Optimised Sizing and Dispatch of Hybrid Power Plants: IJmuiden Ver Gamma as a Case Study

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Summary

With the increasing penetration of renewable energy technologies, the challenge of matching supply and demand, and the ambitious targets for developing offshore wind, focusing on the system integration of offshore wind energy has become a priority. Hybrid Power Plants (HPPs) play a critical role in this, as they allow a more consistent and reliable power supply through a combination of renewable energy generation, storage, and conversion. This report investigates the potential of integrating additional energy technologies, both offshore and onshore, to complement offshore wind developments, inspired by the IJmuiden Ver Gamma tender.

As part of TNO's internal knowledge investment program[1], this study aims to explore how to expand offshore renewable energy generation within the constraint of limited export cable capacity, and optimise asset sizing and operations to increase the export cable utilisation while minimising curtailment. Using an internal optimisation tool (integrating PyDOLPHYN and EMERGE) for combined sizing and dispatch of HPPs, the study evaluates three scenarios for an HPP participating in the day-ahead electricity market. These scenarios are compared to the reference case of IJmuiden Ver Gamma, a 2 GW offshore wind farm with a 2 GW HVDC cable to shore. The scenarios are cumulative and include: adding 200 MWp of floating offshore PV to the existing 2 GW wind farm; integrating 200 MW / 200 MWh of offshore electricity storage; and incorporating a 500 MW onshore PEM electrolyser for hydrogen production. In addition, the optimal combined solar- and storage capacity is investigated in a sizing optimisation exercise.

The results demonstrate the potential of hybrid power plants to enhance offshore renewable energy supply. The addition of 200 MWp of floating offshore PV increased cable utilisation by 1.1% with a minimal curtailment of 0.11%. On top of this, the 200 MWh of offshore storage reduced this curtailment to a negligible 0.03% and further improved cable utilisation by 0.5%. Although these improvements are modest due to the small asset capacities relative to the wind farm size, a future scenario projects that a 1:1 ratio between wind farm size and floating solar capacity could increase power supply by approximately 10%, with curtailment remaining below 5%. Of course, such high capacities of floating offshore solar introduce additional challenges (related to e.g. spatial planning, maintenance, ecology, etc.) that would need to be addressed. In the hydrogen scenario, onshore electrolysis provided additional flexibility by allowing power allocation between the grid and hydrogen production. With at least 25.7% of the generated power used to generate hydrogen, considering an off-take price that ranges from 3.5 to 13 EUR/kg, the addition of an electrolyser alleviates the load on the electricity grid.

However, the financial viability of these technologies is affected by high costs and challenging market conditions. As a result, all considered cases indicate a gap in the business case compared to the wind-only scenario. Turning the business case positive for the considered cases would require solutions like advancements in technology, cost reductions, and/or supportive policy measures (e.g. subsidies). Continued research and development are essential to unlock the full potential of hybrid renewable energy systems by 2040 and 2050. Integrated sizing and energy dispatch optimisation are essential to maximise the benefits of hybrid power plants and support the transition to a sustainable and resilient energy system.

[1] 060.59250/01 KIP WE2 2024 System Transformation

Several limitations were identified in this study, which are suggested to address in a future study. Firstly, the synthetic market data did not account for negative electricity prices, which would increase curtailment and the value of storage and electrolysis. Secondly, the study was limited to the day-ahead market, whereas participation in intra-day or grid balancing markets could improve the business case. Additionally, the case study focused on specific configurations, excluding scenarios where the electrolyser could import power from the grid. The fixed 24-hour optimisation period also limited potential profit maximisation, as it did not consider longer-term energy dispatch.

Contents

Abbreviations

AEP	Annual Energy Production
CAPEX	Capital Expenditures
HPP	Hybrid Power Plant
OPEX	Operational Expenditures
PEM	Proton Exchange Membrane
PV	Photovoltaics
TRL	Technology Readiness Level
TYNDP	Ten Year Network Development Program

1 Introduction

Offshore renewable energy is essential to Europe's transition toward a secure, cost effective, and climate-neutral energy system in the next decades. A significant step in scale is required to achieve the ambitious targets of a fivefold increase in offshore capacity by 2030, and a 25-fold increase by 2050 in the North Sea [1]. Offshore wind energy will be the main supplier for the Dutch power market, aiming towards 21 GW of installed capacity by 2032 [2]. In addition, floating solar energy offers great promise as a complementary technology [3]. By leveraging both wind and solar resources on shared infrastructure, the total energy output could be increased, thereby lowering intermittency with respect to the wind-only case.

Additionally, the introduction of flexible technologies, including hydrogen production and energy storage systems, can help mitigate curtailment, and yield new market opportunities that can help solidify the combined business case. To support in answering such design questions, TNO has developed a cross-departmental tool that integrates dynamic modelling of individual assets with operational optimisation of the combined plant for sizing and operation studies of hybrid power plants (HPPs).

This study presents a case for the upcoming IJmuiden Ver Gamma tender in the Dutch North Sea, exploring opportunities to enhance energy generation beyond the traditional offshore wind setup. The IJmuiden Ver Gamma site entails a (future) wind farm zone of 2x 1 GW installed capacity, located 53-61 km off the Dutch coast, as shown in figure 1.1 [4]. The IJmuiden Ver Gamma tender is currently expected to open in the 3rd quarter of 2025, with commissioning of the site expected after 2030.

The case study in this report addresses the following questions:

- What is the potential to expand offshore renewable energy generation and transport within the constraints of limited energy infrastructure?
- How can optimised asset sizing and daily operations reduce curtailment and increase infrastructure utilisation?
- What are the sensitivities of the business case to different scenarios, considering variations in HPP configuration, asset capacity and hydrogen price?

This report is structured as follows; first, the methodology of TNO's operational optimisation and dynamic modelling tool, as well as the approach for the IJmuiden Ver Gamma case study are presented in chapter 2. Next, the results of the case study are laid out in chapter 3. Finally, the results, their implications and recommendations for further work are discussed in chapter 4.

Figure 1.1: Map view of the Netherlands, with IJmuiden Ver Gamma site highlighted. Adapted from [4]

2 Methodology

In this chapter, the methodology underlying the case study is presented. Section 2.1 provides a detailed explanation of the modelling approach. Following this, section 2.2 outlines the scenarios and main assumptions of the case study.

2.1 Modelling Approach

The in-house modelling tool employed in this study utilises a nested optimisation framework to simultaneously determine the optimal sizing and dispatch of hybrid power plants. A key advantage of this approach is its applicability for scenario evaluation during the design phase. The model consists of two main components, which are integrated into a single, cross-departmental tool. The two model components are described in the following sections.

2.1.1 EMERGE: a MILP model for optimised asset scheduling

TNO's Energy Management systEm for Renewable Generation and storagE (EMERGE) [5] was created to model the planning and operation of a hybrid power plant (HPP), consisting of generation sources such as wind and solar PV generation, as well as storage and conversion assets, such as batteries and electrolysers.

The basic structure of the EMERGE model as used for this study can be split in three parts: resource availability and forecasting, optimisation and setpoint generation (as output). A schematic overview of these three stages is shown in Figure 2.1 below.

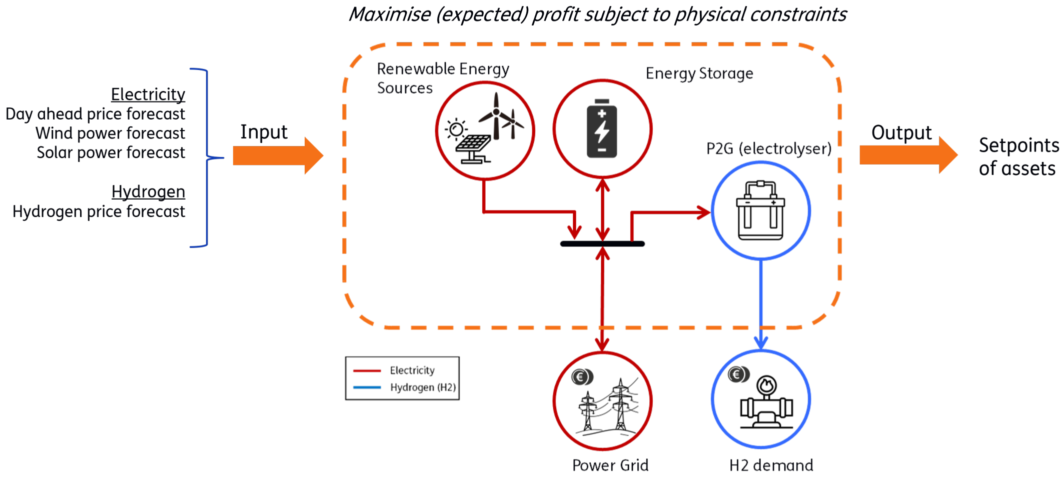


Figure 2.1: Schematic overview of the EMERGE process flow, with the different model steps highlighted.

In this case study, EMERGE is used for simulation of the day-to-day operation of the HPP. This simulation starts with generating the forecasts for the upcoming day, by collecting (historical) meteo and market data (day-ahead and hydrogen) for the relevant day. Then, the collected meteo data is used to generate a power forecast for the generation assets, e.g. wind and solar PV. Using this forecast data, a Mixed Integer Linear Programming (MILP) optimisation is used to optimise for the best - i.e. most profitable - operational strategy of the HPP as a whole. This optimization makes use of linearised representations of the generation, storage and conversion assets. Finally, the optimisation solution yields a time series of setpoints for every asset within the HPP. This collection of setpoints serves as the optimal planning for the next day, which is then fed into the dynamic PyDOLPHYN modelling tool described in the next section.

2.1.2 PyDOLPHYN: a dynamic modelling and optimisation tool for multi-energy systems

PyDOLPHYN [6, 7, 8] is a TNO-developed modelling framework for dynamic simulations and optimisation of multi-energy assets. It allows to find a cost-effective optimal result, that may have been impossible to find when running static simulations on value chains or focusing only on the dynamics of an individual asset component. PyDOLPHYN combines component-level physics and techno-economics, and it can be used in system integration, asset design and operation studies. The framework is based on connections of physical blocks, each of them representing one component (e.g., electrolyzer, battery, storage, water desalination). Optimal asset sizing and operation can be computed, adhering to physical bottlenecks, such as transient effects and dynamic efficiency levels. It can use dynamic pricing for the different energy vectors (e.g., electricity, hydrogen) and complex constraints. With this, control strategies can be defined for both short and long-term predictions (e.g., pre-emptively store hydrogen to sell it at the highest value for the market/off-taker), and the accuracy of techno-economic KPIs can be improved.

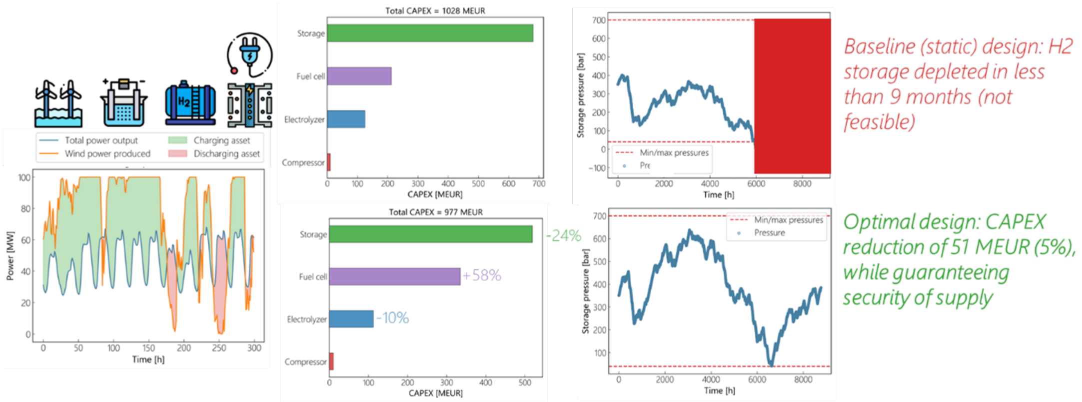


Figure 2.2: Example of an optimised hydrogen storage volume using PyDOLPHYN.

In this work, PyDOLPHYN was used as a tool to to calculate the energy flows and the interactions between the different components based on the setpoints given by EMERGE. It can provide complementary insights to a qualitative analysis and static simulations (with fixed efficiency, simple constraints, etc.), regarding the volatility of the different energy sources and a more realistic quantification of the KPIs. As an example, figure 2.2 shows a static analysis where a hydrogen storage volume is aimed to be optimised: this static calculation does not consider the dynamics along the year, leading to either too small (infeasible design, failing to provide security of supply) or too large (very expensive) sizes.

2.2 Scenarios

Three distinct scenarios were modelled and compared against the reference case. For all scenarios, identical input data was utilised for power generation profiles and market data. Weather data was sourced from the climate year 2015, with wind energy generation profiles derived from the Dutch Offshore Wind Atlas (DOWA) and solar energy generation profiles obtained from Renewables.ninja [9].

To generate synthetic electricity market prices, the COMPETES-TNO model [10, 11], a European power optimisation and economic dispatch tool, was employed. The use of synthetic market data, as opposed to historical data, is justified by the need to account for the projected penetration of renewable generation by 2030, which significantly impacts electricity market prices. To ensure a representative dataset of electricity market prices and to maintain a good correlation with renewable generation, the weather data from the climate year 2015 was used as input for this market modelling tool.

Figure 2.3 presents a segment of wind and solar resources along with market data. The price curve in this figure reveals a correlation between periods of high resource availability and lower electricity prices. The average electricity price across the dataset is 64 EUR/MWh.

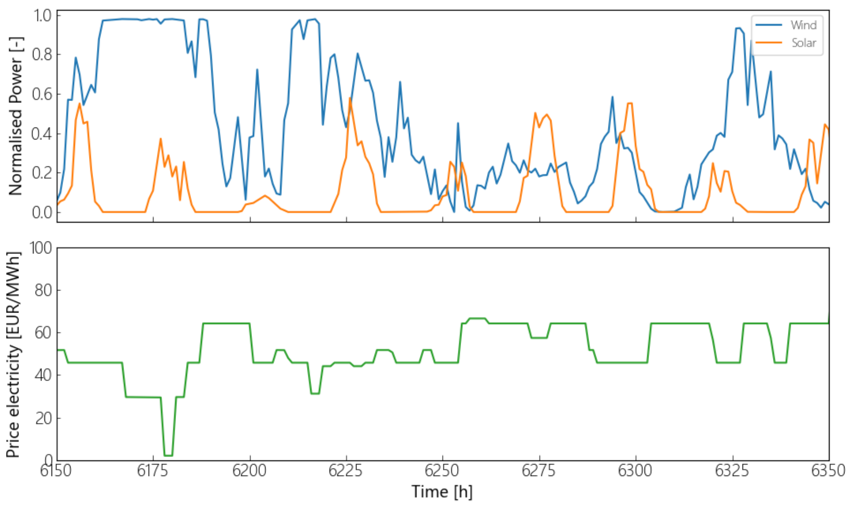


Figure 2.3: Segment of the normalised power generation profiles of the wind and solar resources (top) and synthetic electricity market price (bottom).

The energy scenario applied in this study is based on the Ten Year Network Development Plan (TYNDP) published by ENTSO-E, specifically the Global Ambition scenario [12]. This scenario envisions a high degree of electrification, requiring flexible solutions on the supply side to meet electricity demand. It is important to note that a limitation of the synthetic market data is the absence of negative electricity prices.

In the reference case, only the 2 GW wind farm and the 2 GW export cable are considered. Due to the distance to shore, a 2% power loss is accounted for during transmission through the HVDC cable. Subsequently, three different scenarios will be considered, as illustrated in figure 2.4. These scenarios build upon the reference case and each other:

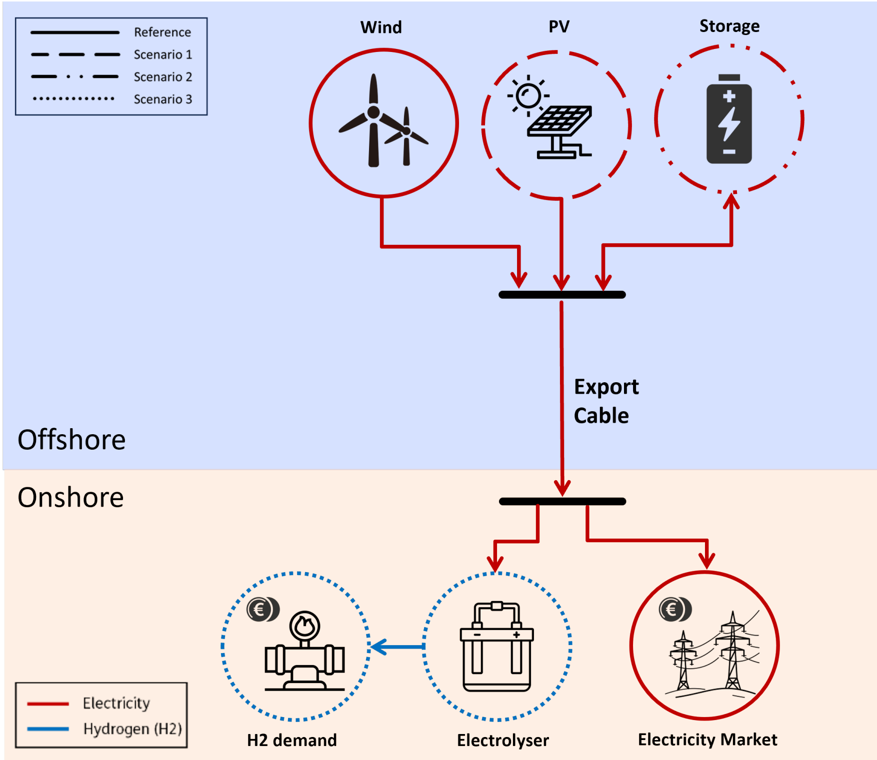


Figure 2.4: Overview of the different scenarios considered. Each scenario builds upon the previous one. For example, Scenario 3 includes an electrolyser and hydrogen demand in addition to the elements of Scenario 2, etc.

1. The first scenario considers the implementation of floating offshore PhotoVoltaics (PV) to enhance export capacity through additional renewable generation. Due to the complementary nature of wind and solar resources, co-locating offshore wind and solar installations can increase power generation and export with only a minor penalty in curtailment. For this case study, an additional 200 MWp[2] of solar capacity is included, achieving a 1:10 ratio of solar to wind energy capacity. Although Chapter 3 will explore various solar capacities, it is anticipated that the technology readiness level (TRL) of floating offshore PV will not be sufficient to reach gigawatt-level capacity by 2030. Furthermore, a 200 MWp capacity aligns better with the scale of previous offshore wind tenders in the Netherlands, considering potential upscaling [13].

2. The second scenario involves the integration of electricity storage to improve the value of offshore renewables within the constraints of limited export cable capacity. The addition of offshore electricity storage offers two primary benefits: energy buffering and time-shifting of power export. Energy buffering helps reduce curtailment and maximise power export, while time-shifting allows energy to be stored and exported later, capitalising on higher electricity prices. Similar to the solar generation capacity in the first scenario, a modest storage capacity of 200 MWh is selected because of the state of technology, achieving a 1:1 ratio between floating PV and storage capacity. However, an optimisation exercise will be conducted to consider higher storage capacity values, and determine the optimal combination of the two. The maximum C-rate of the electricity storage is assumed to be 1 in all cases, and the type of electricity storage assumed is not specific to any particular technology.

[2] DC Power

3. The third scenario explores the potential benefits of an onshore Proton Exchange Membrane (PEM) electrolyser to improve system flexibility through self-consumption of a portion of the power generated, before the rest is injected into the grid. In this case, a 500 MW PEM onshore electrolyser is connected to the offshore hybrid power plant. The electrolyser is located onshore but is not connected to the grid, meaning it can only consume power generated offshore. The profitability of electrolysis is, next to the assumed cost data, highly dependent on the hydrogen price; therefore, both a lower bound and an upper bound for the hydrogen off-take price are considered. These bounds are 3.5 EUR/kg and 13 EUR/kg, respectively.

Table 2.1: Summary of the different scenarios considered

	Wind	Solar	Battery	H2
	GW	GWp	GWh	GW
Reference	2			
Scenario 1	2	0.2		
Scenario 2	2	0.2	0.2	
Scenario 3	2	0.2	0.2	0.5

The three scenarios are summarised in table 2.1. The main focus of this study is on the system integration aspect of the Hybrid Power Plant (HPP), which will be quantified by the cable utilisation rate — the percentage of time during which power is exported at full cable capacity — and curtailment. The business case for each scenario will also be addressed; however, it is important to note that the business case is highly dependent on cost and market price assumptions, which are highly uncertain for 2030. The main cost assumptions for this case study are summarised in table 2.2, with the cost data for offshore wind based on internal TNO data.

The HPP simulation is performed over a full year, aggregating revenues and costs. Subsequently, the total costs and revenues are projected over the HPP's operational lifetime of 25 years to determine the final profit. While 25 years may be a conservative estimate for the lifespan of a modern wind farm, it is considered optimistic for the other assets of the HPP. For simplicity, and due to the inherent uncertainty involved, no discount rate is applied in this case study when calculating the financial results.

Table 2.2: Assumed component costs for this case study

	CAPEX	OPEX	source
	EUR/W	% CAPEX/year	
Offshore Wind	2.5	1.6	TNO data
Offshore Floating Solar	0.725	4.75	[14]
Offshore Electricity Storage	1.4	0.5	[15, 16, 17]
Onshore PEM Electrolyser	2	4	[18, 19]

3 Results

The results of the case study are presented and analysed in this chapter. A summary of the main results of all considered scenarios is provided in table 3.1 below. A detailed analysis of the results for each individual scenario follows in sections 3.1 to 3.3. For detailed waterfall plots of the financial results, the reader is referred to appendix A.

In table 3.1, cable utilisation is calculated as the ratio between AEP and the total energy that could have been exported annually, if the export cable was used at maximum capacity all of the time. Curtailment is the ratio between the energy that could not be exported due to reaching the export cable capacity limit and the total energy available from wind and solar resources.

In the reference case, the cable utilisation rate is observed to be 53.3%, with no curtailment. The absence of curtailment can be attributed to the lack of negative electricity prices in the synthetic market data, and the matching power capacities of the wind farm and export cable. The export capacity factor of 53.3% is achieved due to 2015 being a relatively good wind year. But also, it is worth noting that modern wind turbines are achieving increasingly better capacity factors offshore. The baseline revenues over the 25-year operational lifetime are 11.04 billion euros, while the profits are 4.04 billion euros. The financial results for each scenario in table 3.1 is given as a percentage increase or decrease with respect to the reference case.

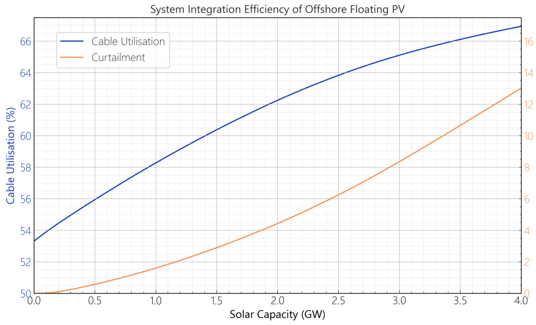
Table 3.1: Summary of the main results of all considered scenarios

	Wind	Solar	Battery	H2	Cable Utilisation	Curtail-ment	Revenues	Profits
	GW	GWp	GWh	GW	%	%	MEUR	MEUR
Reference	2				53.3	0	11040	4040
Scenario 1	2	0.2			54.4	0.11	+1.97%	-2.48%
Scenario 2	2	0.2	0.2		54.9	0.03	+3.30%	-6.66%
Scenario 3 Low H2 price	2	0.2	0.2	0.5	54.9	0.03	+9.18%	-45.0%
Scenario 3 High H2 price	2	0.2	0.2	0.5	54.9	0.03	+120%	+260%

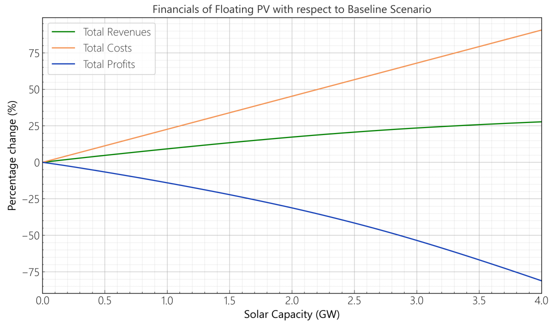
3.1 Offshore Wind and Floating PV

Including solar energy generation in the form of floating offshore PV alongside the existing wind farm results in an increase in both cable utilization and curtailment. When 200 MWp of solar capacity is added to the reference case, the cable utilisation rate increases by approximately 1 percent to 54.9%, while curtailment rises to 0.11%. The low curtailment value is due to the good complementarity between wind and solar resources in the Dutch North Sea. This complementarity allows for significant solar energy generation with only a minor penalty in curtailment, thereby boosting both the Annual Energy Production (AEP) and the capacity factor, without the need for additional export capacity.

Although it is unlikely that the installed capacity of floating PV at IJmuiden Ver Gamma will reach a 1:1 ratio with the wind farm size, a future scenario could project an approximate 10% increase in cable utilisation with curtailment remaining below 5% for a 2 GW solar farm. This is demonstrated in figure 3.1a, where both cable utilisation and curtailment are plotted against a wide range of solar generation capacity. Such large-scale solar generation would of course introduce additional constraints, particularly in terms of spatial planning. However, the potential for increased cable utilisation and energy production is evident from the figure. Another point of interest can be identified at a solar capacity of 1.4 GWp. Up to this point, the rate of change of the cable utilisation is higher than the rate of change of the curtailment. Beyond this point, there will be a steeper percentage increase in the curtailment.



(a) Cable utilisation and curtailment



(b) Costs, revenues and profits

Figure 3.1: Offshore system integration results for solar capacities ranging from 0 to 4 GW

When analysing the financial implications of integrating additional offshore solar energy generation, figure 3.1b illustrates that the incremental costs rise more rapidly than the revenue generated from the extra power supply. This trend highlights a financial gap in the business case for 2030, which must be addressed to achieve a positive business case towards 2040 or 2050.

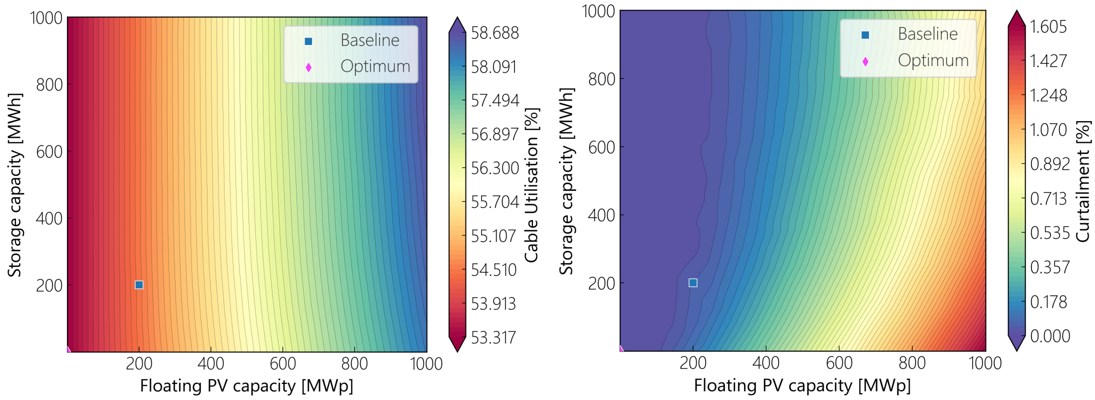
3.2 Offshore Renewable Generation with Storage

In the case of combined wind and solar generation with additional offshore energy storage, we observe two main effects from the results in Table 3.1. Firstly, curtailment is reduced to a negligible 0.03%. This reduction in curtailment leads to an increase in cable utilisation rate, now at 54.9%. Despite this increased power export, the additional revenues do not offset the extra investment and operational expenses of offshore electricity storage, resulting in a 6.66% decrease in profits compared to the reference case.

Figure 3.2 presents the results of a two-dimensional optimisation exercise using particle swarm optimisation with three generations and 90 particles each. The objective: profit maximisation. The starting point, or Baseline (as shown in the graph), was 200 MWp of solar energy generation and 200 MWh of electricity storage. Due to the challenging business case for offshore solar and storage by 2030, the results indicate the optimum point to lie in the bottom left corner of the graphs.

However, considering the system integration value of storage, offshore storage could be a valuable addition to the offshore hybrid power plant, as it minimises curtailment and thereby increases export capacity within the constraints of limited energy infrastructure. Figure A.3a shows that if the main goal is to enhance export cable utilisation, increasing solar capacity rather than storage is more effective, as the penalty in curtailment is minimal. Storage does not add power generation; its value lies mostly in reducing curtailment by buffering energy during overproduction. When curtailment is already low, this benefit is questionable.

Another potential benefit of the battery is time-shifting power export to achieve higher revenues during periods of high electricity prices. However, the operational optimisation model utilised in this study limits power and market forecasting to the day-ahead, with battery dispatch limited to 24 hours. Extending the time-shifting capability beyond 24 hours could capture higher market prices over a longer duration. The scale of battery capacity and discharging power is also important compared to the wind farm size and solar generation capacity in this regard.



(a) Cable utilisation (b) Curtailment

Figure 3.2: Contour plots of the 2-D optimisation of storage- and floating PV capacity

Lastly, a battery operating solely in the day-ahead market leads to limited revenue increases. The full potential of electricity storage is realised when it can operate in the intra-day market or grid balancing markets, allowing the hybrid power plant to generate additional revenues from participating in multiple markets simultaneously.

3.3 Offshore HPP and onshore Electrolysis

The integration of an onshore PEM electrolyser enhances the operational flexibility of the plant by providing access to two distinct markets: electricity and hydrogen. The operational optimisation algorithm, aimed at maximising profits, evaluates both markets and allocates power either to the electricity market or to hydrogen production, depending on which option yields higher profits at any given time.

It should be noted that the flexibility is somewhat constrained by the export cable, as the onshore location of the electrolyser prevents it from directly consuming power generated by the wind or solar farm. Therefore, the cable utilisation and curtailment values in table 3.1 are not different compared to the previous scenario. Despite this limitation, the electrolyser can still utilise a portion of the power before it is fed into the grid, thereby reducing the load on the electricity grid.

For the low hydrogen price scenario, the power flow distribution is such that 25.7% of the power is directed to the electrolyser, while 74.3% is sold to the grid. The revenue distribution resembles this power allocation, as illustrated in figure 3.3. Considering the results in table 3.1, it is noteworthy that although the electrolyser facilitates increased revenues, the CAPEX and OPEX of the PEM electrolyser are substantial. This results in a challenging business case, with profits decreasing by 45% compared to the reference case.

In the high hydrogen price scenario, figure 3.4 shows a significant shift in power allocation. With hydrogen priced at 13 EUR/kg, the dispatch algorithm prioritises running the electrolyser for maximum full-load hours to achieve the highest profits. Consequently, 38.9% of the power

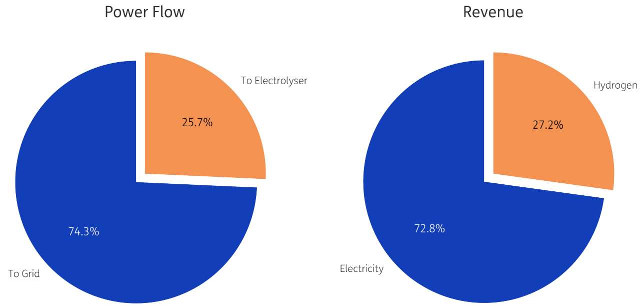


Figure 3.3: Power flow and revenue distribution for a H2 off-take price of 3.5 EUR/kg

exported to shore is consumed by the electrolyser, while 61.1% is sold to the grid. This increased self-consumption of power alleviates grid stress and generates substantially higher profits in the hydrogen market, as indicated in table 3.1

This scenario demonstrates a positive business case. However, it is important to acknowledge that a hydrogen off-take price of 13 EUR/kg is an unrealistic scenario for 2030. Nonetheless, it is important to realise that there is a break-even point, which can be achieved through various means.

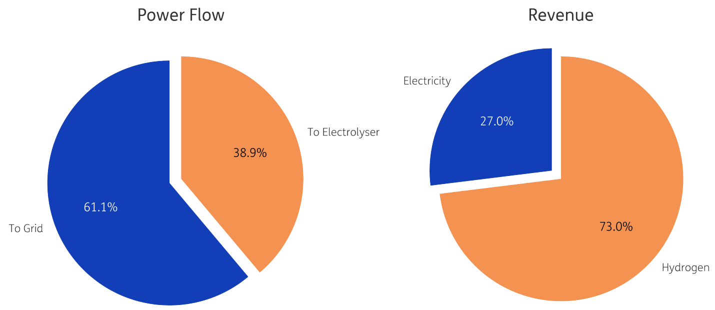


Figure 3.4: Power flow and revenue distribution for a H2 off-take price of 13 EUR/kg

4 Discussion

This study utilised an optimisation tool that integrates both the scheduling and sizing of a hybrid power plant, incorporating the potential additional benefits of flexible operation. This approach allows for a more accurate estimation of potential revenues and system flexibility compared to tools that do not account for operational aspects. Moreover, it ensures the feasibility of the end result, as the energy flows are based on physical models rather than approximated functions.

The tool was applied in a case study for IJmuiden Ver Gamma to explore the potential of integrating additional energy technologies, both offshore and onshore, to complement offshore wind developments. The study aimed to assess the potential for increasing power export capacity within the constraints of limited cable capacity, and to identify the sensitivities of the business case to different scenarios. This approach provided insights into how various technologies and operational strategies could enhance the overall performance and affect the economic viability of offshore wind projects.

Regarding floating solar technology, it is expected that more than 200 MWp will likely not be realised by 2030 for IJmuiden Ver Gamma. However, a future scenario is projected where a 1:1 ratio between wind farm size and solar generation capacity can be achieved, with less than 5% curtailment. This suggests that integrating photovoltaic energy alongside offshore wind farms offers a significant opportunity to optimise the use of existing export cable capacity, leading to a maximised and more reliable power supply.

Under the assumptions of this study, adding storage capacity to offshore wind and solar does not significantly improve cable utilisation. Furthermore, the curtailment reduction and battery operation in the day-ahead market alone did not yield a significant revenue increase. However, batteries could considerably enhance the business case by participating in various markets for grid stability. The ability to store energy and release it during peak demand times or when electricity prices are higher can provide substantial economic benefits. Additionally, storage systems can offer ancillary services such as frequency regulation and voltage support, further enhancing grid stability and reliability. However, this was not inside the scope of this study.

Onshore electrolysis emerges as a valuable addition for system flexibility, allowing for the self-consumption of (a portion of) the power before it is fed into the grid. By operating in a base load mode, the plant owner can ensure a consistent maximum power supply to the grid, aiding in grid congestion management. Additionally, the production of hydrogen introduces an extra revenue stream. This dual-market approach enables the plant to adapt to market conditions, optimizing revenue generation based on real-time prices from both the electricity and hydrogen markets. Under the given assumptions, a break-even point in the business case can be achieved when hydrogen prices range between 3.5 and 13 EUR/kg.

Despite these advantages, this study revealed the presence of clear gaps in the business case for the hybrid power plant, particularly when considering the year 2030, where costs are the primary drivers. The business case is sensitive to several factors that will undoubtedly evolve towards 2040 and 2050:

- **Operational strategies**: Decisions on plant operation, whether focusing solely on profit maximisation or using the electrolyser for baseload or peak-shaving and the import/export limitations. The choice of operational strategy will significantly impact the overall efficiency and profitability of the hybrid power plant.

- **Cost**: Technological advancements, capital costs, and strategies to de-risk immature technologies. The pace of innovation in renewable energy technologies, storage solutions, and electrolysis will play an essential role in reducing costs and improving the economic viability of hybrid power plants.
- **Market prices**: The future landscape of the energy sector, the penetration of renewables, the electrification of demand, and their impact on market dynamics. Fluctuations in electricity and hydrogen prices, driven by supply and demand dynamics, will influence the revenue potential of hybrid power plants.
- **Policy and incentives**: The role of subsidies, legislation, and tender criteria in improving the business case. Government policies and regulatory frameworks will be critical in shaping the market environment and providing the necessary support for the deployment of hybrid power plants offshore.

Looking towards 2040 and 2050, the business case for hybrid power plants could become positive. However, achieving this requires a focus on research and development (R&D) and continued research efforts. Advancements in technology, cost reductions, and supportive policy measures will be essential to overcome the current challenges and unlock the full potential of hybrid power plants. Collaboration between industry stakeholders, policymakers, and researchers will be a driving force behind innovation and in creating a sustainable and profitable future for hybrid renewable energy systems.

Several important limitations were identified in this study:

- **Electricity prices:** Incorporating the possibility of negative electricity prices in the synthetic market data would enhance the realism of the case. This adjustment would increase the curtailment in the reference scenario, as the wind farm would be curtailed during periods of negative electricity prices. Consequently, the value of electricity storage and the electrolyser would rise, as they could consume power that would otherwise be curtailed.
- **Market participation:** The study was confined to participation in the day-ahead electricity market alone. However, the value of a HPP with energy storage and conversion is maximised when it also participates in intra-day or grid balancing markets, potentially turning the business case positive.
- **HPP configuration:** The case study was limited to a specific set of configurations, although various other scenarios are conceivable. The electrolyser was not connected to the grid, and while importing power from the grid would introduce grid tariffs, it could be worthwhile to investigate the additional benefits of an electrolyser that can also consume power directly from the grid, allowing for greater advantage during periods of low (or negative) electricity prices.
- **Time horizon of energy dispatch:** Another limitation is the fixed 24-hour period for operational optimisation of the HPP. By maximising profits daily, the electricity storage is discharged by the end of each day, as additional profit can be made within that day. However, even more profit could potentially be realised by selling the stored electricity one day later, which is not currently considered by the algorithm. Extending the time horizon beyond a 24-hour period for energy dispatch would be required to explore this possibility.
- **Uncertainty of cost data:** The study's cost data is subject to high uncertainties. It is recommended to perform a sensitivity analysis using different cost values for each component. This analysis would identify the cost components with the highest sensitivities and indicate where the greatest gains can be achieved in bridging the gap in the business case.

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Appendix A
Financial Results

In this appendix, the waterfall plots of the revenues, costs and profits for each scenario are presented. Furthermore, the contour plots of the revenue and profits for the solar- and battery capacity optimisation are shown.

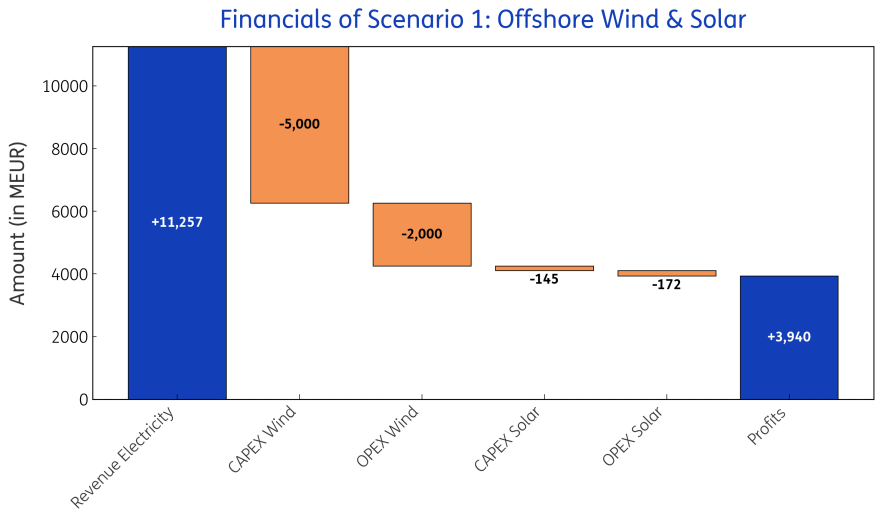


Figure A.1: Financial results of the first scenario

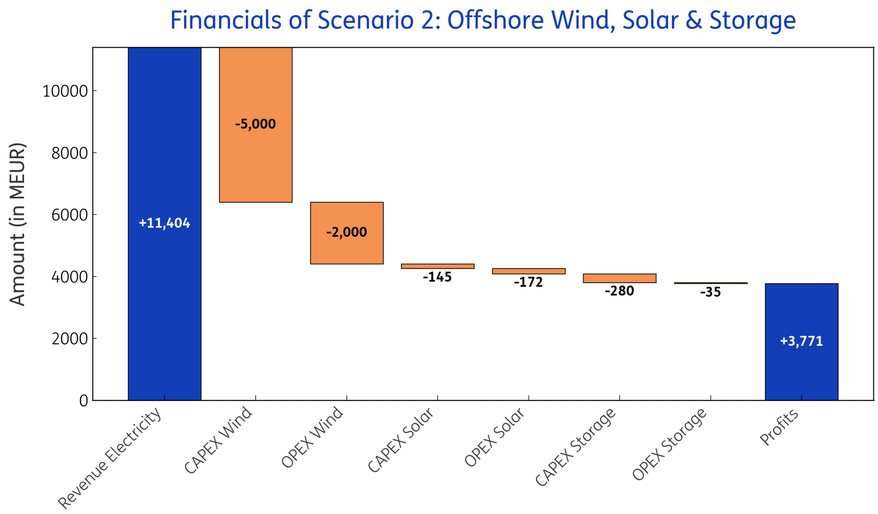
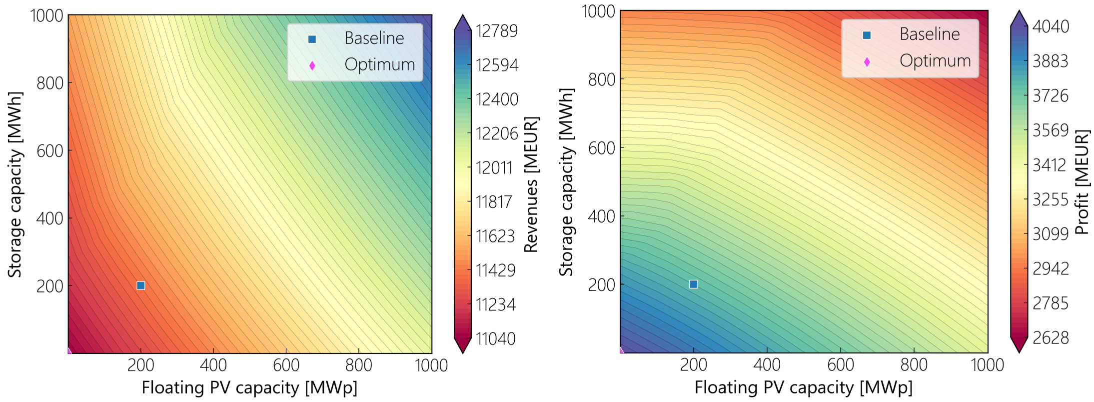


Figure A.2: Financial results of the second scenario



(a) Revenue (b) Profit

Figure A.3: Contour plots of the 2-D optimisation of storage- and floating PV capacity

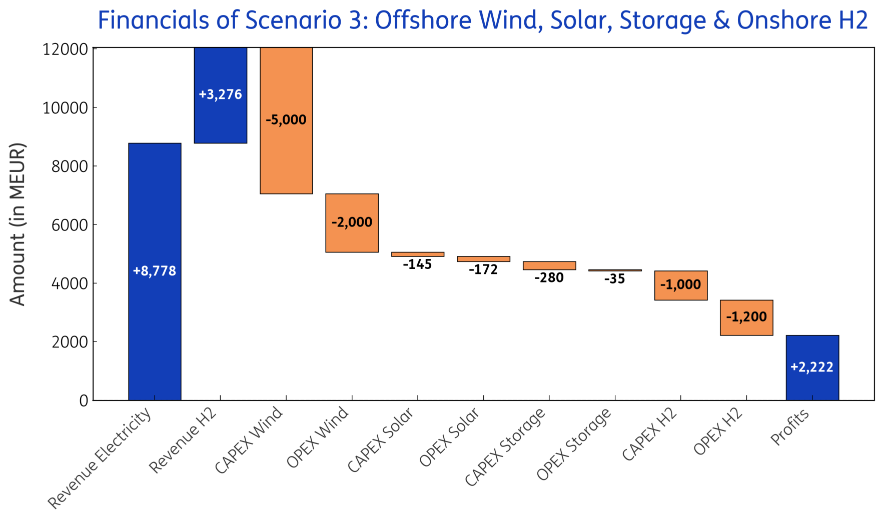


Figure A.4: Financial results of the third scenario, with low hydrogen price of 3.5 EUR/kg

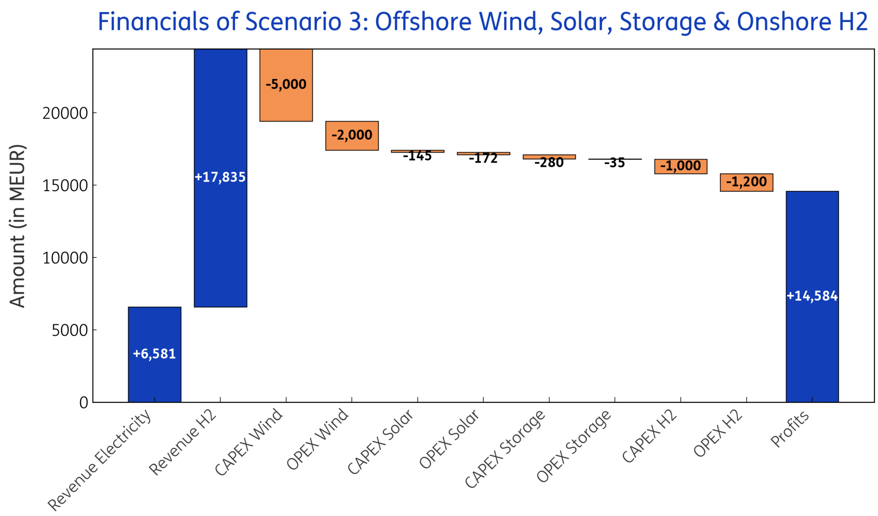


Figure A.5: Financial results of the third scenario, with high hydrogen price of 13 EUR/kg

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