://ec.europa.eu/energy/data-analysis/market-analysis_en

4 Towards 60GW offshore wind portfolio by 2050

4.1 Scenarios selected and modelling approach

The national CO₂ targets defined by the Netherlands of an emissions reduction of 49% by 2030 compared with 1990, proposed in the Coalition Agreement, means a reduction of approximately 71 Mton of CO₂ equivalents by 2030 compared with an unchanged policy [8]. The following (long-term) objectives for 2030 and 2050 arise from the Climate Act:

- *In 2050, the Netherlands must have reduced greenhouse gas emissions by 95% compared with 1990;*
- *An intermediate target of a 49% reduction in greenhouse gas emissions has been established for 2030; and*
- *Another target stipulates that electricity generation must be 100% CO₂ neutral by 2050*

Therefore, the assumptions considered in this study are based on the definition of two reference national scenarios:

- **Baseline scenario, NECP2030:** based on the Dutch Integrated National Energy and Climate Plan (NECP) 2021-2030 [1], The figures in the final version of the NECP are based on the Climate and Energy Report (KEV) 2020 by the Netherlands Environmental Assessment Agency (PBL)⁵.
- **Sensitivity scenarios of NECP 2030:** since there is still a large uncertainty how the market drivers, including demand, flexible capacity, vRES deployment and EU-ETS CO₂ prices, will fluctuate by 2030, based on the NECP scenario, different sensitivities have been performed following *ceteris paribus* approach.
- **TRANSFORM scenario, 2030 and 2050:** based on the Dutch decarbonized Energy System Scenario (TRANSFORM) by 2030 and 2050 [5].

The Figure 4 includes a summary of the input data considered for the NECP, its sensitivities by 2030 and for the TRANSFORM scenario by 2030 and 2050. Models used for this analysis are existing TNO Energy System Models (ESM) and Power System Models (PSM) configured and set up under the scenarios selected. Firstly, the **OPERA ESM**⁶ [9] has been run under the NECP and TRANSFORM scenarios by 2030 and 2050 and then, its output (such as the hourly time series of demand for electricity and flexibility, the imports and exports) has been fed in to the **EYE PSM**⁷ model [10] to obtain future electricity prices and the merit order effect. Additionally, the output of the future electricity prices from the EYE model have been also compared with the results of the **COMPETES PSM**⁸ [11] under the same scenarios with the aim to have a robust range of uncertainties and range of trends and behaviour of the future power market (see Figure 5).

⁵ <https://www.pbl.nl/publicaties/klimaat-en-energieverkenning-2019> and Parliamentary document 32 813 no. 400

⁶ OPERA is a high detailed model of the Dutch energy system considering a detailed database for all the technological systems available, with high degree of choice in flexible technology options.

⁷ EYE model has been developed to model the behaviour of flexible assets in the Dutch electricity system market, therefore it allows the modelling of high detailed flexible assets.

⁸ COMPETES models the electricity market for the EU27 and UK countries. It accurately reproduces the interconnection of electricity trading as flexible solution for the e.g. Dutch market. It has been applied for simulating the NECP and TRANSFORM scenarios.

	Today	(KEV, 2020) 2030	Wind - Solar competition	From importer To exporter	Higher CO ₂ prices	Higher flexible demand	Traded volumes in SPOT market	Accelerated RES integration	Decarbonized system
SCENARIOS Main assumptions	2019	BASELINE 2030	Solar PV Grid	Net exports	EU-ETS CO ₂	FLEXIBLE DEMAND	MARKET SETUP	TRANSFORM 2030	TRANSFORM 2050
Total elec. demand (TWh)	112	137	137	137	137	137	137	165	270
Total flex.* demand (TWh)	0	30	30	30	30	0; 30; 40	30	44	315
Net exports (%demand)	-11%	+11%	+11%	-5%; +11%; 20%	+11%	+11%	+11%	+20%	+20%
Solar PV (GW)	3.9	20	10 ; 15; 20	20	20	20	20	39	127
Onshore Wind (GW)	3.6	6.9	6.9	6.9	6.9	6.9	6.9	8	12
Offshore Wind (GW)	0.9	11.5	11.5	11.5	11.5	11.5	11.5	14.5	60
CCGT Natural gas (GW)		17.8	17.8	17.8	17.8	17.8	17.8	17.8	12.8
ETS costs (€/Tn CO ₂)	20	43	43	43	28; 43; 75; 100	43	43	7.6	400
EPEX (%)	25	100	100	100	100	100	20; 30; 40	100	100
RES cost (€/ MWh)	0	0; 1.6	0; 1.6	0; 1.6	0; 1.6	0; 1.6	0; 1.6	0; 1.6 ; 1.9	0; 1.6 ;1.9

Figure 4 Scenarios selected with input data based on the NCEP by 2030 and TRANSFORM by 2030 and 2050

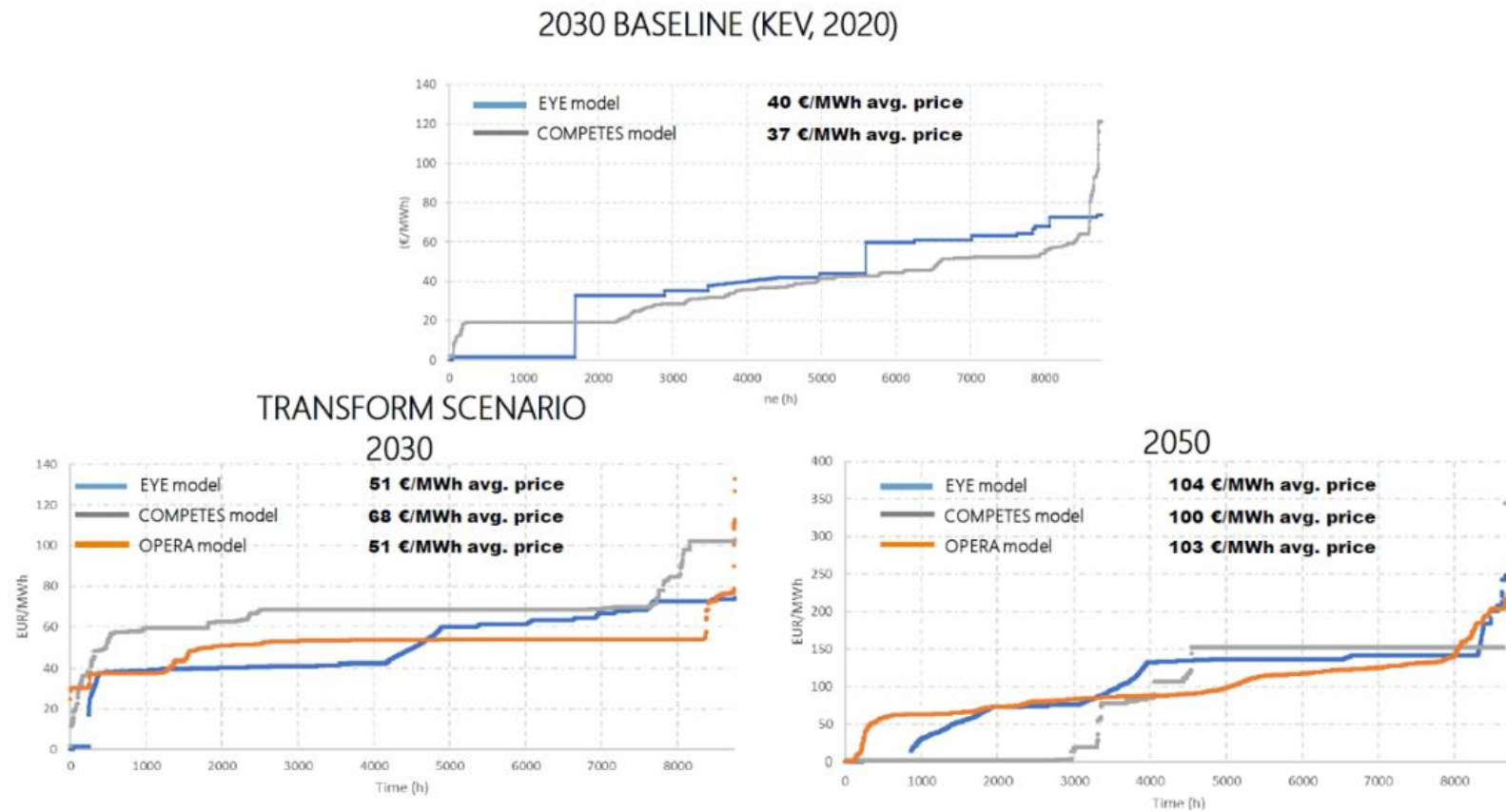


Figure 5 Comparison of electricity clearing price duration curve for NECP 2030, TRANSFORM 2030 and 2050 performed by OPERA, COMPETES and EYE models

4.2 Results on future offshore wind profitability

The modelling results for each scenarios are explain in each of the subsections below. The market analysis is based on the following considerations and figures:

- Simulated clearing prices at hourly frequency for each scenario year are represented as the price duration curve.
- Price setting technologies are presented with their marginal costs. Energy mix including supply and demand for electricity and flexibility are shown using a Sankey diagrams. The offshore wind utilization is also included to provide insights of the curtailment needs other type of contracts on top of the day-ahead power market bidding.
- The order of the setting technologies are: must run assets enter first in the bid. are located in the first part of the price curve. Then, near or zero prices are due to RES supply (0 €/MWh is the marginal cost for solar energy, 1.6 €/MWh is the marginal cost for wind energy onshore and offshore). After, the conventional fossil-fuelled assets and biomass, are those which set higher prices and they are on the opposite extreme part of the curve. Generally, flexible assets are included in the middle range of the price duration curve and are characterized by high prices. This is justified in the energy mix supply for the electricity and flexibility demand: in this model (EYE) if flexible assets are not completely fed by RES, their marginal cost is due to conventional energy sources, which then sets high prices.
- Average future electricity price is visualised as a dashed lined and represents the threshold for offshore wind positive profitability. The LCOE is below the limit, the offshore wind business will keep a total positive profit.
- The RES value (offshore and onshore wind and solar) is also presented as part of the market analysis. Estimated as:

$$RES\ Value = \frac{\sum(clearing\ price * generation)}{\sum generation}$$

- Additional PPA or bilateral contracts are not explicitly modelled yet in the current version of the EYE model. Having said that, to replicate what happens under more realistic conditions, in certain scenarios the “production and consumption” of energy in PPA’s is taken into account by reducing the overall capacity of energy generating assets and electricity demand in the market.

4.2.1 Baseline scenario, NECP 2030

In this baseline scenario, the maximum LCOE value for offshore wind to have a positive business case is 40 €/MWh Figure 12 (1).

Flexible assets have a large share as price setting technology, as well as the gas assets, depending on the EU-ETS CO2 prices and gas price.

Under this scenario, both renewable capacity and flexibility capacity play a main role. That means, although wind and solar sources influences as decreasing electricity prices, the flexibility assets make the system more expensive. The overall trend is a slight decrease in the average prices with respect of 2019-prices (43 €/MWh).

The utilization of offshore wind is 100% in this scenario, and the value of the different RES are the following: 40 €/MWh for offshore wind, 35 €/MWh for onshore wind and 36 €/MWh for solar.

4.2.2 Sensitivity analysis of NECP 2030

4.2.2.1 Flexible capacity: brings higher prices and more revenues

Under this scenario, the same parameters of the Baseline remains the same with the exception of the flexible capacity. Two additional simulations are performed considering that i) there is no flexible capacity (named No flex) and the ii) flexible capacity of the electrolyser is doubled (double flex).

The Figure 12 (2) includes the Baseline scenario with the two sensitivities in order to better understand the impact of the flexibility in the electricity prices. Flexibility is one of the main market drivers that influence significantly electricity prices:

Average clearing price is 23.6 €/MWh in the No flex scenario and 51 €/MWh for the Double flex scenario, compared to the baseline scenario with 40 €/MWh. This means that flexible demand increases the prices. The RES values vary accordingly, where offshore wind value varies from 23.5 to 51.1 €/MWh, onshore wind from 28.1 to 46.8 €/MWh and solar from 16.5 to 46.9 €/MWh.

Wind utilization drastically decreases when no flexibility is simulated (up to 55%) and remains 100% in the Double flex. That means for a large scale renewable deployment the flexible asset capacity need also to increase for a full RES utilization. In total around 33% of the total RES production is curtailed in the No flex sensitivity. This highlights the importance and the need of a flexible demand when RES supply will increase in the next decades. To better understand how the flexible demand influences prices the following behaviours are described:

- Maximum Flexible capacity is 8.54 TW in the Baseline 2030 and 15.05 TW in the Doubled Flex scenario. The total flexible demand is 30.32 TWh/yr in the Baseline 2030 and 39.03 TWh/yr in the Double Flex scenario: this shows that a double flexible capacity installed does not mean a doubling of flexible demand, due to the fact that the installed capacities of energy generation assets (including RES) does not change.
- Onshore and offshore wind generation and share between the supply to electricity and to flexibility demand remains unchanged with the variation of flexible capacity installed. Whereas the wind generation is lower in the scenario with no flex assets, this is due to curtailment and it is illustrated in Figure 6. The total production for offshore and onshore wind decreases in the No flex scenario (from 49 TWh/yr to 27 TWh/yr for offshore wind and from 15 TWh/yr to 9 TWh/yr for the onshore wind generation). On the other hand, solar supply does not change because as its marginal cost is 0 €/MWh, it always enters first in the merit order.
- In the Double flex scenario, the biomass production doubled and the gas production also increases by 5 TWh/yr compared to both Baseline 2030 and No flex scenario. As the total demand has increased, gas and biomass assets, with high marginal costs, are needed to fulfil the new flexible demand. This leads to higher prices, for both flexible demand and average clearing prices.
- Same behaviour is observed for batteries, they are activated only when flexible demand is non-zero.

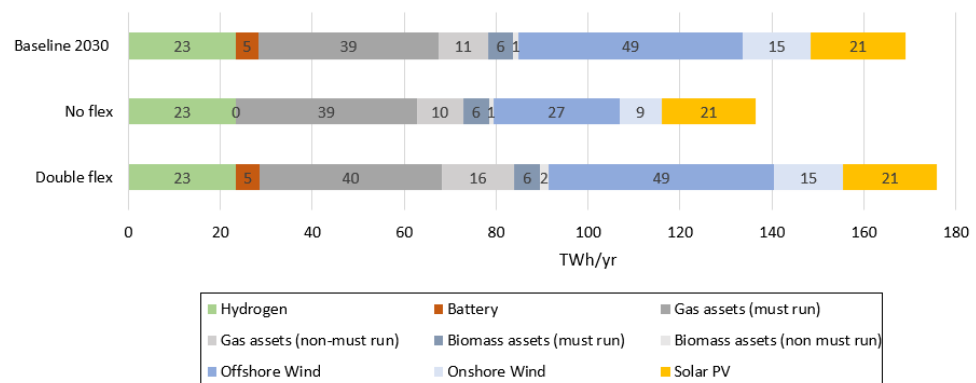


Figure 6 Electricity generation by different assets for Baseline 2030, No flex and Double flex scenarios for the total production (TWh/yr).

4.2.2.2 Total demand: impacts flexibility demand and offshore wind value

Under this scenario, the same parameters of the Baseline remains the same with the exception of the total demand. Two additional simulations are performed considering that i) total demand for electricity decreased by 5% (130 TWh/yr) with respect to the Baseline (named 5%) and the ii) total demand for electricity increased by 20% (164.4 TWh/yr), shown in the Figure 12 (3). The flexible demand remains the same as the Baseline.

The total demand is one of the main market drivers that influence significantly electricity prices; a higher demand increases the average electricity market price to 44 €/MWh, a lower demand reduces it to 39 €/MWh. This is reflected in the value of RES, offshore wind value varies between 39 and 44 €/MWh, onshore between 33 and 48 €/MWh and solar between 34 and 51 €/MWh.

As regards RES generation electricity and flexibility supply (Figure 8): the increase of total demand let a higher RES share and less flexible capacity needs. On the contrary, if the demand decreases and the RES deployment increase, a general lower utilization of RES is estimated.

- Onshore wind: 11.5% of the total generation supplies the flexibility demand in the both sensitivity analysis, compared to the 13.5% of the Baseline scenario.
- Solar increases slightly the supply to flexibility in the 5% scenario with a 6.3% of the total generation supplying the flexible demand, and decreases it in the 20% scenario with less than 1%; in the baseline scenario it was 4%.
- Offshore wind, on the other side, strongly varies its supply: 40% to flexibility and 60 % to electricity in the 5%, 19% to flexibility and 81% to demand in the 20% scenario.

Concerning offshore wind, it is observed a reduction in its utilization by 2% when demand decreases by 5%. Furthermore, a variation in the market setup is also seen, in the 5% scenario there is a 60% supply of offshore wind to electricity, 38% to flexibility and 2% to other type of contracts or curtailed; whereas, on the 20% scenario there is 18% supply to flexibility and 82% to electricity.

Investigating the electricity generation through the different sensitivity analysis (Figure 7), it is observed that:

- Flexible demand varies but independently on the demand variation, it increases by 10% in the 5% scenario and it decreases by 26% in the 20% scenario compared to Baseline 2030. This gives the idea of the adaptability of flexibility

need through different electricity demand supply when RES generation remain fixed: a lower demand needs higher flexibility, a higher demand needs less. The ratio of flex demand is 20% of the total demand in the 5% scenario case, and 12% in the 20% scenario case, compared to the 22% in the Baseline scenario.

- An increase in generation is observed for the gas assets: must run assets increases their production slightly for the 20% scenario, whereas, non must run assets strongly increase their generation passing from 9.6 TWh/yr to 25 TWh/yr; this also justifies the increase of prices.
- Biomass assets also strongly increasing their production: from 0.9 TWh/yr to 3.4 TWh/yr.
- On the other side, battery compared to the baseline scenario decrease their production in both scenarios by 35% in the 5% scenario and by 12.5% in the 20% scenario.

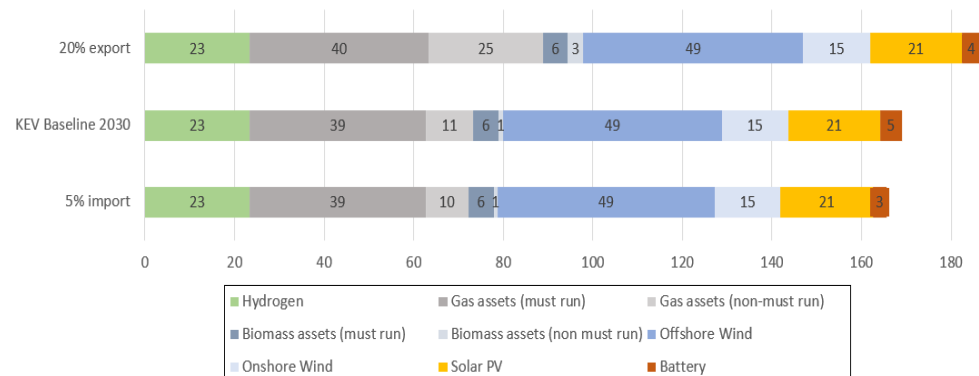


Figure 7 Total electricity generation by different assets for 20% export scenario, Baseline KEV 2030 and 5% import scenario.

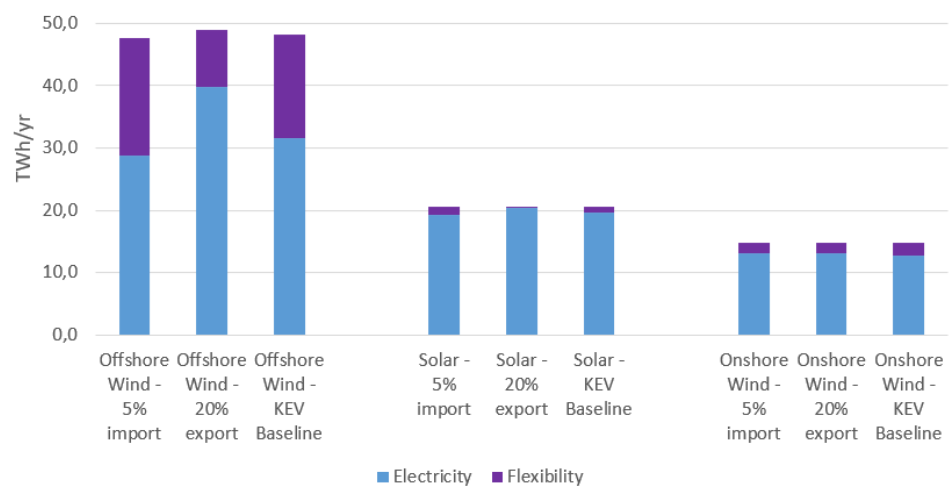


Figure 8 Variation in supply to electricity and flexibility demand by RES generation.

4.2.2.3 EU-ETS CO₂ prices

Under this scenario, the same parameters of the Baseline scenario remains the same with the exception of the EU-ETS CO₂ prices. Baseline price is 43 €/MWh. Additional simulations are performed considering i) 28 €/MWh (named ETS_28 scenario); ii) 75 €/MWh (ETS_75) and iii) 100 €/MWh (ETS_100) (Figure 13 (4)).

Impact of EU-ETS CO₂ prices on electricity prices is not significant if this is the only changing variable. Future electricity prices fluctuated across sensitivities between 36.6 €/MWh for the ETS_28 scenario, 46 €/MWh for the ETS_75 and 51 €/MWh for the ETS_100 sensitivity.

The rests of the demand and supply variables and RES assets are not affected. This means that the variation in the costs are only due to variations in production costs for conventional assets and variations in asset technology type production. Therefore, to better understand the behavioural changes in the conventional assets, the following observations have been noted (Figure 9):

- Gas production decreases by increasing CO₂ prices, since the marginal cost depends on fuel costs and CO₂ emission. Marginal cost for gas assets varies between a range of 55-75 €/MWh with low ETS CO₂ cost, to a range between 80-100 €/MWh with high ETS CO₂.
- The gas production decrease is replaced by biomass generation as they are independent to ETS CO₂ costs, and their marginal cost depends only on the fuel cost and it ranges between 72-82 €/MWh. This is expected, when CO₂ costs are high, biomass assets become cheaper (and hence preferred) over gas assets which now have higher cost than biomass. This means that gas assets' marginal cost increases and becomes higher than the marginal cost of biomass, therefore biomass enters first in the merit order and starts to generate power. On the other side, when CO₂ costs are very low biomass, which have in general a high marginal cost are never activated.
- Battery generation drops with the highest ETS CO₂ cost, meaning that with high ETC CO₂ cost, battery are not convenient anymore, and their supply is again substituted by biomass assets.

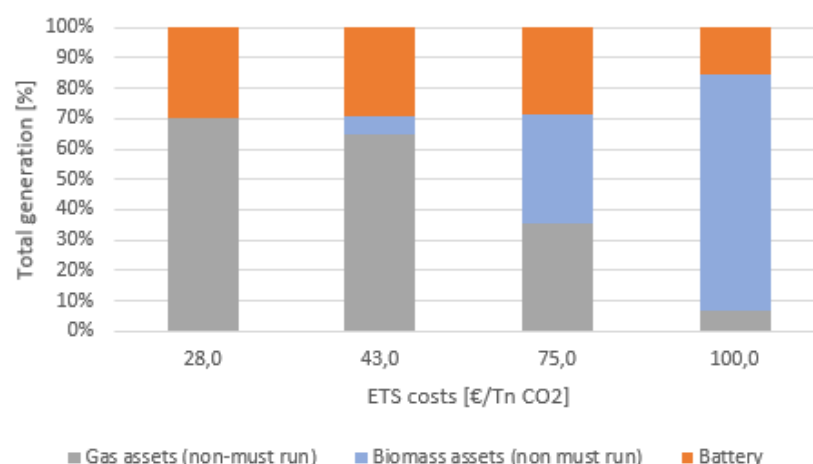


Figure 9 Total generation of gas (grey), biomass assets (blue) and battery (orange) for the 3 sensitivity scenarios and Baseline 2030 KEV (43) in percentage.

4.2.2.4 Solar Wind capacity: cannibalization effect

Under this scenario, the same parameters of the Baseline remains the same with the exception of the solar capacity. Two additional simulations are performed considering that i) there are 10 GW and ii) 15 GW of solar installed capacity in the system, with respect to the 20 GW of solar capacity in the Baseline scenario (Figure 13 (5)).

The cannibalization effect does not show a significant effect in the future electricity prices but in the value of the RES.

In general, a reduction of solar capacity produces higher prices because the demand will be supplied by conventional assets with higher marginal costs. The average clearing price is 46 €/MWh in 10GW-sensitivity and 43 €/MWh for the 15-GW sensitivity. The RES value also increases with higher clearing prices, but it produces higher value for solar when its installed capacity is reduced: offshore value is 43 €/MWh, onshore is 40 €/MWh and solar is 52 €/MWh.

As less RES supply mean lesser energy available for flexible demand, and flexible demand in the SPOT market decreases from 36% to 27%, increasing the share of electricity demand from 64% to 72% between the 10GW-sensitivity and Baseline scenario. Then, a reduction of RES capacity also reduces the supply to flexible demand from 26% to 12%.

More detailed analysis shows that:

- Under the 10GW-sensitivity, gas generation increases by almost 5 TWh/yr compared to the baseline scenario; as well as the biomass from 1 TWh/yr to 1.8 TWh/yr.
- RES demand type supply varies, increasing the supply to electricity demand and reducing the supply for flexible demand when less solar capacity is simulated, this is shown in Figure 10. This happens because the electricity demand compensation, due to a reduction in the solar capacity installed, is met by a larger supply of RES (offshore and onshore wind) and by a larger supply of conventional assets (gas and biomass). These behaviours reflects on clearing price and eventually on RES values. Hence, when solar capacity decreases, conventional assets are activated increasing the clearing prices and in particular the value of solar. Nevertheless, offshore value decrease as its share of flexible supply decreases to increase the electricity demand supply providing a lower value.

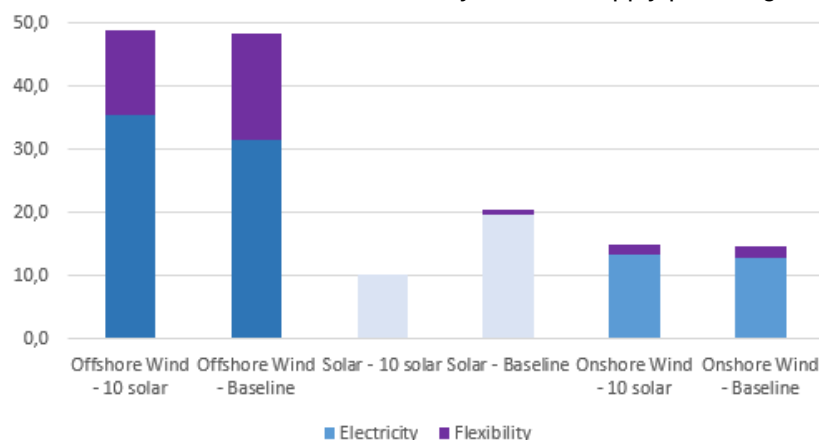


Figure 10 Variation in supply to electricity and flexibility demand by RES generation with lower solar capacity installed

4.2.3 TRANSFORM scenario, 2030 and 2050

Under the TRANSFORM scenario, the price duration curves are characterized by higher prices, with an average of 51 €/MWh for 2030 and an extremely high price of 104 €/MWh in 2050 (Figure 13 (6)). This causes an increase also in the RES value; from 51 to 104 €/MWh for offshore, from 49 to 105 €/MWh onshore and from 43 to 104 €/MWh for solar energy.

To understand the main causes of the increase on prices, the technology setting the price are investigated, based on their marginal cost and on the full load hours (FLH) (Table 2 for 2030 and Table 3 for 2050). For both timeframes, flexible assets: electrolyser (Hydrogen), the hybrid boiler and the battery are the main driver of the price, defined by very high marginal cost, especially by 2050. (Table 3 and Figure 10). Flexible assets depend on the gas technology and the EU-ETS CO₂ prices that, by 2050 are estimated to increase radically, about 447 €/kTon.

Table 2 TRANSFORM 2030 price setting technology (€/ MWh)

Technology	Clearing price range	Marginal cost	Hours setting the price
[units]	€/MWh	€/MWh	h
RES (Solar)	0	0	29
RES (Wind)	1,6	1,6	213
Flex (Industrial Heat Pump)	17,2-59	-	570
Flex (Electrolyser)	18-59,7	35,73	1470
Flex (Hybrid boiler)	21,3-59,8	39,80	2383
Flex (Battery)	24,3-59,7	-	216
Gas	59,9-72,4	59,98-73,73	2802
Biomass	72,5-74,2	71,98-81,45	1083

Table 3 TRANSFORM 2050 price setting technology (€/ MWh)

Technology	Clearing price range	Marginal cost	Hours setting the price
[units]	€/MWh	€/MWh	h
RES (Solar)	0	0	221
RES (Wind)	1,6	1,6	646
Flex (Electrolyser)	14,1-140,6	137,24	4520
Flex (Hybrid boiler)	132,6-136	134,07	796
Flex (Battery)	72,5-226,2	charge - discharge	2450
Gas	242-248	242,06-270,21	94

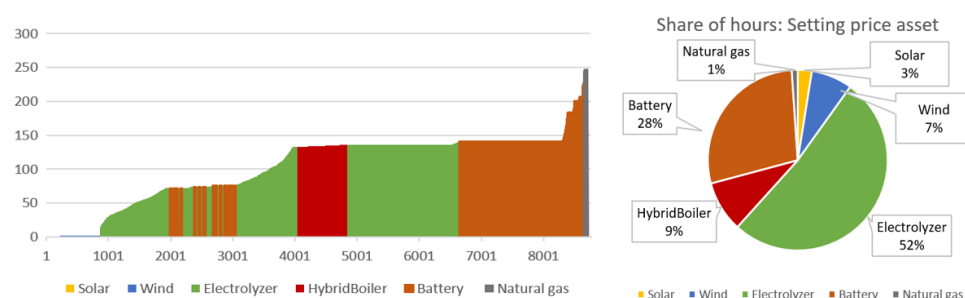


Figure 11 Price duration curve for technology (€/ MWh) and share of hours by assets

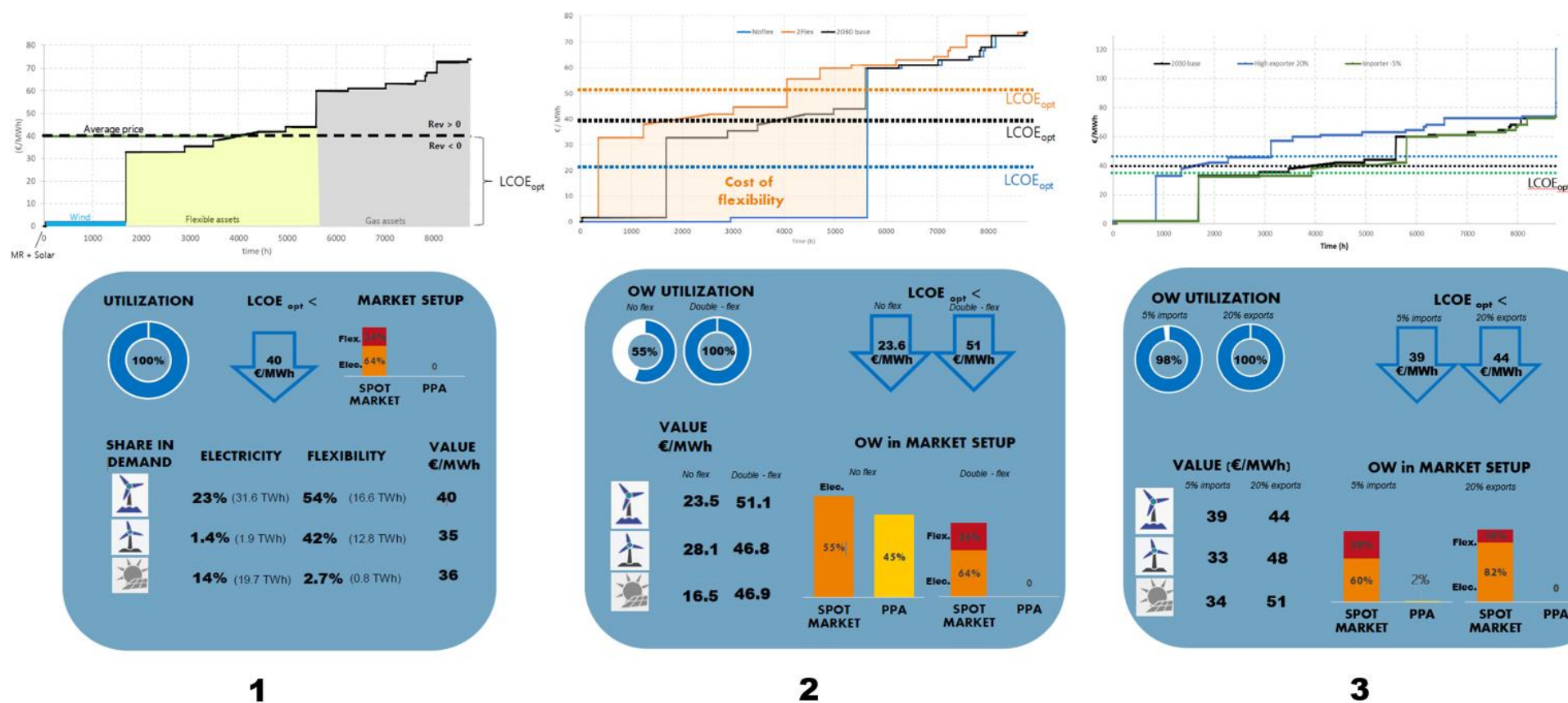


Figure 12 Price duration curve and price setting technologies (€/ MWh), top figure, and summarize of the main results (blue square) for (1) NECP 2030, (2) Flexibility sensitivity analysis and (3) Demand sensitivity analysis.

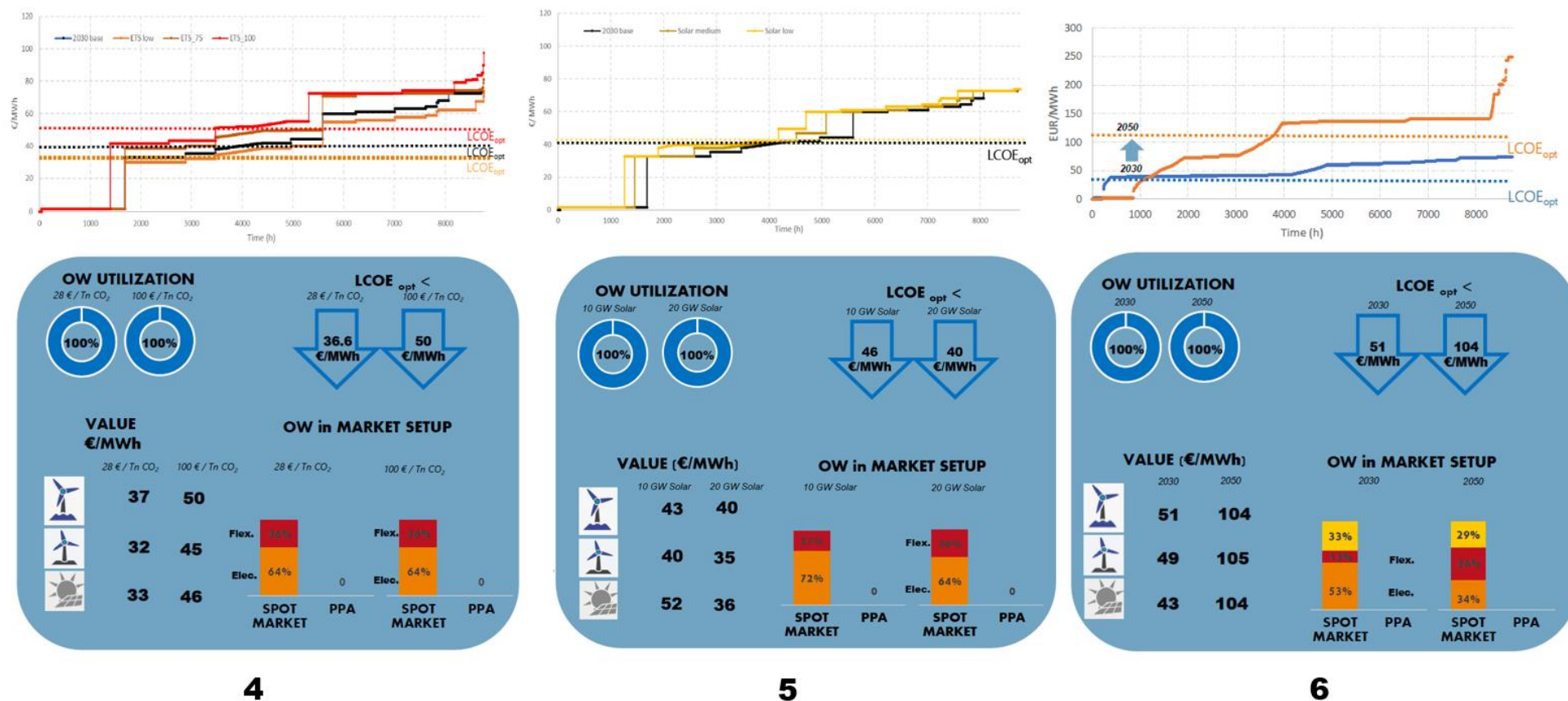


Figure 13 Price duration curve and price setting technologies (€/ MWh), top figure, and summarize of the main results (blue square) for (4) ETC CO₂ , (5) Cannibalization sensitivity analysis and (3) TRANSFORM 2030 and 2050 scenarios.

5 P2X: increasing offshore wind revenues by producing green hydrogen

5.1 P2H becomes central player for offshore wind business

The large amount of power and the strongly fluctuating supply make conversion of electricity to hydrogen an interesting prospect. Hydrogen makes it possible to use variable RES on a large scale in the future energy system. As shown in previous sections, integrating high RES shares into the power system will create need for higher flexible capacity, making the electricity prices fluctuate, and enhancing price volatility and risks exposure. However, it is still unclear how all this can be fit in without endangering the stability of the network. The objective of this study is to:

- Estimate the techno-economic conditions that should be necessary for the offshore wind business to obtain higher profit by selling green energy in the power market or to produce green hydrogen by 2030.
- Identify the type of market mechanisms and future incentives that may be required for a long-lasting offshore wind business case.
- Estimate the optimum electrolyser capacity to host future offshore wind deployment.

The concept examined lies in developing a power-to-hydrogen business model under different scenarios and system actions by 2030 under the TRANSFORM scenario using the maximization of profit as the optimization criterion.

The wind producer's bidding strategy is set before the closure of the day-ahead market and the decisions are based on the forecasted model output: offshore wind generation and electricity prices in 2030. The strategy is simulated by the business model resulting from an optimization process that evaluates performance hour by hour and under different conditions related to the electrolyser. Particularly, the total profit is obtained by either selling the wind power in the power market or producing green hydrogen which is sold to third parties annually. It is required to supply a fixed annual green hydrogen demand, the electrolyser works at a minimum continuous load to avoid start-up times and the minimum utilization is 10%. Investment costs, capital expenditure and operational expenditure of the new concept are analysed and taken into account as Levelized cost of Electricity (LCOE), when selling the wind energy in the power market and Levelized cost of Hydrogen (LCOH), when selling into the hydrogen market. Financial analysis is conducted to decide the optimum conditions for the combined system to be profitable and competitive with the power market.

The output of the model performance under different scenarios is quantified and analysed to find the optimum dimensions and conditions for the electrolyser to become a new complementary source of revenue for the wind producer. The revenues of the wind producer are also analysed by changing the bidding strategy in the day-ahead power market to obtain the highest possible profit including the electrolyser technology. Different incentives are considered in a sensitivity analysis to evaluate the need from the offshore wind producer to get net positive profit.

5.2 Business model configuration

The objective function of the business model is to maximize the offshore wind producer's profit. It is defined as the sum of the difference between the revenues and costs. The configuration, variables and parameters of the model can be found in the series of equations below, Figure 14 and Table 4.

The optimization problem is based on the model and equations developed by [12] which was applied to Spanish wind portfolio integrated in the power market.

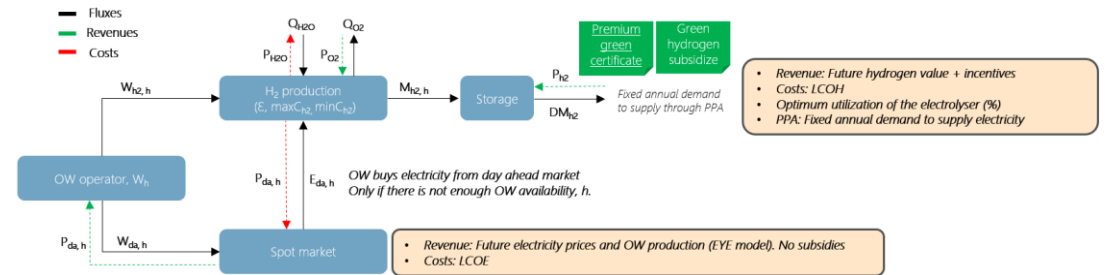


Figure 14 Flow diagram of the power-to-hydrogen business model combining the offshore wind power generation and electrolysis. The solid lines represent the electricity/chemical production flow, the dash lines represent the financial flow. The green and red arrows indicate the revenues and the costs from the wind producer's perspective. Where W is the wind power generation, DA is the day-ahead market, E_{da} is the energy bought in the power market to supply minimum requirements of energy to electrolyser when W is not enough.

Series of equations applied in the optimization problem:

- $Total\ annual\ profit = \sum_{h=1}^{8760} [(Revenues - Costs)_{day\ ahead\ h} + (Revenues - Costs)_{hydrogen\ h}]$
- $Revenues_{day\ ahead,\ h} = W_{da,h} * P_{da,h}$
- $Cost_{day\ ahead,\ h} = W_{da,h} * LCOE_h$
- $Revenues_{hydrogen,\ h} = W_{H2,h} * P_{H2,h} + Q_{O2,h} * P_{O2,h}$
- $Costs_{hydrogen,\ h} = LCOH_h * M_{H2,h} + Q_{H2O,h} * P_{H2O,h} + E_{da,h} * P_{da,h}$

The list of parameters is shown in Table 4. The constraints of the offshore wind power generation, power market and green hydrogen production considered are:

- $W_{da,h} + W_{H2,h} = W$
- $W_{da,h} \geq 0$
- $W_{H2,h} \geq 0$
- $E_{da,h} + W_{H2,h} \leq Max\ capacity\ electrolyser\ (Max\ cap)$
- $E_{da,h} + W_{H2,h} \geq Minimum\ electrolyser\ continuous\ load\ (Min\ load)$
- $Annual\ DM_{H2} \geq Annual\ required\ green\ hydrogen\ demand\ to\ supply$
- $0 \leq Tank\ Level \leq Maximum\ capacity\ storage$

The future electricity prices, total electricity demand, offshore wind capacity and generation and optimum LCOE are considered under the TRANSFORM scenario by 2030.

Table 4 Variables and parameters in the P2X optimization model

Assumptions	Acronym	Value	Variable (V) / parameter (P)
Price electricity (average) TRANSFORM 2030	$P_{da,h}$	€/MWh	P_h
Wind generation sold in power market	$W_{da,h}$	MWh	P_h
Wind generation sold to H ₂ production	$W_{h2,h}$	MWh	P_h
Energy bought from the power market	$E_{da,h}$	MWh	P_h
Offshore wind portfolio in NL	-	14.5 GW	P
Offshore wind capacity factor	-	48%	P
Offshore wind portfolio business case	-	700 MW	P
LCOE	LCOE	40 €/MWh	V_h
LCOH	LCOH	2 to 5.5 €/Kg _{H2}	V_h
Maximum capacity electrolyser	Max cap	10 to 3 Tn/h	V_h
Conversion factor electrolyser	ϵ	55 - 65 MWh/Tn H ₂	P
Minimum continuous operation electrolyser (avoid start up times)	Min load	10% of Max cap.	P
Amount of oxygen generated	$Q_{O2,h}$	0.5 t _{O2} /Tn H ₂	V_h
Amount of water needed	$Q_{H2O,h}$	1.5 t _{H2O} /Tn H ₂	V_h
Production of H ₂	$M_{H2,h}$	-	V_h
Total annual hydrogen demand required	DM _{H2}	4000 Tn	P
Price of O ₂	P_{O2}	76 €/Tn H ₂	P
Price water + cooling water	P_{H2O}	1.02 €/Tn H ₂	P
Price H ₂	P_{H2}	2.4 €/kg H ₂	P
Green certificates for green hydrogen	GC	10 €/MWh	P

5.3 Sensitivity analysis and results

Several cases have been run in order to evaluate the optimum conditions by optimizing the LCOE, LCOH, the capacity of the electrolyser and hence, the utilization of the electrolyser to maximize the profit of the offshore wind producer. With the condition to make the total profit of the decoupling to hydrogen production technology higher than the conventional system with no decoupling.

In the baseline business model configuration, a reference 700 MW offshore wind farm is modelled with an electrolyser of the same power capacity and decides to either sell energy to the spot market or to the electrolyser for hydrogen production.

The cases are here described and all the results are illustrated in Table 5:

- Case 0. All the energy is being sold in the spot market: it results in a profit of 36.01 M€ for offshore wind.
- Case 1. The OWF chooses to either sell to the spot market or to the electrolyser: the profit increases to 41.4 M€. However, the electrolyser utilisation is only 18%.
- Case 2. To optimise the electrolyser utilization, its size is reduced by a factor of three (1:3): no significant reduction of the total profit is produced. This highlights the need for further research into multi objective optimisation to maximise both offshore wind profits and electrolyser utilisation.
- Case 3. A further sensitivity analysis is investigated, where the LCOE and LCOH are varied to see their influence on the offshore wind profit: the highest profit, 49.9 M€, is naturally obtained at the lowest operating costs of wind and the electrolyser. Further results are illustrated in Figure 15 and Figure 16.

Setting the LCOH constant, means that the utilization rate does not impact the profits, hence when the electrolyser is scale down (1:3) in Case 2 the profits slightly decrease as less hydrogen is produced compare to Case 1. In reality the LCOH is dependent on the utilization rate, as it is illustrated in Figure 16 (left). Therefore, to have an overview of the revenues dependency on LCOE and LCOH Case 3 is investigated, the results are presented in Figure 15. As expected, with lower costs then the profits are higher, and with larger costs then the lower the revenues reaching negative values when LCOE value is higher than 50 €/MWh and the LCOH is higher than 4 €/KgH₂.

From Figure 16 (left) the utilization rate of the electrolyser on the different sensitivity analysis is illustrated. It increases with low LCOH and high LCOE. This effect is justified by the correlation of the LCOH to its utilization, the more the electrolyser is used, the more the fixed investment cost are covered by the hydrogen production.

Therefore, a high utilization rate will reduce its LCOH. On the other side the LCOE seems to be indirectly proportional, low LCOE are related to low utilization rate, meaning that when the LCOE is low the system seems to prefer to sell the electricity to the SPOT market instead of feeding the electrolyser, oppositely when the LCOE is very high, the electrolyser is preferred, increasing its utilization.

Finally, Figure 16 (right) presents again the results illustrated in Figure 15 but on a graphical representation. The limit from which the profit start to be positive is highlighted by the grey layer. Furthermore, from this Figure it is clear that the LCOE is the parameter prevalently affecting the profits: larger variation in the profits are determined by variation in the LCOE. When the LCOH is constant the variation of LCOE strongly impacts the profits, semi-vertical colour dots sequence. On the other hand, for constant LCOE, the changes in the LCOH impact slightly the profits, semi-horizontal colour dots sequence.

Table 5 Sensitivity analysis of the P2H optimization to increase total offshore wind business profit

Case	Description	Total OW profit (m€)	Capacity electrolyser (Tn)	Utilization electrolyser (%)	Green H2 (Tn)	LCOE (€/MWh)	LCOH (€/KgH ₂)
0	No P2H. 100 % OW to SPOT market.	36.0	-	-	-	40	-
1	P2H ideal conditions. Optimization b/w SPOT or H2	41.4	10	18	19000	40	3
2	P2H downscaled electrolyser capacity.	39.6	3	36	9000	40	3
3	P2H. Sensitivities varying LCOE and LCOH (best case)	49.9	3	40	10000	20-30	2-2.5

		LCOE								
Elect%		20	30	40	45	50	55	60	70	80
40 %	2	49.9	37.8	25.9	19.5	14.8	10.0	5.4	-2.8	-11.3
33 %	2.5	49.1	35.6	22.6	16.3	10.7	5.1	0.0	-8.7	-17.1
30 %	3	46.7	32.7	20.0	13.6	7.0	1.0	-5.0	-14.4	-23.1
LCOH	3.5	44.2	30.7	17.4	10.9	4.4	-2.6	-7.7	-19.6	-29.6
	4	42.4	29.2	15.4	9.1	2.4	-4.8	-11.4	-23.5	-34.8
	4.5	40.1	27.2	13.4	6.9	-0.7	-6.4	-14.1	-26.1	-38.6
	5	39.1	26.0	11.9	4.6	-2.0	-9.4	-15.1	-29.3	-41.3
	5.5	36.4	23.3	9.4	2.7	-4.3	-10.8	-17.5	-30.9	-44.8
Profit (m€)										

Figure 15 OW profit (M€) sensitivity analysis based on LCOH and LCOE variation and electrolyser utilisation rate for the optimal LCOH.

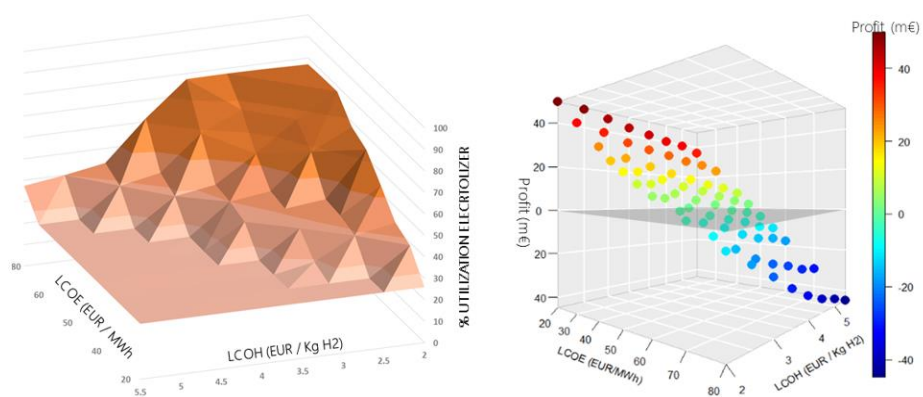


Figure 16 Electrolyser utilization (%) depending on LCOE and LCOH (left). Optimization OW profits results depending on LCOE and LCOH (right).

Conclusions and further research

The business case configuration in this study is modelled to reflect the rapidly changing in the power market that are a consequence of the energy transition towards renewables. Modelling results under the NECP and TRANSFORM scenarios by 2030 and 2050 indicate that the main drivers and their impacts are:

- Flexibility is a necessary source to allow a complete utilization of vRES generation and adequacy of the system. However, a larger flexible demand requires larger supply from conventional assets, characterized by high marginal costs. Hence it produces higher prices and higher values for vRES.
- Demand variation impacts prices: a larger electricity demand requires a larger supply from conventional assets, increasing prices. Nevertheless, offshore wind value decreases, as it increases its supply share to electricity demand compared to flexibility. Furthermore, changes in the demand also affects offshore wind utilization and flexibility: lower the electricity demand, lower the offshore wind utilization and higher the flexibility needed to maintain the system stability.
- ETS CO₂ costs affect prices and vRES value, due to the increase of gas assets marginal cost. However, gas assets production drops if their marginal costs become more expensive than biomass. Same behaviour observed for battery, higher prices lower the application.
- Competition between wind and solar deployment integration: lower capacity of solar energy installed, higher the prices due to the need of larger supply from conventional assets. Furthermore, it also affects the RES value: solar value increases, whereas offshore wind value decreases, as its supply share to electricity demand increases, instead of supplying flexibility.

Therefore, from the market perspective and offshore wind business it is possible to conclude that:

- Future electricity prices are sensitive to abovementioned specific market drivers.
- To achieve a climate neutral system, high penetration of RES is required in conjunction with flexibility. Such combination increases future electricity prices with higher volatility and risk exposure.
- Offshore wind business is vulnerable to those changes. Currently offshore wind profit relies on subsidies scheme. The era of zero-subsidies has arrived and offshore wind business will need to look into other markets to increase the net profit.
- Increasing offshore wind profit by producing green hydrogen could be profitable under specific conditions. Research on optimum electrolyser size, LCOH and % electrolyser utilisation is a key for future positive OW business.
- Current study shows the need of further research into multi objective optimisation to maximise both offshore wind profits and electrolyser utilisation. The necessity for balancing both the offshore wind profits and the electrolyser capacity/utilisation will be a necessary problem to be solved for an efficient future energy system. Sizing the electrolyser allows a higher utilization rate, this parameter is important when modelling the LCOH, as they are strongly dependent. Furthermore it has been observed that the LCOE is the value prevalently impacting the profits, both because it affects the utilization rate of the electrolyser, as selling to SPOT market is preferred when the LCOE is lower, and for the natural effect of the lower the costs to produce the same product, higher the profits.

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