

Grid connected offshore wind with energy storage



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Executive Summary

Co-locating storage with offshore wind can create economic value, and is a key enabler for integrating more renewables into the electricity system

Co-locating energy storage with offshore wind offers an opportunity to enhance flexibility, overcome offshore grid constraint and support the integration of renewable energy sources. As offshore wind capacity is expected to increase drastically in the Netherlands, questions arise around how to manage variability, alleviate grid congestion, and extract maximum value from generated electricity. In this context, offshore storage - placed behind the meter - warrants a closer look.

Two behind-the-meter storage technologies are taken into consideration. These technologies are 1) the FLASC Hydro-Pneumatic Liquid Piston Technology and 2) Offshore Lithium-Ion (li-ion) Battery System. Different storage configurations were assessed by varying power (5–10% of wind farm capacity) and storage duration (4–16 hours). The model was applied for the year 2030 under various scenarios, including a base case and a more flexible system with higher offshore storage penetration.

This study finds that, based solely on day-ahead market revenues, energy storage is able to recover only part of its annualised CapEx and OpEx – typically between 20% and 30%. This highlights that stacking of revenue streams is necessary to make the business case for storage viable. Limited storage utilisation, e.g. 40% in the base case, shows that there is still sufficient room in the storage left to explore these other revenue streams.

When increasing power and storage duration, absolute revenues are increased, however for storage duration a diminishing rate applies, particularly beyond four hours of storage duration. Importantly, declining marginal revenues coincide with decreasing capital costs for larger configurations. The optimal configuration differs per technology: for li-ion batteries, a medium-duration, high-power setup performs best, while for FLASC, larger configurations benefit from stronger capital cost reductions.

It is important to note that the input data used in this analysis — including round-trip efficiency and capital expenditure (CapEx) estimates — were provided by Seaway 7 and have not been independently verified by TNO. For modelling purposes, a round-trip efficiency of 80% was assumed for both technologies. However, more recent evaluations suggest that actual efficiencies differ: lithium-ion batteries typically achieve higher efficiencies (around 85%), while FLASC systems may operate closer to 75%. Whether similar differences exist in CapEx is currently unknown. These assumptions have a significant influence on the economic comparison between the technologies. In particular, it would improve the relative performance of lithium-ion storage in terms of market revenue recovery.

DISCLAIMER

The economic performance of storage configurations in this study is based on cost assumptions provided by Seaway 7. These figures were used consistently across all analyses.

The analysis also underscores the significant influence of long-term contracts on the value of co-located energy storage. While these contracts are primarily designed to stabilize revenues for renewable generators, their structure can either enable or constrain the role of storage. In particular, the design of Contracts for Difference (CfDs) plays a decisive role. A conventional two-sided CfD removes price volatility and thereby eliminates the arbitrage opportunity that storage relies on. Alternative CfD designs, however, can preserve market signals and allow storage to operate in a way that supports system flexibility. Similarly, Power Purchase Agreements (PPAs) that allow for co-optimisation of wind and storage output can unlock new business models and improve the overall value proposition. As the Netherlands continues to refine its offshore wind support schemes, it is essential that the role of energy storage is explicitly considered in the design of long-

term contracts to ensure alignment with broader system integration and flexibility goals.

Overall, this study highlights that while day-ahead market revenues can contribute to the business case for co-located offshore energy storage, they are not sufficient on their own. Unlocking the full value of storage requires access to additional revenue streams and thoughtful integration into long-term contract frameworks. In particular, CfD designs must be carefully structured to preserve incentives for flexibility and avoid unintentionally discouraging storage deployment. These findings provide a foundation for future work — including the OESTER project — aimed at exploring the broader system value and operational role of offshore energy storage in a decarbonized energy system.

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1 Introduction

Large scale generation of renewable electricity poses significant challenges for integration into the electricity system. While electricity production classically has been designed to follow load, renewable energy production is predominantly driven by weather conditions and is intermittent by nature. With the existing ambitions for 2030 and beyond, renewable energy production may lead to frequent and significant overproduction at times of windy and sunny weather conditions. In the Netherlands, the target for offshore wind is to increase the capacity fivefold by early 2030's (from 4.7 GW in 2024 to 21 GW in 2032) and by sevenfold in 2050 (about 72 GW). At other instances, under windless and cloud-covered conditions, electricity demand will have to be covered almost completely by other sources. The main options to enable electricity system balance in an efficient way is to create flexible demand and/or curtail the production if the flexible demand cannot follow the production.

The Netherlands has significant challenges ahead in flexibly balancing supply and demand of renewable electricity. There are a multitude of methods available to balance the grid where flexibility on the demand side is required to minimize the curtailment of the supply side. Conversion of renewable electricity is one route, e.g. by water electrolyses, and green hydrogen is gaining a lot of attention. However, converting hydrogen back to electricity is very inefficient, with round trip efficiencies below 50%, and the present cost is much higher than anticipated. As we look to co-location and multi-use wind farms (wind + floating solar + electrolyser) and the challenges of optimising the operations and business cases, offshore storage warrants a closer look. Storing electricity offshore allows generation and grid supply to be decoupled in time, enabling energy to be delivered when it better aligns with demand — for example, by providing a more consistent power supply to electrolyzers. Where hydrogen can be used as a bulk component for the chemical industry, e.g. in making synthetic fuels or used in industrial processes requiring heat or converting it in power stations to electrons when the supply of wind and solar power is low.

Onshore storage may be an obvious alternative to offshore storage, particularly for local grid congestion areas. However, onshore storage also comes with its own significant challenges, especially in a densely populated country like the Netherlands. In contrast, co-locating energy storage offshore can help overcome offshore grid constraints and enable operational strategies that are not feasible with onshore storage alone. The interest in offshore storage is reflected in Dutch offshore wind tenders already, including flexibility criteria and Dutch climate policy for 2030-50 already hints at more ambitious co-location targets for offshore wind and storage, as also indicated in the recent Letter to Parliament (Min. EZK, 2024).

1.1 Goal of the study

This study explores the added value of co-locating energy storage next to offshore wind farms, assessing both the business case for wind farm operators and the broader societal benefits. This study focusses only on the day-ahead market. Other revenue potential revenue streams for storage remain out of scope. Hence, the study presents the business case evaluation including only the additional revenues that the offshore wind developer can achieve in the day ahead power market. The added value of offshore storage is assessed for the year 2030.

Additionally, the study investigates the impact of long-term contracts, i.e. Power Purchase Agreements (PPAs) and Contracts for Difference (CfDs), on the economic viability of storage systems.

The analysis focusses on one upcoming offshore wind farm site in the Netherlands: Doordewind, site I with a capacity of 2 GW. This site has been selected due to their relevance in terms of development timelines and technological interest. Doordewind and its timing ahead in the future represent a case where offshore energy storage technologies might reach higher levels of maturity and market penetration.

Two distinct offshore storage technologies with varying power capacities and storage durations are considered to allow for comparative analysis:

1. **FLASC Hydro-Pneumatic Liquid Piston Technology**¹: This innovative technology, developed by Dutch start-up FLASC B.V., uses hydro-pneumatic liquid pistons for energy storage.
2. **Offshore Li-ion Battery Systems**: Li-ion technology, well-established in onshore applications with known performance metrics (e.g., cost, efficiency, and lifetime), serves as a comparison technology for this study.

Appendix A provides more information on these two technologies, including the rationale behind the selection of these two technologies, technical & economic characteristics and a comparison between them.

To generate quantitative results, the study applies an electricity dispatch model of the Dutch day-ahead market - the EYE model - in combination with a techno-economic optimisation model.

The remainder of this report is structured as follows. Chapter 2 outlines the scope of the study, including the technologies in focus, key assumptions, and scenarios. Chapter 3 describes the modelling methodology applied to assess the economic performance of co-located storage. Chapter 4 presents the modelling results, starting with the base case and followed by the performance of alternative storage configurations, a larger share of offshore storage in the energy system. It also discusses the impact of a grid constraint and long-term contracts, i.e. PPAs and CfDs on the added value of storage.

This is followed by chapter 5, which compares the additional revenues of the day-ahead market to the CapEx and OpEx of the two technologies with different configurations. Lastly, conclusions and recommendations are presented in chapter 6.

¹ For more information, refer to: <https://offshoreenergystorage.com/>

2 Scope

This chapter defines the scope and underlying assumptions of the analysis. It begins by describing the approach that is taken to conceptualise the storage and wind for model implementation, including the system setup where storage is co-located behind-the-meter of offshore wind and connected to the grid via a unidirectional cable to the grid. This section also presents the future energy system scenarios – Climate Ambition and National Drivers in 2030 from Netbeheer Nederland (2024) – in which the storage systems are evaluated.

Then, the chapter clarifies which revenue streams are included in the assessment, focussing on the Dutch day-ahead market. Lastly, the chapter discusses in what way grid constraints and long-term contracts (PPAs and CfDs) are evaluated in this study.

2.1 Modelling Approach and Scenarios

To assess the added value of co-locating storage besides offshore wind farms, a model-based approach is applied. While the model methodology is further described in chapter 3, this section outlines the physical setup and system configuration in scope.

This study focuses on a hybrid energy system consisting of an offshore wind farm and a behind-the-meter energy storage system. In the model, the system consists of three major components (Figure 1):

- **Offshore wind farm**
The analysis focusses on one upcoming offshore wind farm sites in the Netherlands: Doordewind, site I with a capacity of 2 GW.
- **Energy storage system**
The energy storage system is grid-connected and co-located with the wind farm. It is assumed that the storage is only able to charge from the wind farm and not from the electricity grid.
This study considers two technologies: 1) a FLASC / Hydro-Pneumatic Energy storage technology and 2) a lithium-ion (li-ion) battery. For more information on the technologies, please refer to Appendix A. For these two technologies, various energy storage configurations are evaluated, varying the power (MW) to 5% and 10% of the wind farm capacity and storage duration (4-16h). A roundtrip efficiency of 80% is assumed for both technologies. It should be noted that more recent evaluations indicate these efficiencies differ in practice between technologies: implications of this are discussed in chapter 5.
- **Unidirectional connection to the electricity grid**
The hybrid energy system is connected to the Dutch electricity grid. Since it is assumed that the energy storage system can only charge from the wind farm, this grid connection is unidirectional. Therefore, no electricity flow is possible from the grid to the hybrid system.

It is assumed that the hybrid energy system is only coupled with the Dutch day-ahead market. Other electricity markets or revenue streams are not taken into consideration in this study. This is further detailed in section 2.2.

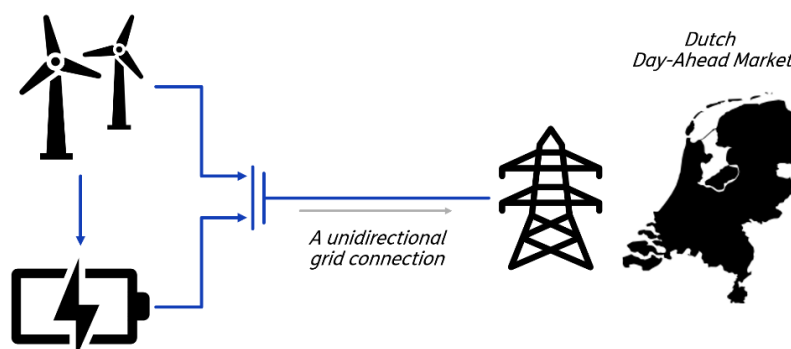


Figure 1 Representation of system in scope for this study

To assess the sensitivity of the ES performance to different future energy system conditions in 2030, the ES is evaluated across two pre-defined energy system scenarios developed by Netbeheer Nederland (2024):

- **Scenario 1 National Drivers (2030)**

In this scenario, the government plays a central role in steering the energy transition. The focus is on self-sufficiency through large-scale domestic renewable energy production and a shift towards a circular economy.

- **Scenario 2 Climate Ambition (2030)**

This scenario follows as closely as possible the existing, intended and scheduled climate policy in the Netherlands and is based on the Klimaat- en energieverkenning (KEV) 2022 and the Coalition Agreement.

The most important differences between these scenarios that influence the performance of the ES are 1) the installed generation capacity of renewable energy sources and 2) the electricity demand. These factors have an effect on price volatility and market price dynamics and therefore, influence the business case of ESS. How these differ across both scenarios is presented in Table 1.

Table 1 Key differences between National Drivers and Climate Ambition scenario, adapted from Netbeheer Nederland (2024)

		National Drivers	Climate Ambition
Installed generation capacity	Onshore wind	10.3 GW	9.1 GW
	Offshore wind	21.5 GW	21.5 GW
	Solar PV	76.1 GW	59.3 GW
Electricity demand		233 TWh	184 TWh

2.2 Economics of energy storage: revenue stacking

The business case of energy storage consists of multiple revenue streams. These revenue streams are stacked to create a viable business case. Below is an overview of the key revenue streams that are currently relevant or emerging in the near future.

This project focuses exclusively on the Dutch DAM as the primary source of revenue for energy storage. This means that other potential revenue streams are not included in the

analysis. As a result, the business case presented here does not reflect the full business case of energy storage. Nevertheless, the Day-Ahead Market remains a critical component of the revenue stack. By analysing this market alone, meaningful insights can be derived into the added value of energy storage to offshore wind.

Overview of revenue streams for energy storage

Energy Trading (Arbitrage)

Energy storage enables projects to buy electricity when prices are low (charging) and sell it when prices are high (discharging). This price differential—driven by fluctuations in supply and demand—forms the basis for arbitrage revenues. In the Netherlands, this primarily takes place on the Day-Ahead Market (DAM) and increasingly on the Intraday Market.

Portfolio Optimisation

For entities managing a broader energy portfolio (e.g. wind farms, solar assets, and demand), storage can enhance overall portfolio value. It can reduce imbalance costs, prevent curtailment of renewable generation, and help meet contractual delivery obligations more efficiently.

Grid Services

Energy storage can provide valuable services to the electricity grid, including:

- Frequency Containment Reserve (FCR): rapid response to frequency deviations.
- Automatic/Manual Frequency Restoration Reserve (aFRR/mFRR): balancing services over longer timeframes.
- Congestion Management: storage can help alleviate local grid congestion, which is particularly relevant in areas with limited grid capacity.

Resource Adequacy / Capacity Mechanisms

Although the Netherlands does not currently operate a full capacity market, discussions are ongoing about mechanisms to ensure long-term system adequacy. In the future, storage assets may be compensated for being available during periods of high demand or system stress.

Network Cost Optimisation

In some cases, storage can reduce grid connection or transmission costs by limiting peak power flows (peak shaving) or by optimising the use of contracted grid capacity. This is especially relevant for projects with a direct grid connection.

2.3 A firm grid is not a given anymore

Historically, offshore wind projects in the Netherlands have been developed under the assumption of firm grid access – meaning that all generated electricity could be transported to shore without curtailment. This assumption has been a cornerstone of the offshore wind business case, supported by dedicated offshore grid infrastructure developed by TenneT.

However, in the future this might not be the case anymore. As outlined in the original IJmuiden Ver Gamma tender criteria, the Dutch government is introducing the concept of non-firm access to the offshore grid. The rationale behind this change lies in the increasing pressure on the electricity grid, both offshore and onshore. With growing volumes of variable renewable generation, grid congestion and system balancing challenges are becoming more frequent. By allowing for non-firm access, the system operator gains more flexibility to

manage these challenges, albeit at the cost of reduced certainty for wind farm operators. For developers, this means that energy yield projections must now account for potential curtailment, and mitigation strategies—such as co-located energy storage—may become more attractive.

In the tender criteria the maximum number of points are awarded for a 250 MW capacity reduction contract (capaciteitsbeperkingscontract, CBC in Dutch) for a maximum of 15% of the hours of the year for a 1 GW offshore wind farm.

This is modelled by constructing a profile for the grid connection, instead of a constant grid connection of 2 GW. To construct this profile, assumptions need to be made about the hours which will have a grid connection reduction. For this two factors are used:

- A high wind production: the grid connection will only be reduced during hours for the wind production exceeds a certain value;
- A low residual load: the grid connection will only be reduced during hours with high wind production and a low demand.

The figure below shows which 15% of the annual hours are selected. First a horizontal line is drawn at 1500 MW for offshore wind. This corresponds to a 25% grid capacity reduction for a 2 GW offshore wind farm. Next, the residual load is determined to end up with 15% of the hours in the top-left corner of the figure.

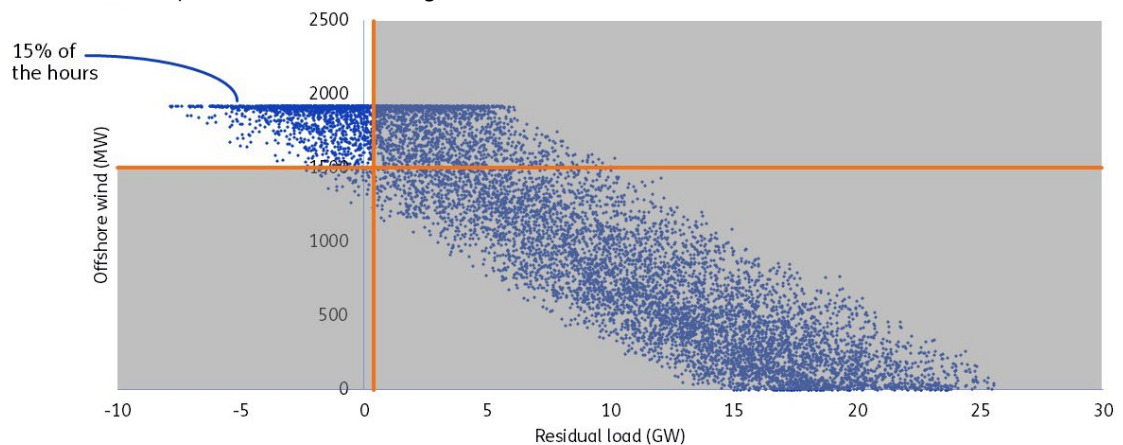


Figure 2 Selection of 15% of the hours from a total of 8760 hours per year. Each dot represents one hour of the year with a combination of wind production and residual load. The values for these are taken from the energy system scenarios used for the analysis.

The figure below shows for a 24 hour period, how a reduced grid connection will result in curtailed wind energy, if no other measures are taken. Energy storage will be able to charge during these hours and shift the load, such that it can be sold later in the day.

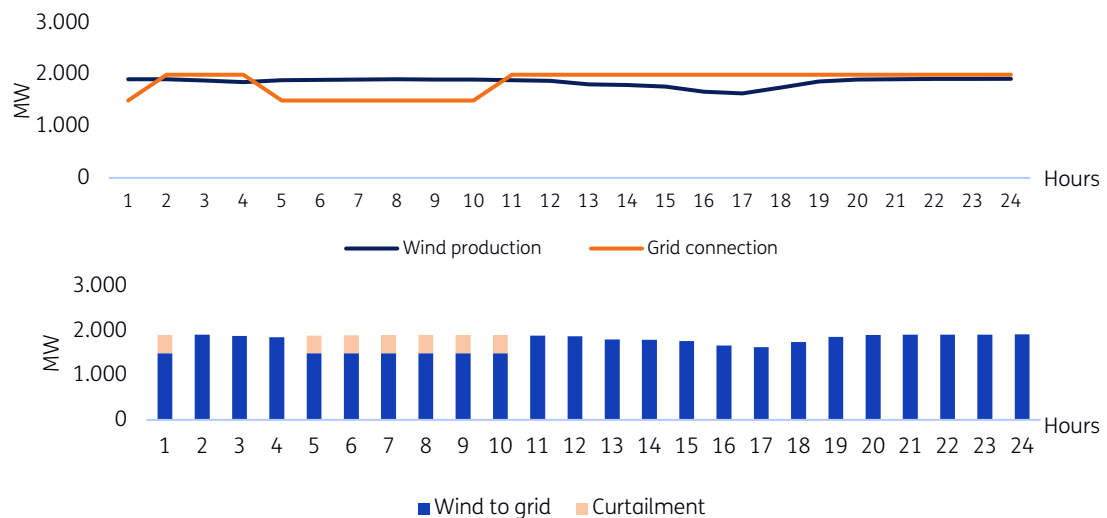


Figure 3 The effect of a reduced grid connection for wind to grid and curtailment.

2.4 Long term contracts: PPAs and CfDs

Long term contracts have an increasingly important role in the energy transition. Renewable generation such as offshore wind park typically have high investment costs and low operational costs. The business case of such an asset requires a steady cash flow, which can be guaranteed by long term contracts. To this end, Power Purchase Agreements (PPAs) and Contract-for-Difference (CfDs) are considered. Typically, PPAs are between private parties and CfDs between renewable assets and the government.

Contracts-for-Difference

A CfD is a long-term financial agreement designed to stabilize revenues for electricity generators by reducing exposure to volatile market prices. Under a CfD, the generator and the counterparty (often a government or market operator) agree on a fixed “strike price” for electricity. The actual payments depend on the difference between this strike price and the market price.

There are two main types of CfDs: one-sided and two-sided. A one-sided CfD provides support only when the market price falls below the strike price. In this case, the generator receives a top-up payment. If the market price exceeds the strike price, the generator keeps the additional revenue. A two-sided CfD includes both upward and downward adjustments. If the market price is below the strike price, the generator receives a payment; if it is above, the generator pays back the difference.

In the Netherlands, there is growing interest in introducing two-sided CfDs to support offshore wind development. While one-sided CfDs have been used in the past, two-sided CfDs are already a key part of renewable energy policy in countries like the United Kingdom, where they form the backbone of the Contracts for Difference scheme. Other countries, such as Denmark and Germany, have also implemented or are exploring similar mechanisms to support large-scale renewable deployment.

In this study, different ways in which CfD criteria can be defined, are considered — particularly in relation to how payments are handled when energy is routed to storage rather than directly to the grid. These design choices can significantly influence the operational

behaviour and economic value of co-located energy storage. The CfD designs and their effects are described in Section 4.6.1.

Power Purchase Agreements

PPAs are long-term contracts between electricity producers and consumers, typically private entities. In the context of offshore wind, PPAs offer a mechanism to secure predictable revenue streams, which is essential for financing capital-intensive projects. These agreements often span 10 to 20 years and define a fixed or formula-based price for the electricity delivered.

For offshore wind developers, PPAs reduce exposure to volatile spot market prices and improve bankability by providing revenue certainty. On the demand side, large industrial consumers—such as chemical producers, data centres, and manufacturing companies—enter into PPAs to meet sustainability targets, hedge against future electricity price increases, and demonstrate corporate climate commitments.

Compared to CfDs, which are typically backed by governments and offer a guaranteed strike price with symmetric payments, PPAs are negotiated bilaterally and may involve more complex risk-sharing arrangements. However, both instruments serve the same fundamental purpose: enabling investment in renewable energy by stabilizing cash flows.

The influence of different PPA structures on the value of co-located energy storage with offshore wind is explored. While all PPAs aim to stabilize revenues, their design can significantly affect the operational flexibility and market exposure of the offshore wind farm and the role of storage. The PPA structures and their effects are described in Section 4.6.2.

3 Simulating the behaviour of energy storage with the BDEYE method

To assess the value of energy storage when co-located with offshore wind, a two-part modelling approach is used. The first component is a market simulation model that captures the behaviour of energy market participants. The second component is an optimisation model that determines how a storage system would operate to maximize revenue.

Figure 4 provides an overview of the modelling framework. It shows the key inputs used in the analysis and how these feed into the EYE market simulation model and the optimisation model. The EYE model produces hourly market clearing prices and wind production profiles, which are then used as inputs to the optimisation model. The optimisation model calculates the optimal charging and discharging behaviour of the storage system, subject to technical constraints and market conditions.

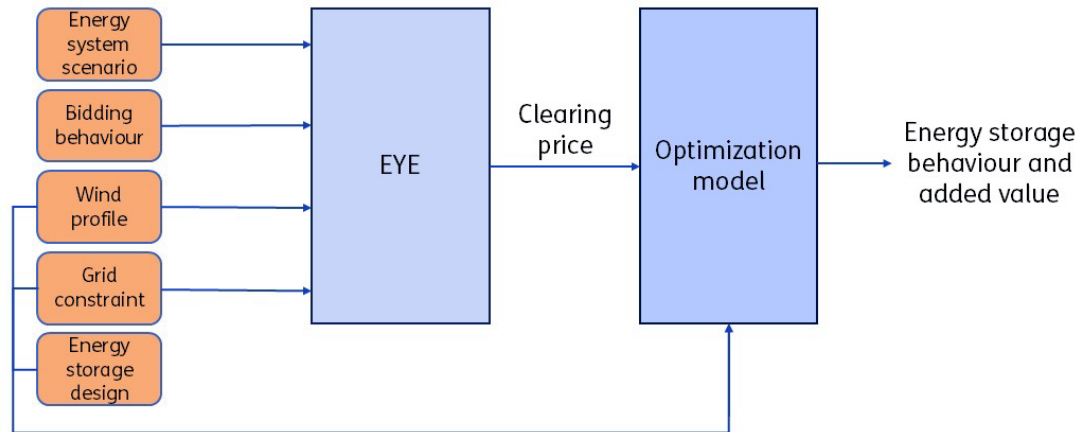


Figure 4 Overview of the modelling framework used in this project.

3.1 Modelling the Energy Market: BDEYE

To model the energy market dynamics in our analysis, we use the BDEYE method, which combines the Belief-Desire-Intention (BDI) framework with the EYE simulation model (van der Veen et al., 2025). EYE is a multi-energy market simulation model developed over several years through industry-driven use cases. It is designed to simulate market interactions by capturing the reasoning and decision-making processes of market participants.

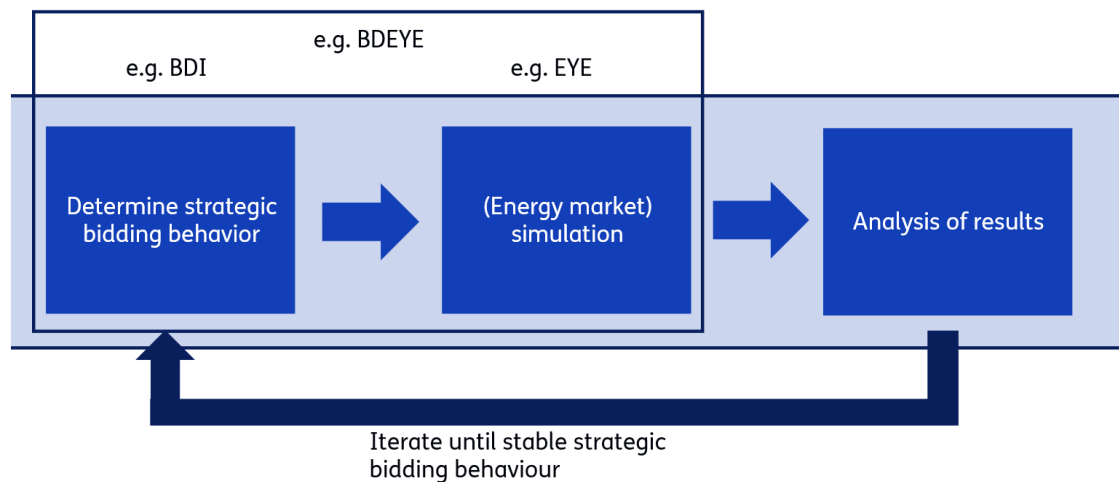


Figure 5 Overview of the BDEYE method which consists of agent-based modelling of energy markets (EYE) with agentic reasoning capture of trading strategies (BDI). By analysing and iterating stable strategic bidding behaviour can be found.

The BDI framework, originating from philosophy and computer science, is used to model intelligent behaviour. It structures agent behaviour around three core components:

- **Beliefs:** What the agent knows or assumes about the world (e.g., market prices, demand forecasts, regulations).
- **Desires:** The agent's objectives (e.g., maximizing profit, meeting production targets).
- **Intentions:** The strategies or actions the agent commits to (e.g., bidding strategies, contract choices).

In BDEYE, each market participant is modelled as an agent with its own beliefs, desires, and intentions. These agents interact in simulated wholesale and local energy markets, submitting bids based on their internal logic and responding to market outcomes. The simulation iteratively updates agent behaviour and market conditions until a stable scenario is reached.

EYE supports a wide range of bidding behaviours, from simple marginal cost bidding to complex strategies that incorporate forecasts, contract rules, and previous market outcomes.

By combining structured agent reasoning with detailed market simulation, BDEYE provides a transparent and flexible framework for exploring how different market designs, contract structures, and system assumptions influence energy market outcomes.

The next section (3.2) describes the optimisation that is largely applied throughout this study to calculate storage revenues, which are optimised based on market outcomes generated through EYE simulations. However, another approach to generate storage revenues is through application of a heuristic within EYE. Within the EYE model, generators have imperfect foresight (or myopia) and therefore have limited knowledge about the future. As a result, generators, but also specifically storage operators, must determine their bids with the limited information they have. This leads to suboptimal revenues. To simulate the bidding behaviour with imperfect foresight, a heuristic is applied for offshore storage to determine its bids. In the flexible system scenario, the EYE model with heuristic bidding is applied to

reflect the uncertainty in market behaviour when multiple offshore wind farms with co-located storage are present.

3.2 Optimising the behaviour of energy storage

To evaluate the operational behaviour and added value of energy storage co-located with offshore wind, an optimisation model that builds on the market outcomes generated by the EYE simulation is used. Specifically, the model uses hourly day-ahead market (DAM) clearing prices over a one-year horizon to determine the optimal charging and discharging schedule for the storage system.

The objective of the model is to maximize total revenue from the combined offshore wind and storage asset, based on market prices. Contractual structures such as PPAs and CfDs are incorporated in later stages of the analysis by modifying the revenue function accordingly.

The optimisation is subject to a set of technical and operational constraints:

- Storage capacity and (dis)charge rate limits, which define the physical boundaries of the storage system.
- Round-trip efficiency, accounting for energy losses during charging and discharging.
- A strict charging constraint, which ensures that the storage system can only charge from the offshore wind asset and not from the grid.
- A grid export constraint, which limits the total power that can be exported to the grid in each hour. This constraint can be constant or time-varying, allowing us to explore the impact of grid capacity reductions.
- The model assumes perfect foresight, using the full time series of market prices and wind generation from the EYE simulation.

An important assumption is that the storage system is relatively small to the overall market and therefore does not influence market prices. This allows us to treat the optimisation as a post-processing step, independent of the market simulation. In later stages of the study, the system-level effects of larger-scale storage deployment are explored using heuristic methods, but these are outside the scope of the optimisation model described here.

4 Results

4.1 Base case results

The results of the base case are presented and discussed. The set-up of the energy system follows the National Drivers scenario and the hybrid system of the offshore wind farm and ES have the following configurations:

- Wind farm of 2 GW
- ESS with power equal to 10% of the wind farm (200 MW) and 4 hr storage duration (800 MWh)
- Firm grid capacity of 2 GW

4.1.1 Behaviour of the Energy Storage

The goal of the hybrid system – offshore wind farm in combination with ES – is to maximise their combined revenues. The ES can add revenues to the hybrid system by conducting arbitrage. This occurs when the ES charges electricity generated by the offshore wind farm during low price periods and discharges electricity during higher price periods. After accounting for efficiency losses, the ES earns profit through this price spread.

To maximise revenues, the ES has to select optimal hours to charge and discharge to capture the largest possible price spreads. These hours are local price valleys and peaks. An example of how the ES operates is presented in Figure 6, which shows the Day Ahead market clearing price (€/MWh) during an archetypical day and the hours of charging and discharging. The orange highlighted areas display the local price valleys and as Figure 6 shows, this is when the ES charges. The purple highlighted areas display local price peaks, and these are the hours the ES discharges (as shown in Figure 6).

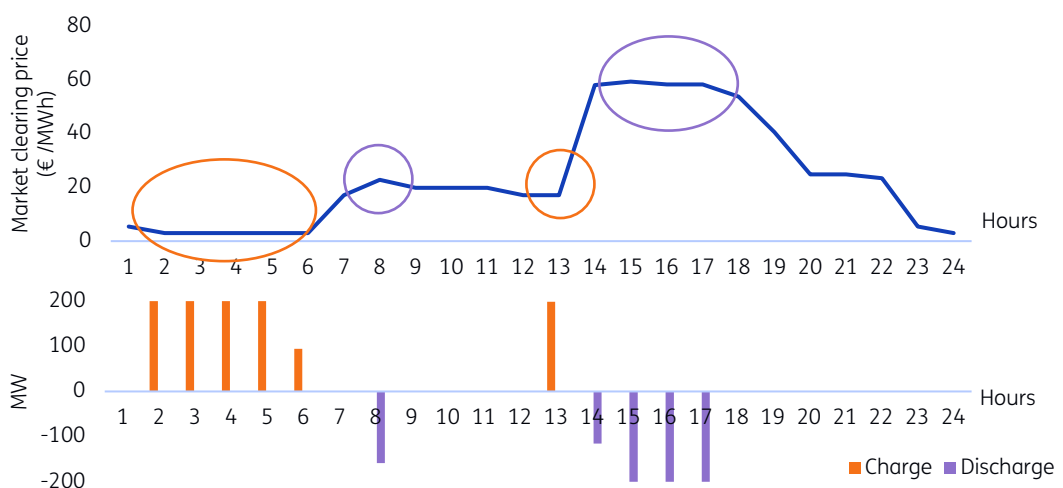


Figure 6 Illustrative daily profile of electricity price and storage operation. The storage charges during low-price hours and discharges during high-price hours, demonstrating typical arbitrage behaviour in response to market price fluctuations

As discussed above, the ES selects optimal hours to charge and discharge in order to maximise revenues. Because it is not profitable to store electricity at every moment, only a fraction (4%) of the total electricity generated by the offshore wind farm is charged to the storage before being exported to the grid. Most (the other 96%) of the electricity generated by the offshore wind farm is exported directly to the grid, because the ES only intervenes when it expects to create additional revenues. This selective routing of electricity highlights the strategy of the ESS: goal of revenue maximisation rather than continuous operations.

As discussed above, the ES selects optimal hours to charge and discharge to maximise revenues. Because it is not profitable to store electricity at every moment, only a fraction (4%) of the total electricity generated by the offshore wind farm is charged to the storage before being exported to the grid. Most (the other 96%) of the electricity generated by the offshore wind farm is exported directly to the grid, while the ES only intervenes when it expects to create additional revenues. This selective routing of electricity highlights the strategy of the ES: goal of revenue maximisation rather than continuous operations.

4.1.2 Performance of the Energy Storage

This section reflects on the ability of the ES to increase revenues in the day-ahead market in this hybrid set-up.

The results show that the ES can create additional revenues when co-located next to an offshore wind farm. By integrating the ES, total annual revenues are increased by 7% (Figure 7, left side) as compared to the stand-alone offshore wind farm, amounting to an additional €18 million in revenues. It is important to note that total revenues generated by the ES are higher than €18 million. The total revenues generated by the ES are €24 million, as presented in the orange part of Figure 7, (left side). However, wind energy revenues are reduced slightly as part of their electricity flows through the storage and thus, the output of wind and affiliated revenues decrease by €6 million. Therefore, additional revenues as a result of the ES are equal to €18 million. The ES is able to capture profitable price spreads, adding a revenue stream on top on the offshore wind farm.

This last point becomes clear when reviewing the capture price (€/MWh) that the ES is able to obtain as compared to the offshore wind farm, in both the case as a stand-alone unit ('Only wind') and a hybrid set-up ('Wind & Energy Storage') as presented on the right side of Figure 7.

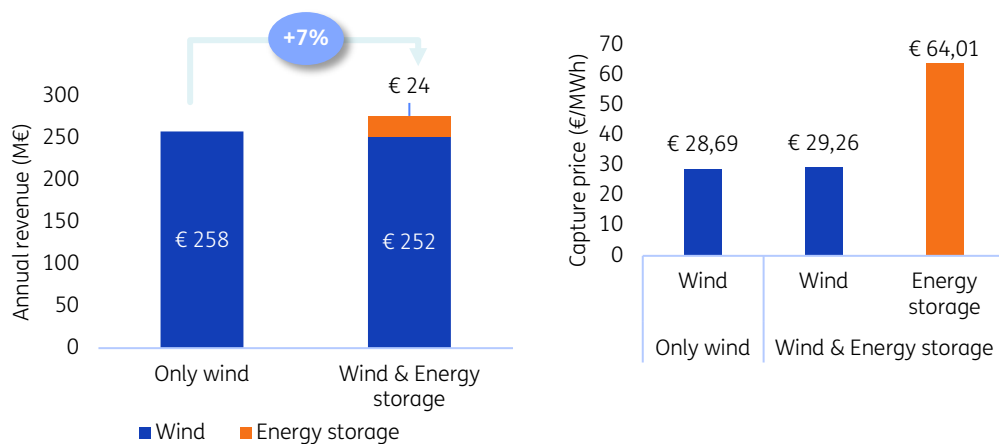


Figure 7 Modelling results showing annual day-ahead market revenues (million €) (left) and capture price in €/MWh (right) in the case of wind without storage ('Only wind') and wind with storage ('Wind & Energy storage')

The capture price (€/MWh) of the ES are around two times as high as the unit revenues of wind. Where wind is a price taker² in the market, the ES has flexibility to select favourable moments to discharge, leading to significantly higher unit revenues compared to the electricity generated by the wind farm that is exported directly to the grid.

Although the ES can generate additional revenues, results show the ES is not utilised to its maximum technical potential. In the base case, ES utilisation is equal to 40%, meaning that the storage was used for 40% of its theoretical full-cycle annual capacity. This is because the ES is not able to generate maximum revenues in the hours it is not utilised. The ES chooses to reserve the capacity of the storage for the most lucrative moments. For this, it is dependent on the market dynamics and volatility of the electricity market price. If the electricity market price is relatively volatile – there would be price peaks and price valleys within the duration of the storage – utilisation will increase. As this study only considers the day-ahead market and this market is less volatile compared to other markets, it is consistent with expectations that storage utilisation is not high.

This also highlights the potential for revenue stacking with the ES as discussed in section 2.2, as the storage has untouched capacity (60%) which can be reserved for unlocking other revenue streams.

4.2 Diminishing marginal revenues when increasing storage duration

The previous section discussed the performance of ES with one specific configuration. This section will present how different ES configurations (power and storage duration) affect its financial performance.

When increasing the power, the ES can deliver a larger amount of electricity per hour when charging and discharging. This means it can charge and discharge more electricity when electricity prices are low or high. Model results show that doubling the storage power relative to the wind farm from ~ 5% to 10% (i.e. from 100 MW to 200 MW) – allowed the storage to make better use of these moments, leading to an increase in the additional annual revenues. This can be derived from Figure 8 (left and right), where an ES of 200 MW and 4 hour storage duration has around double revenues (18.3 million) compared to an ES of 100 MW with the same storage duration (9.4 million).

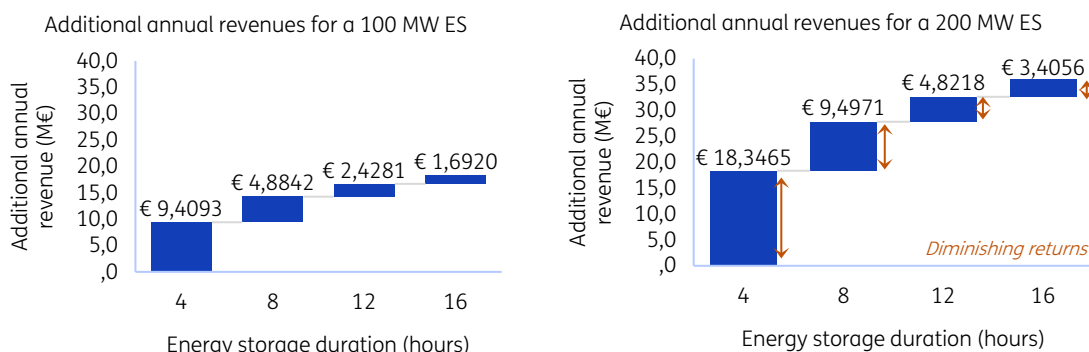


Figure 8 Additional annual day-ahead market revenues for a 100 MW ES (left) and 200 MW ES (right) with increasing storage duration (4-16h)

² In the day-ahead market, offshore wind is typically considered a *price taker*. This implies that it submits bids at (or near) zero marginal cost and does not exert influence on the market clearing price. Its intermittent and non-dispatchable nature mean it accepts prevailing prices rather than actively shaping them.

Increasing the storage duration (hours) means the ES can store more electricity (MWh) in total. This gives the ES more flexibility to shift electricity from one time to another – for example from a windy morning to a calm afternoon. However, modelling results show diminishing returns when increasing storage duration of the ES (Figure 8): the first four hours of storage capture the largest additional annual revenues, and each additional hour is less profitable. So, even though storage duration increases flexibility, the ability of the ES to capitalise on this flexibility is dependent on price volatility and market dynamics. Both 100 MW and 200 MW ES experience these diminishing returns as seen, respectively, in Figure 8 (left and right).

4.3 Performance of ES across scenario's

As described in section 2.1, the sensitivity of the ES's performance to different future energy system conditions is evaluated across two pre-defined energy system scenarios: 1) National Drivers and 2) Climate Ambition (Netbeheer Nederland, 2024).

Figure 9 show that ES performance is relatively stable across both scenarios. Both the capture price (€/MWh) revenues and total annual additional revenues constitute a similar proportion of the wind revenues in both scenarios. In scenario Climate Ambition, the capture price (€/MWh) and total annual revenues are lower compared to the National Drivers scenario for both wind and energy storage. This can mainly be attributed to the lower total annual electricity demand leading to lower electricity prices.

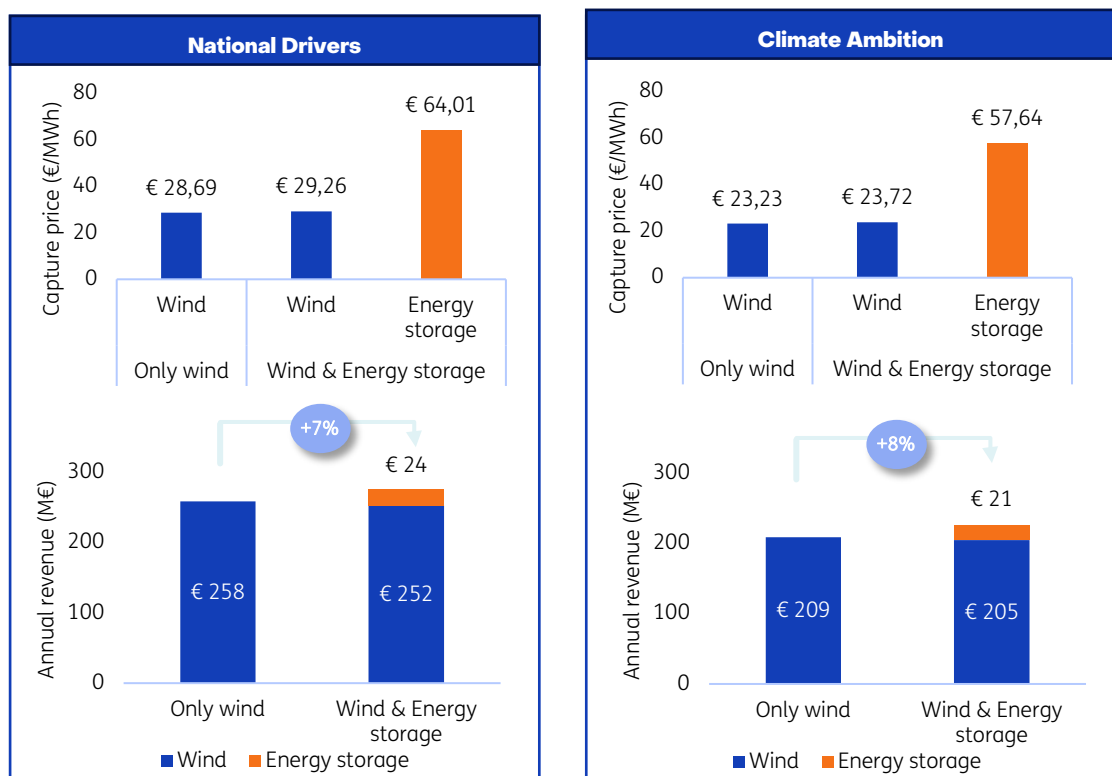


Figure 9 Performance of ES in terms of unit revenue (per MWh) and additional annual revenues for two scenarios

4.4 Grid constraint

A firm grid connection is not a given anymore for offshore wind. Before offshore wind farms could be certain that they would be able to transport all of the produced energy to the Dutch grid, but in the IJmuiden Ver Gamma tender criteria, a capacity reduction contract has been included. This can provide an opportunity for energy storage, as it can shift the production at these hours, thereby avoiding curtailment.

It is not yet clear which hours will be chosen for a grid capacity reduction. At least it must be hours with a high wind production, otherwise the reduced capacity will not have an effect. The figure below shows the potential revenue loss from a grid capacity reduction for the hours in which the wind production exceeds the reduced grid capacity. For each hour the potential revenue loss is equal to the curtailed wind production multiplied by the clearing price of that hour. From these hours we have to select 1314 hours; 15% of 8760 hours in a year. The 1314 hours with the highest potential revenue loss have a total loss of 9.8 M€, which is 3.8% of the total yearly revenue of the offshore wind park. The lowest total potential revenue loss is 0.2 M€, or 0.1% of the total yearly revenue. This shows that whether the grid capacity reduction has a large effect on the business case of offshore wind depends largely on which hours will be chosen. In a system with high wind penetration, there is a correlation between high wind production and electricity prices. As such, it can be that the curtailed energy would not deliver any revenue, so there is also no revenue loss. The modelling of the grid constraint was described in Section 2.3. The selected hours result in a total potential revenue loss of 3.2 M€. That is, if energy storage would not be present.

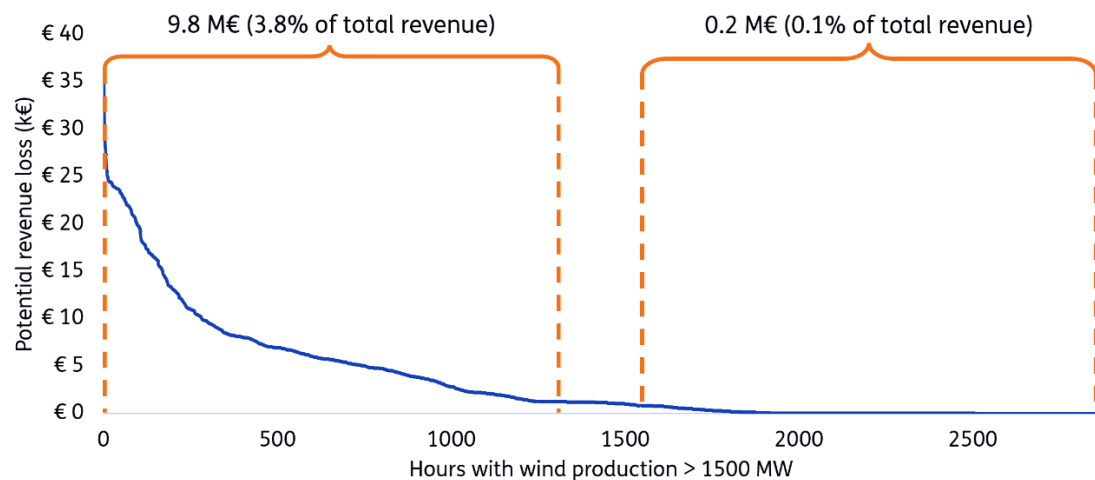


Figure 10 The potential revenue loss for each hour with a wind production exceeding 1500 MW. The highest and lowest total potential revenue losses are 9.8 M€ and 0.2 M€ respectively.

The reduced grid capacity influences the business case of energy storage only if it also affects its behaviour. The energy storage optimises its behaviour to maximize its revenue stream. To this end it charges during low price periods and discharges during high price periods. The energy storage is now able to charge “for free” during reduced grid capacity hours, as otherwise this energy would have been curtailed. However, this only impacts the business case significantly, if it would not have charged during these hours otherwise. If this is not the case, then it follows that we still have the same business case as before. The figure below shows an 18 hour period for which the behaviour is not affected significantly. The clearing prices have a low price period on the left and high price period on the right. In between there is a local price max and min. The energy storage will fully charge and

discharge during the low and high price periods. In between it will discharge and charge a bit for additional revenue. Now a grid constraint is imposed during the first 7 hours. As the energy storage was already charging during these hours, there is no significant change in energy storage behaviour during this 18 hour period. The only difference is that now the energy storage can charge “for free” instead of incurring a slight opportunity cost. However, when we consider the offshore wind park and energy storage as one entity, then also this is not the case, since the offshore wind park already lost this revenue due to the reduced grid capacity.

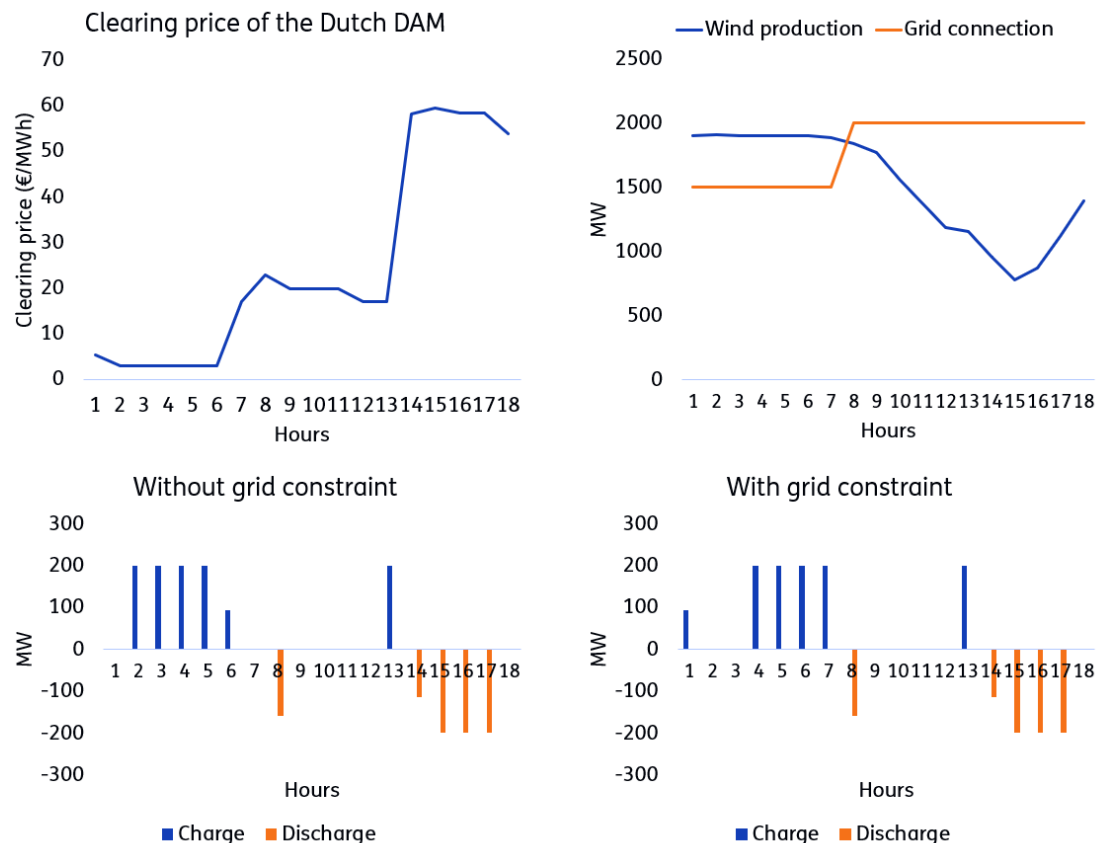


Figure 11 The behaviour of energy storage for an 18 hour period with and without a grid constraint. Top left: the clearing price on the Dutch DAM; Top right: the wind production and grid connection capacity; Bottom left: the energy storage behaviour without a reduced grid capacity; Bottom right: the energy storage behaviour with a reduced grid capacity.

It turns out that most of the hours in which there is a reduced grid capacity, the behaviour of energy storage is unaffected. This is due to the correlation between high wind production and low prices. The energy storage was already charging during these low price periods, so the reduced grid capacity did not influence the behaviour of energy storage. Of course, there are some hours in which there is an effect, thus there is a slight increase in additional annual revenue generated by energy storage. This is shown in Figure 12. On the left we have the additional annual revenue for the case without a reduced grid capacity and on the right with a reduced grid capacity. There is a slight increase of ~0.3 M€ for each duration.

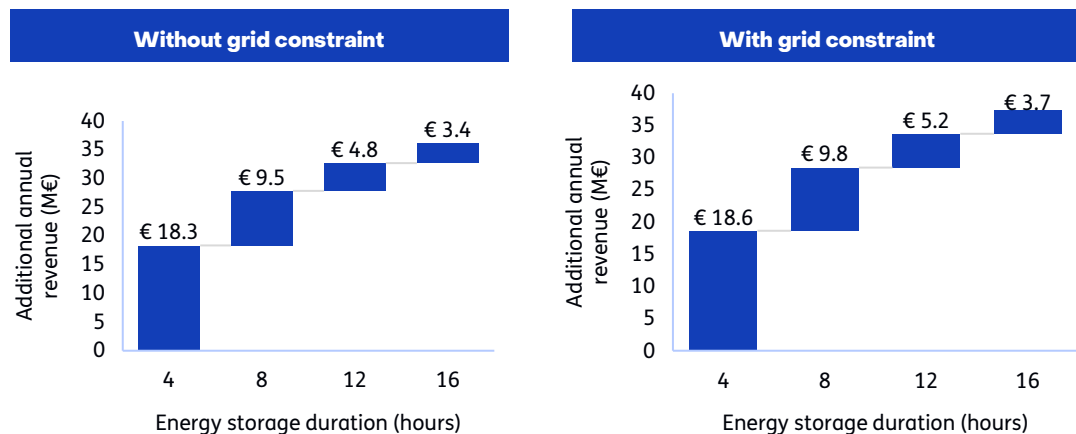


Figure 12 The additional annual revenue by introducing energy storage without a reduced grid capacity (left) and with a reduced grid capacity (right).

To conclude, from the offshore wind perspective, energy storage can be utilised to prevent revenue losses due to a reduced grid capacity. How large these potential losses are depending highly on which hours will be selected by the grid operator. From the energy storage perspective, the effect of a grid constraint is less than what might be initially expected. This is since the behaviour of energy storage remains mostly the same, due to the correlation between a reduced grid capacity and low price periods. This also implies that the business case for energy storage is not dependent on the presence of a grid constraint.

4.5 Flexible system

Up until now, the performance of a single energy storage (ES) co-located with an offshore wind has been considered. In this section, the scope is expanded, and a more flexible energy system is assessed, in which a total of 500 MW of offshore storage capacity is deployed next to multiple offshore wind farms. This scenario is considered to explore what effect a larger share of offshore storage has on (1) the business case of the ES and (2) the functioning of the energy system from a system perspective.

For this, the EYE model including the heuristic is applied to account for myopia of storage operators as described in 3.1. Furthermore, the total offshore wind generation capacity (21.5 GW) is divided across three setups as presented in table 2.

Effect on the business case

The effect of increasing offshore energy storage to 500 MW has a limited effect on the business case for offshore ES. With a total of 184 GW of installed generation capacity in the National Drivers scenario in 2030, the assumed capacity – 500 MW – of offshore storage is equal to less than one percent of the whole. As a result, increasing the capacity of offshore storage to 500 MW has little effect on market price formation. Therefore, the day-ahead market revenues offshore storage is able to generate, will remain stable as this depends on arbitrage opportunities arising from the market price dynamics.

Table 2 Assumption on total generation capacity of offshore wind setups (with or without grid constraint and storage)

Offshore wind setups	Generation capacity
Without grid constraint and without storage	11.5 GW
With grid constraint and without storage	5 GW
With grid constraint and storage	5 GW

Nonetheless, the EYE model results for the flexible system show lower additional revenues and lower storage utilisation compared to the optimisation model in the same situation. This difference can be explained by the nature of the EYE model, which is a simulation model that operates under imperfect foresight. As generators within the model do not have knowledge on future prices, a heuristic bidding strategy for the storage is applied to determine its bids in the day-ahead market. This leads to less optimal charging and discharging, and ultimately lower economic performance as compared to the optimisation model, which assumes perfect foresight. For more information on the EYE and optimisation model, please refer to chapter 3.

Effect on a system level

Theoretically, co-locating storage next to an offshore wind farm can dampen the profile (i.e. smooth out the variability) of the combined assets' output. By charging during periods of high wind production and discharging during low-output or high-price hours, the storage reduces the variability of the wind farm's export to the grid. This leads to a more stable and predictable generation profile.

However, in this scenario, only 3% of the electricity generated by offshore wind assets is stored in the ES before being exported to the grid. The rest (97%) is exported directly to the grid. As a result, the ES has a limited effect on the combined profile and no dampening occurs.

In addition, storage could theoretically dampen price volatility in the electricity market by storing electricity during periods of ample supply and discharging it when there is a shortage. A greater deployment of offshore storage can therefore contribute to a more stable market with lower price volatility and enhance system flexibility. However, as discussed previously, the assumed capacity of offshore storage – 500 MW – constitutes less than one percent of the total installed generation capacity, i.e. 184 GW. Therefore, it has limited effect on price formation and thus, price volatility. To enable this reduced price volatility and increased system flexibility through energy storage, more storage is needed. System studies as Netbeheer Nederland scenarios (2025) indicate the need for 7 to 10 GW of large scale batteries for short term balancing in 2030.

When considering which type of storage is needed, co-locating storage next to offshore wind can still bring added value compared to onshore storage. One of the key benefits on a system level from offshore storage lies in enabling a more effective use of the offshore electricity grid. Offshore storage systems have the potential to alleviate pressure on the offshore grid temporarily by absorbing excess wind generation during periods of limited grid capacity or congestion. Rather than exporting the wind electricity when it is produced, the ES store the electricity and shift the export to the grid to less constrained hours. This flexibility translates into a more efficient use of offshore infrastructure. From a societal perspective, it may lead to significant cost savings by avoiding or deferring investments in grid expansion.

When considering which type of storage are needed, co-locating storage next to offshore wind can still bring significant added value. By storing the electricity at the point of generation, offshore storage can help manage and alleviate congestion and reduce the need for excessive offshore infrastructure investments. However, these benefits are not captured in this study, as the scope is limited to the economic performance of offshore storage in the day-ahead market. Due to this, effects on congestion or infrastructure investments are not quantified but remains highly relevant for future research.

4.6 Value of energy storage with long term contracts

High investment projects such as offshore wind farm need stable revenue streams to ensure a business case and bankability. To this end most project have long term contracts which ensure these stable revenue streams. The following sections discuss the effects of Power Purchase Agreements (PPAs) and Contracts-for-difference (CfDs) on the added value of energy storage.

4.6.1 Contracts-for-Difference (CfD)

Different CfD designs influence the added value of energy storage when co-located with offshore wind. The payment structure — specifically, what the wind generator earns when sending energy to the grid versus to storage — fundamentally shapes storage behaviour.

Three configurations are considered. First, under a conventional two-sided CfD, the combination of offshore wind generator and energy storage receives a fixed strike price for all electricity produced, regardless of market conditions or destination. This eliminates price volatility entirely, removing the arbitrage opportunity that storage depends on. As a result, storage remains inactive — there is no viable business case.

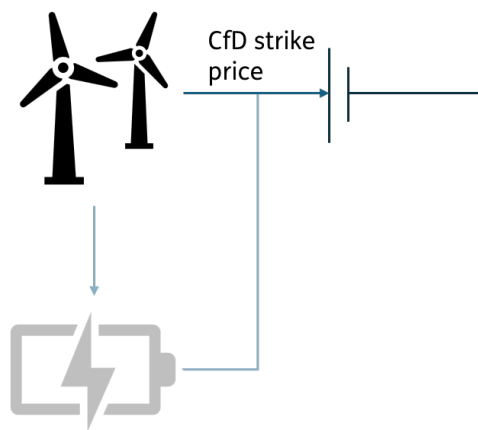


Figure 13 Overview of the energy flows under a simple two-sided CfD. If both offshore wind and energy storage receive the CfD strike price, then there is no role for energy storage.

The second configuration is inspired by the UK's Allocation Round 7 (AR7). In this setup, both the offshore wind asset and the energy storage system are located behind submeters, which are themselves behind the grid connection point. The wind generator receives the CfD strike price for all output, even if the energy is routed to storage. The storage system can only charge from the wind asset and not from the grid. With this design, storage effectively

charges at zero marginal cost and discharges at market prices. This restores the arbitrage opportunity, but also leads to frequent cycling, as storage will charge even during hours when it would not do so under merchant conditions.

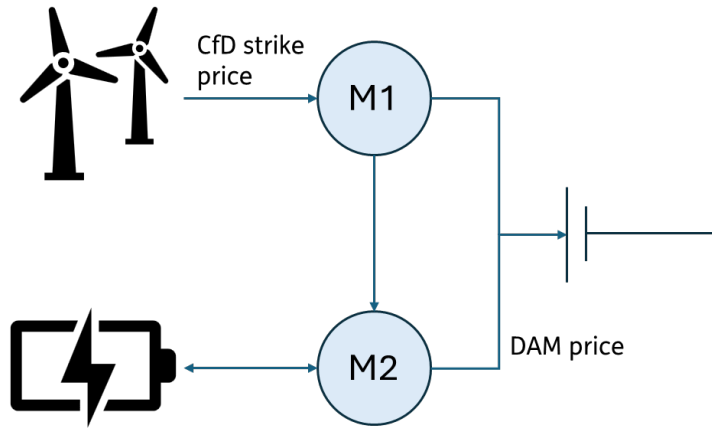


Figure 14 Overview of the energy flows under a AR7 inspired CfD. Offshore wind always receives the CfD price, regardless of whether it goes to grid or to storage. Storage receives the DAM price for discharging. This results in frequent charging cycles for storage.

Finally, a merchant-like CfD configuration is considered, where the wind generator receives the CfD strike price only for energy delivered directly to the grid. Energy routed to storage receives the CfD strike price minus the market price. Effectively, the storage system pays the market price to charge. This setup reintroduces real price signals and opportunity costs, resulting in storage behaviour that closely resembles a merchant setup — charging selectively and discharging only when spreads are favourable.

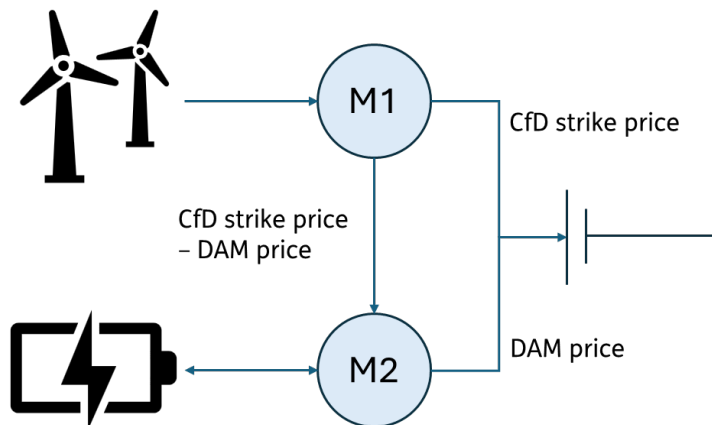


Figure 15 Overview of the energy flows under a merchant-like CfD. Offshore wind always receives the CfD price for wind to grid, and the CfD price minus the DAM price for wind to storage. Storage receives the DAM price for discharging. This reintroduces the DAM price signals to energy storage resulting in market-based behaviour for storage.

These three configurations demonstrate that differences in CfD criteria can lead to vastly different storage behaviours — from doing nothing, to being almost always active, to behaving in a market-based way. While most attention in CfD design currently focuses on ensuring stable revenues for offshore wind and avoiding unintended consequences such as negative

prices, less emphasis is placed on how these schemes influence the role of flexibility and storage. As the energy system evolves, it is essential that CfD design not only supports renewable deployment but also enables the effective integration of flexible assets. These dynamics should be carefully considered when designing CfD schemes.

4.6.2 Power Purchase Agreements (PPAs)

Different PPA structures influence the added value of energy storage when co-located with offshore wind. While all PPAs aim to provide revenue stability for the generator, the way they allocate wind production and expose it to market signals can significantly affect how — and how much — storage is able to add value. Some structures leave room for storage to operate independently on uncontracted volumes, while others integrate storage more directly into the delivery strategy. These differences shape the operational role of storage and its contribution to the overall business case.

Three PPA configurations are considered:

- **Profile-following PPA:** A fixed percentage of the offshore wind generation is contracted under a PPA. The remaining share is sold on the spot market, allowing energy storage to operate on the residual volatility and capture arbitrage opportunities.
- **First-cut PPA:** The first X MW of offshore wind output is allocated to a PPA, with any excess generation exposed to market prices. This structure creates a clear boundary between contracted and merchant volumes, enabling storage to optimise around the uncontracted portion.
- **Profile-smoothing PPA:** The offshore wind and energy storage systems are co-optimised to deliver a flatter, more predictable power profile. The goal is to reduce variability and align better with the needs of the offtaker. This configuration represents a joint business model, where the improved delivery profile is expected to command a higher PPA value than offshore wind alone.

The figure below shows an visual overview of the three configurations considered. For the top figures the orange and green line represents the offshore wind supply going to the PPA. For the bottom figure the light-blue line represents the new smoothed profile going to the PPA.

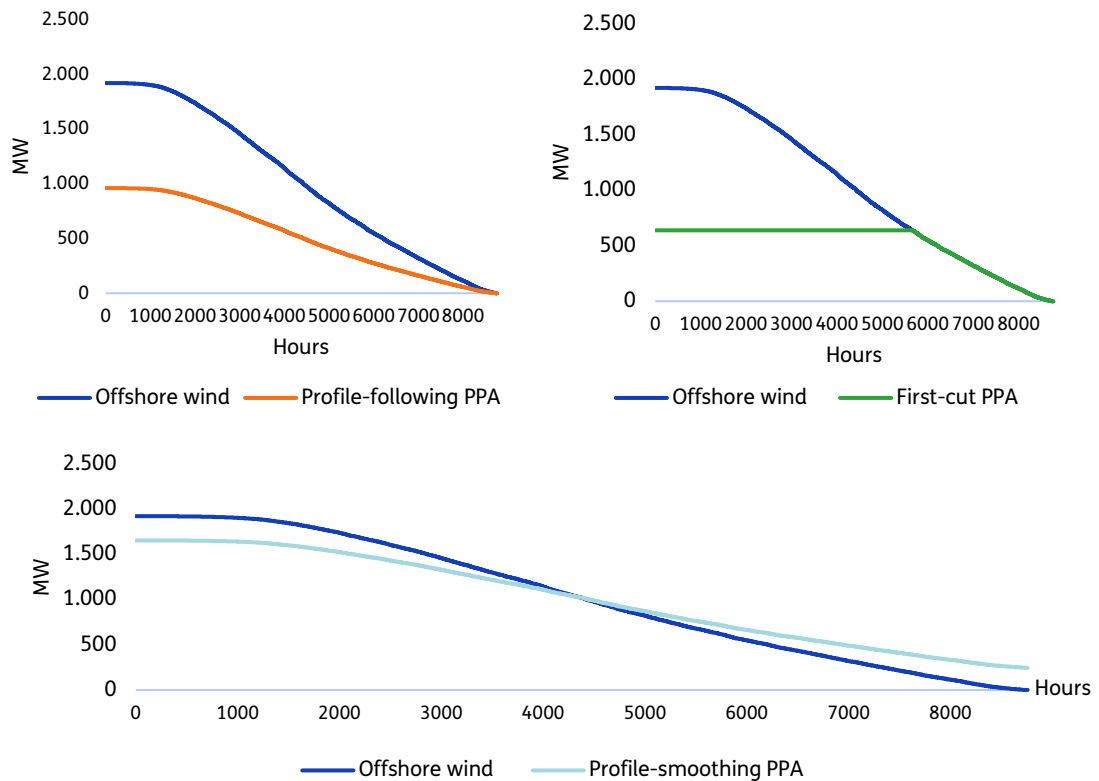


Figure 16 Overview of the three PPA configurations considered in this study. Top-left: the profile-following PPA with 50% of the offshore wind production going to the PPA; Top-right: the first-cut PPA with the first 638 MW going to the PPA; Bottom: the profile-smoothing PPA where the energy storage is used to smooth the profile of offshore wind.

Profile-following PPA

Without a grid constraint, the presence of the profile-following PPA does not alter the behaviour of storage. The system behaves identically to a scenario with a smaller wind farm that only produces the uncontracted share. In this case, the key design consideration is sizing the storage system appropriately to match the residual, market-exposed generation.

When a grid constraint is introduced, the dynamics shift slightly. We assume that PPA-contracted volumes are prioritised for delivery to the grid. This limits the flexibility of the storage system, as the contracted share must be delivered first. However, the overall impact on storage behaviour remains modest, as the uncontracted portion still provides sufficient opportunity for arbitrage in most hours.

First-cut PPA

In the first-cut PPA configuration, the first 638 megawatts of offshore wind output are allocated to a PPA, while the remaining generation is sold on the market. The 638 MW was chosen to ensure that 50% of the annual wind volume is going into the PPA, just like in a 50% profile-following PPA. This effectively splits the wind production into two profiles: a stable, contracted portion and a residual, market-exposed portion that primarily consists of high-output periods.

Due to the high penetration of wind in the modelled scenarios, these peak production hours tend to coincide with lower market prices. As a result, the market-exposed portion of the

wind generation receives relatively low revenues, as shown in the figure below. In this context, energy storage plays a more prominent role: by shifting excess energy from low-price periods to higher-price hours, it can significantly enhance the value of the uncontracted share.

While the relative contribution of storage is higher in this configuration compared to the profile-following PPA, the absolute value added by storage is somewhat lower. This is likely due to the limited volume and lower baseline value of the market-exposed energy. Nonetheless, the first-cut PPA highlights how contractual allocation can shape not only the opportunity space for storage, but also the economic conditions under which it operates.

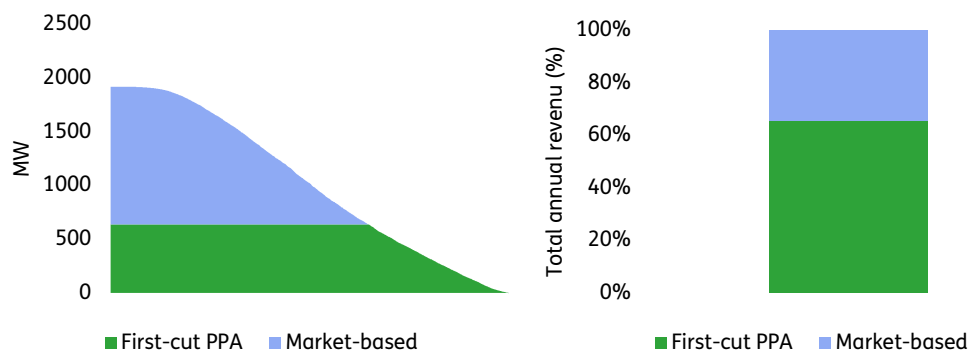


Figure 17 Left: the volume of first-cut PPA and market-based is both 50%. Right: the total annual revenue for first-cut PPA is ~65% compared to ~35% for market-based, due to a correlation between high wind production and low prices.

Profile-smoothing PPA

The business model of the profile-smoothing PPA differs from the previous two. The energy storage is used to smooth the profile of offshore wind and obtains a higher value for the smoothed profile. Whereas in the previous two PPA configurations the business case of energy storage depended on the revenue streams obtained by energy storage on the DAM, in this configuration it depends on the increase in PPA value. This increase in value should cover the investment of energy storage. In the previous configurations we only considered arbitrage on the DAM as a revenue stream. The remaining capacity of the storage asset could be used on other markets, such as the imbalance market, to value stack multiple revenue streams. In this configuration it's the question whether or not this is possible, which depends on the criteria of the PPA.

The design of the energy storage determines how much it can smooth the profile. The charge and discharge rates determine how much the storage can take off or add to the profile. Storage with a (dis)charge rate of 200 MW will only be able to go from 2000 MW to 1800 MW and from 0 to 200 MW. It will never be able to get both values towards 1000 MW. The capacity is mainly interesting in combination with the profile. If high wind production hours are clustered together, then the storage needs to first charge a lot, before a low wind production cluster arrives when it can discharge again. Due to a finite capacity, it will be fully charged or discharged before this happens, again posing a constraint. Finally, the efficiency of the storage system will not be a 100%, some energy will be lost during charging and discharging. As such, the profile might be smoother, but the total annual production will be lower than without a storage system. Taking this all in consideration an energy storage with

(dis)charge rate of 200 MW, a capacity of 800 MWh and a round-trip efficiency of 80% can smooth the profile as in the figure below.

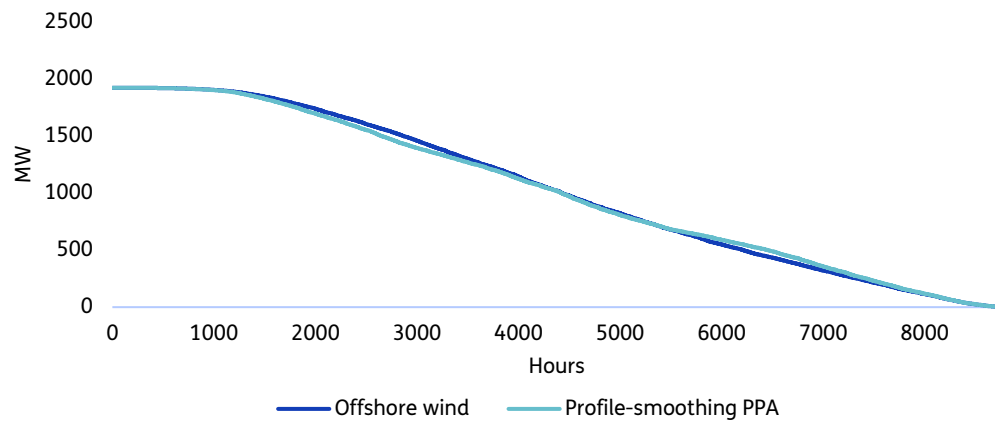


Figure 18 The profile-smoothing PPA is only able to smooth the profile to some extent due to constraints posed by its (dis)charge rate, capacity and efficiency.

5 Economic Performance of Energy Storage

To assess the economic viability of the ES, this chapter compares the additional revenues generated by the ES in the day-ahead market, as presented in chapter 4, with its capital and operational expenditures (CapEx and OpEx). While this does not represent a full financial analysis – including amongst others costs and other revenue streams – it provides initial insights in the economic viability of the ES. This will be done for three different storage configurations: 100MW-4h, 200MW-4h, 200MW-8h, and two technology types: the FLASC technology and a li-ion battery. For each configuration, additional revenues from the National Drivers scenario are taken into consideration. Revenues from long-term contracts, i.e. PPAs and CfDs as described in the section 4.6 do not fall under this scenario and are therefore not taken into account in this analysis.

To assess the economic viability, the following factors are calculated:

- The **annualised CapEx of the ES** using a capital recovery factor (CFR), spreading the initial investments over the lifetime of the ES
- The **annual OpEx of the ES** as a 2% of the total CapEx
- The **additional annual revenues the ES** generates compared to an offshore wind farm without storage in the day-ahead market

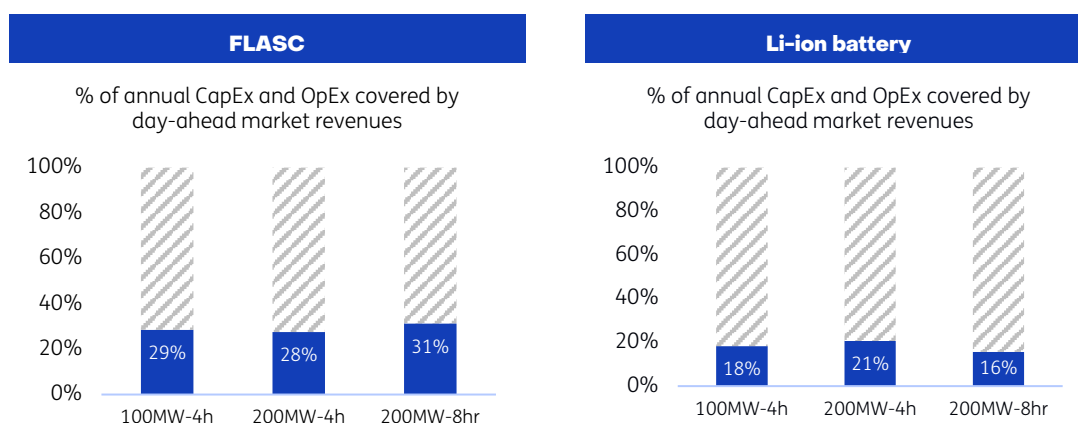
The annualised CapEx is calculated through multiplying the total CapEx with the Capital Recovery Factor³. Total CapEx figures are based on indications provided by a partner within the project, Seaway7, and presented in

. The additional annual revenues that are taken into account in this comparison are the revenues from the National Drivers scenario. This study applied a uniform round-trip efficiency of 80% for the FLASC technology and li-ion battery, based on preliminary estimates early in the project. As a result, the revenues for both technologies in this analysis are the same. However, more recent evaluations suggest that the actual efficiencies are substantially different between the two technologies, i.e. an efficiency of ~70-75% for the FLASC technology and ~85-90% for li-ion battery. These different efficiencies were not accounted for in the modelling, and would affect the results, leading to higher revenues for the higher-efficiency Li-ion battery compared to the lower-efficiency FLASC storage.

Table 3 Unit (kWh) CapEx of storage technologies and configurations considered in this economic assessment

Technology types	Storage configurations		
	100 MW-4h	200 MW-4h	200 MW-8h
FLASC	900 €/kWh	900 €/kWh	600 €/kWh
Li-ion battery	1400 €/kWh	1200 €/kWh	1200 €/kWh

³ With assumed WACC of 6% and a lifetime of 30 years



DISCLAIMER

! The comparison between FLASC and Li-ion battery storage technologies shown here is based on assumed CapEx figures provided by Seaway7 and an efficiency of 80% for both technologies. In reality, the actual efficiencies differ between the two technologies and cost assumptions may vary. These factors affect the cost recovery potential for both technologies.

Figure 19 Percentage of annual CapEx and OpEx recovered by day-ahead market revenues for two technologies (left FLASC, right Li-ion) with different configurations (size and storage duration)

Comparing these two figures allows to determine which share of the annual CapEx and OpEx is covered by the revenues of the ES in the day-ahead market and how this differs across technology types and storage configurations. This is presented in Figure 19 (left and right).

One key conclusion that can be drawn looking at Figure 19 is that day-ahead market revenues generated by the ES are insufficient to recover the annual CapEx and OpEx across all cases. As discussed in Section 2.2, the business case of energy storage consists of multiple revenue streams. Since this study only focuses on revenues from the day-ahead market, additional revenue streams will have to be stacked to recover the Capex and create viable business case.

Next to that, when analysing these two graphs, it becomes clear that for the FLASC technology, a larger share of CapEx can be covered by the day-ahead market revenues compared to the Li-ion battery. This can be attributed to the fact that FLASC has lower CapEx for each configuration compared to the Li-ion battery (see Table 3).

When comparing the performance of storage configurations of the FLASC technology, it can be concluded that configurations of 100 MW-4h and 200 MW-4h have relatively similar performance. As the CapEx per kWh of storage duration is the same for both systems, total CapEx are double and revenues, as concluded in section 4.2 are around double as well. Therefore, the ratio between CapEx and day-ahead market revenues is roughly equal for both configurations.

Furthermore, the system of 200 MW-8h storage duration can recover the largest share (40%) of the annual costs compared to the other FLASC storage configurations. In Section 4.2, it was described that, while keeping the power of the ES the same, increasing the storage duration results in diminishing returns in terms of revenues in the day-ahead market. However, Table 3 shows that this storage configuration has the lowest CapEx per kWh. So, even though increasing storage duration can lead to diminishing returns in revenue per additional MWh, a concurrent (33%) reduction in CapEx per MWh more than offsets this effect. Therefore, the overall financial performance of the 200 MW-8h storage duration ES improves compared to the other two.

When comparing the performance of storage configurations of the Li-ion technology, the second configuration in Figure 19 (200 MW-4h) is able to cover the largest share of the CapEx through day-ahead market revenues. Although both 100 MW and 200 MW ES with 4 hour storage duration have similar per MWh revenues as discussed previously, due to lower investment cost per MWh this configuration is able to recover a larger share of its annual costs.

6 Conclusion and recommendations

6.1 Conclusions

This study assessed the added value of co-locating energy storage (ES) next to offshore wind farms from the perspective of the asset operator and on a societal level. Through model-based analysis, the economic performance of two storage technologies, 1) FLASC system applying Hydro-Pneumatic Liquid Piston Technology and 2) Li-ion battery was explored with different configurations. These included power capacities of 100 MW and 200 MW, corresponding to 5 and 10% relative to the wind farm and storage duration ranging from 4 to 16h.

Multiple storage configurations were analysed under different energy system scenarios, based on National Drivers and Climate Ambition from IP2024. A key assumption in the modelling approach is that storage charges exclusively from the co-located wind farm and not from the grid. The scope of the study was limited to the day-ahead market, focusing on the arbitraging potential of the storage in this market. It should be noted, however, that this is only one of the different revenue streams which storage can obtain. Balancing markets are not included as part of the potential revenue stack of storage within this study.

The economic performance of these configurations was assessed using a set of input assumptions for technical and cost parameters. Key values, such as capital expenditure (CapEx) and round-trip efficiency, were provided by Seaway 7 and have not been independently validated by TNO. For modelling purposes, a uniform round-trip efficiency of 80% was applied to both technologies. However, more recent evaluations suggest that actual efficiencies may differ — with lithium-ion batteries typically achieving higher

Table 4 Modelling results showing additional revenues in day-ahead market and cost (CapEx & OpEx) recovery by day-ahead market revenues in National Drivers & Climate Ambition scenarios

		Additional annual day-ahead market revenues (%) ⁴	Cost (CapEx & OpEx) recovery (%) by day-ahead market revenues
<i>Technology</i>	<i>Storage configurations</i>	Results from National Drivers & Climate Ambition	
FLASC/HPES	100MW-4h	2-4%	26-29%
	200MW-4h	7-8%	25-28%
	200MW-8h	10-12%	29-31%
Li-ion	100MW-4h	2-4%	16-18%
	200MW-4h	7-8%	19-21%
	200MW-8h	10-12%	14-16%

⁴ *Additional revenues* refer to the increase in annual revenues resulting from the co-location of storage next to the offshore wind farm, compared to a reference case in which the wind farm does not have any storage

efficiencies (around 85%) and FLASC systems operating closer to 75%. Whether similar differences exist in CapEx is currently unknown. These assumptions have a direct influence on the comparative outcomes and should be revisited as more validated data becomes available.

Both higher power capacity (MW) and increased storage duration (MWh) increase the revenues the storage is able to capture in the day-ahead market, though diminishing returns apply when increasing storage duration. This can be attributed to the fact that the most profitable arbitrage opportunities in the day-ahead market are captured by the first hours of storage duration as described in section 4.2. Each additional hour of storage duration is able to capture less profitable price spreads because of market dynamics and price formation in the day-ahead market.

When comparing these additional annual revenues to the annual costs for two storage technologies – HPES/FLASC and Li-ion, systems with relatively low cost (CapEx and OpEx) per kWh and high revenue per MWh are able to recover the largest share of these cost. This specifically applies to the FLASC storage of 200MW-8h which is able to recover the largest share (29-31%) of annual CapEx and OpEx, as strong diminishing CapEx cause the gap between cost and revenues to decrease. Cost recovery for other configurations is also presented in Table 4.

It is important to note that day-ahead revenues represent only one of several potential income streams for energy storage. The results underline that stacking multiple revenue sources is essential to make the business case viable. Model outcomes show that storage utilisation in the base case configuration (200 MW-4 h) was limited to around 40%. A large share of storage capacity remains available to participate in other markets and unlock additional value.

A grid capacity constraint was considered, based on the tender criteria for IJmuiden Ver Gamma. From the offshore wind perspective, such a constraint can result in curtailment and revenue losses. However, the extent of these impacts largely depends on the specific hours during which the grid operator chooses to reduce capacity. From the perspective of energy storage, the impact of the grid constraint is less significant than one might initially expect. This is because the operation of energy storage systems remains largely unchanged, due to the correlation between reduced grid capacity and periods of low electricity prices. In essence, energy storage was already operating as if a grid constraint were in place. This highlights the added value of energy storage—not only from a market standpoint but also from the perspective of grid operators.

Looking at a more flexible energy system, where 500 MW of offshore storage was assumed across different wind farms, effects on market dynamics were limited. This is because this capacity (500MW) is less than one percent of the total installed generation capacity, therefore, market price formation was not significantly affected. The societal value of offshore storage lies in the ability to more effectively make use of the offshore grid, potentially reducing both congestion and investments in offshore infrastructure. By combining offshore and onshore storage, improved market functioning can be achieved, whilst harvesting the benefits of offshore storage.

Finally, the value of energy storage was assessed in the context of long-term contracts, such as Power Purchase Agreements (PPAs) and Contracts for Difference (CfDs). The behaviour and added value of energy storage are highly influenced by the specific terms of these contracts. A traditional two-sided CfD offers no opportunity for co-locating energy storage

with offshore wind, whereas alternative CfD designs may cause storage systems to either follow or disregard market signals. Pairing energy storage with a PPA can enhance the value of the remaining market-exposed portion of wind generation or support the development of new business models that command higher PPA values. While energy storage can deliver significant value when combined with long-term contracts, the extent and nature of this value depend heavily on contract design. From a policy perspective, it is crucial that criteria are structured to enable the integration of energy storage in ways that align with broader societal benefits.

6.2 Recommendations

Building on the findings of this study, several key avenues emerge for future research and policy development to better understand and support the role of co-located offshore energy storage.

Most of these avenues will be covered by the upcoming OESTER (Offshore Electricity Storage Technology Research) project⁵. Various partners from across the European offshore renewable energy sector have joined forces in this project. It is a three-year initiative, with major energy industry players such as RWE, Vattenfall and TNO, aiming to accelerate the development and deployment of offshore electricity storage technologies. The OESTER project addresses key challenges in the renewable energy transition such as system integration and demonstrates the benefits of adopting this technology.

The key avenues for future research and policy development:



1. Expand scope to include multiple revenue streams

This study focused exclusively on the Dutch day-ahead market, yet in practice, energy storage systems can access a broad range of revenue streams. Future analyses should incorporate these additional value streams to provide a more comprehensive assessment of the economic viability of (offshore) energy storage.



2. Ensure Energy Storage is Considered in CfD Design for the Netherlands

The design of Contracts for Difference (CfDs) plays a pivotal role in determining whether energy storage can be viably paired with offshore wind. Policymakers should ensure that future CfD frameworks in the Netherlands explicitly take energy storage into account, so that contract structures do not unintentionally limit its integration or value.



3. Explore Co-Optimisation of Offshore Wind and Storage in PPAs

Innovative Power Purchase Agreement (PPA) structures that allow for joint optimisation of wind and storage output could unlock additional value. These may include profile-smoothing mechanisms or flexible delivery terms that improve revenue certainty and operational efficiency. Future commercial strategies should evaluate how such co-optimised PPAs impact bankability and investor confidence.

⁵ For more information, please refer to: <https://www.tno.nl/en/newsroom/2025/02/start-offshore-electricity-storage/>



4. Coordinate Offshore and Onshore Flexibility Strategies

Offshore storage alone will not provide sufficient flexibility to integrate the projected 70+ GW of offshore wind by 2050. A coordinated approach that includes onshore energy storage systems, demand-side response, and strategic grid reinforcements is essential. Policymakers and system operators should align offshore and onshore flexibility strategies to ensure efficient and resilient energy system integration.

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Appendix A Storage technologies considered and comparison

This is work done by project partner Seaway7

A.1 FLASC Hydro-Pneumatic Energy Storage (HPES)

FLASC's HPES system, developed in collaboration with Seaway7, is a long-duration, modular storage solution tailored for offshore environments.

HPES description

Hydro-Pneumatic Energy Storage (HPES) systems rely on the thermo-elasticity of gas. The use of HPES in the context of offshore applications is an active research topic. A one-year lasting, successful small-scale test (Figure 19) confirmed that it is possible to utilise the ocean as a natural heatsink and this increases efficiency by allowing the thermodynamic process to operate at quasi-isothermal conditions. Results from hundreds of charging/ discharging cycles confirmed a very high thermal efficiency (>93%) without any measurable impact on surrounding water temperature and encouraged upscaling of this technology for commercial offshore applications [1].

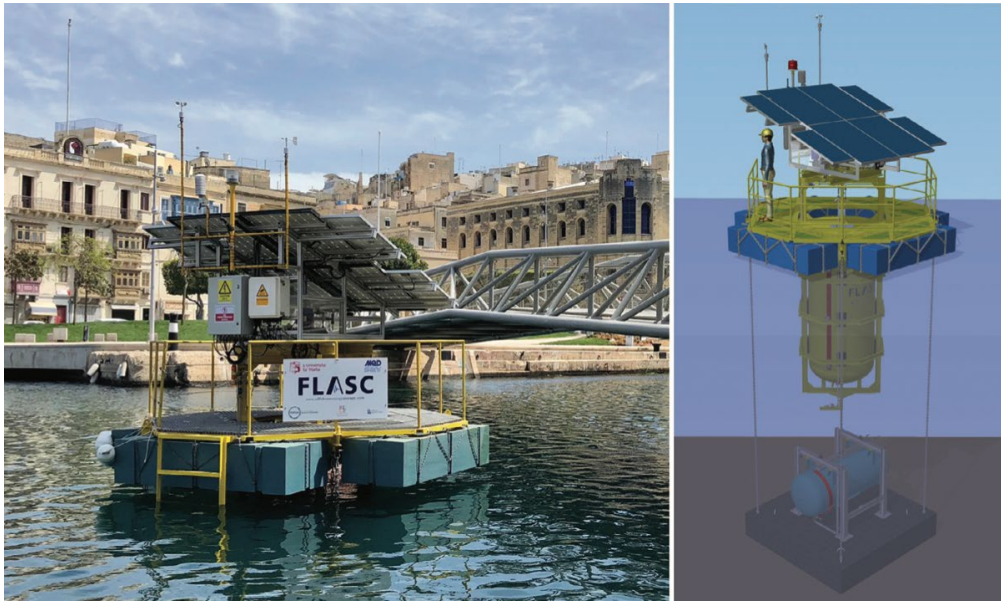


Figure 20: The FLASC HPES marine prototype deployed in Malta in 2018

Every HPES system has two key components: a Pressure Containment System (PCS) and an Energy Conversion Unit (ECU). The PCS houses the pressurised fluids and contributes to the energy storage capacity (kWh) of the system. The energy stored primarily depends on the total volume and maximum pressure that the system can sustain.

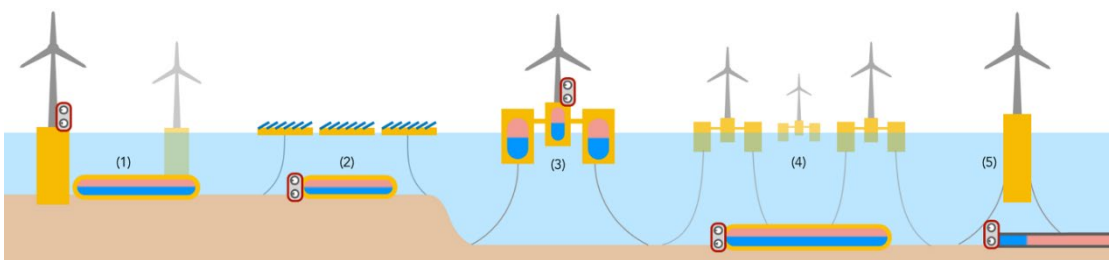


Figure 21: Possible configurations of the FLASC HPES solution: (1) bottom-fixed wind; (2) offshore PV; (3) floater-integrated; (4) stand-alone centralized unit; (5) in a repurposed existing offshore pipeline.

The ECU converts electrical power into hydraulic power to charge the system and hydraulic power into electricity during discharging. A key advantage of HPES systems is that the PCS and ECU can be sized independently, resulting in a flexible approach that can be optimised across a range of applications, from low-power and high-capacity to high-power and low-capacity options (Figure 21).

The pre-charged HPES system discussed in this report can be deployed in relatively shallow waters (40-400m) for co-location with established offshore renewable generation. The FLASC system is an Open Gas Cycle system with an energy density of 18

kWh/m³ @ 350bar. Considering the efficiency of the hydraulic conversion process on the charging and discharging side of the system, the overall round-trip efficiency was seen to be 65-70%.

In this study, it was assumed that the efficiency of the subsea storage system is 70% for a de-centralised case and 68.8% for a centralised case. The latter considers losses in the transformer required as an interface between the inter-array and storage system voltages.

The Unit CAPEX corresponds to €900/kWh or €600/kWh for a 4-hour or 8-hour HPES system, respectively. This comprises the cost of capacity (€/kWh) and the cost of power (€/kW). The cost of capacity corresponds to the Pressure Containment System cost and is based on a design with steel pipelines and includes fabrication and installation cost. The cost of power then corresponds to the ECU cost, based on the expected electrical and hydraulic equipment cost.

The HPES system is not affected by cycling degradation. It will require monitoring and period maintenance of the topside equipment, with an expected intervention period of 5 years. This is already accounted for in the OPEX consideration. The subsea PCS is generally maintenance free, some marine growth may develop on the outside, but this is manageable and does not interfere with the storage capacity. It could however influence the heat-transfer characteristics of the PCS walls, which may in turn affect the efficiency of the system. However, based on past tests on marine prototypes, this did not result in a measurable impact on the efficiency.

Summary of Key Characteristics:

- **Storage Duration:** 4–12 hours
- **Round-Trip Efficiency:**@p
 - Decentralized: 70.0%
 - Centralized (with transformer): 68.8%
- **Energy Density:** 18 kWh/m³ (Design pressure 350bar)
- **CAPEX:**
 - €900/kWh (4-hour system)
 - €600/kWh (8-hour system)
- **OPEX:** 2% of CAPEX annually
- **Maintenance:** Minimal; 5-year intervention cycle
- **Deployment:** Suitable for shallow waters (40–400m); flexible configurations (bottom-fixed, floater-integrated, centralized)

A.2 Offshore Li-ion Battery Storage

Initial screening considered both subsea and topside battery configurations. Subsea battery systems are currently limited to small-scale applications (kWh range), which do not align with the scalability requirements of this study (50 MWh+). In the screening no actor has been identified for providing concepts or offering large-scale subsea battery solutions for offshore wind field.

The solution included was based on current Offshore Hydrogen Production solutions and replacing the fuel-cells with battery pack. A key technology future within the battery is adopted and that is the current battery stacking technology for marine applications and vessels. This solution has allowed for effective packing of MWh Size storage solutions that will fit nice in a topside facility dedicated to battery storage. The foundation can either be monopiles or jackets.

Key considerations for the Li-ion battery solution:

- **Scalability:** Configurable in unit sizes from 50 MWh to 200 MWh
- **Deployment:** Topside installation simplifies maintenance and integration
- **Commercial Readiness:** Proven technology with established supply chains and performance data



Figure 22 Illustration of jacket with structure. The Battery Solution will explore effective stacking of Li-Ion batteries in marine environment

Cost evaluation

Current containerized battery solutions are available offshore with a cost estimated in range €3000 - €4000/kWh. These are expensive solutions to scale MWh. Instead we consider a fully stacked solution that does not include containerized batteries but instead build a custom made topside facility for the battery packs.

The solution included in this study takes advantage of state of art batteries for marine applications with the goal to reach a cost-effective offshore battery solution.

Below is a breakdown of the topside stacked battery solution:

Table 5 Cost breakdown of the topside stacked battery

500MWh Topside Storage cost breakdown	
	M\$
Stacked Batteries	375
Transformers and inverters	150
Foundation	50
Installation	17
Total for Topside Storage	592

The cost estimation gives a unit-cost of 1184 USD/kWh (1050EUR/kWh) for offshore Li-Ion batteries. For this study an evaluation of cost impact due to scaling the unite size from a 140MWh offshore facility to a 1600MWh facility. This evaluation concludes that a smaller system will have higher unit cost estimate to 1600 EUR/kWh and a larger solution will bring down unit cost to 1200 EUR/kWh.

The cost estimation are based on early concept solutions based on stackable maritime batteries that includes cost of transformers and inverters. A full system architecture of this solution is not performed.

Key Characteristics:

- **Storage Duration:** <1 hour
- **Round-Trip Efficiency:** ~90%+
- **CAPEX:**
 - €1600/kWh (small scale)
 - €1200–1400/kWh (larger scale)
- **OPEX:** 2% of CAPEX annually
- **Deployment:** Topside installation; scalable in 50–200 MWh units

A.3 Summary Comparison Table

Feature	FLASC HPES (Seaway7)	Offshore Li-Ion Batteries
Storage Duration	4–12 hours	<1 hour
Round-Trip Efficiency	68.8–70%	~90%+
CAPEX (€/kWh)	600–900	1200–1600
OPEX (% of CAPEX)	2%	2%
Lifetime	25 – 30 years	8 – 10 years
Cycle degradation	None	2 – 3%
Maintenance	5-year cycle	Annual inspection
Deployment	Subsea	Topside
Scalability	Modular (PCS & ECU)	Modular (stackable units)
TRL at Start/End	3 → 4	6+ (mature)

Appendix B Input to business model

HEPS Scenarios Modelled:

Storage solutions for TNW (700 MW) and Doordewind (2 GW):

FLASC / Seaway7			
700MW Wind Farm:	35MW / 140MWh (4hr)	70MW / 280MWh (4hr)	70MW / 560MWh (8hr)
2GW Wind Farm:	100MW / 400MWh (4hr)	200MW / 800MWh (4hr)	200MW / 1600MWh (8hr)

with corresponding cost:

FLASC / Seaway7			
	5% x 4hr	10% x 4hr	10% x 8hr
700MW Wind Farm:	900EUR/kWh	900EUR/kWh	600EUR/kWh
2GW Wind Farm:	900EUR/kWh	900EUR/kWh	600EUR/kWh

Li-ion Scenarios Modelled:

Storage solutions for TNW (700 MW) and Doordewind (2 GW):

Offshore Batteries			
700MW Wind Farm:	140MW / 140MWh (1hr)	280MW / 280MWh (1hr)	560MW / 560MWh (1hr)
2GW Wind Farm:	400MW / 400MWh (1hr)	800MW / 800MWh (1hr)	1600MW / 1600MWh (1hr)

with corresponding cost:

Offshore Batteries			
700MW Wind Farm:	1600EUR/kWh	1400EUR/kWh	1400EUR/kWh
2GW Wind Farm:	1400EUR/kWh	1200EUR/kWh	1200EUR/kWh

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