North Sea Energy
offshore system integration

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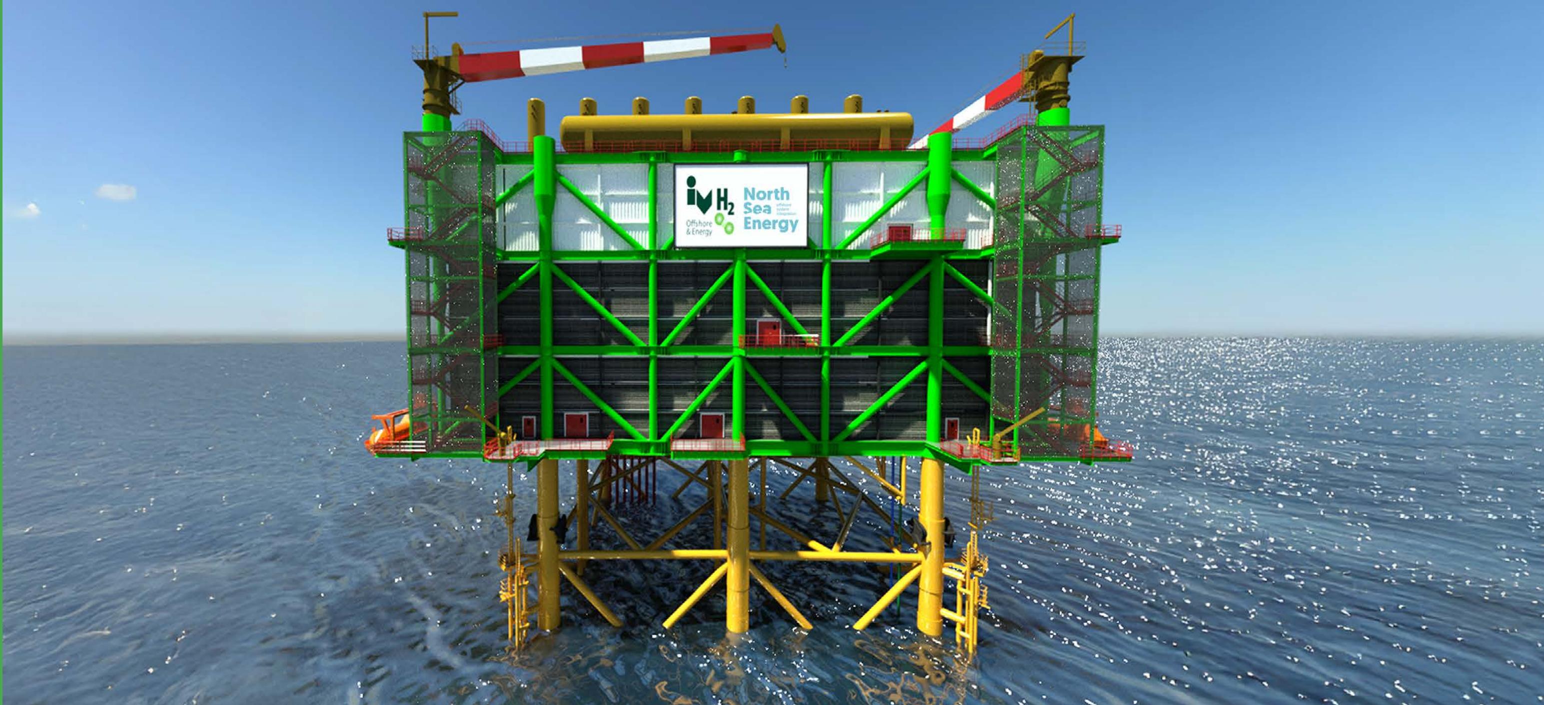
North Sea Energy 2023-2025

Scaling Offshore Wind-to-Hydrogen Systems: A Pathway to Feasibility and Integration by 2050



Navigating the North Sea transition!

For centuries, the North Sea has been a source of economic strength, ecological richness, and international cooperation. Always subject to change, yet steadfast as a connector of nations, cultures, and economies. Today, it once again takes center stage—this time as a lighthouse region for the transition to a sustainable, affordable, and reliable energy system. The North Sea Energy program marks an important step in this development.

North Sea Energy is a dynamic research program centered around an integrated approach to the offshore energy system. Its aim is to identify and assess opportunities for synergies between multiple low-carbon energy developments at sea: offshore wind, marine energy, carbon capture and storage (CCS), natural gas, and hydrogen. At the same time, the program seeks to strengthen the carrying capacity of our economy, society, and nature.

The offshore energy transition is approached from various perspectives: technical, ecological, societal, legal, regulatory, and economic. Our publications provide an overview of the strategies, innovations, and collaborations shaping the energy future of the North Sea. They reflect the joint efforts of companies, researchers, and societal partners who believe in the unique potential of this region as a hub for renewable energy and innovation.

What makes this program truly distinctive is not only its scale or ambition, but above all the recognition that we are operating in a dynamic field of research. The energy transition is not a fixed path, but a continuous process of learning, adapting, and evolving. New technologies, a dynamic natural environment, shifting policy frameworks, and changing societal insights demand flexibility and vision. Within this program, we work together to ensure that science and practice reinforce one another.

This publication is one of the results of more than two years of intensive research, involving over forty (inter)national partners. This collaboration has led to valuable insights and concrete proposals for the future of the energy system in and around the North Sea. All publications and supporting data are available at: https://north-sea-energy.eu/en/results/

We are deeply grateful to all those who contributed to the realization of this program. In particular, we thank our consortium partners, the funding body TKI New Gas, the members of the sounding board, the stakeholders, and the engaged public who actively participated in webinars and workshops. Their input, questions, and insights have enriched and guided the program.

At a time when energy security, climate responsibility, and affordability are becoming increasingly urgent, this work offers valuable insights for a broad audience—from policymakers and professionals to interested citizens. The challenges are great, but the opportunities are even greater. The North Sea, a lasting source of energy, is now becoming a symbol of sustainable progress.

With these publications, we conclude an important phase and look ahead with confidence to the next phase of the North Sea Energy program. In this new phase, special attention will be given to spatial planning in the North Sea, European cooperation, and the growing importance of security in the energy system of the future.

D3.2A

North Sea Energy 2023-2025

Scaling Offshore Wind-to-Hydrogen Systems: A Pathway to Feasibility and Integration by 2050

Prepared by:

TNO
Iratxe Gonzalez-Aparicio, Martin Wevers, Aitazaz Raja

Approved by:

TNO
Madelaine Halter

The project has been carried out with a subsidy from the Dutch Ministry of Economic Affairs and Climate, National Schemes EZK-subsidies, Top Sector Energy, as taken care of by RVO (Rijksdienst voor Ondernemend Nederland)

Contents

Executive summary

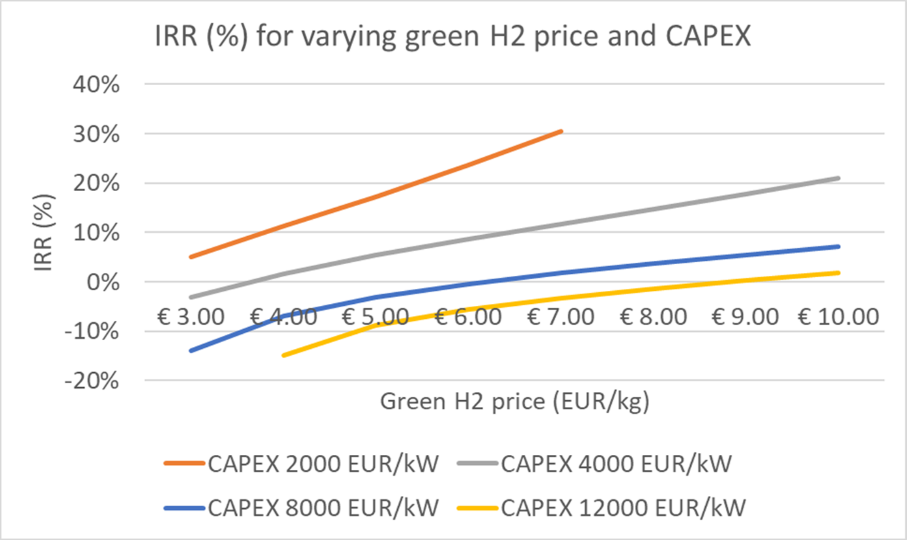
By 2050, wind and solar energy—primarily offshore wind—are expected to supply approximately 70% of the Netherlands' electricity demand, following the Dutch government ambitions. This transformation necessitates a rapid scale-up of offshore wind capacity, from 4.7 GW in 2024 to 21 GW by 2030, and eventually reaching potentially 70 GW by mid-century. However, current offshore wind farms produce power offshore and the electricity is transported via subsea cables , reliant on subsea cables and substations to shore, faces significant challenges, including high installation costs, limited space, and grid bottlenecks onshore. These constraints threaten the feasibility of timely achieving offshore wind deployment targets, climate goals and ensuring a reliable energy supply.

Offshore hydrogen production offers a promising alternative to complement traditional electricity transmission. Converting a portion of offshore wind energy into hydrogen can reduce the need for costly transmission infrastructure, alleviate grid congestion, and enable long-term energy storage. Recognizing this potential, the Dutch government has initiated two offshore hydrogen demonstration projects, targeting a combined electrolyzer capacity of up to 550 MW by 2033. The second project (Demo 2), analysed in this study, focuses on a ca. 500 MW electrolyzer located near the Ten Noorden van de Waddeneilanden offshore wind area.

This study evaluates the economic feasibility of the business case of Demo 2 in and energy system configuration for the Netherlands that fits with the Climate Agreement goals for 2030. It also explores pathways for achieving profitability by 2050 by evaluating different national and European scenarios on electrification growth and hydrogen market development in Europe. With the use of a merit-order-based energy market model electricity and hydrogen prices are projected for different scenarios, and this impacts the business case extensively.

The study furthermore examines various configurations of grid connectivity, electrolyzer size, and operational modes to identify key parameters that influence the business case of a 500 MW electrolyzer connected to offshore wind farms. Insights include the interplay between CAPEX, electricity prices, electrolyzer utilization, and hydrogen prices. Additionally, the study explores the role of subsidies, grid tariffs, and hydrogen market dynamics in improving economic viability.

Key findings under the assumptions considered in this study suggest that while current configurations face a business gap at 6–13 €/kg of green hydrogen market prices in order to become a positive business case, strategic interventions—including CAPEX reductions, optimized electrolyzer sizing, and government support—can close this gap. By 2050, evolving market conditions and technological advancements are expected to make offshore hydrogen production economically competitive, provided that policies align with these developments.



For a e.g. CAPEX of 4000 €/kW the positive business case would occur with a 6 €/kg of green hydrogen price (or higher). Maintaining the CAPEX fixed to 4000€/kW, the business case starts becoming positive at a hydrogen price of 6€/kg with an IRR of 8%. Decreasing the hydrogen price will lower the IRR and therefore, to have a positive business case, it is necessary to decrease the interest rate. At a 4 €/kg of hydrogen price, the IRR is set <2% for a positive business case.

The recommendations includes:

Integrated System Design and Dispatch Optimization: Carefully select the electrolyzer capacity relative to the wind farm size to optimize the balance between:

- Market Participation: Align electrolyzer capacity with hydrogen price signals to maximize profitability under dynamic pricing schemes.
- Infrastructure Utilization: Minimize curtailment and grid congestion by leveraging co-optimization of electricity and hydrogen production.

Targeted CAPEX Reduction

Support CAPEX subsidies, tax incentives, and modular electrolyzer designs to lower upfront costs and improve business viability. Those are critical measures identified to narrow the business gap

Market Design for Price Certainty

Evaluate appropriate grid tariffs in line with the system value and impacts on infrastructure of offshore hydrogen develop design and operational strategies to balance grid integration with infrastructure cost savings. For example, assessment of the potential implementation of Contracts for Difference (CfD), hydrogen price floors, and green hydrogen premiums to stabilize revenues and boost investor confidence.

Grid Tariff Reform

Design dynamic and discounted grid tariffs that reflect the system value of hydrogen production and incentivize off-peak electricity use.

1 Introduction and goal of this study

By 2050, wind and solar energy—primarily offshore wind—are expected to dominate, supplying around 70% of the Netherlands' electricity. Achieving this ambitious vision requires an unprecedented scale-up of offshore wind capacity: increase capacity from 4.7 GW in 2024 to 21 GW by 2030 and tripling that to potentially 70 GW by mid-century[1]. Today all offshore electricity is transmitted to the mainland through subsea power cables. However, as offshore wind capacity expands, it faces significant challenges, including high cost of cable and substation installation[2] and maintenance, limited physical space, and the constrained capacity of the onshore grid, all of which risk becoming bottlenecks in the energy transition. Additionally, ensuring reliable power supply during periods of low renewable generation remains a pressing concern. Offshore hydrogen production presents a promising solution to unlock the full potential of offshore wind (Venugopalan, Garcia Navarro, & Buijs, 2024), (Buijs, Bulder, Koornneef, Peters, & Weeda, 2022). By converting a portion of offshore wind energy into hydrogen, reliance on power cables can be reduced, onshore grid pressure relieved, and long-duration energy storage and system flexibility enabled. Hydrogen provides a complementary pathway to deliver offshore energy, and can help to ensure that the Netherlands achieves its climate targets.

In the near term, up to the early 2030s, green hydrogen production will primarily occur onshore, using surplus electricity from nearshore offshore wind farms. Looking beyond 2030, large-scale offshore wind farms situated further from shore have the potential to integrate multi-energy hubs that combine electricity generation with hydrogen production. By 2040, these hubs are projected to achieve a combined offshore hydrogen production capacity of about 10 GW[3], ensuring offshore wind energy can meet growing demand while balancing the power system.

To accelerate the offshore transition towards GW-scale projects, the Dutch government has committed to support two offshore hydrogen demonstration projects, targeting a combined capacity of up to 550 MW by 2033. The first demonstration project (Demo 1) is scheduled to launch around 2030. The government plans to select a consortium to develop the project. It will feature an electrolyser with a capacity of approximately 30–50 MW, situated near the Hollandse Kust Noord offshore wind farm. The second demonstration project (Demo 2), planned for operation by 2033, will scale up to around 500 MW electrolyser, located in the Ten Noorden van de Waddeneilanden offshore wind area. In November 2024, the Ministry of Climate and Green Growth outlined its plans to the Dutch Parliament, publishing draft Ministerial Orders and site decisions for the upcoming offshore wind tenders. Given the nascent state of offshore hydrogen technology, these early projects are not expected to be immediately profitable, necessitating government subsidies to cover construction and operational costs.

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[1] https://english.rvo.nl/topics/offshore-wind-energy/new-offshore-wind-farms

[2] E.g. https://www.vrt.be/vrtnws/en/2024/10/24/princess-elisabeth-energy-island-costs-spiral/ and https://nos.nl/artikel/2494399-stroom-op-zee-tientallen-miljarden-duurder-dan-verwacht

[3] Groenenberg, R., Fatou Gomez, J., Janssen, F., Yousefi, H., Jayashankar, G., Martín Gil, A., Satish, A., González-Aparicio, I., Slot, H., Wevers, M., Aitazaz, R., Klootwijk, B., Rojer, J., & Bot, E. (2025). *North Sea Energy 5 D1.1-D1.3: Storylines and blueprints for the integration of three NSE hubs in the future energy system of The Netherlands and the North Sea.* North Sea Energy.

However, the future business case for offshore wind-to-hydrogen projects remains challenging. It is unclear how to achieve profitability in the long term. Additionally, the current international uncertainties—such as the aftermath of the COVID-19 pandemic, geopolitical conflicts like the Russian invasion of Ukraine, and rising global protectionism—pose risks to the European Union's (EU) competitiveness and its position as a global economic power. The low-carbon transition is essential for Europe's future, reducing reliance on volatile fossil fuel imports (Draghi Report, 2024). However, achieving ambitious targets for electrification and hydrogen development faces significant uncertainties, particularly regarding price volatility in electricity and hydrogen, which complicates investment decisions. In this study, TNO provides insights to reduce the business gap in 2030 and make best decisions towards 2050. The Demo 2 project is selected to study the business gap around 2030 and a system of 500 MW electrolyser towards 2050. The main research questions that are answered in this study are:

- How big is the business gap to reach a positive case in 2030?
- What are the key aspects to reduce the gap and what is dependent on?
- How could this change towards 2050?

The business gap in 2030 and the key aspects to fill the gap towards 2050 are answered in chapter 2. The business case towards 2050 are addressed in Chapter 3, evaluating different national and European scenarios on different electrification growth, and on the hydrogen market developments in Europe, which, in consequence, the electricity and hydrogen prices are expected to be different, impacting the business case. Conclusions and recommendations are presented in Chapter 4.

2 Offshore wind to hydrogen 2030

2.1 Approach: scenarios and configuration

The Demo 2 project is the next step along the pathway to the large-scale production of offshore hydrogen. Demo 2 will have an electrolyser with a capacity of around 500 MW and the preferred location is in the Ten Noorden van de Waddeneilanden offshore wind area with 700 MW installed capacity, being operational in 2033. In this study the below lay-out based configuration is considered (Figure 1).

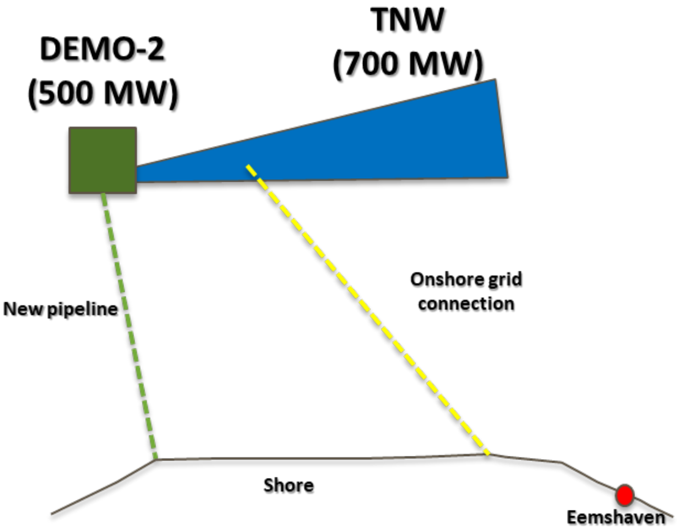

Figure 1 Sketch of the DEMO 2 lay-out, considering 500 MW offshore electrolyzer, 700 MW wind farm and a grid connection to shore.

The Dutch electricity system scenario selected when the Demo 2 is operational around 2033 follows the national and European policies for 2030, assuming the same market design and conditions than today. The scenario selected is based on the Routekaart Elektrificatie and the revised version of the Renewable Energy Directive (RED III)[4] and FIT 55 (Figure 2). This scenario has been used in several other previous studies, providing a robust reference for this analysis (Gonzalez-Aparicio , et al., December 2022). Table 1 and Annex I summarize the demand, supply and the main costs used for the modelling exercise. In summary:

- the demand includes a clear goal on high industrial electrification;
- the supply includes full deployment of offshore wind (21.5 GW) and electrolyzer capacity (5.1 GW) (North Sea Wind Power Hub, 2023). Althoguh the goal of 21.5 GW offshore wind capacity installed by 2030 has been delayed in the current Climate Agreement, this study assumes that by the operationalizaion of the DEMO2 (earlies 2030) , the goals of 21 GW of offshore wind has been achieved.

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[4] REDIII: 42% green hydrogen constraint in 2030, 60% in 2035. Means that 42% of hydrogen consumption in industry needs to be from RFONBO’s (Renewable Fuels of Non-Biological Origin). https://www.consilium.europa.eu/en/press/press-releases/2023/03/30/council-and-parliament-reach-provisional-deal-on-renewable-energy-directive/

In order to analyse the business case under 2030 Dutch electricity system, an electricity market model is used: a TNO-developed merit-order-based energy market model (Verstraten & Weijde van der, 2023) that involves an Input: an energy system's description, profiles and bidding strategies. The execution of the model is performed by simulations of the hourly day-ahead electricity and hydrogen markets in 2030. The output of the model are the market results such as clearing prices, clearing volumes which are used for the post-financial analysis.

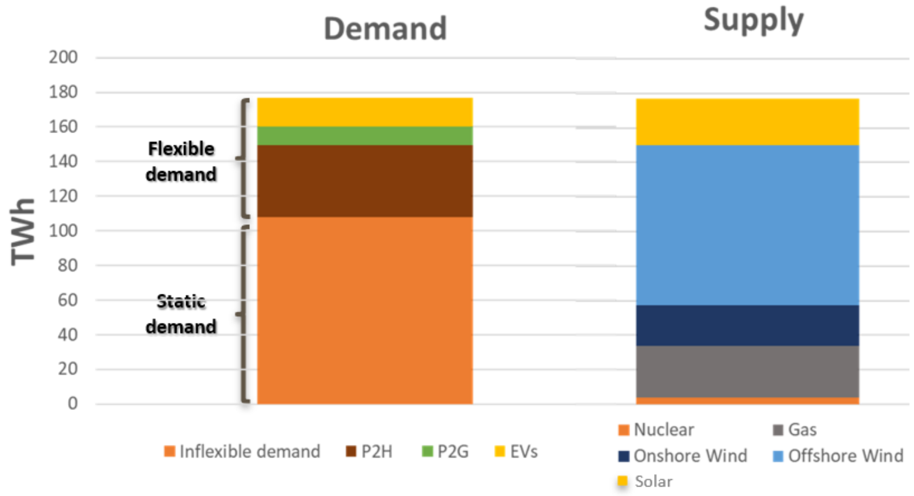

Figure 2 Energy mix of the demand and supply (TWh/yr) for the scenario selected, considered as high electrification scenario by 2030.

Table 1 Parameters considered in the scenario selected based on the RED III by 2030

Demand		
Inflexible annual demand (TWh/yr)	Electrolyzer capacity (GW)	P2H capacity (GW)
108	5,1(demo 2 + rest)	8,6
Supply (capacity GW)		
Onshore wind	Offshore wind	Solar
7,2	21,5 (demo 2 + rest)	25,3

The approached followed to analyse the business cases for the demo 2 are based on different configurations of grid connection and to the electrolysers. These configurations selected for the Demo 2 plays a relevant role when the wind-to-H2 system aims at providing flexibility to the system and act as peak shaving, or aims to optimally utilize the electrolyzer to produce a certain amount of H2 baseload (Figure 3).

Recent scenario assumed is to connect the DEMO 2 to the TNW wind farms substation. At the same time, the TNW substation connects (200MW) to a DDW substation for electricity to shore. In this study it is assumed that the cable capacity can vary in size: from off-grid, that is no cable connection to shore to cable connected to shore with 700 MW size. It is assumed that the connection to shore is bidirectional, so that it is possible to consumed electricity from the grid.

Varying grid connections and operational modes lead to different wind and electrolyzer utilization, higher rates of curtailment and consequently, impacting the business case (Figure 4).

Grid connected

- **Copper plate (market based approach)**: Demo 2 is fully connected to the grid (700 MW grid connection). The electrolyser operates based on electricity price, at low prices it is fully on (even at times of low wind, in that case cheap electricity is taken from grid), at high prices it is off (even in times of high wind, in that case expensive electricity is transported to the grid).
- **Baseload**: Two different cases are considered
    - Maximum baseload (500 MW grid connection): The electrolyser always runs at full capacity. If there is no wind, the electricity is taken from the grid (even at high prices). Excess wind (>500 MW) is transported to the grid. In this case, part of the electricity is non-green.
    - Minimum baseload (50 MW grid connection): The electrolyser has a minimum load of 50 MW (10% of maximum load), taken from the grid if there is no wind. Wind energy is used for electrolyser, excess wind is transported to the grid (>500 MW and <550 MW) and curtailed (>550 MW).

Off grid configuration: In this configuration the DEMO 2 is not connected to the electricity grid (0 MW connection) and 100% of the wind produced is used to make hydrogen. The excess wind (>500 MW) is curtailed.

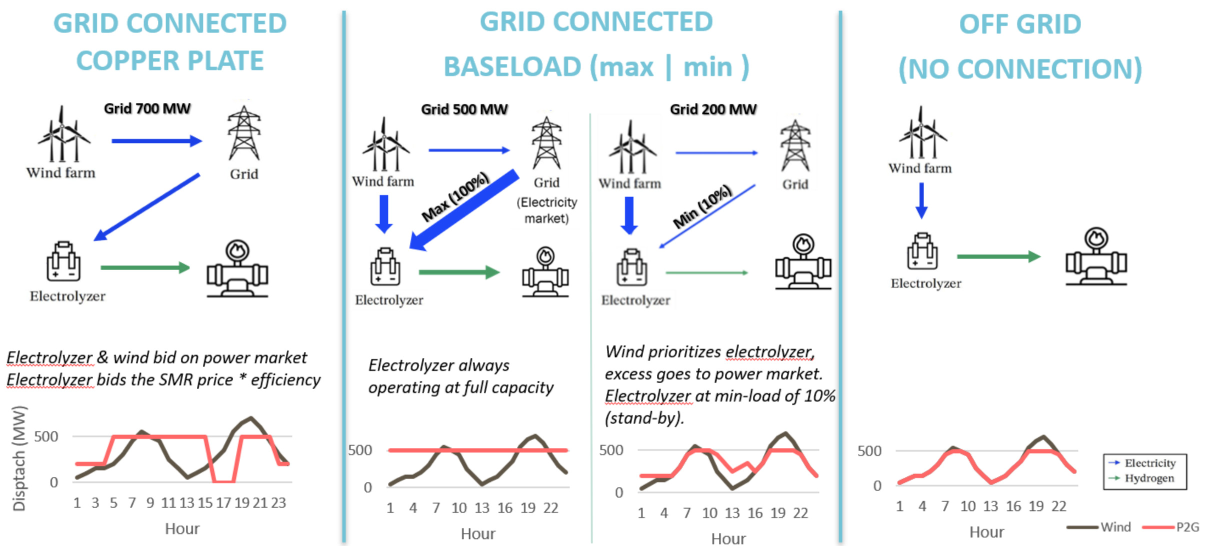

Figure 3 Configurations of the DEMO 2 case study with different grid size connections and operational modes of wind-to-H2. Recent scenario assumed is to connect the DEMO 2 to the TNW wind farms substation. At the same time, the TNW substation connects (200MW) to a DDW substation for electricity to shore. In this study it is assumed that the cable capacity can vary in size: from off-grid, that is no cable connection to shore to cable connected to shore with 700 MW size. It is assumed that the connection to shore is bidirectional, so that it is possible to consumed electricity from the grid.

2.2 Results

2.2.1 Operational modes

The outcomes of the simulations for different operational modes of wind to hydrogen by 2030 are the following:

In the Copper Plate Configuration

- Electricity Allocation: One-third of wind energy is used for hydrogen production (via the electrolyzer), while two-thirds is sold to the electricity market due to consistently high electricity prices.
- Electrolyzer Utilization: The electrolyzer utilization is the lowest among configurations, at 23%, primarily because electricity prices often exceed the hydrogen production value.
- Hydrogen Production: Most hydrogen is produced from wind power, with some contribution from grid electricity at low prices (average 34.3 EUR/MWh) and during periods of low wind output (<500 MW).

Off-Grid and Baseload-minimum Configurations

- Electrolyzer Utilization: Both configurations achieve a utilization rate of approximately 65%, as they follow the wind power profile.[5]
- Curtailment: Due to limited grid connection (50 MW), wind curtailment is 6% for the off-grid configuration and 2% for Baseload Min.
- Baseload Min Distinction: Baseload Min achieves slightly higher utilization than Off-Grid due to the need to maintain a minimum 50 MW load. When wind power is insufficient (<50 MW), grid electricity is used at relatively high prices (78.6 EUR/MWh).

Baseload-maximum Configuration

- Electrolyzer Utilization: This configuration ensures 100% utilization by operating the electrolyzer at maximum capacity continuously.
- Hydrogen Production: A majority of hydrogen is produced from wind power, but a significant portion (31%) is classified as "non-green hydrogen," produced using electricity from the grid, above a certain electricity price threshold that is not considered green (following the delegated act)[6]. Grid electricity is often expensive and not renewable due to insufficient wind power to meet the full 500 MW demand.

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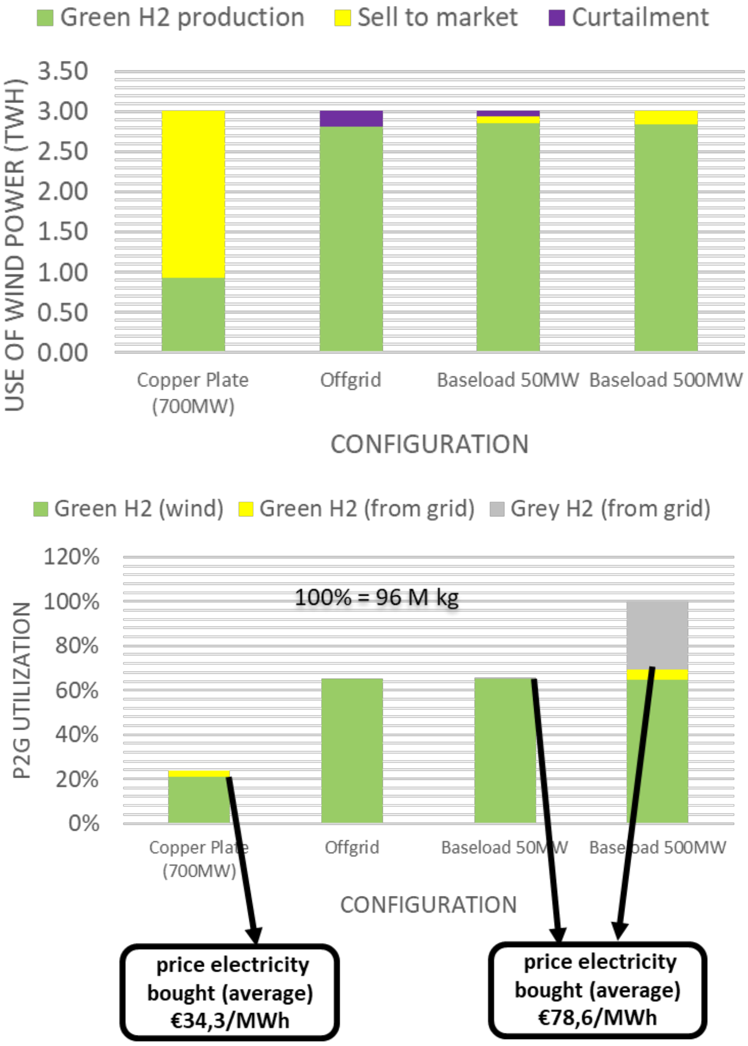
[5] Note that this ulitiziation rate is based on an optimistic wind profile with limited wake effects and a very good wind year (in terms of annual yield). Wake effects, detoriation of performance and system losses may result in lower annual yields, certainly in the case when reference wind years with lower yields are simulated.

[6] The electricity consumed from the grid to produce hydrogen is considered green electricity when the electricity price is below 20€/MWh or 36% of the CO_2 price assumed in the study, which corresponds to 32.4 €/MWh. Additionally, electricity is also classified as green when it is sourced directly from a new renewable energy installation through a Power Purchase Agreement (PPA) or off-grid connection, in line with the criteria set by the RED III – delegated act.



price electricity bought (average) €34,3/MWh

price electricity bought (average) €78,6/MWh

Figure 4a) offshore wind and b) electrolyzer utilization on the different operational modes and grid connection sizes.

2.2.2 Business gap in 2030

Under the assumptions selected, the economic feasibility for different grid configurations of the Demos 2 is achieved at 6-13 €/kg of green hydrogen in 2030 (Figure 5). For example,at 6 EUR/kg hydrogen selling price (market price) the baseload and max. load configurations result in an IRR of 5%. Anything above that price results higher IRR, which means a positive business case. Note that the selection of 5% to become a positive business case in an illustrative example. The figure show the range of hydrogen market prices at different IRR to become positive business case.

The off-grid and grid-connected systems (forcing a H2 demand to be produced) have smaller business gaps than the copper plate at higher hydrogen prices. High CAPEX and low profits for hours in which non-renewable based hydrogen is produced.

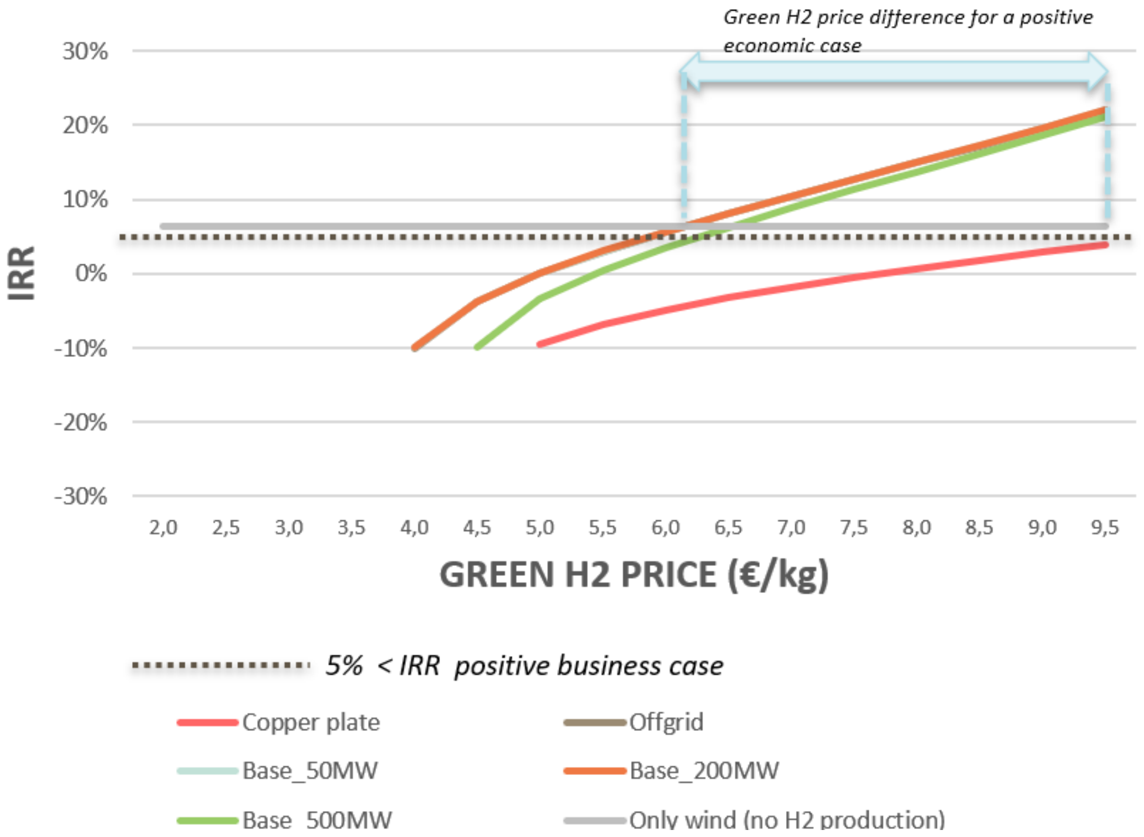


Figure 5 Economic feasibility of the different grid configurations for the DEMO 2. Assumptions: no grid tariffs included to pay when consuming electricity, no infrastructure costs for H2 and electricity, no subsidies or premiums for wind and H2, no start-up or ramp-down costs of electrolysers. CAPEX offshore electrolysers is assumed for this calculation on 4000€/KW.

The Copper Plate configuration results in the largest business gap when green hydrogen prices are low. During periods when renewable energy production is insufficient to meet onshore electricity demand, traditional gas -power plants are deployed in the Netherlands, setting electricity prices at an average of approximately 75 EUR/MWh. In this scenario, grid-connected electrolysers remain idle because wind energy is prioritized to supply onshore demand, thereby reducing the reliance on traditional power plants. In other words, higher revenues are made by selling the wind power as electricity in the power market.

In contrast, the off-grid configuration, as well as the baseload configurations, prioritize hydrogen production even when gas-fired power plants are running. At a green hydrogen price of 3.50 EUR/kg, wind farms generate higher income—approximately 77 EUR/MWh—by producing hydrogen compared to selling electricity to the market at 75 EUR/MWh during these periods. While this makes hydrogen production economically viable under these configurations, it results in lower overall system efficiency. This inefficiency arises because these configurations allow for hydrogen production at times when methane-fired power plants are operational, indirectly leading to less efficient energy utilization across the system. Despite the reduction in efficiency, the off-grid and baseload configurations offer a significant advantage in terms of infrastructure requirements; that is, the reduction on connection capacity. By reducing the dependency on extensive electricity grid infrastructure, these configurations highlight a critical trade-off in system integration: prioritizing efficiency versus minimizing infrastructure needs. This balance is a key consideration when evaluating the role of hydrogen production within the broader energy system.

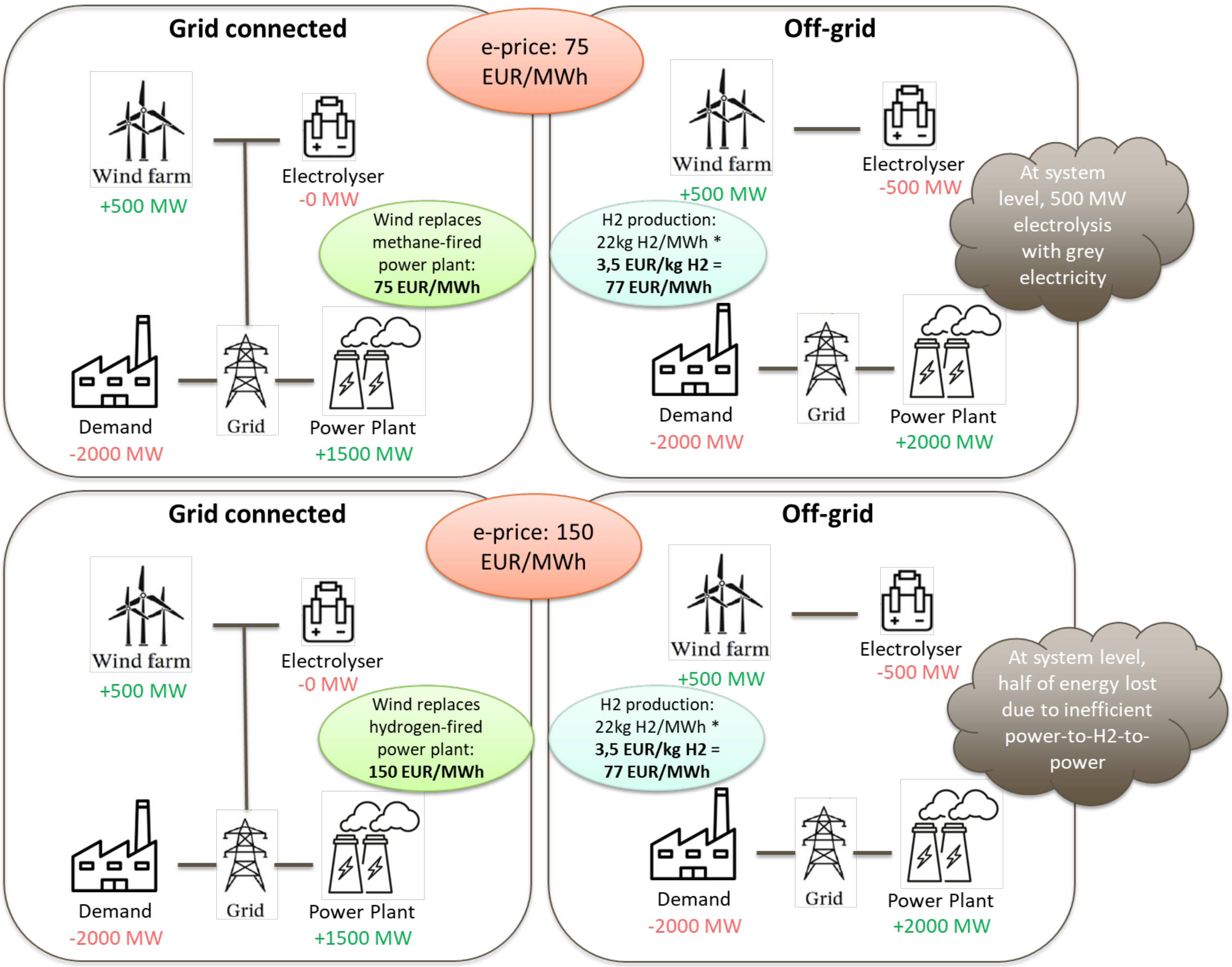


Figure 6 (top) Illustrative example of the grid connection vs. off-grid connection revenues, at low electricity prices (bottom) at high electricity prices.

Towards 2050, as gas power plants are phased out and replaced by green hydrogen-fired plants, the energy system dynamics will significantly change. The electricity price is expected to rise substantially, as green hydrogen is a more expensive fuel than natural gas. Operating power-to-gas and gas-to-power processes simultaneously — both using green hydrogen — introduces system inefficiencies. Consequently, in such a scenario, off-grid hydrogen production will never be more profitable than grid-connected production, as grid electricity will be more cost-efficient than self-supplied electricity from hydrogen-fired power plants.

2.2.3 CAPEX versus price of green hydrogen

Under the configurations selected for this study, the business case becomes positive when increasing the hydrogen market price and lowering the CAPEX (and hence, the OPEX assumed)With a 500 MW electrolyser, comparing the grid-connected (copper plate option, that is, under a market based approached with no hydrogen fixed demand) and the off-grid configuration, with assumed CAPEX in 2030 for offshore electrolysis of 4000€/KW, the off-grid configuration reaches a positive business case with lower green H2 (market) prices than the copper plate (Figure 7 and 8).

In the copper plate, the utilization is 23%, comparing with the 65% in the off-grid. This is because selling the electricity directly is more profitable than converting hydrogen and then selling it. To turn the business case positive, CAPEX should be largely subsidized or green H2 price increases >12 €/Kg. (Figure 7 and for assumptions considered). In the off-grid case, there is a fixed requirement to use all electricity from wind for the production of hydrogen.. To turn the business case positive CAPEX should be largely subsidized or green H2 market prices increase to approximately 7 €/kg.

That is, under these conditions with a hydrogen market price of 3.5EUR/kg there is a gap of 3.5 EUR/kg to turn the business case positive, i.e., the market price should be 7EUR/kg or there should be some kind of subsidy on production e.g. SDE++ like to close the gap.

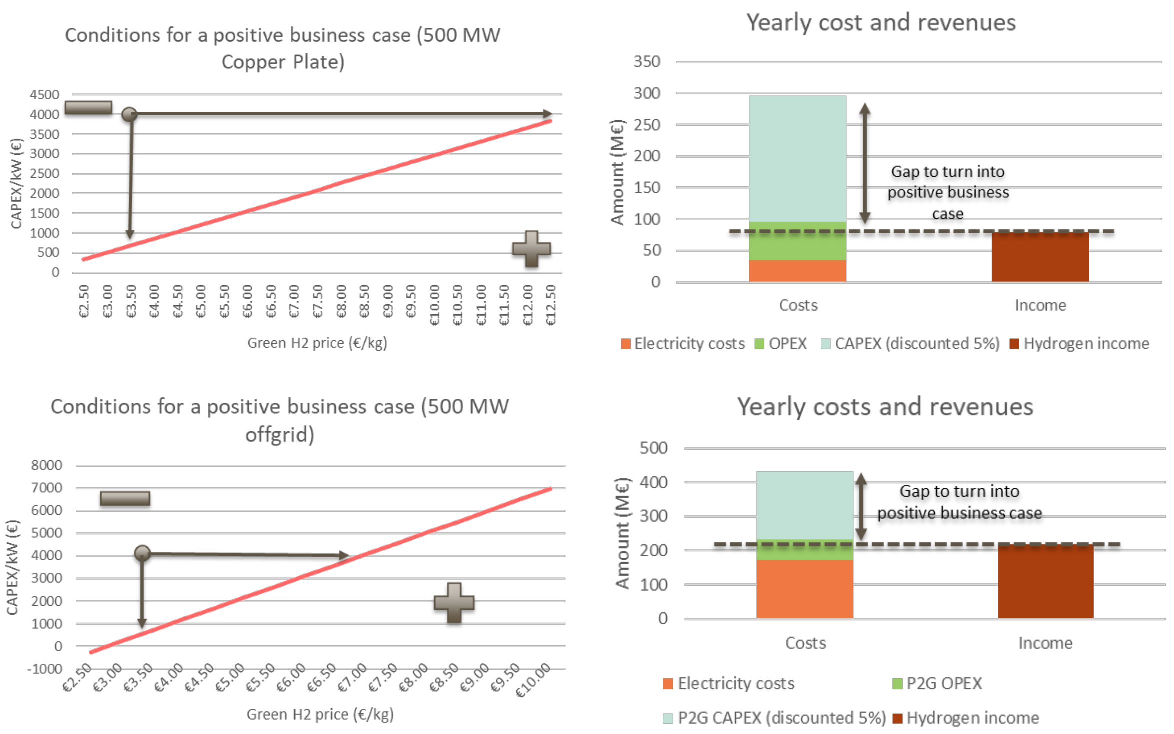


Figure 7 Business case evaluation for the 500 MW electrolyser, (top) grid connected under a market based approach, CAPEX: 4.000€/kW (2.000M€), OPEX €12M/year, Green H2 price: €3,50/kg, No grid tariffs considered. (Bottom) off grid configuration: cost of electricity 174€M, yearly produced hydrogen 62.7 M kg, CAPEX: 4.000€/kW (2.000M€) → 200 m€/year, OPEX €60M/year, Green H2 price: €3,50/kg, No grid tariffs considered.

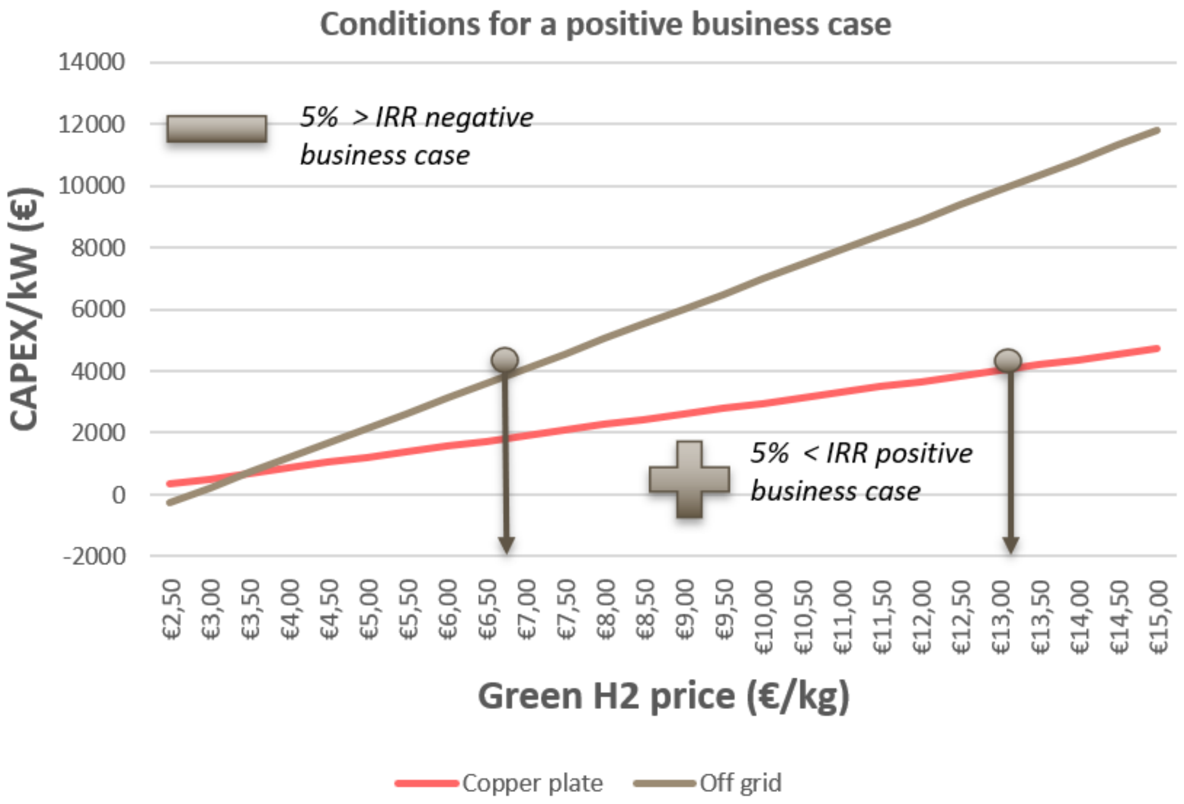


Figure 8 Comparative analysis between CAPEX and green H2 price of the market based approach (copper plate) and the off grid configuration. The H2 price between 6-13 €/kg makes the positive business case in 2030.

2.2.4 Electrolyzer size

Reducing the size of the electrolyzer would increase the full load hours, improving the business case. As an example, considering the off-grid configuration with a 100 MW electrolyzer, the utilization increase to 96%, comparing to the 65% with the 500 MW electrolyzer. The H2 price at which the business case turns positive is 5.5 €/ kg approximately.

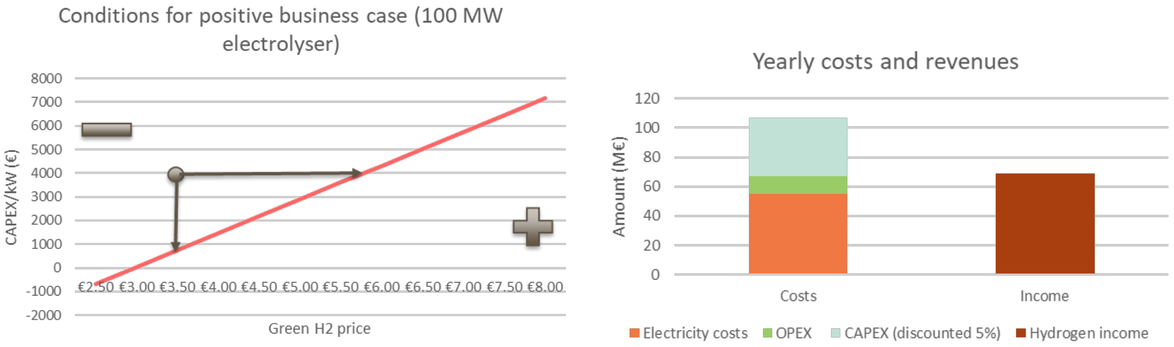


Figure 9 Business case for a reduced size of electrolyzer to 100 MW. The assumptions are that the 700 MW wind gives priority to 100 MW electrolyzer and there are no minimum load requirements, so that there is no tariffs. Cost of electricity is 55M€, yearly produced hydrogen is 18.5 M kg. , Green H2 price: €3,50/kg, CAPEX 4000 €/kg (400 M€) → 40 m€/year. OPEX 12 M€ / year.

Reducing the ratio between the wind and electrolyzer size, lowers the H2 price and the gap of the business case is lowered in 2 €/kg of green H2.

Variables	500 MW	100 MW
Elec. utilization	65%	96%
CAPEX (4000€/KW capacity elect.)	200m€/y	40m€/y
H2 produced yearly	62,7M kg	18,5M kg
OPEX	€60M/year	€12M/year

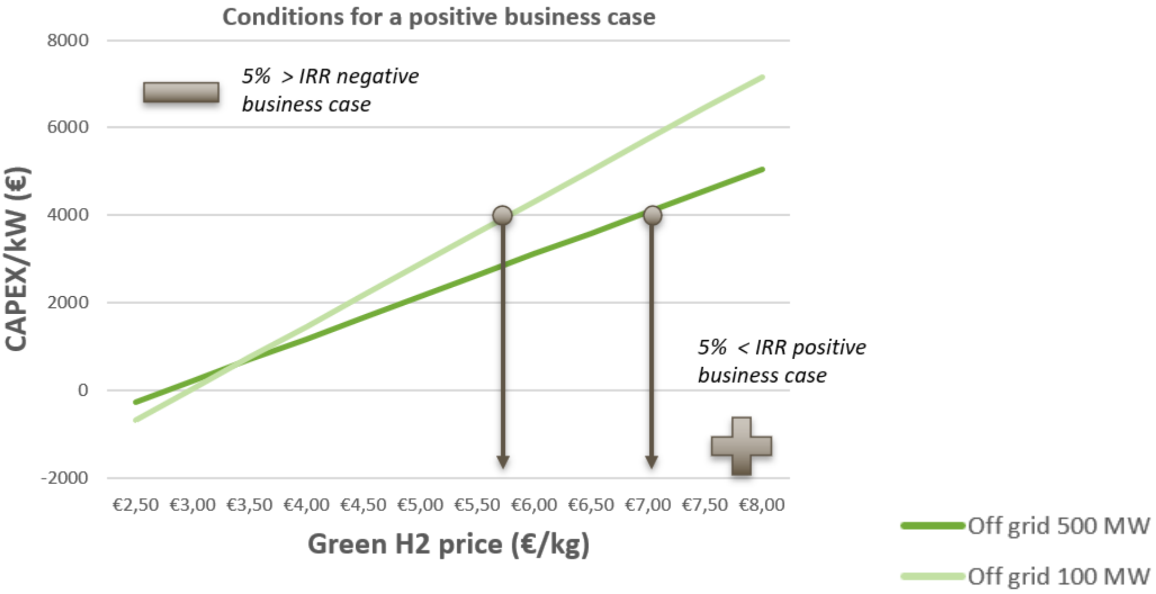


Figure 10 Break-even point on the electrolyzer size versus green H2 price for a positive business case.

The electricity consumed from the grid to produce hydrogen is considered green electricity when the electricity price is below 20€/MWh or 36% of the CO_2 price assumed in the study, which corresponds to 32.4 €/MWh. Additionally, electricity is also classified as green when it is sourced directly from a new renewable energy installation through a Power Purchase Agreement (PPA) or off-grid connection, in line with the criteria set by the RED III – delegated act[7].

2.3 Conclusions: key aspects to improve towards 2050

The insights on the grid configurations of the wind to H2 systems for the demo 2 are:

- In the **Copper Plate** setup, where electricity and hydrogen prices compete, the electrolyser's low utilization (23%) is due to electricity prices being higher than hydrogen production prices for most of the time. No fixed hydrogen demand is assumed in this scenario.

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[7] : https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32023R1184

- The **Baseload 500 MW** configuration forces the electrolyzer to operate at full capacity, achieving 100% utilization. However, 31% of hydrogen is produced using non-renewable, grid-sourced electricity, as wind power alone cannot sustain the demand.
- The **Off-Grid** and **50 MW Grid Connection (Baseload Min)** configurations achieve moderate utilization rates of 65%. All wind energy is used for hydrogen production, with minimal curtailment (6% and 2%, respectively), limited by grid connection capacity.

It is important to note in the results of this analysis that with this scenario, for market prices of green H2 above around EUR 3,50, configurations in which the electrolyser has higher full load hours (off grid, smaller electrolyser) lead to a better business case, whereas for market prices of green H2 below EUR 3,50, a copper plate configuration yields the best results. This only holds if flexible power plants run on conventional gas power plants, which are not expensive (around EUR 70/MWh). When flexible power plants run on green hydrogen, electricity will be more expensive and producing hydrogen from expensive electricity, while at the same time that hydrogen is burned to generate electricity is not efficient, so copper plate will be the most profitable.

Therefore, the analysis of the business case done towards 2050 is based on an electrolyzer connected to the grid, following the market based approach (copper plate scenario), it is not looked at the off grid case anymore. Therefore, international perspective on the hydrogen and electricity prices are considered for the analysis.

Overall, the key aspects to consider to improve the business case towards 2050 are:

- Strong interplay between CAPEX, electricity price and electrolyzer load hours to form business case.
- Supports in CAPEX and premiums on green H2 prices are two directions to focus subsidies. Sensitivity analysis showed impact on both aspects.
- Dimensioning the ratio between the wind farm and electrolyzer is very important for the business case
- Large electrolyzer systems with small size wind farms create low operating hours, creating a larger business gap
- Large system base load with forced high electricity prices as input is not economical. It also consumes non-RES electricity from the grid. Off grid (or limited grid connected) showed smaller economic gap although the impact on the system is larger.
- Trade-off between grid connection size and system efficiency could improve the economics and impact less at system level. Intermediate way to operate the electrolyzer (between limited grid size and copper plate).
- Reducing the costs (CAPEX) or subsidizing through financial mechanisms

3 Business case 2050

Towards 2050, Europe's energy system aims to achieve CO2 neutrality, primarily relying on wind and solar energy. However, international uncertainties—including the aftermath of the COVID-19 pandemic, geopolitical conflicts (e.g., the Russian invasion of Ukraine), and rising global protectionism—create challenges for the European Union (EU) as it seeks to maintain competitiveness and solidify its position as a global economic power. The low-carbon transition is vital for Europe's future competitiveness, reducing reliance on volatile fossil fuel imports (Draghi Report, 2024). However, ambitious targets for electrification growth and hydrogen development face considerable uncertainties, particularly regarding electricity and hydrogen price volatility, which impact the business case for investments.

To navigate these uncertainties and provide a more robust approach, multiple energy scenarios are explored, reflecting varying rates of electrification growth, industrial transformation, and EU dependency. These scenarios guide the assessment of the 2050 business case for grid-connected electrolyzers, incorporating an international perspective on fluctuating hydrogen and electricity prices and following a market-based approach (copper plate scenario).

3.1 Scenarios and future electricity prices

Two scenarios are selected to study the business case towards 2050, looking at the European outlook for 2030, 2040 and 2050. The scenarios selected follows the North Sea Wind Power Hub (NSWPH) and Ten year Network Development plan 2020 (TYNDP2020) (North Sea Wind Power Hub, 2023). In addition, the results for 2030 have been compared with the scenario 2030 based on the Climate Agreement (Chapter 2). The NSWPH and TYNDP2020 scenarios are considered as upper and lower band for an ‘optimistic’/ high Variable Renewable Energy and a ‘pessimistic’/ low Variable Renewable Energy bandwidth.

At the time of this study, the NSWPH was the most recent and aligned with policy dataset that was available. It is an extension of TYNDP2022, with updated policies on North Sea countries. Each scenario considers different development in production, demand and flexibility and therefore, has an impact on the electricity price formation and on the operations of the electrolyser (Figure 11). It provides a wide European vision of the future power system and investigates how power links and storage can be used to make the energy transition happen in a cost-effective and secure way.”

The scenarios reach 55 % of GHG reduction in 2030 and net zero in 2050. The TYNDP scenarios include energy system data on supply of hydrogen and methane, generation capacities for electricity generation and demand for a number of energy carriers. This data is presented on a national level and, where applicable, disaggregated into several sectors: agriculture, energy, industry, residential, tertiary, transport and other. The data is present for 2030, 2040 and 2050. TYNDP scenarios indicate that they were constructed over the period 2020 – beginning 2022 and therefore include, as much as possible, the major policy changes that have occurred during this period. However, as ENTSO-E and ENSTOG also state in their disclaimer on the use of the TNYDP scenarios: “*The invasion of Ukraine by Russia on 24 February 2022 has led to a major overhaul of energy policy objectives in terms of energy* *security and diversification of supply that the TYNDP 2022 scenarios do not currently reflect."*[8]. Additionally, the governments of the core focus countries of the NSWPH consortium, Netherlands, Germany and Denmark, all formed new governments that sharpened their focus on sustainability and a renewable future in the period of 2030 - 2050, which was not been reflected in the TYNDP data.

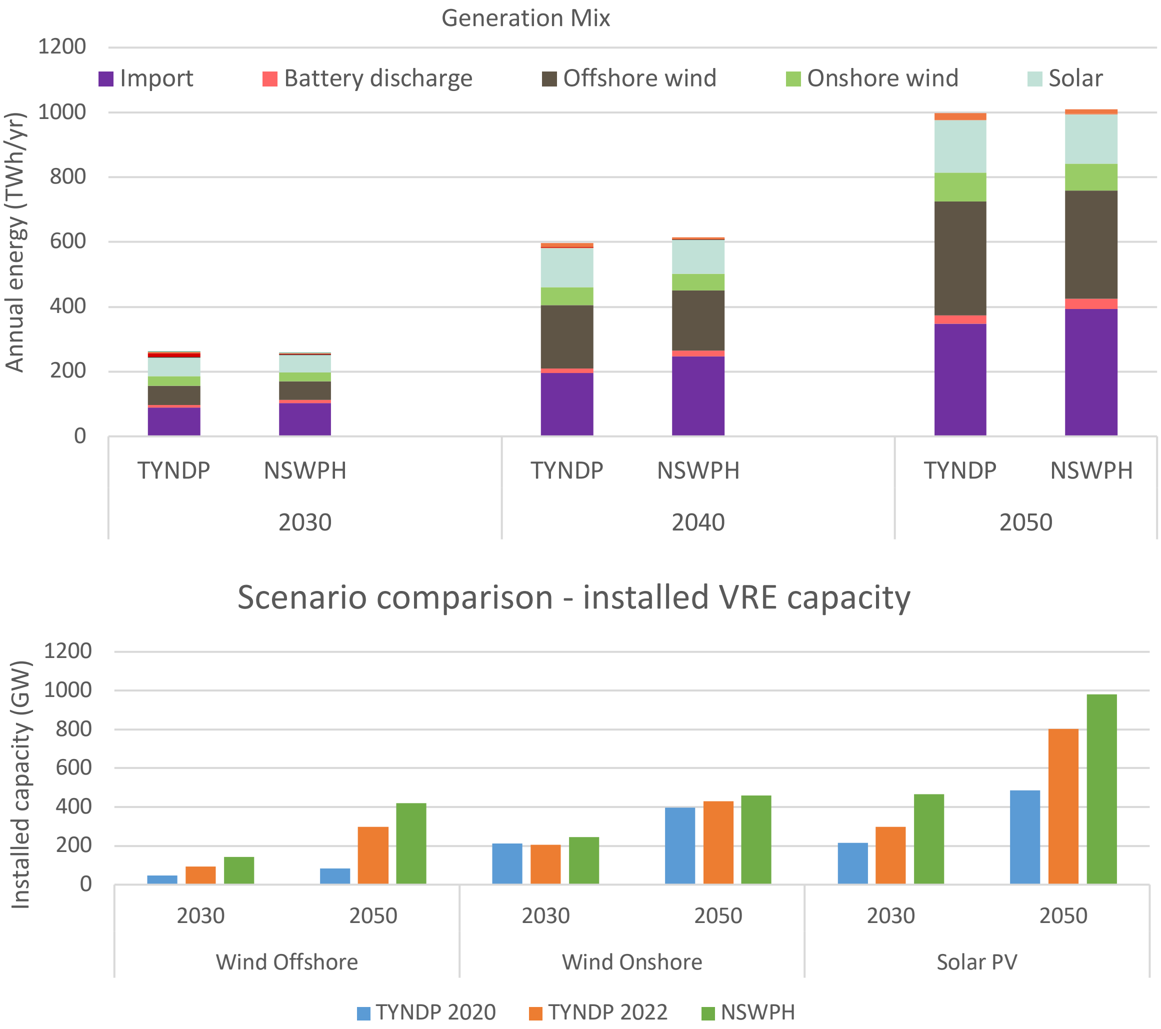

Figure 11 a) Generation mix and b) Installed capacity of onshore and offshore wind and solar PV, for 2030 and 2050 under the different scenarios selected.

In the graphs below, the electricity price duration curves are shown for varying years and scenarios. The curves can be split into four distinctive price ranges:

- ~ €0/MWh: Enough renewables to cover all base and flexible demand (considering import/export and storage). Renewables are price-setting.
- Between €15/MWh and €60/MWh: Enough renewables to cover base demand, but not enough to cover all flexible demand (considering import/export and storage). Therefore power-to-gas and power-to-heat and other flexible load become price setting.

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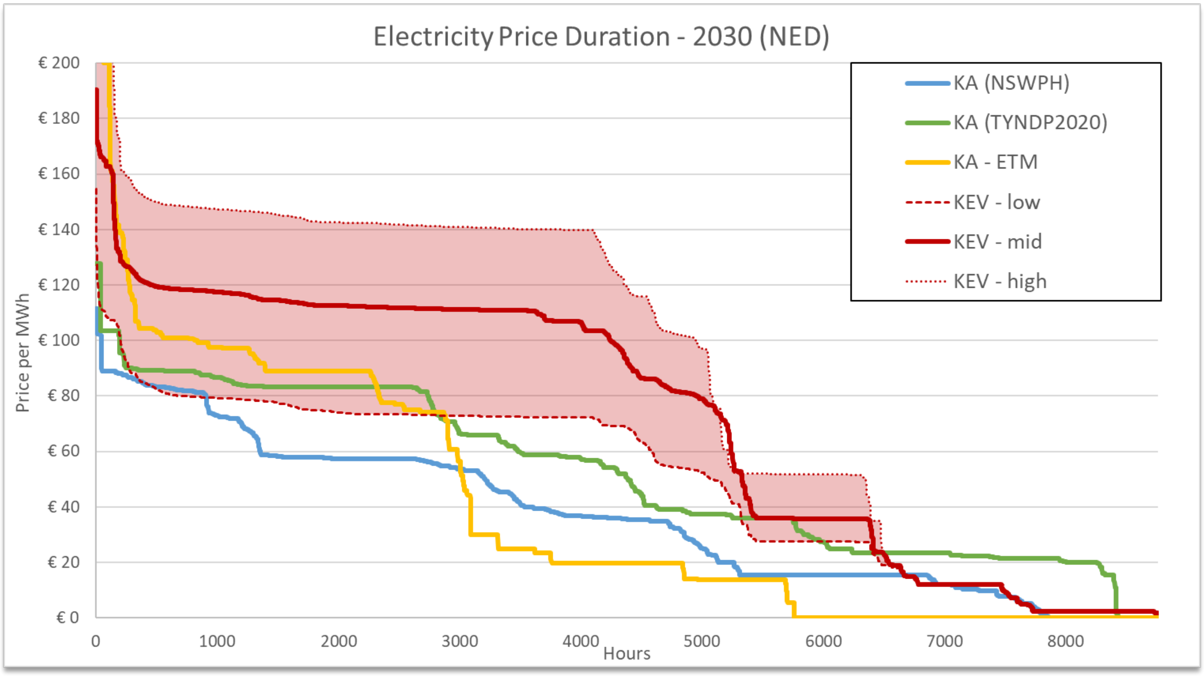
[8] https://2022.entsos-tyndp-scenarios.eu/download/

- Between €60/MWh and €120/MWh: Not enough renewables to cover base demand (considering import/export and storage), so need for gas-fired power plants, which are then price-setting.
- Above €120/MWh: Insufficient gas-fired power plants to cover base demand (considering import/export and storage), so need for expensive back-up powerplants and/or load shedding.



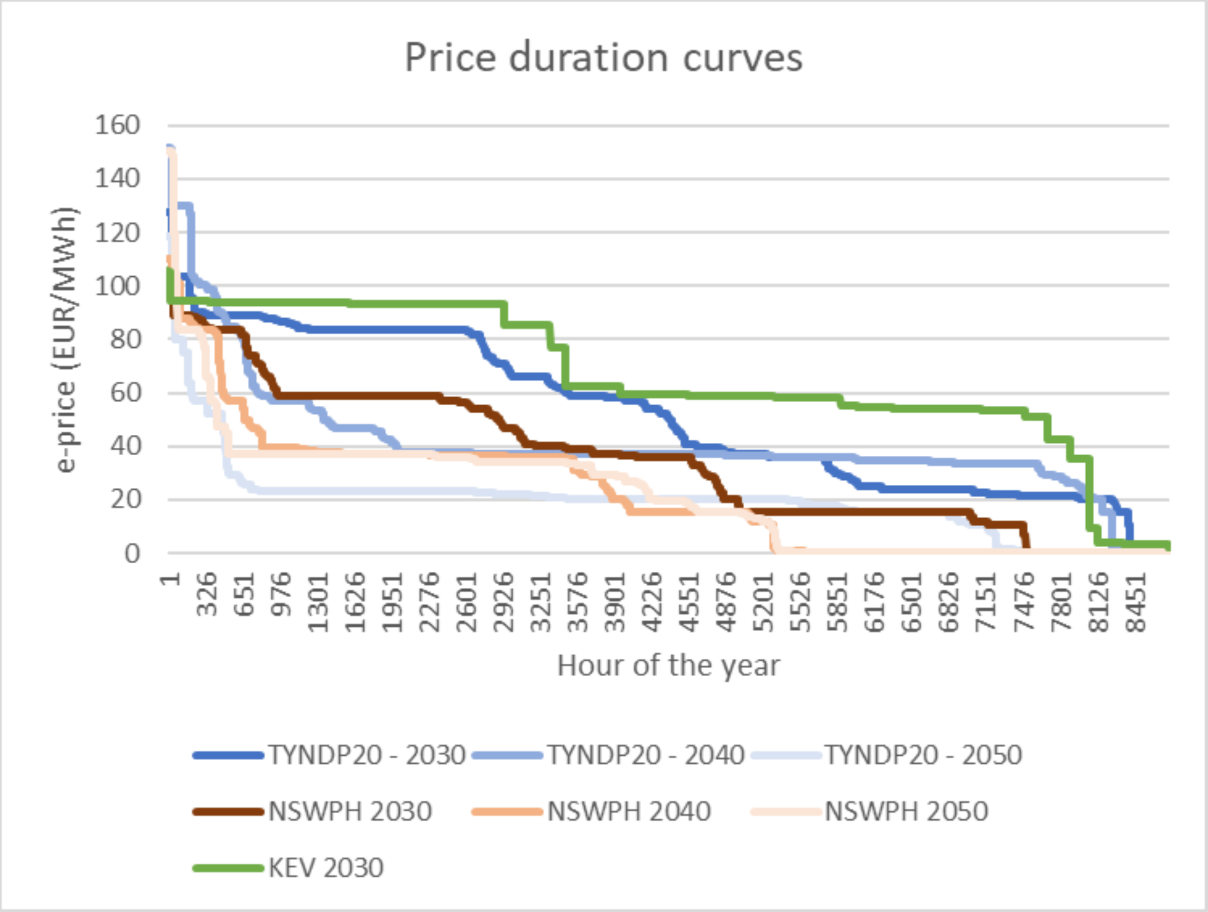


Figure 12 Electricity duration curves for (top) 2030 and (bottom) 2030, 2040 and 2050 for different scenarios selected. For 2030, the Climate & Energy Outlook 2022 (KEV) is used as a reference.

An integrated electricity, hydrogen and gas market model to determine the cost-optimal dispatch of the three energy carriers is employed in this study (Koirala B. , et al., 2021). The model minimises the total marginal costs of the system, including production, transport, storage and conversion. No investment costs and decisions are modelled. The resulting dispatch can be analysed along with the system marginal costs, which serve as a proxy for commodity prices. These system marginal costs are calculated under the assumption of perfect foresight, and do not include scarcity pricing. The modelled energy system includes 9 North Sea countries and 20-30 nodes per energy carrier for the Netherlands.

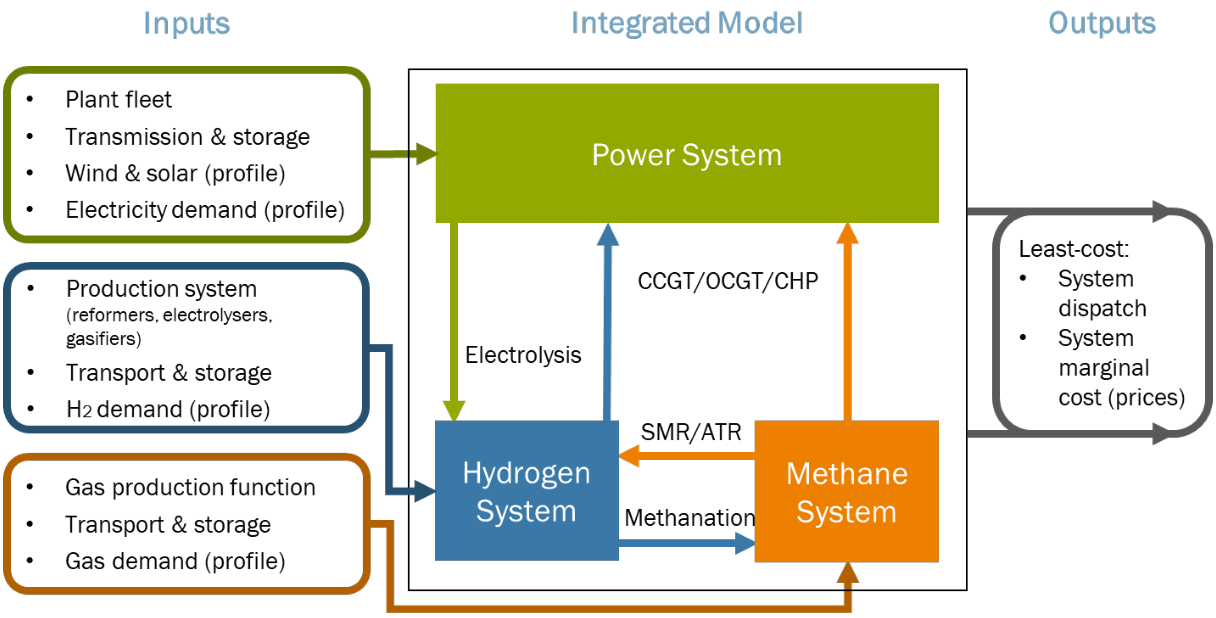


Figure 13 Modelling configuration to simulate the business case in 2050 (Koirala B. , et al., 2021).

3.2 Financial analysis

The business case towards 2050 is firstly based on a 500 MW electrolyzer, varying the H2 prices between 3 to 13 €/kg. Different CAPEX are also assummed with an evolving technology, to assess the feasibility trends and the sweet spot.

In this section the financial analysis is presented in the form of different indicators. At first, the revenues of the electrolyzer is shown under the scenarios selected, showing their dependency on the future electricity prices (section 4.2.1). Then, the impact on the CAPEX and hydrogen price is included in the business case and the influence on the Internal Rate of Return[9] (IRR) in order to show that varying the size and reducing the investment costs can lead to a better business case (section 4.2.2, 4.2.3).

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[9] Internal Rate of Return (IRR): the annual rate of growth that an investment is expected to generate. IRR is calculated using the same concept as net present value (NPV), except it sets the NPV equal to zero.

3.2.1 Hydrogen versus electricity prices

Assuming a 500 MW electrolyzer and several H2 prices, the revenues (annual income) of the electrolyzer are highly dependent on the electricity prices. In the table and figure below, the revenues of the electrolyzer are included, by the difference between the income from the H2 produced at different prices and the electricity prices. At this stage, no costs of CAPEX and OPEX are included.

Higher electricity prices lead to lower revenues on the green Hydrogen production. In the TYNDP scenario, the electricity prices tend to get lower from 2030, 2040 and towards 2050, which affects positively the business case. In the NSWPH scenario, the electricity prices are lower, so that the revenues are higher. The business cases are better when the Hydrogen prices are higher (Figure 14).

Table 2 Annual Electrolyzer Revenues (MEUR)

	H2 prices		
Scenario	**3 EUR/KG**	**6 EUR/KG**	**12 EUR/KG**
TYNDP 2030	82	213	473
NSWPH 2030	129	301	645
KEV 2030	33	101	238
TYNDP 2040	80	228	524
NSWPH 2040	176	392	825
TYNDP 2050	153	348	737
NSWPH 2050	178	404	856

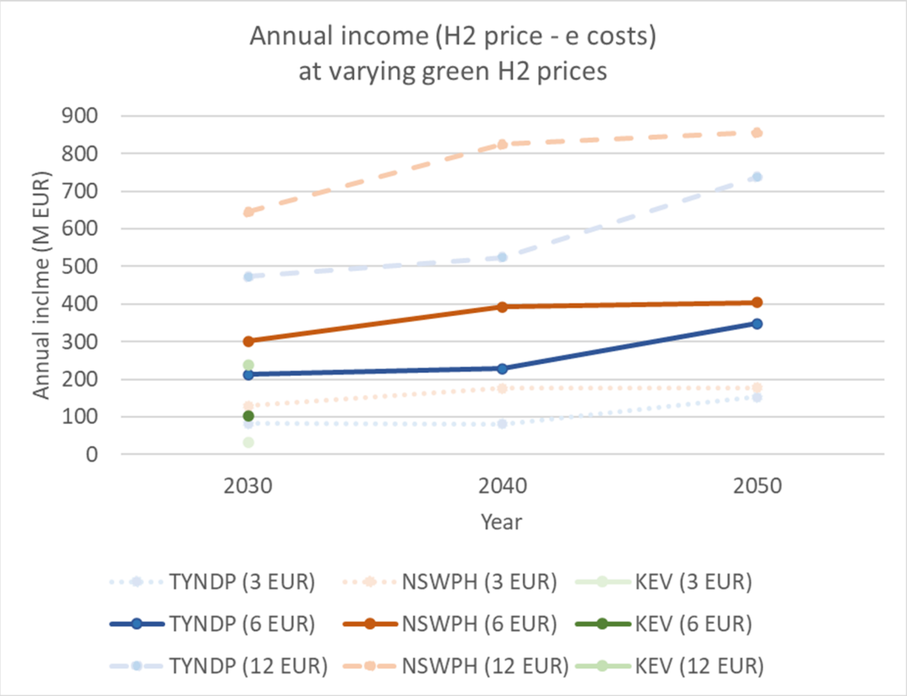
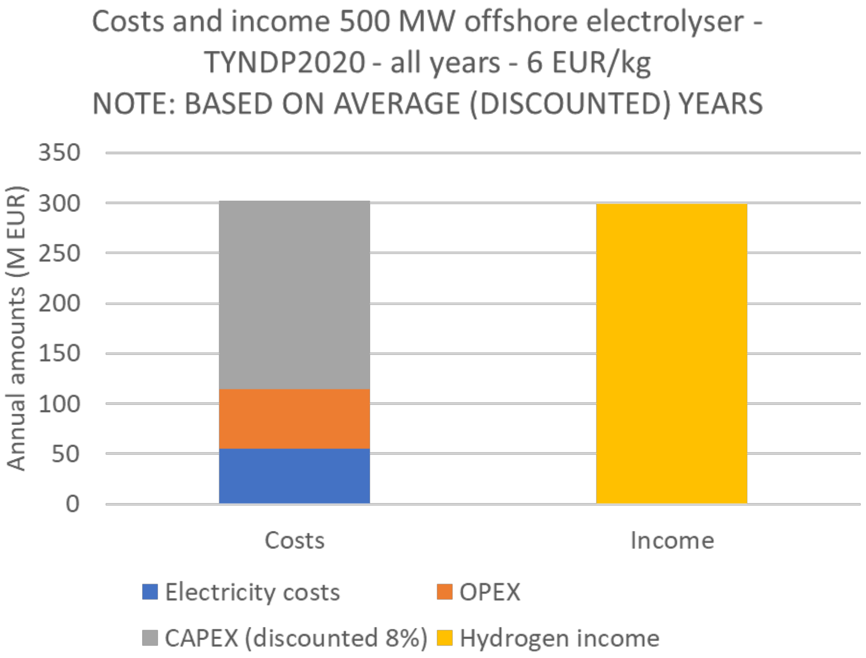


Figure 14 Revenue of the green Hydrogen, based on the three scenarios selected, for different hydrogen prices.

3.2.2 Impact of CAPEX

The CAPEX and OPEX are included in the analysis to show a simple business case, based on the annual costs and the revenues. The business case is evaluated through the Internal Rate of Return (IRR) Note that it is considered an 8% of discounted average of the years 2030, 2040 and 2050. All the investments are done today (2025) and it will be operational in 2030. The revenues are coming in the lifetime of 25 years; considering a discount rate of averaged 5 years of 2030, 10 years of 2040 and 10 years of 2050. The hydrogen price is considered constant for the 25 years lifetime.

In the TYNDP 2020 scenario, assuming the base parameters with a fixed CAPEX of 4000 €/kW (H2 price of 6€/kg, discount rate is 8%), the costs and income are equal, that means that the business case is neutral, not negative and not positive – the sweet spot (Figure 15a). However, the CAPEX has a significant impact on the overall business case: by increasing the CAPEX up to 8000 €/kW, the yearly costs are two times higher than the revenues, turning into a negative business case. By reducing the CAPEX to 2000 €/kW the yearly income is 100m€ (including the discounted ratio) (Figure 5b).



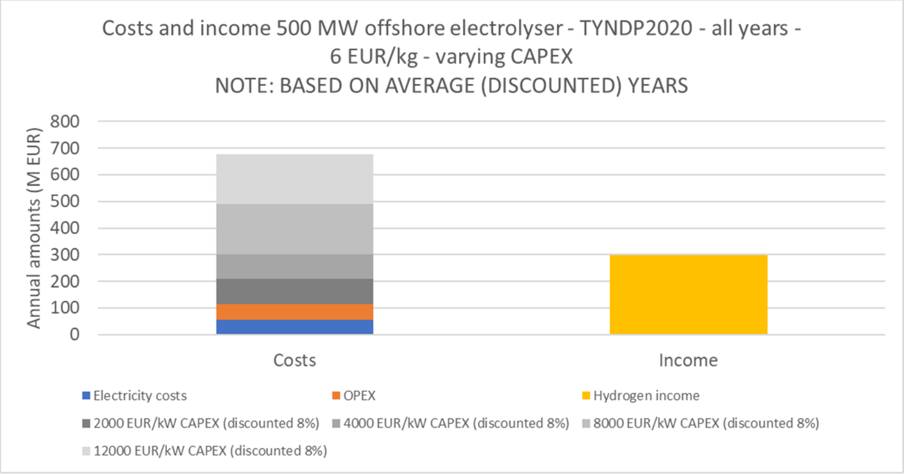


Figure 15 a) Base parameters (CAPEX and H2 price fixed) b) Varying CAPEX. C) varying the Green Hydrogen price and impact of IRR.

3.2.3 Impact of hydrogen price, CAPEX and IRR

The sweet spot in which the business case is neutral, with different CAPEX and hydrogen prices is reflected in Figure 16a. Above the blue line, the business case would turn into a negative business case and below would turn into a positive business case. For example, for a CAPEX of 4000 €/kW the positive business case would occur with a 6 €/kg of green hydrogen price (or higher). Maintaining the CAPEX fixed to 4000€/kW, the business case starts becoming positive at a hydrogen price of 6€/kg with an IRR of 8% (Figure 16b). Decreasing the hydrogen price will lower the IRR and therefore, to have a positive business case, it is necessary to decrease the interest rate. For example, at a 4 €/kg of hydrogen price, the IRR is set <2% for a positive business case. The Figure16c includes a representation of the variation between CAPEX, IRR and Hydrogen price under the TYNDP 2020 scenario.

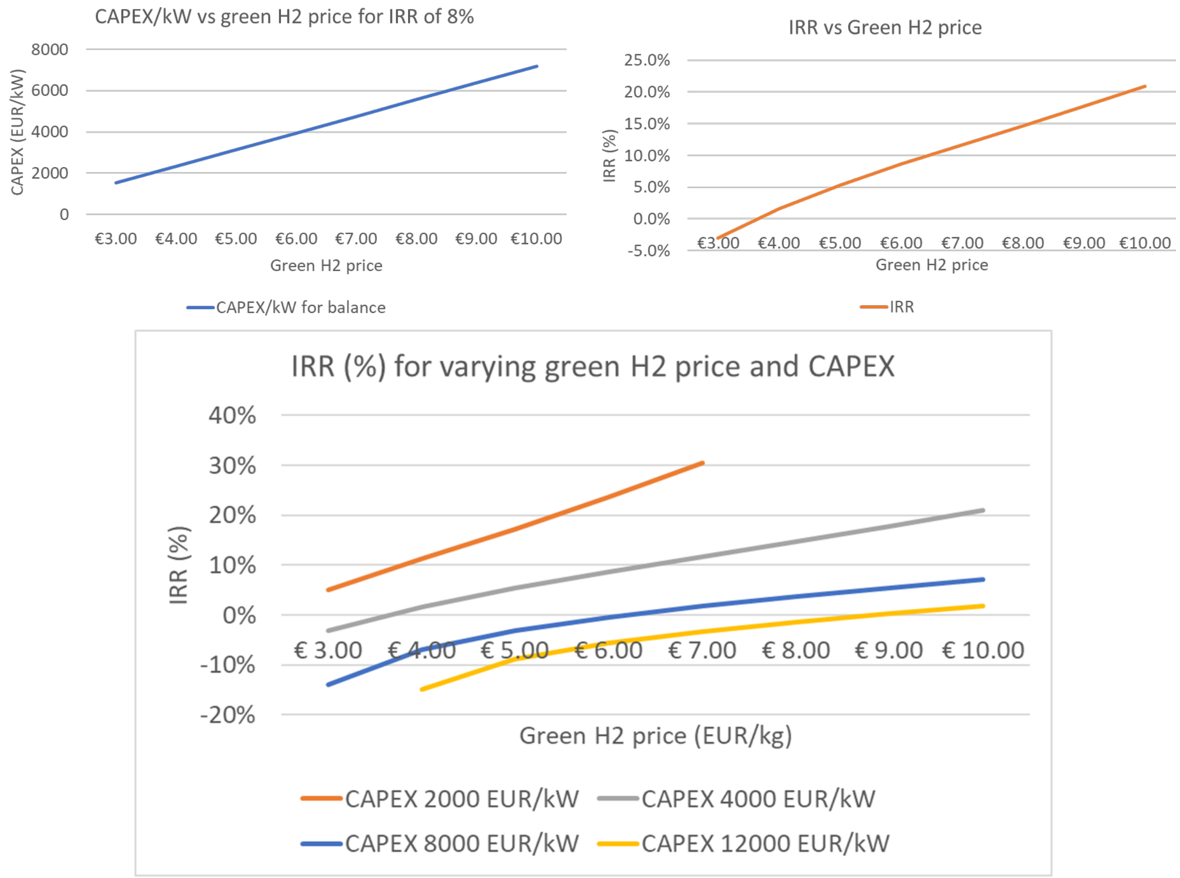


Figure 16 Sweet spot for a positive business case varying a) CAPEX and hydrogen price b) hydrogen price and IRR c) IRR, CAPEX and H2 price.

So far, the hydrogen price has been considered constant (the same assumption of the price) throughout the years 2030, 2040, 2050 to calculate the business case. However, due to maturing and de-risking technology, it is expected that the green hydrogen price is dynamic. It will decrease over the years[10]. Therefore, here, it is assumed that the green hydrogen price in 2040 and 2050 are respectively 75% and 50% of the price in 2030 (Figure 17). For example,

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[10] Green Hydrogen Prices Will Remain Stubbornly High for Decades

for a CAPEX of 4000 €/kW, and green H2 price of 6 EUR/kg in 2030 (so 4,5 EUR/kg in 2040 and 3 EUR/kg in 2050), the business case turns positive with the IRR around 4%. That is, the business case turns worse since the revenues decrease by hydrogen price reduction. In that case, the drivers of the feasibility of the business case are

1. Scenario choice will determine the electricity prices
2. Hydrogen price development
3. CAPEX reduction
4. Discount rate

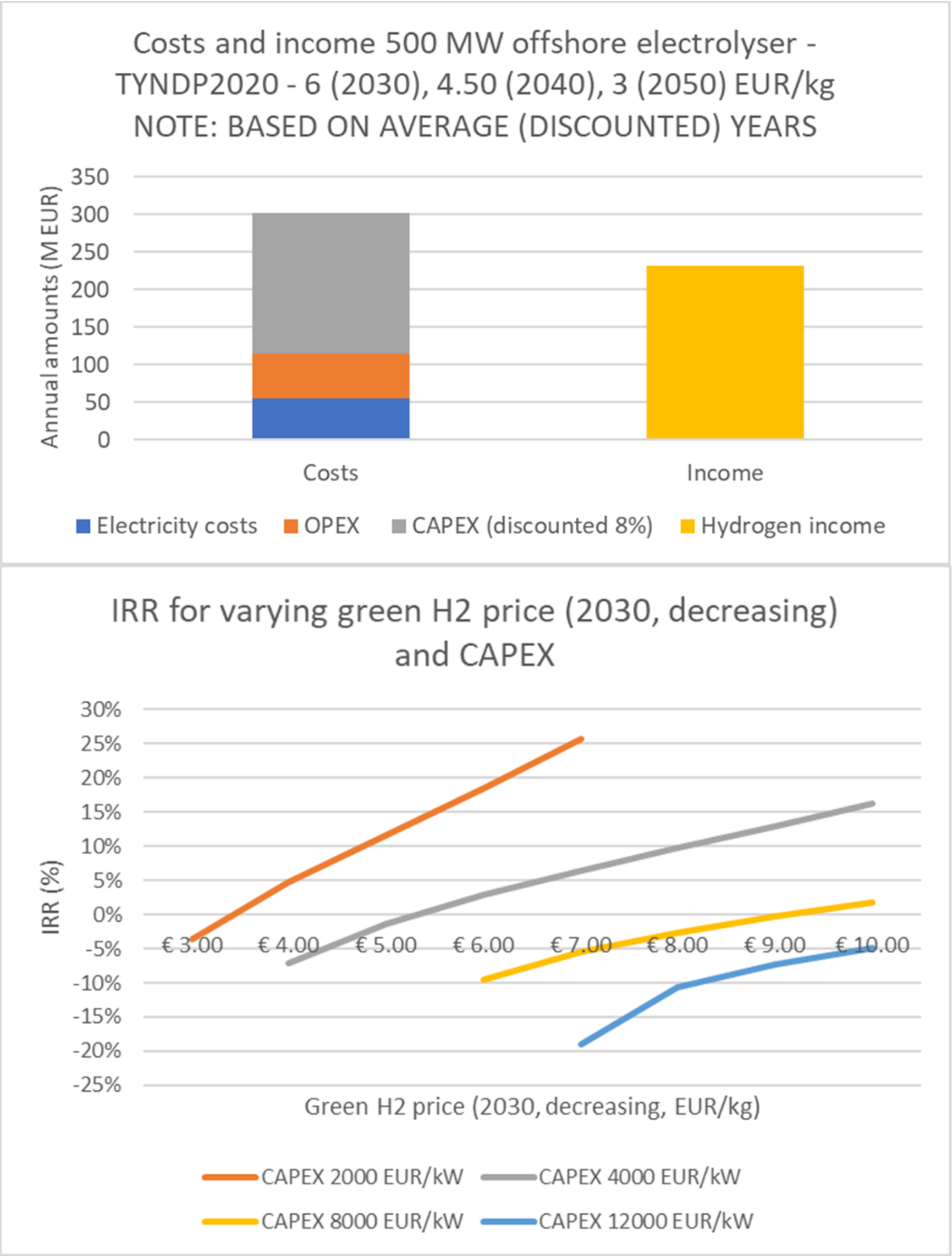


Figure 17 a) Revenue and cost and b) CAPEX, IRR and Hydrogen price variation, based on a dynamic hydrogen price over 2030, 2040 and 2050.

3.2.4 Impact of the grid tariffs

So far, grid tariffs for the offshore electrolyser have not been considered. Even though grid tariffs are currently debated, within current legislation demand within the Dutch bidding zone is required to pay them to the TSO. The graph below shows the impact on the business case of 2024 EHV (extra high voltage) tariffs without discount. This reduces the IRR from 8% to 4%.

Recently, the Dutch regulator ACM approved discounted tariffs (also known as ATR85/NFA85), which could reduce the tariffs by more than half. The ACM recently approved a number of code changes that should stimulate flexible use by large consumers. This should result in less electricity consumption during peak times, which will create more space on the electricity grid. In this case, demand does not have a firm grid capacity all the time, but only 85% of the time. This is not included in the analysis, as it is unknown when the TSO will request the limitation of capacity and therefore difficult to analyse the impact on the business case. It could be argued however that offshore electrolysers hardly cause congestion, so that the loss of revenue by the limitation of capacity will be limited.

This study excludes any fee or tariff to the Hydrogen Network Operator for hydrogen transport to shore via the pipeline .

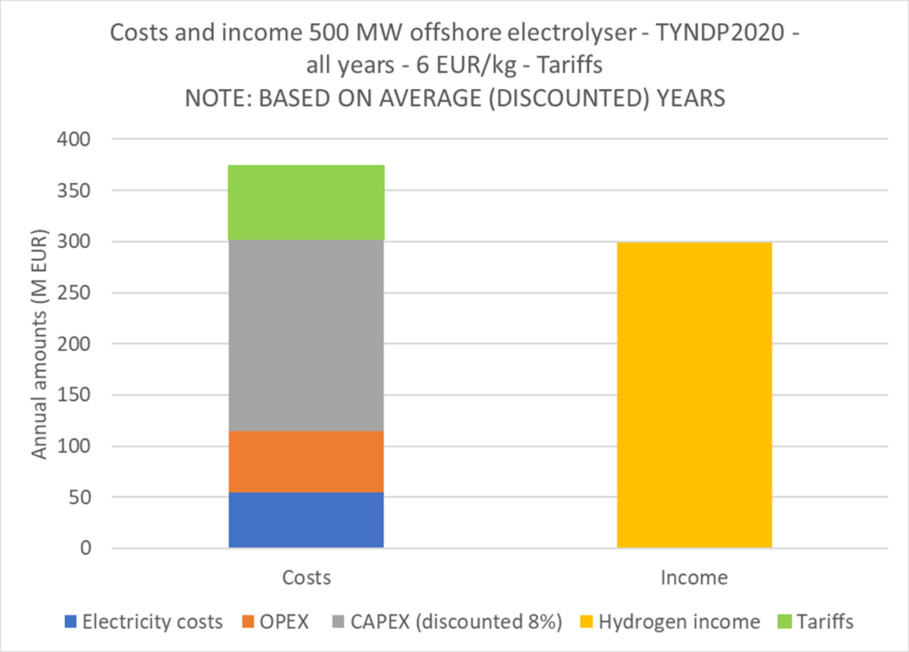


Figure 18 a) Revenues of the electrolyzer for the TYNDP scenario considering grid tariffs.

4 Conclusions and recommendations

The feasibility of offshore wind-to-hydrogen systems, as explored in this study, hinges on several key factors and challenges. In the short term, achieving a positive business case for Demo 2 requires hydrogen prices in the range of 6–13 €/kg. Current configurations reveal varying degrees of feasibility: off-grid systems and smaller electrolysers offer higher utilization rates and reduced wind curtailment, making them more economically attractive. However, these configurations also come with trade-offs in terms of system efficiency and infrastructure needs. Reducing capital expenditure (CAPEX) and providing targeted subsidies are identified as critical measures for narrowing the business gap during this period.

Another factor influencing the business case is the impact of grid tariffs. The financial analysis highlights that grid tariffs impact on the economic feasibility of grid-connected electrolysers. As currently assumed, the inclusion of non-discounted 2024 grid tariffs leads to a reduction from 8% to 4% in the revenues generated by electrolysers. The tariffs increase operational costs by penalizing electricity consumption during high-demand periods, which negatively affects the profitability of hydrogen production. Furthermore, the variability of electricity prices due to grid congestion amplifies the importance of grid tariffs, as high electricity costs during periods of low renewable generation diminish the electrolyser’s ability to operate cost-effectively.

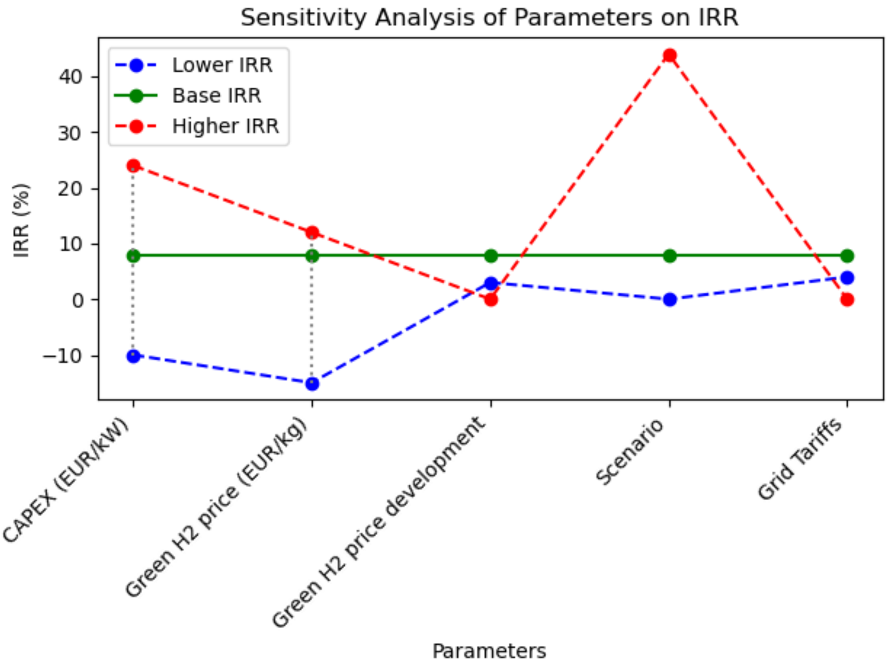
Looking towards 2050, the dynamics of the energy system and hydrogen market will evolve significantly. Long-term feasibility is contingent on addressing the strong interdependencies between CAPEX, electricity prices, and electrolyzer load hours. Market-based approaches, such as the copper plate configuration, are likely to become the preferred strategy as grid-integrated systems optimize efficiency. However, the trajectory of green hydrogen prices will play a decisive role in determining economic success. While dynamic pricing is expected to reflect cost reductions from technological maturation, lower hydrogen prices could adversely affect profitability if not offset by corresponding declines in CAPEX or operational expenses.

Moreover, the transition towards profitability will require substantial policy and market support. Measures such as CAPEX reductions through subsidies or tax incentives, enhanced electrolyzer efficiency, and price premiums for green hydrogen can significantly improve the economic viability of offshore wind-to-hydrogen projects. Additionally, strategies to balance grid integration with infrastructure cost savings will be essential to optimize both system-level efficiency and project economics.

The table and figure below summarizes the impact of different parameters on the profitability of the offshore electrolyzer business case of this study. These sensitivities are CAPEX, green hydrogen price (development), scenario (i.e. electricity prices) and grid tariffs. The table is based on a Once At a Time (OAT) approach; i.e. each sensitivity analysis varies one parameter while the rest keeps the base, for a lower and/or higher range of sensitivity.

Impact of parameters on IRR of offshore electrolysis (BASE = 8% IRR)

Parameters sensitivity	Sensitivity Base case	Sensitivity (lower IRR	Sensitivity higher IRR	Lower IRR	Base IRR	Higher IRR
CAPEX (EUR/kW	4000	8000	2000	-10%	8%	24%
Green H2 price (EUR/kg)	6	3	9	-15%	8%	12%
Green H2 price development	Stable	Decreasing	Empty	3%	8%	
Scenario	TYNDP2020	empty	NSWPH scenario		8%	44%
Grid Tariffs	no grid tariffs	grid tariffs	Empty	4%	8%	



Recommendations

Integrated System Design and Dispatch Optimization: Carefully select the electrolyzer capacity relative to the wind farm size to optimize the balance between:

- Market Participation: Align electrolyzer capacity with hydrogen price signals to maximize profitability under dynamic pricing schemes.
- Infrastructure Utilization: Minimize curtailment and grid congestion by leveraging co-optimization of electricity and hydrogen production.

Targeted CAPEX Reduction
Support CAPEX subsidies, tax incentives, and modular electrolyzer designs to lower upfront costs and improve business viability. Those are critical measures identified to narrow the business gap

Market Design for Price Certainty
Evaluate appropriate grid tariffs in line with the system value and impacts on infrastructure of offshore hydrogen develop design and operational strategies to balance grid integration with infrastructure cost savings. For example, assessment of the potential implementation of Contracts for Difference (CfD), hydrogen price floors, and green hydrogen premiums to stabilize revenues and boost investor confidence.

Grid Tariff Reform
Design dynamic and discounted grid tariffs that reflect the system value of hydrogen production and incentivize off-peak electricity use.

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6 Annexes

6.1 Main data for 2030 business case evaluation

Prices considered in this study

- CO2 price = 90 €/ton
- SMR price = 82 €/MWh
    - $\frac{\text{Natural gas cost}}{\text{SMR efficiency}}[€/MWh] + \text{SMR CO2 emission [Tn/MWh]} \times \frac{\text{CO2 price[€/Tn]}}{\text{SMR efficiency}}$
- Natural gas price = 35 €/MWh
- Grey H2 = 2.45 €/Kg (competing with SMR)
- Green H2 = Unknown, modeled as a variable

Electrolyzer

- Efficiency = 66%
- (setting price of the technology) Willingness to pay = 54 €/MWh (SMR price * electrolyser efficiency)
- 1 MWh = 22 kg of H2

Costs

- WIND CAPEX: €1.750 M (€2.500 M/GW)
- WIND OPEX: 2,5%
- P2G CAPEX: €2.000 M (€4.000 M/GW)
- P2G OPEX: 3% CAPEX

The electricity used from the grid to produce H2 when there is not enough wind power is considered green electricity when the electricity prices are less than 20€/MWh or the electricity price is 36% of the CO2 considered.

In this study it is assumed a price of 32.4 €/MWh. It is also considered green electricity when the elecrticity used comes directly from a (new) renewable source, in the form of a Power Purchase Agreements or offgrid (Reference source RED III – delegated act[11]).

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[11] : https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32023R1184

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