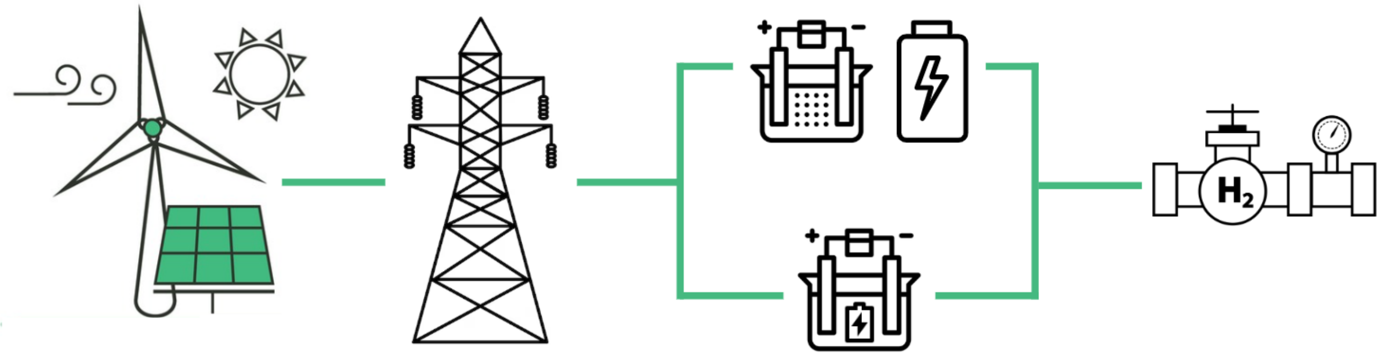
Delft University of Technology

Sustainable Energy Technology (SET)

MSc Thesis report

A comparison of the Levelised Cost of Hydrogen (LCOH) between the Battolyser and a system consisting of a battery and an electrolyser.



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Executive Summary

The Netherlands has set ambitious climate targets, aiming to become climate neutral by 2050, which implies a 100% reduction of greenhouse gas emissions compared to 1990 levels. Solar and wind power are key to replacing fossil fuels in electricity generation, but their intermittent output creates a need for both short-term and seasonal energy storage. At the same time, sectors such as heavy industry, aviation and shipping remain challenging to electrify directly. Renewable hydrogen, also referred to as RFNBO-compliant hydrogen, is emerging as a clean and flexible energy carrier that helps fill the gaps where green electricity alone is not enough. It can be stored, transported, and used in applications where direct electrification is not feasible. Unlike grey hydrogen produced from fossil fuels, renewable hydrogen is made by using electricity from solar or wind to split water into hydrogen and oxygen, significantly reducing carbon emissions.

Producing renewable hydrogen remains expensive due to the high capital costs of electrolysers and the limited availability of cheap renewable electricity. Producing renewable hydrogen in a way that is both economically sustainable and scalable is important to decarbonize global industries and provide renewable seasonal storage. To evaluate and compare the economic performance of hydrogen production methods, the Levelised Cost of Hydrogen (LCOH) is used. LCOH represents the average cost of producing hydrogen over the lifetime of a facility, accounting for capital, operational, and energy costs. As the renewable hydrogen market is not yet completely developed, metrics such as Net Present Value (NPV) are less suitable for determining the competitiveness of the technologies. Therefore, it is important for renewable energy companies, like Eneco, to create renewable hydrogen with the lowest LCOH to be competitive in the hydrogen market.

One approach to lowering costs is to pair electrolysers with batteries, where revenues from storing electricity and selling it to the grid, known as arbitrage revenue, can help offset operational expenses. This can be achieved through two types of systems: the Battolyser, an innovative technology that combines battery storage and hydrogen production in a single device, and a system where a battery and electrolyser are co-located but operate as separate units. These systems have distinct advantages and disadvantages, which have not yet been evaluated and compared. Therefore, the main research question is: **How does the Battolyser compare to a system with a separate battery and electrolyser in achieving the lowest levelised cost of hydrogen (LCOH) compliant to RFNBO (EU) standards?**

To answer this question, this research analyses four different co-located system configurations. Each configuration combines either an alkaline or PEM electrolyser with an LFP lithium-ion battery or a vanadium redox flow battery, selected for their technological maturity and future potential. Together with the Battolyser, the five systems considered are:

- Battolyser
- Alkaline electrolyser + Lithium-ion battery
- PEM electrolyser + Lithium-ion battery
- Alkaline electrolyser + Redox flow battery
- PEM electrolyser + Redox flow battery

Financial and technological characteristics of the systems have been identified, taking the Dutch market into account. The five systems are simulated by using a novel techno-economic simulation model that has been created for this research. The model simulates the systems in a framework based on Dutch hourly electricity prices between 2030 and 2050. The simulation model focuses on three main operational strategies: battery charging, battery discharging, and hydrogen production. The systems are simulated on an hourly basis for the period 2030–2050, using a combination of mixed onshore wind and solar power profiles contracted through a Power Purchase Agreement (PPA), together with grid electricity as power input in the base case simulations. The model uses a controller with a three-hour receding horizon to anticipate electricity price fluctuations. The simulation framework ensures an objective comparison by keeping operational strategies and regulatory compliance consistent while varying system-dependent parameters such as electrolyser efficiency, minimum stable load, and system costs.

The base case simulations showed that the Battolyser performs best with an LCOH of 9.96 €/kgH_2. Among the four battery-electrolyser combinations, the system with a lithium-ion battery and a PEM electrolyser came closest to matching the performance of the Battolyser, followed by the alkaline and Li-ion system. Although redox flow battery systems have longer lifespans and flexible sizing, their higher costs result in poor LCOH performance, because the technical benefits do not compensate for this. Notably, Figure 1 shows that the LCOH values lie close to each other, with a spread of 1.40 €/kgH_2 when including redox flow systems, and just 0.40 €/kgH_2 when excluding them.

Several analyses, including sensitivity and scenario analyses, were performed to understand the robustness of these findings. A local sensitivity analysis was performed by varying electricity prices by plus and minus 20% compared to the base case, to examine how changes in electricity costs impact LCOH performance. This analysis showed that the PEM + Li-ion system, followed by the ALK + Li-ion system, both perform better than the Battolyser when the electricity prices increase, as the systems can take full advantage of the flexibility by dynamically shifting operation. They can produce

hydrogen at nominal capacity during one hour, switch to battery charging the next hour when electricity prices are low, and then sell electricity back to the grid during high-price periods. In contrast, the Battolyser performed significantly worse under these increased conditions, as it cannot separate battery operation from hydrogen production, which limits the system's ability to fully exploit price fluctuation.

In the global sensitivity analysis, five key parameters (CAPEX, OPEX, electrolyser efficiency, battery capacity, minimum stable load) were varied to investigate the absolute effect on the LCOH, as well as their interaction with other parameters. This analysis shows that varying the electrolyser efficiency has the highest absolute effect on the LCOH. In addition, electrolyser efficiency is present in every statistically relevant interaction term. This shows that electrolyser efficiency is not only a significant factor on its own but also influences the impact of other parameters, making it the most important determinant of LCOH.

This is confirmed in the scenario analysis, where the systems are simulated with a more steady offshore wind power profile, in contrast to the mixed wind on land and solar power profile in the base case. The Battolyser and alkaline systems, both of which have better electrolyser efficiencies than the PEM system, perform better under these steady conditions. In contrast, the PEM-based systems show a decline in performance, requiring significantly lower offshore wind PPA prices to achieve LCOH levels similar to those in the base case. This indicates that under stable power conditions, electrolyser efficiency becomes a more dominant factor in contrast to operational flexibility.

Finally, the Battolyser and co-located systems were compared to standalone alkaline and PEM electrolysers. The standalone systems outperformed the hybrid configurations due to their lower cost structure and ability to channel all available power directly into hydrogen production. The alkaline electrolyser achieved a lower LCOH than the PEM system in the base case, the reduced electricity price scenario, and under an offshore wind profile. This advantage can be attributed to its higher electrolyser efficiency. These findings indicate that adding a battery to an electrolyser does not necessarily lead to lower LCOH. However, the standalone systems lacked operational flexibility, making them perform worse under scenarios with higher and more volatile electricity prices, where the PEM + Li-ion system performed better.

In conclusion, this research explored whether combining battery storage with electrolysis could lower production costs through electricity market arbitrage. The Battolyser was compared with four battery-electrolyser systems for renewable hydrogen production. The results show a small spread in LCOH and that there is no single system that performs best across all situations. Among the hybrid systems, the Battolyser achieves the lowest LCOH in the base case, the reduced electricity price scenario, and under an offshore wind profile. Its strong performance can be attributed to its high electrolyser efficiency, which proves to be a significant factor in determining the LCOH. Nonetheless, standalone electrolysers outperform the Battolyser in these scenarios due to their lower cost structures and direct power use. However, when electricity prices rise and become more volatile, systems with separate batteries and electrolysers perform better, with the PEM + Li-ion configuration achieving the lowest LCOH.

It is recommended that Eneco prioritizes hydrogen production systems with high electrolyser efficiency as a strong option for RFNBO-compliant hydrogen. Standalone electrolysers should be considered when electricity prices are expected to follow patterns similar to the base case. However, Eneco should remain open to using separate battery and electrolyser setups in case when electricity prices are expected to rise. Since the LCOH differences between systems are relatively small, it is further recommended that the system selection should be guided by additional factors such as environmental impact and the availability of technologies within the European market.

While the system choice is important to provide a competitive edge in the hydrogen market, the results also highlight a broader challenge for renewable hydrogen. Eneco expects that the willingness-to-pay for renewable hydrogen will be approximately €9/kgH_2. Figure 1 shows that no system is able to produce renewable hydrogen below this threshold and thus a cost gap remains. Therefore, future research should investigate the renewable hydrogen market in the Netherlands and potential subsidy schemes. Moreover, it is recommended to expand the simulation model to allow a more detailed comparison between the systems as this simulation model has some limitations. Possible additions include incorporating optimization horizons that reflect the day-ahead electricity market, enabling dynamic power allocation, exploring participation in additional energy markets, and performing environmental life cycle assessments.

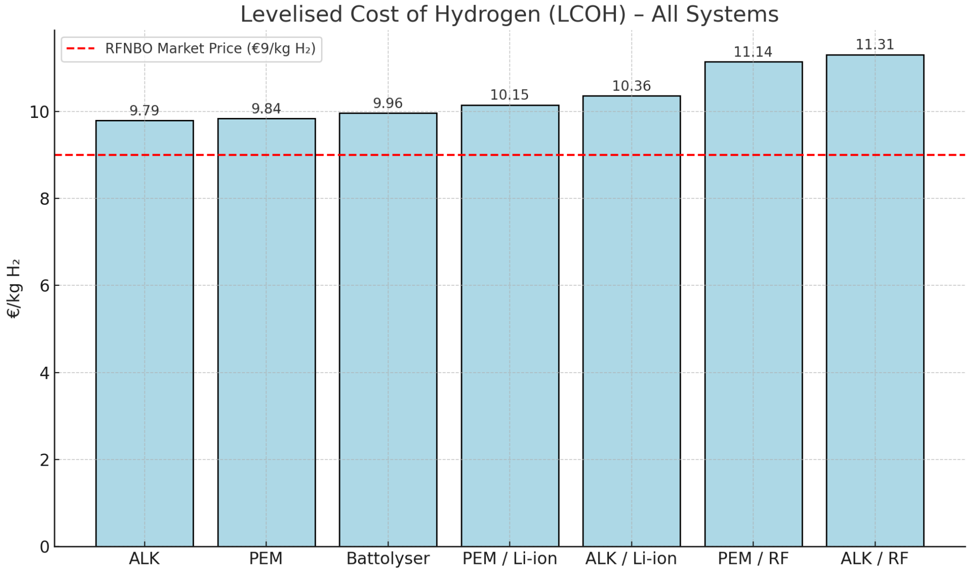

Figure 1: Overview of base case LCOH values compared to the expected willingness to pay price of renewable hydrogen.

Acknowledgments

This thesis was written in fulfillment of the requirements for the degree of Master of Science in Sustainable Energy Technology at Delft University of Technology. It marks the final milestone of my academic journey in Delft.

Throughout my studies at TU Delft, I have been intrigued by the challenges and opportunities of the energy transition. This thesis offered the chance to explore several aspects of renewable energy systems, particularly hydrogen production and energy storage. By examining both the technological and financial aspects, I gained a deeper understanding of the renewable energy market and the complexity of implementing these systems in practice.

I am sincerely grateful to my academic supervisors, Prof.dr.ir. Zofia Lukszo and MSc. Justin Starreveld, for their guidance, constructive feedback, and support throughout this project. Their expertise and insights were essential in shaping the final outcome. A special thanks goes to Prof.dr. Fokko Mulder, whose expertise helped deepen my understanding of the Battolyser, and whose lectures first sparked my interest in exploring it further. I would also like to thank Prof.dr.ir. Laurens de Vries for being part of the thesis committee.

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Finally, I would like to acknowledge the use of OpenAI ChatGPT for helping to improve the language and rewrite parts of this thesis.

Floris van Wingerden
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Contents

List of Figures

List of Tables

Abbreviations

Abbreviation	**Definition**
ACER	Agency for the Cooperation of Energy Regulations
ALK	Alkaline
ALK-Li	Alkaline electrolyser & lithium ion system
ALK-RF	Alkaline electrolyser & redox flow system
BESS	Battery Energy Storage System
BMS	Battery Management System
BoP	Balance of Plant
BoS	Balance of System
C-rate	(Dis)charge rate
CAPEX	Capital Expenditure
DoD	Depth of Discharge
DUD	Demand Unit Document
EHS	Extra High Voltage System
EoL	End of Life
EPC	Engineering, Procurement & Construction
ESS	Energy Storage System
ETS	Emission Trading Scheme
EU	European Union
FF	Full Factorial
FullRen	Fully Renewable
GHGE	Greenhouse Gas Emissions
GI	Green Index
GoO	Guarantees of Origin
HHV	Higher Heating Value
HS	High Voltage System
H_2	Hydrogen
HVAC	High Voltage AC Converter
IEA	International Energy Agency
KOH	Potassium Hydroxide
kWh	Kilowatt hour
LCOE	Levelised Cost of Electricity
LCOH	Levelised Cost of Hydrogen
LFSM-UC	Limited Frequency Sensitive Mode for Underfrequency Consumption
LFP	Lithium Iron Phosphate
Li-Fe	Lithium-Iron
LHV	Lower Heating Value
MPC	Model Predictive Control
MSL	Minimum Stable Load
MWh	Megawatt hour
NPV	Net Present Value
OPEX	Operational Expenditure
OH	Hydroxide
P2G	Power-to-gas
PartRen	Partial Renewable
PEM	Proton Exchange Membrane
PEM-Li	PEM electrolyser & lithium ion system
PEM-RF	PEM electrolyser & redox flow system
PFAS	Per- and Polyfluoroalkyl Substances
PPA	Power Purchase Agreement
RED	Renewable Energy Directive
RF	Redox Flow
RFNBO	Renewable Fuels of Non-Biological Origin
RTE	Round Trip Efficiency
SMR	Steam Methane Reforming
SOC	State of Charge
TFA	TriFluoroacetic Acid
TRL	Technology Readiness Level
VRFB	Vanadium Redox Flow Battery
ZBRFB	Zinc-Bromine Redox Flow Battery

1 Introduction

The Netherlands aims to reduce their greenhouse gas emissions by 49% in 2030, and by 95% in 2050 as part of the 2019 Climate Act [10]. In order to do so, the energy mix of the Netherlands must shift from fossil based power plants to renewable energy power plants such as solar and wind generated electricity. The amount of electricity generated from these renewable plants varies due to the intermittent behaviour of the wind and sun. This impacts the security of supply and has volatile electricity prices as a consequence, which means that short and longer term storage solutions are needed to bridge the gap between supply and demand [11]. Besides the phase-out of conventional electricity generation, industries and heavy transport must also switch from carbon based fuels towards zero-emission based fuels. Hydrogen (H_2) is among the most promising energy carriers, serving both as a means of electricity storage and as a fuel for industrial combustion and heavy transport. Moreover, hydrogen is also used in the food and medical industry, increasing the demand for hydrogen production. There are several processes to create hydrogen of which Steam Methane Reforming (SMR) and electrolysis are the most widely implemented [12]. SMR is a process where methane reacts with water to create carbon monoxide and hydrogen. This process is often followed by the water-gas shift reaction, which turns carbon monoxide and water into carbon dioxide (CO_2) and hydrogen [13]. As seen, this process still emits carbon emissions, which is not desirable, and therefore the focus must shift toward another form of hydrogen production, namely electrolysis. In this process, water is split in hydrogen and oxygen with the use of electricity. There are no side effects in this reaction and this form of hydrogen production can be depicted as renewable hydrogen, when certain criteria are met. The Levelised Cost of Hydrogen (LCOH) measures the cost of producing hydrogen, directly influencing its potential selling price. The LCOH of renewable hydrogen depends on the costs associated with the system, as well as the number of full load hours the electrolyser can operate. Regrettably, renewable hydrogen is on average more expensive than hydrogen made with SMR-processes due to the dependency on the volatile electricity prices associated with renewable electricity generation [14][15]. It is therefore important for renewable energy companies, like Eneco, to create renewable hydrogen with the lowest LCOH to be competitive in the hydrogen market.

One option to produce renewable hydrogen, is to directly couple the electrolyser to a renewable asset, which is also known as a co-located situation. As mentioned, the intermittency of wind and solar electricity generation limits the operation of the electrolyser. There are several electrolysers, each with its specific benefits and challenges, such as an alkaline electrolyser or a proton exchange membrane (PEM) electrolyser. Brauns et al. (2020) addresses the challenges associated with the intermittent use of alkaline electrolysers, which results in the production of impure hydrogen and performance degradation [16]. Moreover, as noted by Kojima et al. (2023), most electrolysers require a certain base load, potentially up to 40%, to maintain standby status [17]. The standby mode allows them to switch from non-producing to hydrogen-producing mode in order to follow the intermittent cycle of the coupled renewable power plant. Thus, if the system is co-located, a form of auxiliary power is needed to keep the electrolyser standby, and prevent performance degradation. Another method for producing renewable hydrogen is to connect the electrolyser to the grid. However, there are several restrictions for hydrogen to be depicted as renewable when an electrolyser is connected to the grid. Similar to the co-located case mentioned above, problems with volatility arise due to the differences in electricity price, making the operation of grid-connected electrolysers also intermittent. A storage solution could be advantageous for both co-located and grid-connected systems, as it allows for the storage of excess electricity, which can later be utilized to maintain the minimum base load of the electrolyser. Additionally, shifting consumption away from peak-price periods and taking advantage of low-price hours can reduce overall production costs by enabling electricity arbitrage. The most common short-term electricity storage method is a battery, with capacities ranging from several kilowatt hours (kWh) to hundreds of megawatts hours (MWh), depending on the type. In the co-located situation, the battery can store excess electricity which the electrolyser can use when the wind is not blowing or when the sun is not shining. In the grid-connection situation, the battery can charge during low or negative electricity prices, and discharge during high electricity prices. The electricity during discharge can be inserted into the grid or it can be used to keep the electrolyser in operation. A new innovation in battery and electrolyser technology is the Battolyser. The Battolyser is an alkaline electrolyser with an incorporated nickel-iron (Ni-Fe) battery, so that the asset can follow the intermittency of wind and solar power plants [18]. The Battolyser has the potential to overcome the challenges mentioned above associated with intermittent renewable energy generation. Before evaluating the performance of such hydrogen production systems, it is essential to develop an understanding of their characteristics, challenges, and benefits.

1.1 Problem Analysis

The transition to a sustainable energy system is dependent on the production of renewable hydrogen, a crucial component in achieving carbon-free seasonal storage and decarbonizing sectors such as industry and heavy transport. However, the widespread adoption of renewable hydrogen faces significant challenges, primarily due to the intermittency of renewable energy generation and the high costs associated with this form of hydrogen production. Addressing these issues is important to ensure that renewable hydrogen becomes a cost-effective and reliable energy carrier.

The levelised cost of hydrogen (LCOH) is a relevant metric for evaluating RFNBO compliant hydrogen, as a lower LCOH enhances its competitiveness and market potential. Moreover, finding the most cost-effective way to produce hydrogen is important for the energy transition, as lower subsidy needs free up public funds to accelerate progress in other areas. Traditional setups to produce renewable hydrogen involve alkaline or PEM electrolysers integrated directly with renewable energy generation or through a grid connection. These setups often face limitations in terms of full load hours and economic feasibility due to the intermittent nature of renewable energy generation. Battolyser Systems has introduced a promising approach that combines the functionalities of a battery and an electrolyser into a single system. This integrated solution combines the ability to store electricity while instantly converting excess renewable energy into hydrogen. By enabling both energy trading and hydrogen production within one device, Battolyser Systems claims to achieve the lowest LCOH for renewable hydrogen by using arbitrage revenue to offset some of the costs [18]. According to Battolyser Systems (2024), a grid-connected Battolyser yields a LCOH of €6.3/kgH_2 when the systems produces one ton H_2 per day [19]. In this study, it is said that a PEM electrolyser would yield a LCOH of €7.2/kgH_2 in the same situation. According to El-Hamalawy et al. (2024), grid-connected PEM electrolysers can reduce their LCOH with 9% when the electrolyser is combined with a BESS [20]. If this reduction in LCOH can be generalized, the LCOH of the PEM electrolyser paired with a BESS (€6.55/kgH_2) would approach that of the Battolyser. Moreover, Superchi et al. (2022) found that the LCOH of a grid-supported alkaline electrolyser with a nominal capacity of 16 MW combined with a wind farm, can either decrease or increase depending on the size of the battery energy storage and other assets [1]. The blue line in Figure 2 shows a graphical representation of the impact of adding a BESS to an electrolyser. It can be seen that the LCOH decreases from 4.97 €/kg to 4.95 €/kg as the capacity of the BESS increases, but then rises to 5.00 €/kg when the capacity continues to grow. Although the magnitude of Superchi's LCOH cannot be directly compared to that of the study by Battolyser Systems due to differing scenarios, the figure illustrates the impact of a BESS on an electrolyser. In the same Figure, the green line represents the Green Index (GI), which is the ratio between the electrical energy coming from renewables and the total energy converted into hydrogen [1]. The figure shows an increase in GI, meaning that more renewable energy is converted in hydrogen with the addition of a battery. Nonetheless, Niaz et al. (2021) stated that adding battery storage to an alkaline electrolyser connected to a PV park increases the LCOH compared to operating without a battery, even though the addition of a BESS increases the operational reliability [21].

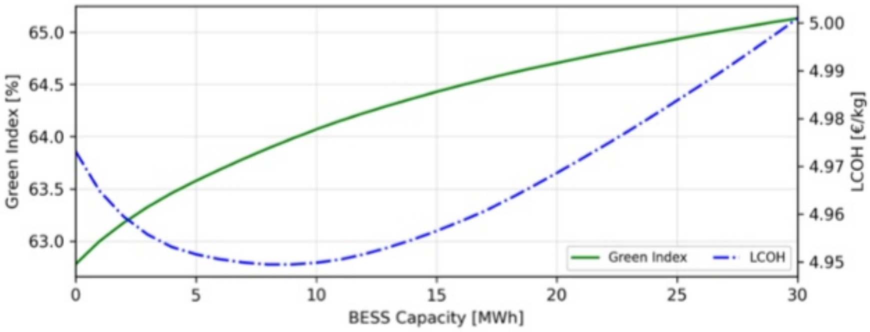


Figure 2: The LCOH (blue) of an alkaline electrolyser connected to a grid and wind farm, with different battery capacities [1].

A direct comparison between the Battolyser and a system that consists of a combination of an electrolyser and BESS has not yet been conducted. Different configurations of a battery and electrolyser can potentially impact the LCOH of the system, as they differ in storage capacity, electricity trading capabilities, and hydrogen production characteristics. This raises the question of how the LCOH of the system with two separate assets compares to the LCOH of the Battolyser.

This thesis aims to address this knowledge gap by comparing the LCOH of RFNBO compliant hydrogen produced using a Battolyser versus a system consisting of a traditional electrolyser paired with BESS in a later-to-be defined renewable energy generation framework. The findings will provide valuable information about the cost-effectiveness of different systems of RFNBO compliant hydrogen production technologies. In order to determine operational strategies, a willingness-to-pay price is forecasted for renewable hydrogen. It may become evident that the LCOH of the systems exceed Eneco's forecast on the expected price for RFNBO hydrogen in the market. If this is the case, the results will provide insight into the subsidy support required to make renewable hydrogen economically viable and competitive imported renewable hydrogen. Producing renewable hydrogen in a way that is both economically sustainable and scalable is important to decarbonize global industries and provide renewable seasonal storage. Improving cost efficiency can reduce reliance on subsidies, freeing up public funds for other climate goals. At the same time, reducing production costs is essential as significant investments are required to initiate and accelerate the energy transition.

For Eneco, a Dutch energy company committed to sustainability, understanding the economic and technical advantages of the Battolyser system is crucial. Evaluating whether this technology offers a competitive edge in RFNBO compliant hydrogen production can inform strategic investment decisions in the renewable energy generation field. Moreover, comparing the characteristics of different configurations of the system with separate assets, will increase Eneco's understanding of hydrogen production methods.

1.2 Research Questions

In order to approach the knowledge gap depicted in Chapter 1.1, the following research question is formulated:

> How does the Battolyser compare to a system with a separate battery and electrolyser in achieving the lowest levelised cost of hydrogen (LCOH) compliant to RFNBO (EU) standards?

To answer the main research question, several sub questions are formulated:

1. What processes should be considered in determining the LCOH for hydrogen production?
2. Which technical and financial aspects need to be evaluated to make a meaningful comparison between both systems?
3. How does a model for evaluating the hydrogen production systems look like?
4. How do variations in relevant parameters affect the LCOH of the systems?
5. What is the recommended system for hydrogen production that minimizes the LCOH when coupled with renewable energy generation?

1.3 Methodology

In Chapter 2, the hydrogen classification will be outlined, followed by a description of the scenario upon which the model and framework will be based. Finally, the Levelized Cost of Hydrogen (LCOH) will be introduced as the metric for evaluating the different systems. Establishing clear boundaries within the framework allows for a thorough comparison of the two systems. This thesis will present a comparative analysis of two systems: one using a Battolyser and the other composed of a separate battery and electrolyser. Both systems will be evaluated within the same consistent framework to ensure an accurate comparison. The system with a separate battery and electrolyser can be configured in several ways, offering two options each for the battery and electrolyser. The details of the Battolyser system and the battery-electrolyser configuration will be discussed in Chapter 3. Chapter 3 will provide a thorough investigation of the technologies, based on the literature. The first part of the chapter will focus on the different batteries, specifically lithium-ion and redox flow batteries, analyzing both their technical and financial characteristics for present-day and 2030 scenarios. A similar investigation will be conducted for alkaline and proton exchange membrane electrolysers. The chapter will then cover the Battolyser system and conclude with an evaluation of general equipment used in hydrogen production systems, such as compressors and power converters. The findings from the literature will be validated using the expertise and knowledge of Eneco. The goal of this research is to determine accurate values for the model, ensuring that the comparison closely reflects a real-life scenario. Chapter 4 will cover the conceptualization and realization of the model used to simulate the systems within the framework. The chapter will begin by translating the framework boundaries into the model. Then, the input and output parameters, as well as system-dependent parameters, will be defined. These system-dependent parameters will include the technical and financial data gathered in Chapter 3. Chapter 5 will present the results from the model. In Chapter 6, the analyses performed on the model will be discussed. A sensitivity analysis will be carried out to determine the influence of various input parameters, and a scenario analysis will explore alternative future scenarios. These will be discussed in Chapter 7. This chapter will also include recommendations for future research. Finally, Chapter 8 will revisit the research questions and provide conclusions based on the findings.

2 Frameworks and Background Information

In this chapter power purchase agreements and guarantees of origin are explained, which are legal frameworks used in energy markets. Next, the hydrogen classification in Europe and the associated regulatory restrictions are highlighted. These restrictions will define the scenarios under which different systems are tested. Following this, the methodology for calculating the levelized cost of hydrogen will be outlined. The goal of this chapter is to establish clear boundaries for the framework that will be modeled.

2.1 Power Purchase Agreement and Guarantees of Origin

There is an important distinction between the physical flow of electricity and the administrative allocation of renewable energy. Electricity always follows the path of least resistance through the grid, so it is physically impossible to prove that a specific consumer is using electricity from a specific source, like a wind farm. The electricity from a renewable energy source is injected into the grid and this is mixed with the injected electricity of all other energy sources on the grid. That means that, in reality, the energy from renewable sources cannot be distinguished from the other energy on the grid. Despite this, legal and administrative tools have been developed to enable renewable energy claims, even if the physical power doesn't flow directly from the source to the consumer [22].

Two of the main instruments used are Power Purchase Agreements (PPAs) and Guarantees of Origin (GoOs). A PPA is a contract between an energy producer and a buyer, securing a certain volume of renewable electricity at an agreed price over a specific period. GoOs, on the other hand, are electronic certificates that prove a certain amount of energy was generated from renewable sources. Under Article 19 of the Renewable Energy Directive (RED II), GoOs are the only officially recognized way to claim the use of renewable electricity in the EU [22]. Each GoO equals 1 MWh and is issued, transferred, and canceled through a standardized system designed to ensure transparency and avoid double counting [23]. To ensure that the use of green electricity reflects real renewable generation, PPA and GoO contracts are matched hourly with the consumer. This is referred to as temporal correlation, meaning that electricity consumption occurs at the same time as the associated renewable generation. For example, a company contracts a PPA for 20 MW of wind power in a certain hour and receives the matching GoOs. Although the company uses 20 MWh of electricity from the grid (a mix of sources), it is allowed to claim that it was powered by green electricity, based on its GoO ownership. The electrons might never come from the wind park, but administratively, the renewable claim is valid as long as the GoOs are allocated to the consumer [23]. This relationship between GoOs and the grid is visually shown in Figure 3.

This highlights the importance of clearly distinguishing between the physical flow of electricity, which is determined by the physics of the grid, and the bookkeeping flow of electricity, which enables the allocation of renewable energy without a direct connection.

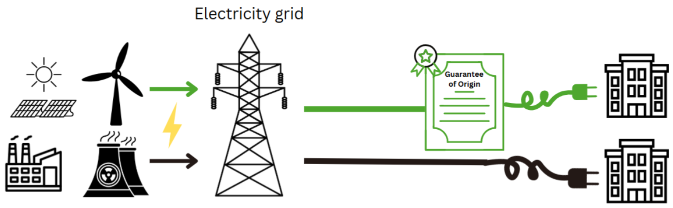


Figure 3: Visual representation of Guarantees of Origin

2.2 Hydrogen Classification

Today, hydrogen is classified into various colors, ranging from grey to turquoise, based on its production methods and environmental impact. The most frequently used forms are grey, blue, and green hydrogen. Grey and blue hydrogen are derived from fossil fuels, with grey hydrogen releasing significant greenhouse gases during production, and blue hydrogen incorporating carbon capture technologies to mitigate emissions. While blue hydrogen serves as a transitional step in the hydrogen economy, the process still relies on non-renewable resources, and carbon storage is not considered a sustainable long-term solution. Hydrogen is classified as green when this is produced through electrolysis and is closely associated with the term renewable hydrogen. However, these color classifications can be misleading when it comes to clearly defining hydrogen's environmental impact. To address this, more precise classifications have emerged, specifically focusing on the actual carbon intensity and renewable nature of hydrogen produced in the European Union (EU). Renewable Fuels of Non-Biological Origin (RFNBO) and low-carbon hydrogen are examples of classifications that better capture the real environmental footprint of hydrogen production. In Europe, the Renewable Energy Directive (RED III) has established targets to decarbonize hydrogen production. It clarifies the requirements for renewable hydrogen production, aiming for 42% of hydrogen production to come from renewable fuels of non-biological origin by 2030, and 60% by 2035 [24][25].

RFNBO compliant hydrogen can be produced when an electrolyser is directly coupled to a renewable energy source, such as a wind or solar power plant. To avoid reusing renewable power plants to create hydrogen, the electrolyser must be coupled to a plant that has been commissioned less than 36 months before the electrolyser is commissioned [26]. This setup is referred to as co-location when the electrolyser is directly connected to the renewable energy source without any grid connection. In such co-located scenarios, produced hydrogen is automatically considered RFNBO compliant without additional restrictions. The electrolyser can also be connected to the grid, however, the electrolyser must be coupled with a renewable energy source through a PPA with GoOs, which will account for the renewable electricity. This approach eliminates the geographical constraint between the electrolyser and the renewable energy source, while regulation still requires hydrogen production to rely on renewable energy through the GoOs. This is to prevent electrolysers from producing hydrogen that is made with non-green electricity and falsely labeling it as RFNBO compliant hydrogen, as it would not meet the renewable energy requirements. According to the Commission Delegated Regulation (EU), the electricity grid is considered fully renewable if the average share of renewable electricity exceeds 90% in the calendar year or if the emission intensity of the used electricity is below 18 gCO_2eq/MJ. If the share of renewable electricity exceeds 90%, the grid shall be considered fully renewable for the following five calendar years, allowing electrolysers to off take fully renewable electricity for RFNBO compliant hydrogen if the *previous* year's average share of renewable electricity exceeded 90% [26]. However, according to the Commission Delegated Regulation (EU), certain scenarios permit an electrolyser to draw additional electricity from the grid while still qualifying as RFNBO compliant hydrogen. This is known as temporal correlation, which occurs when the electricity price is below €20/MWh, or the electricity price is lower than 0.36 times the price of the Emissions Trading Scheme (ETS) [26]. An electrolyser can only consume electricity from the specific grid zone where these temporal restrictions are applied for the hydrogen to be considered RFNBO compliant. Moreover, RFNBO-compliant hydrogen can also be produced using electricity stored in a new storage asset, such as a battery, provided that the asset is located behind the same grid connection point. In such cases, the stored electricity must also comply to the same temporal correlation regulations as stated above. Until 31 December 2029, the temporal correlation requirement is fulfilled if the electricity used for hydrogen production is generated within the same calendar month. However, from 1 January 2030 onward, this correlation must be ensured within the same one-hour period. The electricity grid in the Netherlands is not classified as fully renewable, as its emission intensity was 74.75 gCO_2eq/MJ, with an average renewable electricity share of only 36.3% in 2022 [27] [28]. This means that, currently, a grid-connected electrolyser in the Netherlands can only produce RFNBO compliant hydrogen when the electricity price is below a certain threshold.

RED III sets greenhouse gas emissions (GHGE) requirements for all types of recycled carbon fuels, enforcing a minimum GHGE savings threshold of 70% [29]. The emissions associated with the production of grey hydrogen serve as benchmark, with a reference emission factor of 94 gCO_2eq/MJ [30]. To calculate the CO_2 contribution, the entire supply chain must be taken into account, from production to end use. Evidently, RFNBO compliant hydrogen needs to meet this requirement and the previous mentioned measures ensure that RFNBO-compliant hydrogen qualifies as renewable hydrogen. Hence, the terms RFNBO-compliant hydrogen and renewable hydrogen will be used interchangeably. In some cases, hydrogen does not meet the criteria of RFNBO compliant hydrogen, but it does meet the 70% reduction threshold. This type of hydrogen is referred to as low-carbon hydrogen when it achieves at least a 70% reduction in GHGE compared to grey hydrogen. This corresponds to an emission level of 28.2 gCO_2eq/MJ. Unlike RFNBO compliant hydrogen, low-carbon hydrogen is not entirely produced from renewable sources, but it still offers a significant reduction in CO_2 emissions compared to grey hydrogen. Although RFNBO-compliant hydrogen stimulates the production of renewable hydrogen, low-carbon hydrogen serves as an important intermediate option in the transition to a fully decarbonized hydrogen economy. Energy sourced through renewable PPA contracts and electricity extracted from the grid when it is RFNBO-compliant can be considered as having no associated greenhouse gas emissions (GHGE), meaning their emissions are 0 gCO_2eq/MJ. This category of electricity is referred to as fully renewable (FullRen) electricity. Electricity drawn from the grid that does not meet RFNBO compliance is classified as partially renewable (PartRen) electricity. The emissions associated with this electricity correspond to the grid's GHGE intensity at that time. To calculate the amount of hydrogen produced by the electrolyzer, the total electricity supplied to the stacks (MWh) must be divided by the system efficiency η (kWh/kg), as expressed in Equation (1).

$$H_2 = \frac{E_{\text{stacks}} \cdot 1000}{\eta} = \frac{(E_{\text{FullRen}} + E_{\text{PartRen}} - E_{\text{BoP}}) \cdot 1000}{\eta} \tag{1}$$

The GHGE (gCO_2eq/MJ) of the produced hydrogen is calculated by multiplying the PartRen electricity by the GHGE intensity of the grid (gCO_2eq/MJ) and dividing it by the total amount of hydrogen produced (kg). To ensure unit consistency, the calculation includes a factor of 3600 (MJ/MWh) and is divided by the HHV of hydrogen (MJ/kg). Since the GHGE intensity of fully renewable electricity can be viewed as zero, only emissions from partially renewable electricity contribute to the total GHGE. To qualify as low-carbon hydrogen, this value must be equal to or below the GHGE threshold. The corresponding equation is given in Equation (2).

$$GHGE_{H_2} = \frac{E_{\text{PartRen}} \cdot GHGE_{\text{grid}} \cdot 3600}{H_2 \cdot HHV} \leq GHGE_{\text{threshold}} \tag{2}$$

By combining these equations, the maximum amount of grid electricity that can be utilized while still maintaining the required GHGE threshold for hydrogen production can be determined. The final equation is depicted in Equation (3)

$$E_{\text{PartRen}} \leq \frac{GHGE_{\text{threshold}} \cdot 1000 \cdot HHV \cdot (E_{\text{BoP}} - E_{\text{FullRen}})}{GHGE_{\text{threshold}} \cdot 1000 \cdot HHV - GHGE_{\text{Grid}} \cdot 3600 \cdot \eta} \tag{3}$$

This represents the amount of partially renewable electricity that can be extracted from the grid while ensuring that the produced hydrogen remains classified as low-carbon hydrogen. If the GHGE threshold is exceeded, the entire batch of hydrogen will instead be classified as grey hydrogen. According to RED III, the electricity that is used to split water into hydrogen and oxygen must adhere to the mentioned restrictions. Therfore, a distinction can be made between the power allocated to the BoP and the power supplied to the stacks. By fulfilling the BoP's power demand with non-fully renewable electricity, a greater share of renewable electricity can be allocated to the stacks. The GHGE intensity of the hydrogen produced is determined as shown in Equation (2). All utilized electricity must be taken into account, including the energy that is allocated to the BoP. If the GHGE threshold is not exceeded, the amount of RFNBO-compliant hydrogen can be calculated by multiplying the partially renewable energy supplied to the stacks by the Renewable Energy Share (RES) of the grid from two years prior. Similarly, the amount of low-carbon hydrogen is calculated by multiplying the partially renewable power times 1-RES, which represents the non-renewable share of the grid. These relation are depicted by Equations (4) & (5). This demonstrates that more RFNBO-compliant hydrogen can be produced by using partially renewable grid electricity for the BoP.

$$H_{2,\text{RFNBO}} = \frac{(E_{\text{FullRen}} + E_{\text{PartRen}} \cdot RES) \cdot 1000}{\eta} \quad (4) \qquad H_{2,\text{low-carbon}} = \frac{E_{\text{PartRen}} \cdot (1 - RES) \cdot 1000}{\eta} \quad (5)$$

To sum up, in this thesis hydrogen is classified into three main categories based on its production method and environmental impact. Grey hydrogen, produced via SMR, serves as the benchmark with an emission factor of 94 gCO_2eq/MJ, contributing significantly to greenhouse gas emissions. Low-carbon hydrogen meets the 70% GHGE reduction threshold, resulting in emissions of less than 28.2 gCO_2eq/MJ, but it is not considered fully renewable. RFNBO compliant hydrogen, also achieving at least a 70% reduction in GHGE, must follow stricter regulations to ensure it is exclusively produced from renewable electricity, making it fully renewable. RFNBO hydrogen can be produced through direct coupling with a newly commissioned renewable energy source (built less than 36 months old) or through grid connection under a PPA with GoOs, ensuring renewable electricity supply. Additionally, temporal correlation rules apply, requiring hydrogen production to match renewable electricity availability, transitioning from monthly correlation (until 2029) to hourly correlation (from 2030 onward). While some grid-connected electrolysers may qualify under specific price thresholds (€20/MWh or 0.36 times ETS price), most European grids, including the Netherlands, are not yet classified as fully renewable, limiting RFNBO-compliant hydrogen production from the grid. Lastly, a distinction can be made between power allocated to the balance of plant, and to the stacks, to increase the RFNBO compliant hydrogen production.

2.3 Demarcation of the study

This study focuses on the Netherlands as the primary location due to the availability of data provided by Eneco, which operates predominantly within the Netherlands. Furthermore, within the European Union, the Renewable Fuels of Non-Biological Origin (RFNBO) regulations apply, as outlined in the previous chapter. Within the Netherlands, the systems will be evaluated in the Rotterdam area. Rotterdam has been chosen due to its strategic importance as an industrial hub and its connection to many offshore wind farms.

The time frame for this framework spans from 2030 to 2050, chosen for several key reasons. In 2030, stricter RFNBO regulations will take effect, requiring hourly rather than monthly temporal correlation for hydrogen production, significantly impacting the business case [26]. The system will be connected to the 380 kV network of Tennet, which is the extra high voltage network. By 2030, a new TenneT substation will be built in Rotterdam, and existing substations will undergo expansions, reducing grid congestion and enhancing renewable electricity availability [31]. This makes the 2030 starting point more advantageous, as the system will benefit from the improved infrastructure. Lastly, the 20-year horizon aligns with the typical lifespan of critical system components such as batteries and electrolysers, making it a relevant period for analyzing their long-term operations and financial viability.

The framework will consist of a grid-connected system. Two potential system designs are considered:

1. A grid connected Battolyser system: an integrated electrolyser and battery storage solution.
2. A co-located grid connected system consisting of a separate battery and electrolyser.

A co-located system refers to a configuration in which multiple assets share the same grid connection. In this case, the electrolyser and battery are connected to the same grid access point, meaning that the available power flow is limited by the capacity of the connection and must be shared between both assets. The system will contract electricity from the grid through PPAs and GoOs from recently installed wind and solar parks developed by Eneco. The contracts will follow a pay-as-produced structure, meaning there is no guarantee of a fixed electricity supply, but a consistent price is paid for each MWh generated by the renewable energy source. This means that the power that reaches the electrolyser follows the intermittent power profile of the renewable generation, which is a typical contract for renwables like solar and wind power [32]. The contracted electricity can be used for the system, or it can be resold to the electricity market to generate more revenue. The primary objective of the system is to produce hydrogen in compliance with RFNBO regulations, ensuring that the sourced electricity meets the required sustainability criteria.

When hydrogen is produced from the electrolyser, it must be compressed to meet the requirements of its storage or distribution method. The Netherlands is currently developing the HyNetwork (part of GasUnie) hydrogen infrastructure, which is expected to be completed by 2033 [33]. According to Hynetwork (2024), the HyNetwork will be constructed in phases, with the area surrounding Rotterdam set for completion in Q4 2026 [34]. The remainder of the network will be developed gradually, with full integration expected by 2033. Furthermore, long term contracts can be agreed upon with a minimum contract length of 10 years, according to Hynetwork. Consequently, it is assumed that the systems will deliver hydrogen to the network starting from 2030 up until 2050. The hydrogen inserted into the HyNetwork can be used by a party requiring green hydrogen. HyStock, also part of GasUnie, is developing four hydrogen storage facilities with a storage capacity of 20 kilotons of hydrogen. It is expected that the first storage facility will be realized in 2031. HyStock will be the first large scale party that will store hydrogen in the Netherlands. However, according to Eneco, similar pay-as-produced contracts, such as those used for renewable PPAs, can be brokered with hydrogen consuming parties. This ensures that the hydrogen is purchased as it is produced, meaning that the necessity for a storage facility on site is eliminated. The framework in this research will only consider the costs associated with the HyNetwork as it is assumed that a pay-as-produced contract will be agreed on.

3 Technology Description

This chapter covers essential background knowledge needed to better understand the topic of this master's thesis. The chapter looks at the different types of batteries and electrolysers that can be used in hydrogen production systems. The characteristics of the Battolyser will also be explained. This gives an overview of how the assets work with their features. The purpose of these sections is to provide a clear foundation for understanding the financial and technical aspects associated with batteries and hydrogen production systems. This section will first discuss important considerations such as spatial requirements and grid limitations, as these factors influence the deployment of battery and electrolyzer systems. Afterwards, the literature research will explore the technical and financial characteristics of the systems. Lastly, the environmental aspects of the system will be analysed.

When combining a battery and an electrolyzer on the same site, spatial requirements must be considered. Unlike a Battolyser, which integrates both storage and hydrogen production into a single system, a separate battery and electrolyser setup requires significantly more space due to the need for additional infrastructure. The system need components such as extra inverters, cooling systems, and safety zones, increasing the overall footprint. Safety regulations also influence site design, with the PGS37-1 guidelines setting specific requirements for battery container placement to ensure safe distances and minimize fire risks [35]. This is particularly relevant for Li-ion batteries, which pose a potential thermal runaway risk. To reduce this risk, BESS containers must be at least 1 meter apart from each other in clusters of 6 and there must be a distance of at least 2.5 meters between clusters. Additionally, the fire department enforces further safety measures, including emergency access routes and fire suppression systems, which must be factored into spatial planning. At least on one side of the BESS units must be a 4.5 meter wide emergency access route for the fire department. For redox flow batteries, large tanks are needed to store the electrolyte. This means that a larger area is needed for the co-located systems than the Battolyser, to account for these limitations. This means that a larger land area is needed for the co-located systems than for the Battolyser system. Another challenge in developing battery and electrolyser systems, is grid congestion. Many areas in the Netherlands face grid capacity constraints, making it difficult to connect new large scale systems. As a potential solution, the Dutch grid operators provided the possibility to gain priority on the capacity waiting list by offering congestion management contracts. A potential battery system could get connected to the grid before other parties, if the operator is able to work together with the grid operators to use the battery in managing grid congestion. Moreover, TenneT also introduced the ATR85 regulation. The ATR85 rule allows battery systems to receive less high grid tariffs in exchange for less operational flexibility. This could improve the business case for large scale systems. This regulation allows TenneT to restrict the contracted grid capacity for up to 15% of the time per year [36]. This could result in Tennet being able to connect large systems to the grid, even if it would not have been possible due to congestion. The impact of ATR85 curtailment is expected to affect both the Battolyser and co-located battery-electrolyser systems, although the effects may be different depending on the system. Under the ATR85 regulation, TenneT is allowed to curtail grid connection capacity for up to 15% of the hours per year, which is approximately 1,300 hours, with at least 12 hours of advance notice. The exact timing and frequency of curtailment are not fixed and will likely be determined by local grid congestion. In both system configurations, a temporary restriction on grid access could limit the ability to import electricity for hydrogen production or to export power for arbitrage. However, the systems may respond differently in practice. Co-located configurations could potentially mitigate the impact by pre-charging the battery before curtailment and continuing to operate the electrolyser behind the meter using stored energy. This decoupling of operations allows some continuity of hydrogen production, provided that curtailment events are anticipated. The Battolyser, while less flexible in separating battery and electrolyser operation due to its integrated design, can lower its consumption to a minimal standby level when grid access is restricted. This enables it to effectively pause operation with minimal loss, then resume when grid capacity becomes available again. Overall, both systems may experience comparable production or revenue impacts during curtailment windows. However, this thesis assumes that a sufficient grid connection is available for the system, and that an ATR85 capacity contract is not needed to obtain a grid connection. The focus remains on assessing the technical and financial feasibility of battery and electrolyser systems without taking into account the restrictions of the grid. Additionally, while technologies such as redox flow batteries and the Battolyser have the potential to reach or have already reached Technology Readiness Levels (TRL) comparable to Li-ion batteries and alkaline electrolysers, they are not yet as commercially mature. This brings uncertainties regarding costs, long-term performance, and supply chain stability. For the purposes of this thesis, these factors will not be explicitly considered, as the focus remains on evaluating the financial and technical feasibility of the selected technologies. The extra land needed will be taken into account in the land lease further in the thesis.

3.1 Batteries

As the Netherlands expands its energy portfolio with more intermittent renewable energy sources, the gap between supply and demand grows both in the short and long term. Batteries are emerging as a solution to address the short-term imbalance on the electricity grid. They can store electricity when there is a surplus of generation and low prices, which prepares for arbitrage. When a shortage occurs, batteries can discharge and sell the stored electricity to the grid, profiting from higher prices. In addition to participating in the arbitrage market, batteries can also contribute to frequency regulation and load leveling, enabling multiple revenue streams [37]. Therefore, grid balancing not only ensures the reliability and stability of the grid but also can create a positive business case for battery operators. Although several Energy Storage Solutions (ESS) exist, Li-ion batteries are emerging as the dominant technology due to their high energy density and fast response time. According to the International Energy Agency (IEA), Li-ion batteries have outperformed alternatives over the last decade, driven by a 90% reduction in costs since 2010, along with higher energy densities and longer lifetimes [38]. However, lithium-ion batteries do come with certain drawbacks, including the high cost of materials such as lithium and cobalt, safety concerns related to thermal runaway, and a limited lifespan. Another emerging alternative in the energy storage sector is the Redox Flow (RF) battery, which addresses many of the limitations associated with lithium-ion batteries. RF batteries use liquid electrolytes, which do not pose the same safety risks as solid-state batteries, particularly with regard to thermal runaway. Additionally, RF batteries do not experience the same degradation issues caused by deep discharge cycles, giving them a much longer average lifespan, often exceeding 20 years [39]. This long lifespan, combined with the ability to scale power and energy independently, makes Redox Flow batteries an attractive solution for both grid-scale energy storage and long-duration storage applications ranging from hours to days.

Batteries can participate in multiple electricity markets, each with different revenue opportunities. These include the day-ahead market, where electricity is traded a day in advance based on predicted supply and demand, and the intraday market, which allows for adjustments closer to real-time. In addition, batteries can operate in balancing markets, providing fast response services to stabilize frequency deviations. While these flexibility services can significantly enhance the business case for battery storage solutions, predicting their value is very challenging. This is because of the market volatility depending on factors such as weather fluctuations, power outages and frequency deviations. Additionally, as more batteries are deployed, the increasing number of batteries will influence market dynamics and may reduce future revenues. With increasing battery participation in balancing markets, the available revenue per asset is likely to decline due to competition. In addition, the co-location of a battery and an electrolyser could impact operational flexibility for intraday trading and balancing, as their combined energy demands and constraints may limit the battery's ability to respond freely to market signals. Given these complexities, this thesis focuses on the day-ahead market, where prices are more predictable. The flexibility value of batteries in other markets is not considered, as forecasting these revenues over a 20 year horizon in the future is nearly impossible.

The following sections aim to provide a comprehensive analysis of Li-ion and Redox Flow batteries as a tool for grid balancing in the Netherlands, with a focus on both technical and financial aspects. These two battery technologies have been selected for their suitability and maturity for grid balancing. The working principles of the batteries will be explored, as well as their key performance characteristics and their role in grid integration. Moreover, the financial details, such as cost structures, revenue potential, and cost comparisons with other energy storage technologies will also be highlighted.

3.1.1 Lithium-ion Batteries

Lithium-ion (Li-Ion) batteries are known for their high energy density, good cycle life, and relatively high efficiency, typically a round trip efficiency (RTE) of 85% [40]. There are several different lithium-ion chemistries, each with distinct characteristics that influence their performance and suitability for various applications. Battery expert S. Melançon (2023) compared six lithium-based battery chemistries and concluded that Lithium Iron Phosphate (LFP) batteries are the most suitable option for grid-scale energy storage systems [41]. LFP batteries offer a high cycle life, lower production costs, and a significantly reduced risk of thermal runaway compared to other lithium-ion chemistries. These attributes make them particularly well-suited to meet the demands of large-scale energy storage, where safety, longevity, and cost-effectiveness are key considerations. These optimal characteristics of the LFP battery are also confirmed by S. Ezennaya et al. (2024) [42]. Consequently, this thesis focuses on LFP batteries and, throughout this thesis, any reference to Li-ion batteries specifically refers to LFP batteries.

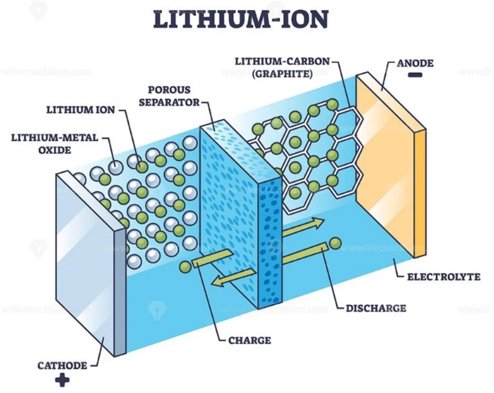


Figure 4: Schematic overview of a Li-ion battery [2]

Li-ion batteries rely on the flow of lithium ions between the anode and the electrode to store and release electricity. During charge, the ions move from the cathode to the electrode, and during discharge they move back to the cathode, generating electricity. Figure 4 shows a schematic overview of a Li-ion battery, where it can be seen that the Li-ions travel through the membrane during charge and discharge. In a LFP cell, the cathode is made from Lithium Iron Phosphate and the anode is typically made from graphite [43]. The electrolyte facilitates the movement of the ions between the electrodes. Multiple individual cells are combined to form a battery pack. Along with a Battery Management System (BMS), which monitors and controls the performance of the cells within the pack, the complete battery system is created. The BMS ensures the safe operation of the battery by managing factors like charging, discharging, temperature, and overall health of the cells. The performance of the battery is determined by several key metrics such as round trip efficiency (RTE), cycle life and response times.

Several studies have investigated the performance characteristics of grid-scale LFP batteries. The round-trip efficiency (RTE) of LFP batteries varies depending on conditions, with Diaz-Gonzalez et al. (2012) finding a range between 78% and 88% [44]. Olabi et al. (2023) found a similar round trip efficiency range between 75% and 90% [45]. The Pacific Northwest National Laboratory (PNNL) reported an RTE of 83%, which falls within this range [46]. Other studies suggest that LFP batteries achieve higher RTE such as 92%-94% under specific conditions, such as low discharge rates or low C-rates [47][48]. Cycle life estimates for LFP batteries also vary. Cycle life is typically assessed based on End of Life (EoL), which is defined as the point when 20% of the battery's initial capacity has faded. The number of charge-discharge cycles per day, combined with the Depth of Discharge (DoD), determines the actual cycle life. Deep discharge cycles can significantly accelerate capacity fade, reducing the battery's lifespan [49]. The cycle life of a battery can be expressed in either years or total cycles. For Li-ion batteries, it is common practice to operate between 1 and 2 cycles per day due to the required rest time between charge and discharge [46]. Diaz-Gonzalez et al. (2012) found a lifespan between 14 and 16 years [44], while the PNNL estimated between 2,400 and 9,100 cycles, equating to approximately 16 years [46]. McCluer et al. (2008) reported a broader range of 6 to 20 years, depending on factors such as depth of discharge (DoD) and C-rate [50]. Olabi et al. found a cycle life of 3000 cycles with a DoD of 80% [45]. GivEnergy, LFP battery manufacturer, states that an LFP battery will last at least 12 years, even with a 100% DoD [47]. Moreover, Elio et al. (2021) found RTEs of 90-95% and a cycle life between 2000-10000 cycles [51]. Furthermore, fast response times ensure that batteries can act on multiple markets, such as the ancillary services markets, day-ahead market and the intra-day market. According to the European Association of Storage Energy (EASE) (2016), Li-ion batteries can have response times of several milliseconds [52]. Moreover, the findings by Elio et al. are in line with the EASE, as they state that Li-ion batteries can achieve a response time of several milliseconds. In a study by Cornell University (2020), the degradation several Li-ion batteries were compared and it was found that there is a capacity loss of 5% to 8% per 30 months with a DoD of 100%, which translates to a degradation of 2% to 3% per year [53]. According to Thunder Said Energy, a research consultancy for energy technologies, the degradation of a Li-ion battery is approximately 2% per 1000 cycles [54]. This translates to a yearly degradation of 0.73% for 1 cycle a day, and 1.46% for 2 cycles a day. The degradation of Li-ion batteries primarily occurs in two ways, namely capacity degradation and efficiency degradation. Capacity degradation refers to the loss of the battery's total storage capacity over time, reducing the amount of charge it can hold. Efficiency degradation, on the other hand, results in increased internal resistance, leading to higher energy losses during charging and discharging. Reniers and Howey (2022) investigated the degradation of a 1 MWh grid-scale lithium-ion battery system. They state that capacity fade has a greater impact on overall battery performance than variations in internal resistance, meaning that the capacity degradation is more dominant than the efficiency degradation [55]. According to the DOE (2022), Li-ion batteries have the potential to provide electricity for up to 10 hours [56]. However, due to the linear cost scaling with duration, Li-ion batteries are not profitable above 8 hour storage. Evelina Stoikou (2024) from BloombergNEF, a global research institute, comes to a similar conclusion as Li-ion systems are technically capable of 6–8 hours, but face competition from lower-cost alternatives beyond this range [57]. Lastly, the C-rate represents the rate at which a battery is charged or discharged relative to its capacity. It is calculated by dividing the discharge or charge rate by the battery's capacity. For instance, if a battery with a capacity of 100 MWh is discharged at 50 MW, the process would take two hours, resulting in a C-rate of 0.5C or C/2. According to EASE, Li-ion batteries can discharge between 10 minutes and 4 hours, which corresponds to a C-rate of 6C and of C/4 [52]. According to a specification sheet by Infinity Power HT, the (dis)charge rate for a 1MW/2MWh Li-ion battery is C/2 [58]. Moreover, Lamboo (2020) reports charge and discharge times between 1 and 4 hours, corresponding to C-rates of 1C and C/4 [59]. A high charge and discharge rates has heat dissipation as consequence, meaning that the efficiency will reduce and that the stacks will degrade faster.

The PNNL has also made predictions regarding the characteristics of LFP batteries in 2030 [46]. According to the PNNL, the cycle life of LFP batteries is expected to remain relatively unchanged, while the round-trip efficiency (RTE) is anticipated to increase from 83% to 85%. Additionally, the U.S. Department of Energy (DOE) (2023) has provided its own estimates for LFP batteries in 2030 [60]. According to the DOE, the cycle life of LFP batteries will be 16 years or 2,640 cycles, with the RTE projected to reach 85% by that time. The International Renewable Energy Agency (IRENA) also made predictions for the RTE in 2030, as they estimate that the RTE rises from 92%-94% to 94%-98% [48]. As observed, the cycle life of Li-ion batteries is expected to increase slightly, indicating a reduction in degradation rates. However, battery degradation is a complex process influenced by numerous factors, making it challenging to predict its exact behavior in 2030. Therefore, a conservative assumption is made that the annual degradation of Li-ion batteries in 2030 will range between 0.73% and 2.5%. It is assumed that the response time will not increase significantly, due to the limitations of power converters associated with connection to the grid. Additionally, as noted by Stoikou and the DOE, the profitability of Li-ion batteries in long-duration storage applications is challenging. With prices for other technologies expected to decrease, it is therefore assumed that the storage capacity of Li-ion batteries will remain similar to current levels. Moreover, the higher the charge and discharge rate, the lower the efficiency. Therefore, it is assumed that the charge and discharge rates will not change significantly. These findings are summarized in Table 1.

Table 1: Technological Characteristics of Li-ion BESS (Present day and 2030)

Component	**Unit**	**Present day**			**2030**		
		Lower Bound	**Higher Bound**	**Source**	**Lower Bound**	**Higher Bound**	**Source**
Storage capacity	hours	0.5	10	[57][56]	0.5	10	assumption
RTE	%	75	94	[44][46][47, 48][51][45]	85	98	[46][48][60]
Charge rate	-	C/4	1C	[58][59]	C/4	1C	assumption
Discharge rate	-	C/4	6C	[52][58][59]	C/4	6C	assumption
Cycle Life	Cycles	500	20000	[46][48][51][45]	2640	9100	[46][60]
Calender Life	Years	6	20	[44][50][46][47]	16	16	[46, 60]
Response time	-	milliseconds	milliseconds	[52][51]	milliseconds	milliseconds	assumption
Degradation	%/yr	0.73	3	[53][54]	0.73	2.5	assumption

Besides the technical characteristics of Li-ion batteries, their financial aspects must also be considered. Even though the associated costs vary per project and size, several studies investigated the costs of Li-ion batteries. The PNNL (2023) reports that the total capital expenditures (CAPEX) for a Li-ion battery range between 324 and 396 EUR/kWh, and 1297 to 1585 EUR/kW [46]. In comparison, IRENA (2017) provides a broader price range of 193 to 812 EUR/kWh, though there is some overlap between the two estimates [48]. Elio et al. (2021) report a CAPEX between 1160 and 3870 EUR/kW, or between 580 and 2420 EUR/kWh [51]. Additionally, CE Delft, a Dutch research institute, states that the total CAPEX of a Li-ion battery is in the range of 310 and 400 EUR/kWh, with an OPEX of 2.5% of CAPEX per year [61]. This estimate by CE Delft is the most applicable as it is based on the Dutch electricity market, however, the previous estimates remain important as benchmarks. Within the PNNL total CAPEX estimate, the cost for the battery pack itself is 160 to 196 EUR/kWh, while the Balance of System (BoS) costs range between 31 and 38 EUR/kWh. For Operational Expenditures (OPEX), PNNL reports costs ranging between 3.72 and 4.54 EUR/kW. The study by Elio et al. state a fixed OPEX between 2.13 and 15 EUR/kW/year [51]. The National Renewable Energy Laboratory (NREL) (2024) has created the annual technology baseline database in the United States, where both current and future projections of LFP battery technology is documented [62]. It is stated here that the CAPEX of an LFP system ranges between 1250 and 1700 EUR/kW in 2022, where the lower range depicts a 2hr BESS and the higher range an 8hr BESS. Moreover, the CAPEX in 2022 is approximately 350 EUR/kWh. According to NREL, the battery back amounts for approximately 53% to 64% of the total CAPEX, while the BoS amounts to 11% to 14% of the total CAPEX. This means that the costs for BoS range from 35 to 49 EUR/kWh, based on the 2022 values by NREL. Furthermore, NREL states that the fixed OPEX ranges between 29 and 85 EUR/kW/yr, which is significant higher than the previous ranges.

For a Li-ion battery in 2030, multiple studies predict a significant reduction in CAPEX. PNNL estimates costs ranging from 950 to 1283 EUR/kW and 238 to 320 EUR/kWh [46]. Their total cost estimate includes the battery pack (104 to 152 EUR/kWh) and battery BoS (24 to 33 EUR/kWh). Similarly, IRENA estimates a broader cost range of 237 to 600 EUR/kWh, which overlaps with PNNL's projections [48]. The DOE also provides an estimate, stating that by 2030, the cost for the battery pack will be approximately 103 EUR/kWh, while the battery BoS will cost around 26 EUR/kWh [60]. NREL (2024) projects a CAPEX range between 1080 and 1650 EUR/kW [63]. Their forecast is based on three cost reduction scenarios compared to 2022 values, with a low reduction scenario of 18%, a moderate reduction of 37%, and an advanced reduction of 52% by 2035. Another NREL study (2023) estimates a cost decrease of 47% in the low-cost scenario, 32% in the mid-cost scenario, and 16% in the high-cost scenario compared to 2022 levels [64]. Applying these reductions to a 2022 CAPEX of 466 EUR/kWh, the projected 2030 range is 247 to 390 EUR/kWh. Later in the study, the applied this reduction rate to a lower starting point of 390 EUR/kWh where the 2030 range would be 200 to 320 EUR/kWh. For OPEX, PNNL projects operational costs between 6.64 and 8.13 EUR/kW per year [46]. The DOE estimates an OPEX of approximately 10 EUR/kW per year [60]. Meanwhile, NREL (2024) provides a broader estimate, with fixed OPEX costs ranging from 23 to 39 EUR/kW per year or 2.5% of CAPEX annually [63]. These findings are summarized in Table 2. The ranges shown are derived from multiple independent sources, and therefore individual values (e.g., for stack or balance of system components) do not correspond to each other. As such, costs should not be calculated by directly summing the individual ranges.

Table 2: Financial Characteristics of a Li-ion BESS (Present day and 2030)

Component	Unit	Present day			2030		
		Lower Bound	Higher Bound	Source	Lower Bound	Higher Bound	Source
Battery stack	EUR/kWh	160	196	[46]	103	152	[46][60]
Battery BoS	EUR/kWh	31	49	[46][63]	24	33	[46][60]
Total CAPEX	EUR/kWh	193	2420	[46][48][61][51][62]	200	600	[46][48][64]
Total CAPEX	EUR/kW	1250	3870	[46][51][62]	950	1650	[46][63]
OPEX	EUR/kW/yr	2.13	85	[46][51][62]	6.64	39	[46][63]
OPEX	%/CAPEX/yr	2.5	2.5	[61]	2.5	2.5	[63]

To ensure that a real-life scenario is modeled, the values from the literature are validated by Eneco. The validation is based on in-house knowledge, data obtained by vendors and third party research. According to Eneco, storage capabilities ranging between 2 and 4 hours have the best profitability for Li-ion batteries. Moreover, the RTE of a battery system is between 85% and 89%, measured from the grid connected, meaning that the auxiliary equipment, such as an HVAC and transformer, is included as well. This is in line with the broad range found in the literature. The cycle life ranges between 15 and 20 years, or 5000 and 9500 cycles, meaning that it is expected that the batteries cycle 1 or 2 times a day. This highlights the impact of operation tactics of these batteries, as the literature suggest very broad ranges depending on the cycles and discharge depth. Related to this, the yearly degradation is estimated to be between 1.5% and 2.6%, or at lowest 30% degradation in 20 years, and at most 40% degradation in 15 years. The charge and discharge rates are in accordance with Eneco, as well as the response time. Regarding the financial parameters, Eneco states that the current battery prices for the stack range between 140 and 180 EUR/kWh. This range is slightly lower compared to the literature research, suggesting that the battery prices have dropped even further. For 2030, the expectation by Eneco is that the battery costs will range between 110 and 180 EUR/kWh.

3.1.2 Redox flow Batteries

Redox Flow batteries (RFBs) are another promising alternative for large-scale, long-duration energy storage applications. Unlike Li-Ion batteries, which store energy chemically within the battery cells, Redox Flow batteries store energy in liquid electrolytes contained in external tanks, which is depicted in Figure 5. RFBs operate by circulating the liquid electrolytes through electrochemical cells where ions are exchanged across a membrane, enabling reversible redox reactions to store and release energy. The power output of the battery is determined by the size of the electrochemical stack, while the energy storage capacity depends on the volume of the electrolyte tanks. This decoupling of power and storage makes Redox Flow batteries interesting for applications that require large amounts of energy storage over extended periods. A key component of an RFB system is the flow management system, which includes pumps and sensors to regulate electrolyte circulation. The systems operate together with the BMS, enabling the charging and discharging of the battery.

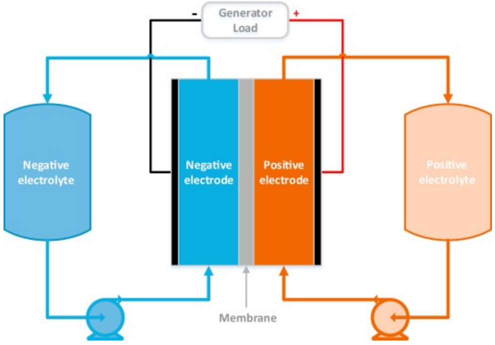


Figure 5: Schematic overview of an RF battery [3]

Among different RFB chemistries, Vanadium Redox Flow Batteries (VRFBs) are the most developed, with a Technology Readiness Level (TRL) of 9 and several commercial projects, whereas other chemistries have TRLs ranging from 3 to 9 [39]. Olabi et al. (2023) state that the market is dominated by VRFBs and Zinc-Bromine RFBs (ZBRFBs), with VRFBs offering higher efficiencies than ZBRFBs [45]. Consequently, this thesis focuses on VRFB technology, and throughout this thesis, any reference to redox flow batteries specifically refers to VRFBs. Compared to Li-ion batteries, Redox flow batteries offer several advantages, such as unlimited daily cycling while Li-ion batteries can cycle between one and two times a day. They also have lower degradation, a lifetime exceeding 20 years, and can achieve 100% depth of discharge without capacity loss [65]. Additionally, VRFBs have no risk of thermal runaway, making them a safer alternative to Li-ion batteries [51].

Several studies have listed the performance characteristics of redox flow batteries. Compared to Li-ion batteries, the round trip efficiency is lower for redox flow batteries. Olabi et al. (2023) and Elio et al. (2021) found an RTE in the range between 65% and 85% [45][51]. According to IRENA (2017), redox flow batteries can have efficiencies between 60% to 85% [48]. Diaz-Gonzalez (2012) also investigated the performance characteristics of RFBs and found an RTE between 65% and 88%, which has a large overlap with the other studies [44]. CE Delft (2023) states a RTE of approximately 70% with a cycle life of approximately 20000 cycles [61]. Moreover, CE Delft states that the storage capacities range between 4 and 40 hours. Besides research and studies, market data of vendors and manufacturers can provide valuable information. Invinity, a RFB manufacturer, states a RTE between 70% and 80% on their data sheet [66]. Cell Cube, another RFB manufacturer, states a RTE between 63% and 78% on their data sheet [67]. The PNNL agrees with the lower value of this range, as they report a RTE of 65% for RFBs, with a cycle life of 12 years, or approximately 5250 cycles [46]. Cell Cube states a cycle life of over 20000 cycles with a DoD of 100%. According to Invinity, their RFBs can discharge between 4 and 18 hours, corresponding to discharge rates of C/4 and C/18 [66]. Moreover, Cell Cube batteries have discharge times of C/4 and C/14, and charge rates between C/2 and C/6 [67]. Moreover, Olabi et al. (2023) found a cycle life range between 2000 and 20000, based on a depth of discharge of 80% [45]. Diaz-Gonzalez found a little less optimistic cycle life, which is between 1000 and 13000 cycles, or between 10 and 20 years. Elio et al. found a cycle life between 10000 and 13000 cycles and a response time of smaller than 100 milliseconds [51]. The study by IRENA is in line with the study of Elio et al. as they report a cycle life of more than 10000 cycles, quick response times and storage up to 20 hours [48]. The data sheet from Invinity mentioned additional performance characteristics, such as a storage capacity ranging from 4 to 18 hours and an annual degradation of less than 0.5%. It also mentions a calendar life of 25 years and a response time of 15 milliseconds when the battery is activated, and up to one minute if the battery has been off [66]. Similarly, the data sheet from Cell Cube reports an average degradation of less than 0.5% per year, with a maximum degradation of 10% over 30 years [67]. The response time for Cell Cube's system is less than 5 milliseconds, and their reported storage capacities range from 4 to 14 hours.

The PNNL (2023) has projected how key performance characteristics of RFBs will develop by 2030, estimating that the round-trip efficiency (RTE) will increase from 63% to 65%, while the cycle life remains at 5,250 cycles [46]. The U.S. Department of Energy (DOE) (2023) shares a similar outlook, forecasting the RTE to be around 65% [68]. In contrast, IRENA (2017) offers a more optimistic outlook, predicting that advancements in electrode, flow, and membrane design could push the RTE to a range of 67% to 95% [48]. Additionally, the DOE expects RFBs to achieve a cycle life of 12 years or approximately 10,000 cycles. Research by Stephan et al. (2023) indicates that future development in RFB technology is not primarily focused on increasing capacity or efficiency but rather on cost reduction and material substitution to lower costs and reduce the CO_2 footprint. They believe that RFBs will maintain a cycle life of over 10,000 cycles and an operational lifespan of around 20 years [69]. This aligns with findings by Poli et al. (2024), which assume that the reported cycle life of 20,000 cycles will remain stable [70]. Degradation, storage capacity, and response time in redox flow batteries (RFBs) are expected to remain relatively stable. The cycle life of RFBs is projected to stay high, with estimates ranging from 10,000 to 20,000 cycles, indicating minimal changes in degradation over time. Similarly, response time is not expected to improve significantly, as RFBs are primarily designed for long-duration energy storage rather than rapid discharge. Since RFBs allow independent scaling of power and energy capacity, substantial increases in storage capacity are unlikely under current designs. The 40-hour storage limit indicated by CE Delft is primarily constrained by financial feasibility.

However, future research focusing on alternative chemistries could potentially extend storage capacity beyond this limit. These findings are summarised in Table 3.

Table 3: Technological Characteristics of redox flow battery (Present day and 2030)

Component	Unit	Present day			2030		
		Lower Bound	Higher Bound	Source	Lower Bound	Higher Bound	Source
Storage capacity	hours	1	40	[48][66][67][71]	1	50	assumption
RTE	%	63	85	[44][46][67][51][45][66][61]	65	95	[46][68][48][70]
Charge rate	-	C/6	C/2	[67]			
Discharge rate	-	C/18	C/4	[66][67]			
Cycle Life	Cycles	1000	20000	[46][48][51][67][45][44][61]	5250	20000	[46][48][69][68][70]
Calender Life	Years	10	20	[44][46]	12	20	[46][69][48][68][70]
Response time	-	milliseconds	minute	[51][48][66][67]	milliseconds	minute	assumption
Degradation	%/yr	0.35	0.5	[67][66]	0.35	0.5	assumption

The costs of redox flow batteries can vary significantly depending on project details and size. Regardless, several studies have provided cost estimations that provide valuable information on current and expected price ranges. The study by Olabi found a broad range for the CAPEX of a redox flow battery, ranging between 106 and 1934 EUR/kWh [45]. According to Diaz-Gonzalez, the costs are approximately 580 EUR/kWh [44]. Research institute CE Delft reports a similar value of approximately 500 EUR/kWh in 2023 [61]. Elio et al. (2021) state a higher CAPEX for RFBs with a range between 1380 and 1780 EUR/kW, or between 135 and 1350 EUR/kWh[51]. IRENA states that the costs for flow batteries were between 300 and 1600 EUR/kWh [48]. The PNNL states that the CAPEX ranges between 2500 and 3700 EUR/kW or 460 and 630 EUR/kWh for a 100 MW RFB with storage between 4 and 8 hours [46]. Moreover, the costs for the battery stacks range between 260 and 360 EUR/kWh, while the battery balance of system ranges between 60 and 72 EUR/kWh. An inquiry was made to Invinity, a RFB manufacturer, where Invinity stated that they agree with a total CAPEX range between 285 and 816 EUR/kWh [72]. They emphasized that the costs depend on the specific details of the associated project. The OPEX reported by Elio et al. is in the range between 3.68 and 18.7 EUR/kW/year [51]. The OPEX reported by the PNNL are within this range, as they provide a range between 5.95 and 9.30 EUR/kW/year. Invinity mentioned that the OPEX is in the range of 1% to 3% of the CAPEX per year.

In 2030, IRENA projects that the CAPEX for redox flow batteries (RFBs) will decline to a range of 105 to 350 EUR/kWh, with a central estimate of 120 EUR/kWh [48]. CE Delft does not provide specific numbers for future RFB costs but suggests that by 2030, their costs will be comparable to those of Li-ion batteries [61]. Based on Table 2, Li-ion battery CAPEX in 2030 is expected to range from 200 to 600 EUR/kWh and 950 to 1650 EUR/kW, with an annual OPEX of 2.5% of CAPEX. However, the PNNL states a higher CAPEX estimate for RFBs in 2030, projecting a range between 2270 and 3390 EUR/kW, or 420 to 570 EUR/kWh, which includes the cost of stacks and the BoS [46]. Within this estimate, PNNL expects stack costs to range between 240 and 330 EUR/kWh, while BoS costs will be between 50 and 58 EUR/kWh. The DOE provides a more moderate estimate, forecasting a CAPEX range of 350 to 370 EUR/kWh for a complete RFB system [68]. Within this, they estimate stack costs at approximately 160 EUR/kWh and BoS costs at 29 EUR/kWh. The DOE also projects an OPEX of approximately 9.62 EUR/kW/year. PNNL anticipates that the OPEX for RFBs will decline to between 5.42 and 8.22 EUR/kW/year by 2030 [46]. Currently, the OPEX for redox flow batteries is estimated to range between 1% and 3% of CAPEX per year. It is assumed that this range will remain similar in 2030, aligning with the expectations of CE Delft [61]. These findings are summarized in Table 4. The ranges shown are derived from multiple independent sources, and therefore individual values (e.g., for stack or balance of system components) do not correspond to each other. As such, costs should not be calculated by directly summing the individual ranges.

Table 4: Financial Characteristics of a RF battery (Present day and 2030)

Component	Unit	Present day			2030		
		Lower Bound	Higher Bound	Source	Lower Bound	Higher Bound	Source
Battery stack	EUR/kWh	260	360	[46]	160	330	[46][68]
Battery BoS	EUR/kWh	60	72	[46]	29	58	[46][68]
Total CAPEX	EUR/kWh	106	1934	[45][44][61][51][48][72][46]	105	600	[48][46][61][68]
Total CAPEX	EUR/kW	1380	3700	[51][46]	950	3390	[46][71]
OPEX	EUR/kW/yr	3.68	18.7	[51][46]	5.42	9.62	[46][68]
OPEX	%/CAPEX/yr	1	3	[72]	1	3	assumption [61]

Although limited, Eneco has some experience with redox flow batteries. The technical and financial characteristics have been validated with the available data. According to Eneco, a round trip efficiency of 80% has been reported in vendor data with a degradation between 0.2 and 0.5%. A lifetime around 20 to 30 years is expected by vendors with charge and discharge rates corresponding with literature. CAPEX assumptions amount to approximately 100 EUR/kW, or 250 EUR/kWh for the whole system. This amounts to the lower side of the range found in literature, while the OPEX is in line with the literature.

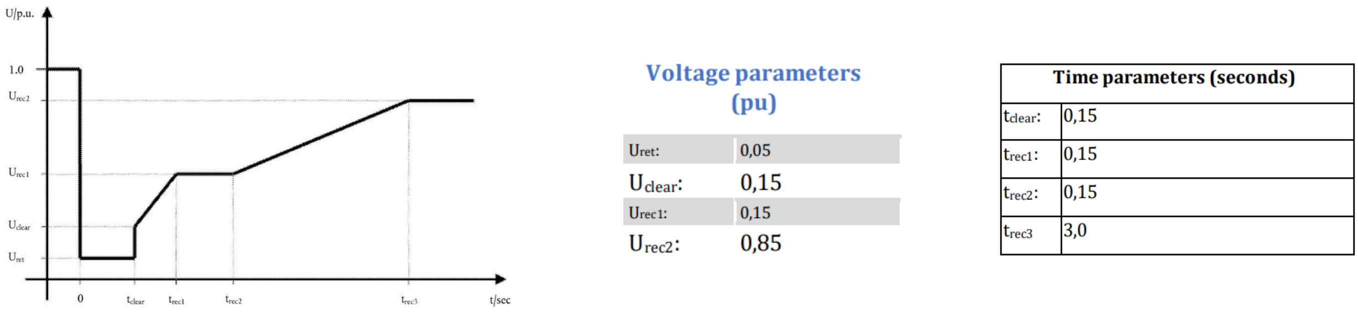
3.2 Electrolysers

As the Netherlands expands its renewable energy capacity, batteries will play a key role in managing short-term energy fluctuations. However, they are not a feasible solution for seasonal energy storage. RFNBO-compliant hydrogen offers an environmentally friendly alternative, providing long-term energy storage and serving as backup power during events such as blackouts. Electrolysers are essential for producing RFNBO-compliant hydrogen by using surplus renewable electricity to split water into hydrogen and oxygen, effectively storing energy in chemical form. This process helps balance the grid by absorbing excess power during high generation periods and reducing demand when supply is low. Two primary electrolyser technologies are Alkaline (ALK) and Proton Exchange Membrane (PEM) electrolysers. Other electrolyser technologies, such as solid oxide and anion exchange electrolysers, are still relatively in early development and will not be covered in this thesis. ALK electrolysers are well-established, cost-effective, and suitable for large-scale hydrogen production. In contrast, PEM electrolysers offer greater flexibility, faster response times, and better performance under variable loads, making them ideal for integration with intermittent renewables. However, as noted by Kojima et al. (2023), most electrolysers require a certain base load, potentially up to 40%, to maintain standby status [17]. The standby mode allows them to switch from non-producing to hydrogen-producing mode in order to follow the intermittent cycle of a renewable power plant. However, alkaline electrolysers are not as well-suited to fluctuating energy inputs, as they require a relatively stable base load to operate efficiently. They are less responsive to intermittent energy sources like solar and wind power compared to other technologies such as PEM electrolysers [73]. Both ALK and PEM electrolysers require a minimum stable load (MSL) to operate efficiently, but they differ in the amount of energy needed to maintain this load. According to another study by IRENA (2020), the MSL for ALK electrolysers is 20% of the nominal capacity, in contrast to 5% for PEM electrolysers [74]. In addition, balance of plant also has a minimum stable load. The balance of plant includes components such as sensors, compressors, converters, and other auxiliary systems. A detailed description of the balance of plant components is provided in Chapter 3.4. The following sections will explore ALK and PEM electrolysers in detail, focusing on their working principles, technical characteristics, and financial considerations for RFNBO-compliant hydrogen production.

There are currently few reliable forecasts for electrolyser performance and costs in 2030, as their financial and technical characteristics are not expected to change significantly in the coming years. This is due to several factors. Firstly, according to Eneco, electrolysers must be ordered around three years in advance. This means that most systems expected to be operational by 2030 will need to be purchased within the next two years, effectively locking in current technology and cost structures. Secondly, the large-scale deployment of electrolysers is still limited, which delays valuable feedback from vendors and operators. This feedback is very important in stimulating innovation. Without widespread implementation, economies of scale and technological improvements remain limited, slowing both cost reductions and efficiency gains. Eneco confirms this outlook, stating that significant advancements in electrolyser technology and cost reductions are more likely to occur after 2030, once larger installations are deployed and more operational data becomes available. For this reason, performance and cost forecasts for 2030 will not be included in this master's thesis.

3.2.1 Grid Restrictions

According to the Agency for the Cooperation of Energy Regulators (ACER) (2023), electrolysers, as power-to-gas (P2G) units, need to adjust their operation to help maintain grid stability and efficiency, as described in Annex 2 – Amended DC Regulation [75]. Electrolysers must comply with the specified regulations, regardless of whether they operate flexibly. These units must remain connected and stable after disturbances in the transmission system and follow a voltage-against-time profile at the connection point, as shown in Figure 6 (left), with parameters specified in in the tables in Figure 6 (middle & right). They are also required to operate within the designated frequency ranges specified in Annex 2, ensuring that they do not compromise system stability or frequency ride-through performance. Additionally, power-to-gas demand units must support the Limited Frequency Sensitive Mode for Underfrequency Consumption (LFSM-UC), meaning they must automatically reduce their consumption when system frequency falls below 49.8 Hz, maintaining this mode for as long as necessary. Compliance also involves a structured certification and operational notification process. Units connected at or below 1000V must hold valid equipment certificates, while those above 1000V must undergo the Demand Unit Document (DUD) process, which includes a compliance statement confirming adherence to technical standards. Furthermore, if a power-to-gas unit provides demand response services, it must meet additional compliance measures, ensuring that it operates in line with system requirements, whether managed independently or through a third party.



Voltage parameters (pu)

U_{ret}:	0,05
U_{clear}:	0,15
U_{rec1}:	0,15
U_{rec2}:	0,85

Time parameters (seconds)	
t_{clear}:	0,15
t_{rec1}:	0,15
t_{rec2}:	0,15
t_{rec3}	3,0

Figure 6: Voltage and time parameters for power-to-gas units response according to ACER

Hydrogen production systems must be capable of responding dynamically to these regulatory requirements by ACER, ensuring that they can adjust their power consumption in real-time to support grid stability. However, such flexibility can have effect on the degradation of electrolyser stacks. Electrolysers stacks depend on delicate chemical balances, and frequent power modulations, especially in response to grid events, can disrupt this balance, leading to increased degradation and reduced lifespan. In this study, the ramp rates of different hydrogen production systems will be determined based on their specific characteristics. However, compliance with the ACER requirements outlined in Annex 2 will not influence whether a particular hydrogen production system is included in the evaluation. In addition, it is assumed that the battery can aid the electrolyser by consuming additional power when the electrolyser has to shut down. Moreover, predicting the consequences of operating hydrogen production systems according to ACER's requirements is very challenging. For this reason, the potential additional degradation as a result of the regulation by ACER will not be taken into account.

3.2.2 Alkaline Electrolyser

Alkaline electrolysers are a well-established and widely used technology for hydrogen production, having been employed for several decades. They operate by utilizing a liquid electrolyte, typically potassium hydroxide (KOH), which facilitates the electrolysis of water into hydrogen and oxygen [76]. During the electrolysis process, hydroxide ions (OH-) are generated at the cathode and travel through the electrolyte to the anode, where oxygen is produced. Figure 7 illustrates a schematic overview of an alkaline electrolyser, showing the movement of OH- ions through the membrane during the process. One of the significant advantages of alkaline electrolysers is their cost-effectiveness. Due to their use of abundant and low-cost materials, including the absence of precious metals in their construction, alkaline electrolysers are generally less expensive than PEM electrolysers. This makes them particularly attractive for large-scale hydrogen production, especially when integrated with stable and reliable energy sources [77]. Despite these challenges, the scalability and affordability of alkaline electrolysers continue to make them a popular choice for applications where cost considerations take precedence over the need for high efficiency or flexibility.

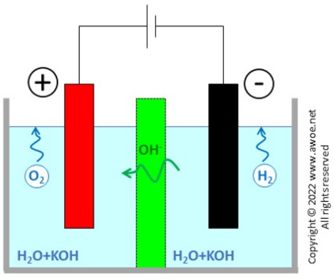


Figure 7: Schematic overview of an alkaline electrolyser [4]

Many studies have examined the performance characteristics of alkaline electrolysers. Literature findings on ALK electrolysers are presented in Table 5 and 6, originally compiled by Travaglini et al. (2025) [9]. The table has been further enhanced with additional values to provide a more comprehensive analysis of ALK electrolyser characteristics. Similar to batteries, these characteristics can vary depending on size, but the ranges stated by studies provide valuable insights. For instance, the lifetime of an electrolyser depends on the operation mode and water purity. A study by IRENA (2020) states that alkaline electrolysers have a proven lifetime of over 30 years, with a stack lifetime of 60,000 hours [74]. Moreover, the study states that the system MSL for ALK electrolysers is 15%, with a maximum load of 100%. A stack efficiency of 47 to 66 kWh/kgH$_2$ and a system efficiency of 50 to 78 kWh/kgH$_2$ is also reported. Finally, ramping the electrolyser up from 0% to 100% (cold start) is reported to take approximately 50 minutes. Nnabuife et al. (2024) also investigated the performance characteristics of ALK electrolysers. According to their study, the system efficiency is 49 kWh/kgH$_2$, which aligns with the findings of IRENA [78]. Nnabuife et al. also report a cycle life of 80,000 hours, or 20 years, for systems operating under intermittent conditions. The study also states a load range between 20% and 100%, with a cold start procedure taking up to 50 minutes. ALK electrolysers have a relatively high MSL to prevent the buildup of flammable gas mixtures within the electrolyser. At low current densities, such mixtures can occur due to gas diffusion across the membrane [78]. Moreover, according to NNabuife et al. (2024), the ramp rate of an ALK electrolyser is between 0.2% and 20% per second. NNabuife et al also mentioned that ALK electrolysers can produce hydrogen between atmospheric (1 bar) and 15 bar. Tahan (2020) agrees with these findings, as this study reports the same pressure range [79]. The study by IRENA reports that ALK electrolysers can deliver pressure between 1 and 30 bar [74]. The study by Gorre et al. (2020) is in line with the lower ramp rate estimate, as a ramp rate of 0.3% is reported, or a ramp up time of 10 minutes to full power [80]. Kiaee et al. (2015) also report ramp rates of electrolysers, as they state the maximum ramp rate for a atmoshperic 2 MW ALK electrolyser of 2.25 kW/second which is equivalent to approximately 0.1%/second [81]. Hassan et al. (2024) provided an extensive overview of various performance characteristics of ALK electrolysers [82]. Their study states that the load range is between 10% and 100% and that these electrolysers can ramp up to nominal capacity within several seconds from MSL. However, the cold start process is reported to take approximately 60 minutes. The study reports a stack efficiency between 62% and 82% concerning the HHV of hydrogen, corresponding to an energy consumption range of 48 to 63.5 kWh/kgH$_2$. Additionally, the electrical consumption of the entire system ranges between 4.5 and 6.6 kWh/Nm^3 of hydrogen, which translates to an efficiency range of 50.1 to 73.5 kWh/kgH$_2$. Lastly, the reported cycle life ranges between 60000 and 90000 hours. According to the study by Travaglini et al. (2025), the lifetime of an ALK electrolyser ranges between 7 and 10 years. Moreover, the cold start up time is found to be 20 minutes [9]

Since the energy requirements for the BoP are challenging to obtain directly, they can be deducted by comparing the system efficiency and the stack efficiency. According to the modified table, the difference in the lower bound is negligible, but the difference in the higher bound is between 78 and 66 kWh/kgH$_2$. This results in a difference of 12 kWh/kgH$_2$, which can be attributed to the energy required for the BoP.

Table 5: Technical specifications for ALK electrolysers. Modified from [9].

Component	Unit	Lower Bound	Higher Bound	Source
System efficiency	kWh/kgH_2	47	78	[83, 84, 71, 74, 78, 82]
Stack efficiency	kWh/kgH_2	47	66	[74, 82]
Stack MSL	%	10	40	[74, 78, 82]
BoP efficiency	kWh/kgH_2	-	12	assumption
Cold start	minutes	20	60	[74, 78, 82, 9]
Ramp up/down	%/sec	0.1	20	[78, 80, 81]
Cycle life	years	7	30	[74, 78, 9]
Cycle life	hours	60000	90000	[74, 78, 82]
Outlet pressure	bar	1	30	[78][79][74]

The range for cost estimates of electrolysers is fairly broad as a result of the availability of the data and the inconsistent system boundaries. The study by IRENA (2020) has conducted a thorough literature research and states a stack CAPEX of approximately 260 EUR/kW, and a system CAPEX between 480 and 970 EUR/kW [74]. According to Nnabuife et al. (2024), the CAPEX of an ALK electrolyser system is approximately 480 EUR/kW, with a stack replacement cost of 215 EUR/kW. This is in line with the research by IRENA (2020). Moreover, this is also in line with the research by Travaglini et al. (2025), where the literature suggests stack replacement costs between 45% and 55% [9]. Moreover, TNO (2024) conducted a study in collaboration with 14 parties, including Shell, Vattenfall, and Eneco, to provide an overview of the key cost components of hydrogen production systems [85]. It is important to note that this study does not make a differentiation between Alkaline or PEM electrolysers. According to this study, the total system CAPEX is estimated at 3050 EUR/kW, based on the mean of the data provided by the contributing parties. This estimate is higher than values reported in some literature studies, which may indicate that this vendor-based data includes additional costs such as contingencies, project-specific requirements, or unforeseen implementation costs that are often not captured in generalized academic estimates. The electrolyser CAPEX accounts for 21% to 35% of the total, resulting in costs ranging from 640 to 1070 EUR/kW, excluding outliers. Similarly, the Balance of Plant contributes 18% to 35% of the total CAPEX, equating to 549 to 1070 EUR/kW, which is on the higher side of the range found by Travaglini et al. Moreover, the total OPEX is estimated at 75 EUR/kW/year, or approximately 2.5% of the system CAPEX. Table 6 shows the findings from the literature research. The ranges shown are derived from multiple independent sources, and therefore individual values (e.g., for stack or balance of system components) do not correspond to each other. As such, costs should not be calculated by directly summing the individual ranges.

Table 6: Financial Characteristics of ALK Electrolysers. Modified from [9].

Component	Unit	Lower Bound	Higher Bound	Source
System CAPEX	EUR/kW	480	1070	[74, 78, 85]
Stack CAPEX	EUR/kW	52	531	[83, 86, 84, 87, 88, 89, 90, 91, 74]
Stack replacement	%/CAPEX	45	55	[92, 93, 78]
Stack OPEX	%/CAPEX/yr	0.9	4	[83, 86, 84, 87, 88, 89, 90, 91]
BoP CAPEX	EUR/kW	280	1070	[83, 86, 84, 87, 88, 89, 90, 91, 85]
BoP OPEX	%/CAPEX/yr	2	4	[84]
System OPEX	%/CAPEX/yr	2.5	2.5	[85]

All findings are validated using the values obtained by Eneco, which consist of vendor data and in-house expertise. The electrolyser stack efficiency is reported to be 50 kWh/kgH_2, with a minimum stable load of 29%. The MSL of the vendors is in line with the literature research. The stack life is reported to be approximately 10 years with a degradation of around 1% per year. The stack CAPEX is approximately 230 EUR/kW, with an OPEX of approximately 60 EUR/kW/year.

3.2.3 Proton Exchange Membrane Electrolyser

PEM electrolysers represent a more modern and advanced technology in hydrogen production. Unlike alkaline electrolysers, PEM electrolysers use a solid polymer electrolyte to conduct protons from the anode to the cathode, resulting in high-purity hydrogen production [94]. In Figure 8, it is shown that H+ protons travel through the solid membrane. Their compact and modular design has made them increasingly popular in applications requiring space efficiency and operational flexibility. A significant advantage of PEM electrolysers is their high efficiency, which allows them to produce hydrogen with a lower energy consumption compared to alkaline systems. Furthermore, PEM electrolyzers can respond quickly to changes in power supply, making them particularly well suited for integration with intermittent renewable energy sources such as solar and wind [95]. This flexibility is a key reason for their growing adoption in renewable hydrogen projects. However, PEM electrolysers are more expensive than alkaline electrolysers, primarily due to their reliance on rare and precious metals like platinum and iridium, which act as catalysts [96]. These materials not only increase the initial capital cost but also raise concerns about the long-term availability and sustainability of these resources. Although not as established as alkaline technology, PEM electrolysers are considered fairly mature and are deemed more appropriate for coupling with renewable energy sources due to the tolerance to short-term load variations [95].

The literature findings on PEM electrolysers are presented in Tables 9 and 8, originally created by Travaglini et al. (2025) [9]. Similar to the ALK table, this table has been further expanded with additional values, providing a more comprehensive analysis of PEM electrolyser characteristics. According to IRENA (2020), PEM electrolysers have reported life times of 50000 to 80000 hours when run at the least demanding conditions, such as lower temperatures and current densities [74]. Moreover, the study states that PEM electrolysers can perform a cold start up in less than 20 minutes, while a shut down only takes a few seconds. The study

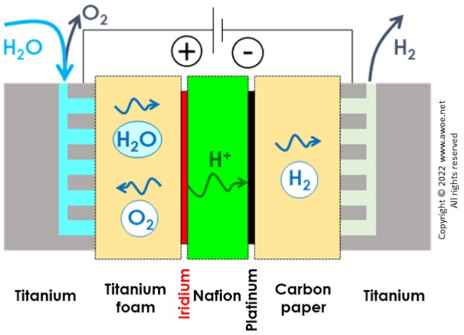


Figure 8: Schematic overview of a PEM electrolyser [5]

also states that the system MSL for ALK electrolysers is 5% with a maximum load of 120%. Finally, a stack efficiency of 47 to 66 kWh/kgH_2 and a system efficiency of 50 to 83 kWh/kgH_2 is reported. According to Nnabuife et al. (2024), PEM electrolysers have a load range between 0% and 100% with operating ranges between 50000 and 75000 hours, or 20 years [78]. Moreover, the efficiency for PEM electrolysers is 49 kWh/kgH_2. According to NNabuife et al. the output pressure for PEM electrolysers can range between 20 and 60 bar. Moreover, Tahan (2022) mentions that PEM electrolyser can deliver hydrogen between 30 and 60 bar [79]. According to IRENA (2020), PEM electrolysers typically deliver hydrogen between 30 and 70 bar [74]. Hassan et al. (2024) provided an extensive review of the performance characteristics of PEM electrolysers [82]. According to their study, these electrolysers operate within a load range of 0% to 100% and can ramp up to nominal capacity within several seconds from warm standby (0% load). According to Lopez et al. (2023), PEM electrolysers can ramp up with 10% to 50% per second [97]. The reported stack efficiency by Hassan et al. varies between 62% and 87% (based on the higher heating value of hydrogen), corresponding to an energy consumption range of 45.3 to 63.5 kWh/kgH_2. Meanwhile, the electrical consumption of the entire system ranges from 4.2 to 6.6 kWh/Nm^3, which translates to 46.7 to 73.5 kWh/kgH_2. Additionally, the PEM electrolysers show a cycle life between 20,000 and 60,000 hours, depending on operation. Since the energy requirements for the BoP are challenging to obtain directly, they can be deducted by comparing the system efficiency and the stack efficiency. According to the modified table, the difference in the lower bound is between 49 and 45.3 kWh/kgH_2, and the difference in the higher bound is between 78 and 66 kWh/kgH_2. This results in a range between 3.7 and 17 kWh/kgH_2, which can be attributed to the energy required for the BoP. According to the study by Travaglini et al. (2025), the lifetime of a PEM electrolyser ranges between 6 and 10 years. Moreover, the cold start up time is found to be 10 minutes [9].

Table 7: Technical specifications for PEM electrolysers. Modified from [9]

Component	Unit	Lower Bound	Higher Bound	Source
System efficiency	kWh/kgH_2	49	83	[83, 84, 71, 74, 78, 82]
Stack efficiency	kWh/kgH_2	45.3	66	[74, 82]
Stack MSL	%	0	5	[74, 78, 82]
BoP efficiency	kWh/kgH_2	3.7	17	assumption
Cold start	minutes	10	20	[74, 78]
Ramp up/down	%/sec	10	100	[74, 78, 82, 97, 9]
Cycle life	years	6	20	[78, 48, 9]
Cycle life	hours	20000	80000	[74, 78, 82]
Outlet pressure	bar	20	70	[78][79][74]

According to IRENA (2020), PEM electrolysers are currently 50% to 60% more expensive than ALK electrolysers in terms of both CAPEX and OPEX [74]. Following this logic, the study estimates stack costs at approximately 390 EUR/kW, with total system CAPEX ranging between 680 and 1350 EUR/kW. Saba et al. (2018) report a broader CAPEX range of 300 to 4590 EUR/kW for PEM electrolysers [98]. Nnabuife et al. (2024) provide a more specific estimate, stating a system CAPEX of 700 EUR/kW, aligning with IRENA's findings, and suggesting stack replacement costs of 210 EUR/kW [78]. This suggests that the assumption made by Travaglini et al. (2025) is slightly higher than Nnabuife's study indicates stack replacement costs closer to 30% rather than higher estimates [9]. As mentioned, the previous TNO study that is conducted with the help of 14 contributing parties, does not make a differentiation between PEM and Alkaline electorlyser. Therefore, the same values can be adopted for the PEM electrolyser characteristics. Table 8 shows the findings from the literature research. The ranges shown are derived from multiple independent sources, and therefore individual values (e.g., for stack or balance of system components) do not correspond to each other. As such, costs should not be calculated by directly summing the individual ranges.

Table 8: Financial Characteristics of PEM Electrolysers. Modified from [9].

Component	Unit	Lower Bound	Higher Bound	Source
System CAPEX	EUR/kW	680	1350	[74, 85]
Stack CAPEX	EUR/kW	63	610	[83, 84, 87, 88, 90, 91, 99][74]
Stack replacement	%/CAPEX	30	50	assumption[78]
Stack OPEX	%/CAPEX/yr	2	4	[84]
BoP CAPEX	EUR/kW	420	1190	[83, 99, 88, 87, 84, 85]
BoP OPEX	%/CAPEX/yr	2	4	[84]
System OPEX	%/CAPEX/yr	2.5	2.5	[85]

The data found in the literature is compared to the available data from Eneco. Data from vendors show that the minimum stable load of PEM electrolysers is estimated to be higher, in order to reduce degradation. For instance, Siemens states a that the PEM electrolyser has a safe minimum stable load of 40%. This 40% minimum stable load is chosen to ensure minimal stack degradation and enables the stacks to increase the lifetime to more than 10 years. However, other vendors report minimum stable loads as low as 5%, with a slightly decreased lifetime of approximately 10 years. The literature is fairly optimistic regarding the efficiency of the PEM electrolyser than the vendors. Current vendors report stack efficiencies between 51 and 56 kWh/kgH_2, which correspond to the higher side of the provided range. The output pressure is reported to be 30 bar for all vendors. The stack CAPEX is approximately 350 EUR/kW, with an OPEX corresponding to the found literature.

3.3 Battolyser

The Battolyser, a new and integrated technology that combines the functionalities of a nickel-iron (Ni-Fe) battery and an alkaline electrolyser, is depicted in Figure 9. This figure shows a schematic overview of a Battolyser stack, where the flow of OH- ions and electricity is shown. The integration of a battery and electrolyser potentially offers unique advantages that makes the Battolyser a promising contender for renewable hydrogen production in combination with intermittent energy sources.

A side effect of a Ni-Fe battery is the unwanted production of hydrogen, which results in lower efficiencies [100]. Prof. Dr. Fokko Mulder and his research group from the Delft University of Technology saw that this side effect could be turned into an advantage when the asset would be used as a combined battery and electrolyser. Prof. Dr. Mulder came up with the concept in 2013 and the Battolyser entered the market in 2021 as product of Battolyser Systems. Since then, several developments have been made, as the renewed Battolyser can store electricity four times faster with twice the capacity of the previous version, due to the new 3D designed electrodes [101].

According to Mulder et al. (2017), during charge insertion, the $Ni(OH)_2$ and $Fe(OH)_2$ electrodes transition into nano-structured NiOOH and reduced Fe, which act as efficient catalysts for the oxygen and hydrogen evolution reactions [6]. Mulder et al. also state that their experimental results demonstrate consistently high overall energy efficiency (80–90%), enhanced electrode storage density and rapid current switching capabilities. A distinctive feature of the Battolyser is its ability to operate across a wide range of charge states, from 100% down to 0%, and even below 0% by discharging electricity back into the grid [18]. In contrast to alkaline and PEM electrolysers, the Battolyser does not need a minimal load to remain in standby mode when the battery is charged. During operation, the incoming energy is divided between hydrogen production and battery charging. The efficiencies and hydrogen split depends on the state of charge of the battery. Once the battery is charged, all incoming power is directed towards hydrogen production. Additionally, like conventional alkaline electrolysers, the Battolyser is built with non-rare earth elements and shares the same robustness as a Ni-Fe electrolyser. These characteristics make the Battolyser suitable for integration with intermittent renewable energy sources. According to Battolyser Systems, the ability to generate extra revenue by injecting electricity back to the grid, results in a low levelised cost of renewable hydrogen [18]. Since the Battolyser is essentially an electrolyser, the same grid restrictions that apply to electrolysers are also relevant to the Battolyser.

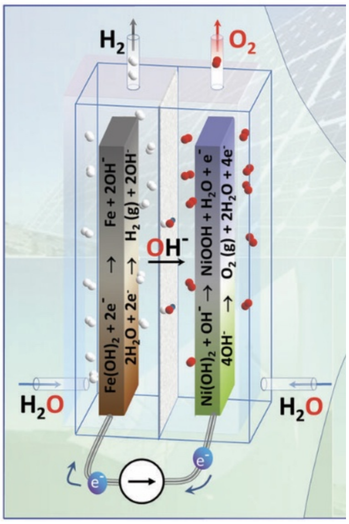


Figure 9: Schematic overview of the Battolyser. Modified from [6].

Battolyser Systems has a data sheet with the performance characteristics of several Battolyser modules, ranging from 2.5 MW to 25 MW [102]. According to the data sheet, the electrolyser stack efficiency ranges between 46.3 and 49.2 kWh/kgH_2, while the system efficiency ranges between 50.1 and 53.2 kWh/kgH_2. The load ranges can take values between 0% and 100%, which means that the MSL of the Battolyser is 0%. Moreover, the ramp up and down rate is 20% of the nominal capacity per second. Besides the electrolyser function, the Battolyser also has storage capabilities. The RTE of the battery stack ranges between 70 and 80%, while the RTE for the system ranges between 68% and 78%. Moreover, the battery can be used in the range between 0% and 100%. The efficiency and hydrogen split depend on the state of charge of the system, making the stack efficiency dynamic. Furthermore, the battery has a charge rate of 1C, meaning that the battery can be charged to 100% in 1 hour at full power. The battery has a discharge rate between C/4 and C/2, meaning that the battery can be fully discharged between 4 and 2 hours. The storage capacity ranges between 1 and 4 hours. The data sheet specifies that the Battolyser will deliver hydrogen at a pressure of 30 barg. Barg refers to pressure measured above atmospheric pressure, which means the absolute output pressure of the Battolyser is 31 bar. According to the data sheet by Battolyser Systems, the system is intrinsically safe and robust in all operational modes, including charge, discharge, and idle, without causing any system degradation. Additionally, the electrodes feature a regenerative catalyst that ensures durable and long-lasting electrolysis. Battolyser electrodes have been proven in nickel-iron batteries that have remained operational for over 40 years.

However, given the complexity of the system, the Battolyser's lifetime is assumed to be 20 years, with a stack replacement after 10 years. This assumption aligns with the Eneco's expectations.

Table 9: Technical specifications for Battolyser

Function	Component	Unit	Lower Bound	Higher Bound	Source
Electrolyser	System efficiency	[kWh$_e$/kg]	50.1	53.2	[102]
	Stack efficiency	[kWh$_e$/kg]	46.3	49.2	[102]
	Load range	%	0	100	[102]
	Ramp up/down	%/sec	20	20	[102]
	Cycle life	years	10	20	[102]
	Outlet pressure	bar	31	31	[102]
Battery	Storage capacity	hours	1	4	[102]
	System efficiency	%	68	78	[102]
	Stack efficiency	%	70	80	[102]
	Load range	%	0	100	[102]
	Charge rate	-	1C	1C	[102]
	Discharge rate	-	C/4	C/2	[102]

Limited financial data is available from Battolyser Systems, as large scale projects are not realized yet. However, Battolyser Systems has shared some financial data with Eneco for modeling purposes. The provided financial data is adopted and applied in this master thesis. It is important to note that the costs of the Battolyser may be reduced when large systems are implemented due to upscaling and economies of scale. The current system CAPEX ranges from 2,100 to 3,875 EUR/kWh, while the stack CAPEX falls between 1,225 and 3,100 EUR/kWh. These costs are expressed in EUR per kWh due to the inclusion of the battery component. From this, the BoP CAPEX can be estimated at 725 EUR/kWh. Additionally, the OPEX is projected to be 3% of CAPEX per year, with an end-of-life salvage value of 10% of CAPEX. Table 10 shows the summarised findings.

Table 10: Financial Characteristics of the Battolyser.

Component	Unit	Lower Bound	Higher Bound	Source
System CAPEX	EUR/kWh	2100	3875	Eneco
Stack CAPEX	EUR/kWh	1225	3100	Eneco
Stack replacement	EUR/kWh	350	400	Eneco
BoP CAPEX	EUR/kW	725	725	Eneco
System OPEX	%/CAPEX/yr	3	3	Eneco
Salvage value	%/CAPEX	10	10	Eneco

3.4 General Equipment Hydrogen Production

The general equipment required to ensure optimal performance and integration of electrolysers includes various components such as desalination units and compressors, which all contribute to the overall efficiency and functionality of the plant.

An important aspect of electrolyser systems is the desalination process. Electrolysers require pure water for the electrochemical reactions that produce hydrogen. Desalination units are used to convert seawater (brine) into fresh water by removing salts and other impurities. The energy required for desalination typically ranges from 3 to 10 kWh/m3 of water. Furthermore, compressors used in electrolyser systems play a significant role in the overall efficiency of the plant. In general, alkaline electrolysers produce hydrogen to atmospheric pressure (1 bar), while PEM electrolysers produce hydrogen at 30 bar. After hydrogen is produced by the electrolyser, it needs to be compressed to a suitable pressure for storage, transportation, or distribution. There are several different compressors, which can be divided in three categories: positive displacement, dynamic and non-mechanical compressors. Mechanical compression is the most used for compressing hydrogen, as non-mechanical compression is not commercially mature yet [103] [104]. For this reason, this thesis will only consider positive displacement and dynamic compression. Positive displacement compression can be subdivided in reciprocating piston compressors; diaphragm, hydraulic and ionic compressors; and screw compressors. TNO (2022) conducted a study on several hydrogen compression methods, on which the following information is based [104]. First, a reciprocating compressor is a compressor that uses a piston to compress hydrogen by drawing it into a cylinder and then reducing its volume with each stroke, increasing pressure. Reciprocating compressors are well-suited for intermittent operation, with a proven track record in processes with frequent starts and stops. The most common hydrogen compression techniques are suction valve unloading and step-less reverse flow control. Speed regulation is limited to 60-70% of maximum capacity to ensure proper valve operation. Second, the operating principle of a diaphragm, hydraulic and ionic compressor is similar to that of a reciprocating compressor, but in this case, a membrane or piston is driven by oil. This type of compressors typically operate at low speeds to preserve the integrity of the piston and hydraulic seals. Moreover, careful operation is necessary to ensure the reliability of the delicate parts, as intermittent use is not favorable. Last, a screw compressor relies on interlocking lobes, such as male and female screws, to build pressure. Screw compressors operate at discharge pressures of up to 30 bar, with this limitation caused by internal leakage within the compressor. A centrifugal compressor is a form of dynamic compression. A centrifugal compressor increases gas pressure by converting kinetic energy into potential energy using a high-speed rotating impeller and diffuser. These compressors have a narrow range in which the compressor works efficiently. These different compressors all have their own benefits and challenges. According to TNO (2022), most large-scale onshore alkaline electrolyser systems use reciprocating compressors due to their maturity and flexible capacity control [104]. An inquiry has been done to Neuman-Esser, a electrolyser and compressor manufacturer based in the United States, and they have confirmed that reciprocating compressors are widely used for electrolyser applications. Such reciprocating compressors have a turndown of approximately 20% to 100%, meaning that they have operational flexibility of 80% depending on the hydrogen flow. According to Neuman-Esser, certain reciprocating compressor configurations can reach an operational range of 0% to 100% through cylinder unloading, recycling lines, and multiple compressor steps.

According to Neuman-Esser (2024), one method to achieve a lower compressor capacity is by unloading cylinders, which temporarily disables compression in specific valves while keeping the machine operational [105]. Another approach is implementing a bypass or recycle line, allowing hydrogen to circulate back to the compressor's inlet. This enables the compressor to idle when hydrogen production is minimal. However, this solution increases capital expenditure (CAPEX) by approximately 5% to 15%, according to Soriano (2025). A third option for expanding the operating range is installing multiple compressors in parallel. In this setup, certain compressors can be turned off while others operate at partial load when less hydrogen is being produced. Further insights were provided by B. Okhuijsen from Siemens, a manufacturer of electrolysers and compressors. He confirmed these three methods for achieving a compressor train with an operating range of 0% to 100%. However, he also highlighted that operating compressors at partial load or frequently starting and stopping them negatively impacts their lifespan. Running at partial load involves adjusting the valve opening and closing times, which causes some hydrogen to be pushed back into the feed-in line. This results in localized heating, which accelerates wear on components such as seals. Okhuijsen stated that the recycling line is a valid approach, as it does not affect the compressor's cycle life. He noted that continuous operation at rated capacity is ideal for compressor longevity. Regarding CAPEX, Okhuijsen suggested that the estimated 5% to 15% increase is on the high side, as similar recycle lines are already integrated into compressors for startup procedures. He mentioned that additional heat exchangers and dryers may be required, though their impact on total compressor CAPEX would be low. Finally, Okhuijsen emphasized that the compressor train can follow the ramping of the electrolysers, ensuring that this is not a limiting factor in system operation.

Compressors are responsible for increasing the pressure and can account for a large share of the energy consumption in the system. The energy required for compression typically ranges from 0.4 to 2.7 kWh/kgH_2, as found by Travaglini et al. (2025) [9]. According to the same study by IRENA (2020), the compression steps result in a loss of 6% to 7% towards the Lower Heating Value (LHV) of hydrogen if this is compressed from 1 bar to approximately 100 bar[74]. According to IRENA, compressing from 1 bar to 30 bar results already in losses between 3.5% to 4%. As a result, this study suggests to operate pressurized ALK electrolysers or PEM electrolysers, even though this increases the costs of the system. These findings are summarised in Table 19

Table 11: Overview of the technical specifications of general equipment for electrolyser systems. Modified from [9].

Component	Unit	Lower Bound	Higher Bound	Source
Desalination energy input	kWh/m^3	3	10	[99, 106, 107, 108]
Compressor energy input	kWh/kg	0.4	3.4	[103, 109, 7]
Compressor losses	%	6	10	[74] Siemens

The study by IRENA estimates that the cost increase for changing the design pressure from 1 bar to 15 bar is approximately USD 150/kW for an alkaline electrolyser [74]. According to Krajenbrink (2024), the CAPEX for the HyNetwork connection will be covered by the applicant, calculated based on a cost per kilowatt. In 2020, the CAPEX was estimated at 1545 EUR for 4 kW, which translates to 386.25 EUR/kW. Additionally, the OPEX will be determined by the Ministery of Climate and Green Growth, which is estimated at 21.13 EUR/kW per year in 2023 [110]. Moreover, the TNO (2024) study also provided financial data on other equipment than the electrolyser systems themselves [85]. According to TNO, 3% to 10% of the total system CAPEX of 3050 EUR/kW is allocated to compressors, translating to a cost range of 92 to 305 EUR/kW. In contrast, Travaglini et al. (2025) reported a significantly higher range of 2200 to 6700 EUR/kW [111, 112, 9]. However, since the TNO study is based on real-world input from vendors, its cost range is adopted in this research. In the TNO (2024) study, the costs for the transformer and HVAC are included within the BoP cost range for electrolysers. Additional costs, such as contingency (17%), indirect costs (9%), and developer costs (9%), contribute to the total 3050 EUR/kW system CAPEX. The costs associated with the hydrogen network, as stated by Krajenbrink (2024), are confirmed by TNO (2024), which reports similar values. Table 12 shows the findings from the literature research. The ranges shown are derived from multiple independent sources, and therefore individual values (e.g., for stack or balance of system components) do not correspond to each other. As such, costs should not be calculated by directly summing the individual ranges.

Table 12: Overview of the financial specifications of general equipment for electrolyser systems. Modified from [9

Component	Unit	Lower Bound	Higher Bound	Source
Desalination CAPEX	€/m^3	0.03	0.03	[108]
Desalination OPEX	%/CAPEX/yr	2.0	2.5	[111, 108]
Brine CAPEX	€/m^3	0.01	7	[113]
Brine OPEX	%/CAPEX/yr	2	2	assumption
H_2 compressor CAPEX	€/kW	92	305	[85]
H_2 compressor OPEX	%/CAPEX/yr	1.7	5	[111, 112, 114, 115]
H_2 network CAPEX	€/kW	386	423	[110]
H_2 network OPEX	€/kW/yr	21.13	21.13	[110]

The values found in the literature have been compared to those from Eneco. The specific energy demand of the desalination and compressors are included in the balance of plant. Chapters 4.2 and 4.5 will further highlight the specific energy demand used for the master thesis. The OPEX for hydrogen transport is approximately €1.5 million per year. The capital expenditure for desalination and brine treatment is included in the balance of plant costs, which range from €100 million to €130 million, depending on the system. Compressors are also included in the BoP, accounting for around €20 million. Maintenance costs vary by system, but include personnel expenses, which are approximately €1 million per year.

3.5 Supporting Equipment for Grid Connection

In addition to the equipment directly related to the hydrogen production systems, it is important to consider the general equipment that applies to both systems. These supporting factors and their implications include the characteristics and costs related to the grid, such as the high-voltage AC converter and transformer. Moreover, land and permit costs associated with the geographical location are also considered. All of these elements play a crucial role in the overall feasibility and cost structure of the system.

Land lease or purchase costs represent a substantial portion of the total expenditure, as suitable land must be secured for the installation of equipment, substations, and other critical infrastructure. According to Eurostat (2025), the land lease costs in the Netherlands range between 73 and 179 kEUR/hectare, with an average of 91.4 thousand euros per hectare. Besides the direct costs associated with the land, the cost of acquiring permits also plays a role, as regional approval is required. This can involve fees for environmental impact assessments, local authority permits, and other legal requirements. In 2024, the building permit costs are 0.87% of the CAPEX, assuming the total CAPEX will exceed 27 million euros [116]. Table 13 shows the findings from the literature researhc. The ranges shown are derived from multiple independent sources, and therefore individual values (e.g., for stack or balance of system components) do not correspond to each other. As such, costs should not be calculated by directly summing the individual ranges.

Table 13: Economic specifications for general equipment for all systems. Modified from [9].

Component	Unit	Lower Bound	Higher Bound	Source
Permit	%/CAPEX	0.87	0.87	[116]
Land lease	k€/hectare	73	179	[117]
Grid CAPEX	M€	3	5	[118]
Grid OPEX	k€/yr	143.57	144.30	[119, 85]
Transformer	M€	5	8	[120]
HVAC CAPEX	€/kW	30	30	[106]
HVAC OPEX	%/CAPEX/yr	1.5	2.5	[106, 121]

Tennet is the Transmission System Operator (TSO) in the Neterlands, who are in charge of the high and extra high electricity grid. The high voltage system (HS) is rated at 110/150 kV, while the extra high voltage system (EHS) consists of a network consisting of 220/380 kV cables. As mentioned in Chapter 2.3, the system will be connected to the EHS network. One of the primary categories is grid-related expenses, which include both operational expenditures (OPEX) and capital expenditures (CAPEX). The CAPEX relates to the initial costs of creating the physical connection from the grid to the system. According to Tennet, the CAPEX for a grid connection to the 380 kV network ranges between 3 and 5 million euros [118]. The OPEX will consist of fixed and variable costs, related to the costs of the network. According to Tennet (2025), the fixed costs are approximately 12.5 thousand euros per year, with variable costs of 55 EUR/kW/yr which can add up to 62 if the maximal rated power is used [119]. It is expected that these costs increase with 7% by 2030, with inflation included [122]. According to the TNO (2024) study, the fixed operational costs for the grid are estimated between 143.57 and 144.30 EUR/kW/year [85]. This value includes both fixed and variable costs as determined by TenneT. The TNO (2024) study also forecasts future TenneT grid tariffs, stating that they will reach 250 EUR/kW/year and eventually rise to 300 EUR/kW/year. If this trend is extrapolated to 2050, grid tariffs could reach 350 EUR/kW/year. A 380 kV transformer is important in connecting the system with the high-voltage grid. The transformer can step down the voltage and it provides electrical isolation between the grid and the downstream components, protecting sensitive equipment from disturbances or faults that may arise on the grid [123]. Transformer losses are typically below 2% according to Ellis et al. (2000), which is similar to the findings by Bush et al (2012), who reported efficiencies between 98.5% and 99.3% [124][125]. The costs for a 380 kV transformer are between 5 and 8 mEUR in Germany in 2021 [120]. Once the voltage has been appropriately stepped down, the HVAC converter takes over the task of preparing the power for the system. It typically includes a rectifier, which converts AC to pulsating DC, followed by filtering circuits that smooth out the pulsations to yield a steady DC output. The power losses in the HVAC system are generally minimal, around 0.5% per station, as can be seen in the table by Travaglini et al. (2025) [9].

According to a study by IRENA (2020), the balance of plant (BoP) plays a large role in determining the overall efficiency of the system. The study states that rectifiers exhibit very low efficiency at low loads, with performance rapidly improving between 15% and 20% load, after which high efficiencies are achieved [74]. Rectifier efficiency is also impacted by operating voltage, with lower voltages resulting in higher current and associated I^2R losses. These electrical losses can have a significant effect on system performance and must therefore be minimized. To mitigate such losses and maintain high overall system efficiency, a high-voltage DC bus can be implemented. Operating at higher voltages reduces the current for a given power level, thereby reducing resistive losses and improving the efficiency of power conversion. Additionally, this configuration allows the batteries in the co-located systems to operate efficiently at higher voltages. However, the implementation of a high-voltage DC bus introduces additional complexity. In contrast to a conventional configuration where a Battolyser is directly connected to the grid via a single rectifier, the high voltage DC (HVDC) bus for the co-located systems requires several additional components. Specifically, a bidirectional DC-DC converter is required between the battery system and the HVDC bus. This converter allows the battery to charge and discharge efficiently across a wide voltage range, and enables precise control over power flow and voltage matching. Furthermore, a unidirectional DC-DC converter is required between the electrolyser and the HVDC bus. Electrolysers typically operate at lower and fixed DC voltages, so this converter steps down the high DC bus voltage to a level suitable for the electrolyser stack. While this extra conversion introduces additional losses, it is essential for compatibility and safe operation. These losses are accounted for in the BoP-specific energy consumption, as discussed in Chapter 4.5, whereas the battery-related losses are included in the round-trip efficiency. To support this system architecture, several passive electrical components are also necessary. High-voltage DC busbars are used to distribute power across the different components, while DC disconnect switches and contactors provide isolation during faults or maintenance. DC circuit breakers are required for fault protection, as they must interrupt DC current without the benefit of zero-crossing. In collaboration with experts from Eneco, the increase in the balance of plant cost structure for the co-located HVDC configuration is estimated to be approximately 10% to 20%. These additional costs are incorporated into the BoP assumptions discussed in Chapter 4.2.

Table 14: Overview of the technical specifications for the systems. Modified from [9].

Component	Unit	Lower Bound	Higher Bound	Source
Transformer efficiency	%	98.5	99.3	[124][125]
HVAC power losses	%	0.5	0.5	[111]

The costs and performance characteristics have been validated with Eneco. The estimated capital expenditures for Tennet amount to 5 million euros for solely the grid connection. The costs can sum up to approximately 18-19 million euros for all other components, including transformers, HVAC and DC bus. Moreover, Eneco estimates the grid OPEX to amount to approximately 10-11 million euros in 2030. This includes the fixed and variable grid tariffs. In addition, Eneco estimates that the land lease in the Rotterdam port area amounts to approximately 130-150 thousand euro per hectare. The permit costs are included in the development expenditures (DEVEX), which are costs associated with the development of the project. The DEVEX are estimated at approximately 9 million euros to get the project ready to build.

3.6 Environmental Considerations

The previous sections focused on techno-economic aspects of the systems, while this section focuses on the environmental aspects of these technologies. The sustainability of large-scale deployment of electrolysers and batteries depends on material use, environmental impact, and long-term resource availability. This section will discuss the qualitative comparison of systems, rather than focusing on the quantitative comparison for the LCOH calculation. The section will highlight several aspects of the components, discussing the critical metal dependency and PFAS usage, for instance. These environmental considerations impact future scalability and may significantly influence material costs as the installed capacity increases.

The five components discussed in previous sections, the alkaline and PEM electrolyser, Li-ion and RF battery, and the Battolyser, vary significantly in their material composition. Alkaline electrolysers typically use nickel-based electrodes and a potassium hydroxide (KOH) electrolyte. While they can function without precious metals, iridium and platinum can be added to improve performance [126]. In addition, PEM electrolysers depend on scarce noble metals, such as iridium for the anode and platinum for the cathode. PEM electrolysers also use a solid polymer membrane, typically Nafion which is a PFAS material that is extremely difficult to break down. In contrast, the Battolyser, only makes use of abundant and non-toxic materials like nickel and iron, without requiring any PFAS or rare earth elements. Besides the electrolysers, the battery structures also pose some environmental challenges. LFP batteries consist of lithium, iron, phosphate, copper and graphite, which is used for the anode. Lithium extraction poses significant ecological challenges, particularly related to water use and land disruption in the mining areas. According to IEA (2025), it is expected that the copper and lithium supply decreases towards 2040, while the demand rises [127]. In addition, vanadium redox flow batteries use large volumes of vanadium dissolved in sulfuric acid, with the electrolyte flowing through cells separated by a membrane. The membrane typically consists of Nafion, relating back to the concerns regarding the break down of PFAS.

The future availability and cost of materials such as iridium, platinum, lithium, and PFAS-based components will influence both the environmental and economic feasibility of scaling these technologies. Iridium is one of the scarcest elements, with a global annual production of less than 8 tonnes. Over 80% of this supply comes from South Africa, and production levels have been declining. Prices fluctuate and have ranged from approximately €120,000 to over €180,000 per kg in recent years. Without reductions in iridium addition, the supply is expected to limit installed PEM electrolyser capacity, leading to increasing CAPEX by 2030 and beyond [128]. Platinum is more abundant, with global production around 180 tonnes per year, but it is also mined in Africa and therefore exposed to geopolitical risks. Average market prices have ranged between €30,000 and €40,000 per kg and it is expected that the price will increase in the long term [129]. For lithium, demand is projected to rise significantly. In the EU alone, lithium demand is expected to increase over 50 times by 2050 compared to 2020 [130]. Lithium prices are expected to average between €20 and €40 per kg in 2030, depending on demand and extraction capacity. There are environmental concerns regarding lithium mining, especially the extraction in water-scarce regions as a lot of water is needed during extraction. This could affect the supply of lithium, and therfore have an effect on the CAPEX of the batteries. Additionally, PEM electrolysers and vanadium redox flow batteries use PFAS-based membranes like Nafion. EU regulation is looking to restrict the use of forever chemicals that pressure manufacturers to stop incorporating PFAS in electrolysers and batteries [131]. Vanadium is primarily used in steel structures, but its demand increases due to the use in vanadium redox flow batteries (VRFBs). Current vanadium prices range from approximately €25 to €50 per kg. Forecasts suggest that prices could rise to around €60 per kg by 2030 if the deployment of VRFBs will increase [132]. Vanadium is often a byproduct of steel and uranium mining and if demand from batteries increases significantly without new sources or recycling, material costs could become a limiting factor. However, even though the vanadium electrolyte can be reused, which reduces the total amount of vanadium needed, it can still pose a limitation to the wide scale deployment of VRFBs. In contrast, the Battolyser has several environmental advantages over the other setups. Nickel and iron are relatively abundant and recyclable, and the system does not depend on rare earth metals. The integrated nature of the Battolyser reduces the need for separate energy storage and electrolysis infrastructure, resulting in lower material usage overall.

The environmental impact and long-term material availability of electrolysers and batteries are important factors for scalability and future installations. Systems that depend on scarce metals like iridium and platinum, or rely on PFAS-based membranes, may rise in costs and face challenges as capacity increases. In contrast, technologies such as the Battolyser and LFP batteries use more abundant and less controversial materials.

4 Model Conceptualisation and Realisation

This chapter describes the operation of the model developed to calculate hydrogen production through different power trading strategies. The model integrates input data and decision mechanisms to optimize energy distribution among electrolysis, storage, and power resale. The primary objective is to maximize profitability while aiming to comply with regulatory requirements for renewable hydrogen (RFNBO) production. The output of the simulation of this operation is later used to determine the Levelised Cost of Hydrogen (LCOH) for both systems. A script has been made in Python 3.9.6 to simulate the performance of various system configurations for this master's thesis. First, Chapter 4.1 outlines the general input parameters that serve as the basis for system operation within the model. Second, Chapter 4.2 discusses system-specific parameters and the assumptions used to model system characteristics. The input parameters are point values selected based on literature and Eneco's expertise. While these values represent informed estimates, it is acknowledged that there is uncertainty associated with these values, which may affect the model outcomes. These point values will be used to determine the base case, on which further analyses will be performed in Chapter 6. Next, Chapter 4.3 describes the model in detail followed by Chapter 4.4, which presents the output parameters obtained from the simulations. Then, Chapter 4.5 shows the assumptions made in the model and in this master thesis. Finally, Chapter 4.6 explains the model validation process.

4.1 General Input Parameters

The model imports multiple confidential datasets from Eneco, consisting of data spanning from 2026 to 2050. These data sets include electricity price forecasts for the Dutch grid, both with and without Guarantees of Origin. Additionally, the model imports data on the available power from wind and solar parks that can be contracted through power purchase agreements (PPAs). This power supply is sourced from a mix of wind and solar parks within Eneco's portfolio that is compliant with REDIII regulations. The costs for contracting these PPAs are also consistent for both systems. The length of the PPA contracts is 18 years, as it is expected by Eneco that the renewable energy share of the Dutch electricity grid exceeds 90% in the final years of of the simulation framework. This assumption is based on market data, the growing deployment of solar and wind energy installations, and the Netherlands' ambition to source 100% of its energy from renewable sources by 2050. Beyond electricity prices and power forecasts, the model also imports ETS price projections, the share of renewable energy, and the greenhouse gas footprint of the Dutch grid. These parameters are essential in assessing whether grid electricity can be utilized to produce RFNBO-compliant hydrogen. Although forecasting these values presents challenges, the inclusion of these datasets provides a consistent framework for evaluating both systems. Moreover, several financial parameters are identical across both systems to maintain a consistent framework. For example, the costs for development, contingency, hydrogen network integration, brine management, and desalination, are considered and viewed constant for all different systems. Additionally, expenses related to construction and labor are included in analysis. Note that some of these costs are system-dependent because they differ with varying size for instance. However, the construction costs are also influenced by experience and economies of scale. The more frequently similar systems have been built, the lower the costs tend to be due to improved efficiency, supply chain optimization, and accumulated expertise in execution. On one hand, the system that includes an electrolyser and batteries requires more components to be constructed and installed, which means the Engineering, Procurement, and Construction (EPC) party will need more time to complete the project. However, Battolyser technology is still in its early stages, and no large-scale Battolysers have been installed to date. This lack of experience could lead EPC parties to apply higher contingencies to account for potential risks and uncertainties. Given these considerations, it has been decided to increase the EPC costs for the systems of combined battery and electrolyser, relative to those of the Battolyser system. This means that the EPC costs will be lower for the Battolyser than for the other systems. Moreover, some variation in land lease, balance of plant and grid fees are modeled as a result of the characteristics of the respective system.

4.2 System Dependent Parameters

The Battolyser system and the combined battery-electrolyser system each have distinct technical and financial characteristics, as highlighted in the literature review. This chapter outlines the initial assumptions and parameter values used in the simulation. As previously mentioned, the simulation timeline spans from 2030 to 2050, covering a total of 20 years. Depending on the system configuration, stack replacements may be required after a certain operational period, as both electrolyser and battery stacks degrade over time based on their characteristics. The maintenance for the battery and electrolyser is performed at the same time, and the whole system is offline for 2 days to simulate the maintenance. The system is offline during this time, however, revenue is generated through reselling of the incoming PPA power. The hydrogen production stacks in all configurations are rated at 90 MW, with system efficiencies varying according to the setup. The power rating for the balance of plant depends on the configuration, as the energy consumption of hydrogen production systems can be divided into the power required for the stacks and the power needed for the BoP. The power directed to the stacks is used to produce hydrogen from water. The power allocated to the BoP is used to operate supporting equipment, such as compressors, desalination units, and sensors. In both systems, hydrogen compressors are necessary to increase the hydrogen pressure to match that of the HyNetwork pipelines. However, as noted in the literature review, the operating output pressures of the electrolysers and the Battolyser differ. As a result, the compressor connected to the PEM electrolyser and Battolyser requires less energy, since the pressure ratio and the compression work is lower. Therefore, the power demand for the BoP differs per configuration and system. The losses from converters, along with the energy demand of sensors, desalination units, and other auxiliary equipment, are assumed to be constant across all systems. A study has been conducted for Eneco, where the BoP power for the compressors is determined for a 45 MW alkaline electrolyser, which produces hydrogen at a rate of 871 kg/hr. Equation (6) has been used to determine the BoP power demand of the compressors. This is added to the BoP power demand of the auxiliary equipment.

$$\text{BoP}_{\text{compressor}}\ [\text{MW}] = \frac{E_{\text{compressor}}\ [\text{kWh/kgH}_2] \times \dot{m}_{\text{H}_2}\ [\text{kgH}_2/\text{hr}]}{1000} \tag{6}$$

It is important to make a distinction between the power demand of the electrolyser stacks and that of the balance of plant (BoP), as these are decoupled components. Incoming power is first allocated to the BoP. For example, if 10 MW of power is available in a given hour, it may fully supply the BoP without delivering any energy to the stacks, resulting in no hydrogen production. The stack minimum stable load (MSL) applies specifically to the stacks and must be met independently of the BoP. Therefore, additional power must be drawn from the grid to meet the MSL of the stacks in order for hydrogen production to occur. This holds for both the co-located systems as for the Battolyser system.

For the energy storage systems, the power rating is set at 100 MW across all battery configurations. The 100 MW power rating has been chosen to align with the scale of the hydrogen production systems as well as the approximate size of the grid connection. However, the storage capacity may vary between setups, as this allows each system to use its unique advantages. For the Battolyser, the stacks for hydrogen production and storage are identical, meaning that these are rated at 90 MW. The C-rate describes how quickly a battery charges or discharges relative to its total energy capacity. For instance, if a battery has a capacity or C of 400 MWh, and it can charge at the rate of 1C, the battery can be fully charged in one hour with a 400 MW power supply. Similarly, if the battery can discharge at a rate of C/4, it takes four hours to fully discharge if the battery can discharge at 100 MW. However, the grid and power rating of the battery will determine the actual charge and discharge rate. The following values for the financial characteristics are based on the knowledge by Eneco in combination with the literature research in this thesis.

4.2.1 Alkaline Electrolyser and Li-ion Battery

For the alkaline electrolyser, the following technical characteristics are used as a starting point. The stack efficiency is 50 kWh/kgH$_2$, with a degradation rate of 1.1% per year. The minimum stable load of the stacks is 12%. The minimum stable load of the stacks enables the electrolyser to produce a limited amount of hydrogen. As frequent start and stops are not widely investigated, the electrolyser will always remain in operation. The stacks will need to be replaced after 10 years. The output pressure of the alkaline electrolyser is 1 bar, which means that the hydrogen needs to be compressed. The BoP power demand is 10 MW, using the Equation 6, with the stacks consistent at 90 MW. The Li-ion batteries have a power rating of 100 MW, and capacity of 400 MWh. The stacks will also need to be replaced after 10 years, where the storage capacity degrades with 2.5% per year. The round trip efficiency is 85% with a minimum state of charge of 20% to limit the degradation. The power rating of the battery is 100 MW, which means it can charge 100 MW in one hour. The battery can discharge with C/4, meaning that the battery can discharge 100 MW in one hour. The electrolyser degrades with 1.1% per year, which means that by the end of its stack life, it will require 100 MW to produce the same amount of hydrogen that initially required only 90 MW. With a BoP demand of 10 MW, the grid connection is sized to 110 MW to allow for this constant hydrogen production. The rationale behind this increasing grid connection capacity is discussed in Chapter 4.5. Consequently, excess power can be directed to the battery when the electrolyser is operating at nominal capacity.

The financial parameters for this system are the following. The CAPEX of the electrolyser stacks is 23 M€ while the CAPEX of the battery stacks is 50 M€. The CAPEX for the BoP is 120 M€, which includes compressors, hydrogen processing, electrical structures, balance of system of the battery and electrolyser, and miscellaneous costs. This also includes the additional DC-DC converter needed to couple the electrolyser to the high voltage DC bus. The grid connection is 19 M€ for the connection, transformer, converters, cables and switch yards. The CAPEX for the HyNetwork is 3 M€. The labor for EPC, site preparation, internal and external management is 130 M€. Then, the Devex and other costs are an additional 9 M€. Lastly, the contingency is estimated at 25 M€ to account for additional expenses. These values are based on the combination of literature research and values provided by Eneco. The operational expenses need to be considered as well. Stack replacement will cost 15 M€ after 10 years for the electrolyser and 20 M€ for the battery. The HyNetwork yearly costs will be 1.5 M€ and the yearly grid fee to Tennet will be approximately 10.5 M€. The land lease for this system will be more than for the Battolyser, and is therefore estimated at 2 M€ (included tax) as the land lease is 139 kEUR/ha, and approximately 15 hectare is needed. The maintenance for the electrolyser is estimated at 5 M€/year, with the combined maintenance estimated at 7 M€/year. Other OPEX, such as water consumption, labor and contingency is estimated at 3 M€ a year.

Table 15: Technical and financial specifications for the ALK + Li system.

Function	Component	Value	Unit
Electrolyser	Stack capacity	90	MW
	Stack efficiency	50	kWh/kgH$_2$
	Stack MSL	12	%
	Stack degradation	1.1	%/yr
	Stack replacement	10	yr
	BoP capacity	10	MW
Battery	Stack capacity	100/400	MW/MWh
	Stack degradation	2.5	%/yr
	Stack replacement	10	yr
	RTE	85	%
	Minimum SOC	20	%
	Charge rate	100	MW/h
	Discharge rate	100	MW/h
System	Grid connection	110	MW

Category	Component	Value	Unit
CAPEX	Electrolyser stacks	23	M€
	Battery stacks	50	M€
	BoP (system)	120	M€
	Grid connection	19	M€
	HyNetwork connection	3	M€
	Labor, EPC, etc.	130	M€
	Devex and other	9	M€
	Contingency	25	M€
OPEX	Stack replacement	35	M€
	HyNetwork	1.5	M€/yr
	Grid	10.5	M€/yr
	Land lease	2	M€/yr
	Maintenance	7	M€/yr
	Other	3	M€/yr

4.2.2 PEM Electrolyser and Li-ion Battery

For the PEM electrolyser, the following technical characteristics are used as a starting point. The literature is very optimistic regarding the stack efficiency, even though, data from Eneco that has been collected through vendors argue the contrary. To represent real life data, the stack efficiency is chosen to be 51 kWh/kgH$_2$, with a degradation rate of 1.3% per year. The minimum stable load of the stacks is 5%. The minimum stable load of the stacks enables the electrolyser to produce a limited amount of hydrogen. As frequent start and stops are not widely investigated, the electrolyser will always remain in operation. The stacks will need to be replaced after 10 years. The output pressure of the alkaline electrolyser is 30 bar, which means that the hydrogen needs to be compressed. The BoP power demand is 5 MW, using the Equation 6, with the stacks consistent at 90 MW. Similar to the previous configuration, the Li-ion batteries have a power rating of 100 MW, and capacity of 400 MWh. The stacks will also need to be replaced after 10 years, where the storage capacity degrades with 2.5% per year. The round trip efficiency is 85% with a minimum state of charge of 20% to limit the degradation. Similar to the previous configuration, the battery can charge and discharge with 100 MW per hour. In contrast, the grid connection is sized to 107 MW, as the electrolyser power demand rises to 102 MW near the end of life of the stacks.

The financial parameters for this system are the following. The CAPEX of the electrolyser stacks is 35 M€ while the CAPEX of the battery stacks is 50 M€. The CAPEX for the BoP is 120 M€, which includes compressors, hydrogen processing, electrical structures, balance of system of the battery and electrolyser, and miscellaneous costs. This also includes the additional DC-DC converter needed to couple the electrolyser to the high voltage DC bus. The grid connection is 18.1 M€ for the connection, transformer, cables and switch yards as a smaller grid connection is needed. The CAPEX for the HyNetwork is 3 M€. The labor for EPC, site preparation, internal and external management is 130 M€. Then, the Devex and other costs are an additional 9 M€. Lastly, the contingency is estimated at 25 M€ to account for additional expenses. These values are based on the combination of literature research and values provided by Eneco. The operational expenses need to be considered as well. The one time stack replacement will cost 20 M€ for the PEM electrolyser and 20 M€ for the battery. The HyNetwork yearly costs will be 1.5 M€ and the yearly grid fee to Tennet will be approximately 10 M€. The land lease for this system will be similar for all co-located configurations, and is therefore estimated at 2 M€ (included tax). The maintenance for the electrolyser is estimated at 6 M€/year, with the combined maintenance estimated at 8 M€/year. Other OPEX, such as water consumption and labor is estimated at 3 M€ a year.

Table 16: Technical and financial specifications for the PEM + Li system.

Function	Component	Value	Unit
Electrolyser	Stack capacity	90	MW
	Stack efficiency	51	kWh/kgH$_2$
	Stack MSL	5	%
	Stack degradation	1.3	%/yr
	Stack replacement	10	yr
	BoP capacity	5	MW
Battery	Stack capacity	100/400	MW/MWh
	Stack degradation	2.5	%/yr
	Stack replacement	10	yr
	RTE	85	%
	Minimum SOC	20	%
	Charge rate	100	MW/h
	Discharge rate	100	MW/h
System	Grid connection	107	MW

Category	Component	Value	Unit
CAPEX	Electrolyser stacks	35	M€
	Battery stacks	50	M€
	BoP (system)	120	M€
	Grid connection	18.1	M€
	HyNetwork connection	3	M€
	Labor, EPC, etc.	130	M€
	Devex and other	9	M€
	Contingency	25	M€
OPEX	Stack replacement	40	M€
	HyNetwork	1.5	M€/yr
	Grid	10	M€/yr
	Land lease	2	M€/yr
	Maintenance	8	M€/yr
	Other	3	M€/yr

4.2.3 Alkaline Electrolyser and RF Battery

Similar to the first configuration, the following technical characteristics are used for the alkaline electrolyser as a starting point. The stack efficiency is 50 kWh/kgH$_2$, with a degradation rate of 1.1% per year. The minimum stable load of the stacks is 12%. The stacks will need to be replaced after 10 years. The output pressure of the alkaline electrolyser is 1 bar, which means that the hydrogen needs to be compressed. The BoP power demand is 10 MW, using the Equation 6, with the stacks consistent at 90 MW. The redox flow batteries have a power rating of 100 MW, and capacity of 800 MWh. It is expected that the stacks will need to be replaced after 25 years, which means that this is outside of the time line. Therefore, no stack replacement is modeled, while the storage capacity degrades with 0.3% per year. The round trip efficiency is 80% with a minimum state of charge of 0%. The redox flow battery can charge with 100 MW and discharge with 100 MW in one hour. Similar to the other alkaline configuration, the grid connection is sized to 110 MW.

The financial parameters for this system are the following. The CAPEX of the electrolyser stacks is 23 M€ while the CAPEX of the battery is 100 M€, for both the stacks as the electrolyte. The CAPEX for the BoP is 120 M€, which includes compressors, hydrogen processing, electrical structures, balance of system of the battery and electrolyser, and miscellaneous costs. This also includes the additional DC-DC converter needed to couple the electrolyser to the high voltage DC bus. The grid connection is 19 M€ for the connection, transformer, cables and switch yards. The CAPEX for the HyNetwork is 3 M€. The labor for EPC, site preparation, internal and external management is 130 M€. Then, the Devex and other costs are an additional 9 M€. Lastly, the contingency is estimated at 25 M€ to account for additional expenses. These values are based on the combination of literature research and values provided by Eneco. The operational expenses need to be considered as well. The electrolyser stacks still need to be replaced after 10 years for 15 M€. The HyNetwork yearly costs will be 1.5 M€ and the yearly grid fee to Tennet will be approximately 10.5 M€. The land lease for this system will be more than for the Battolyser, and is therefore estimated at 2 M€ (included tax) as the land lease is 139 kEUR/ha, and approximately 15 hectare is needed. The maintenance for the electrolyser is estimated at 5 M€/year, with the combined maintenance estimated at 9 M€/year. Other OPEX, such as water consumption and labor is estimated at 3 M€ a year.

Table 17: Technical and financial specifications for the ALK + RF system.

Function	Component	Value	Unit
Electrolyser	Stack capacity	90	MW
	Stack efficiency	50	kWh/kgH_2
	Stack MSL	12	%
	Stack degradation	1.1	%/yr
	Stack replacement	10	yr
	BoP capacity	10	MW
Battery	Stack capacity	100/800	MW/MWh
	Stack degradation	0.3	%/yr
	Stack replacement	25	yr
	RTE	80	%
	Minimum SOC	0	%
	Charge rate	100	MW/h
	Discharge rate	100	MW/h
System	Grid connection	110	MW

Category	Component	Value	Unit
CAPEX	Electrolyser stacks	35	M€
	Battery stacks	100	M€
	BoP (system)	130	M€
	Grid connection	19	M€
	HyNetwork connection	3	M€
	Labor, EPC, etc.	130	M€
	Devex and other	9	M€
	Contingency	25	M€
OPEX	Stack replacement	15	M€
	HyNetwork	1.5	M€/yr
	Grid	10.5	M€/yr
	Land lease	2	M€/yr
	Maintenance	9	M€/yr
	Other	3	M€/yr

4.2.4 PEM Electrolyser and RF Battery

The following technical characteristics are used for the PEM electrolyser as a starting point. The stack efficiency is 51 kWh/kgH_2, with a degradation rate of 1.3% per year. The minimum stable load of the stacks is 5%. The stacks will need to be replaced after 10 years. The output pressure of the alkaline electrolyser is 30 bar, which means that the hydrogen needs to be compressed. The BoP power demand is 5 MW, using the Equation 6, with the stacks consistent at 90 MW. The redox flow batteries have a power rating of 100 MW, and capacity of 800 MWh. The stacks will need to be replaced after 25 years, which means that this is outside of the time line. Therefore, no stack replacement is modeled, while the storage capacity degrades with 0.3% per year. The round trip efficiency is 80% with a minimum state of charge of 0%. The RF battery can charge and discharge with 100 MW per hour, and the grid connection is sized to 107 MW, which is similar to the other PEM configuration.

The financial parameters for this system are the following. The CAPEX of the electrolyser stacks is 35 M€ while the CAPEX of the battery is 100 M€, for both the stacks as the electrolyte. The CAPEX for the BoP is 115 M€, which includes compressors, hydrogen processing, electrical structures, balance of system of the battery and electrolyser, and miscellaneous costs. This also includes the additional DC-DC converter needed to couple the electrolyser to the high voltage DC bus. The grid connection is 18.1 M€ for the connection, transformer, cables and switch yards. The CAPEX for the HyNetwork is 3 M€. The labor for EPC, site preparation, internal and external management is 130 M€. Then, the Devex and other costs are an additional 9 M€. Lastly, the contingency is estimated at 25 M€ to account for additional expenses. These values are based on the combination of literature research and values provided by Eneco. The operational expenses need to be considered as well. The electrolyser stacks will cost 20 M€ to replace. The HyNetwork yearly costs will be 1.5 M€ and the yearly grid fee to Tennet will be approximately 10 M€. The land lease for this system will be more than for the Battolyser, and is therefore estimated on 2 M€ (included tax) as the land lease is 139 kEUR/ha, and approximately 15 hectare is needed. The maintenance for the electrolyser is estimated at 6 M€/year, with the combined maintenance estimated at 10 M€/year. Other OPEX, such as water consumption and labor is estimated at 3 M€ a year.

Table 18: Technical and financial specifications for the PEM + RF system.

Function	Component	Value	Unit
Electrolyser	Stack capacity	90	MW
	Stack efficiency	51	kWh/kgH$_2$
	Stack MSL	5	%
	Stack degradation	1.3	%/yr
	Stack replacement	10	yr
	BoP capacity	5	MW
Battery	Stack capacity	100/800	MW/MWh
	Stack degradation	0.3	%/yr
	Stack replacement	25	yr
	RTE	80	%
	Minimum SOC	0	%
	Charge rate	100	MW/h
	Discharge rate	100	MW/h
System	Grid connection	110	MW

Category	Component	Value	Unit
CAPEX	Electrolyser stacks	35	M€
	Battery stacks	100	M€
	BoP (system)	130	M€
	Grid connection	18.1	M€
	HyNetwork connection	3	M€
	Labor, EPC, etc.	130	M€
	Devex and other	9	M€
	Contingency	25	M€
OPEX	Stack replacement	20	M€
	HyNetwork	1.5	M€/yr
	Grid	10	M€/yr
	Land lease	2	M€/yr
	Maintenance	10	M€/yr
	Other	3	M€/yr

4.2.5 Battolyser

The following technical characteristics are used for Battolyser as a starting point. The stack efficiency is 46.3 kWh/kgH$_2$, with a degradation rate of 1.1% per year. The minimum stable load of the stacks is 0%, which means that the Battolyser can essentially be shut off and only requires power to remain standby. The stacks will need to be replaced after 10 years. The output pressure of the Battolyser is 30 bar, which means that the hydrogen needs to be compressed. The BoP power demand is 5 MW, using the Equation 6, with the stacks consistent at 90 MW. When the Battolyer is not producing hydrogen, the BoP energy demand is set to 2 MW to ensure that the system is kept standby. This power maintains system pressure and sensor functionality, allowing the Battolyser to ramp up instantly when needed in the following hour. The storage part has a power rating of 90 MW, and capacity of 90 MWh. The stacks will need to be replaced after 10 years, as these are the same stacks as the hydrogen production part. The degradation is also 1.1% per year. The efficiency and hydrogen split depend on the state of charge, and the minimum state of charge is 5%. The battery can charge with 1C and discharge with C/4, meaning that in hour the battery can charge 90 MW and discharge 22.5 MW. Similar to the configurations with the PEM electrolyser, the grid connection is sized to 107 MW. However, this will not pose any operational constraints as the battery and electrolyser stacks are one and the same.

The financial parameters for this system are the following. The CAPEX of the stacks is 112.5 M€ and the CAPEX for the BoP is 90 M€, which includes compressors, hydrogen processing, electrical structures, balance of system of the battery and electrolyser, and miscellaneous costs. The grid connection is 15 M€ for the connection, transformer, cables and switch yards. The CAPEX for the HyNetwork is 3 M€. The labor for EPC, site preparation, internal and external management is 115 M€. According to Eneco, approximately 100 M€ can be accounted for this post for a 100 MW alkaline electrolyser. As the Battolyser is a new technology, a 15% EPC increase has been added. Then, the Devex and other costs are an additional 9 M€. Lastly, the contingency is estimated at 25 M€ to account for additional expenses. These values are based on the combination of literature research and values provided by Eneco. The operational expenses need to be considered as well. The electrolyser stacks will cost 35 M€ to replace. The HyNetwork yearly costs will be 1.5 M€ and the yearly grid fee to Tennet will be approximately 10 M€. The land lease for this system is estimated at 1.5 M€ (included tax) as the land lease is 139 kEUR/ha, and approximately 11 hectare is needed. The maintenance for the Battolyser is estimated at 6 M€/year. Other OPEX, such as water consumption and labor is estimated at 3 M€ a year.

Table 19: Technical and financial specifications for the Battolyser system.

Function	Component	Value	Unit
Electrolyser	Stack capacity	90	MW
	Stack efficiency	46.3	kWh/kgH$_2$
	Stack MSL	0	%
	Stack degradation	1.1	%/yr
	Stack replacement	10	yr
	BoP capacity /(standby)	5 /(2)	MW
Battery	Stack capacity	90/90	MW/MWh
	Stack degradation	1.1	%/yr
	Stack replacement	10	yr
	Minimum SOC	5	%
	Charge rate	90	MW/h
	Discharge rate	22.5	MW/h
System	Grid connection	107	MW

Category	Component	Value	Unit
CAPEX	Electrolyser stacks	122.5	M€
	BoP (system)	100	M€
	Grid connection	15	M€
	HyNetwork connection	3	M€
	Labor, EPC, etc.	115	M€
	Devex and other	9	M€
	Contingency	25	M€
OPEX	Stack replacement	35	M€
	HyNetwork	1.5	M€/yr
	Grid	10	M€/yr
	Land lease	1.5	M€/yr
	Maintenance	6	M€/yr
	Other	3	M€/yr

4.2.6 Overview of the Chosen Characteristics Per System

This subchapter presents comparative tables outlining the key technical and financial characteristics of each hydrogen production and storage system considered in the study. These parameters have been selected to reflect realistic, system-specific configurations in collaboration with experts from Eneco and are used as input values for the simulation model. The technical characteristics include factors such as efficiency, capacity, and degradation rates, while the financial parameters cover capital expenditures (CAPEX), operational expenditures (OPEX), and infrastructure-related costs.

Table 20: Overview of technical characteristics of the hydrogen and battery systems.

Component	Unit	Alkaline	PEM	Battolyser
Stack capacity	MW	90	90	90
Stack efficiency	kWh/kgH_2	50	51	46.3
Stack MSL	%	12	5	0
BoP capacity	MW	10	5	5 / (2)
Outlet pressure	bar	1	31	31
Cycle life	years	10	10	10
Degradation	%/year	1.1	1.1	1.1

(a) Hydrogen production systems

Component	Unit	Lithium ion	Redox flow	Battolyser
Stack power	MW	100	100	90
Storage capacity	MWh	400	800	90
RTE	%	85	80	Dynamic
Charge rate	MW/h	100	100	90
Discharge rate	MW/h	25	25	22.5
Cycle life	years	10	25	10
Degradation	%/year	2.5	0.5	1.1

(b) Battery systems

Table 21: Overview of financial characteristics of the hydrogen and battery systems.

Category	Component	Unit	ALK + Li	PEM + Li	ALK + RF	PEM + RF	Battolyser
CAPEX	Electrolyser stacks	M€	23	35	23	35	122.5
	Battery stacks	M€	50	50	100	100	-
	BoP (system)	M€	120	120	130	130	100
	Grid connection	M€	19	18.1	19	18.1	15
	HyNetwork connection	M€	3	3	3	3	3
	Labor, EPC, etc.	M€	130	130	130	130	115
	Devex and other	M€	9	9	9	9	9
	Contingency	M€	25	25	25	25	25
	Total	M€	379	390.1	439	450.1	389.5
OPEX	Stack replacement	M€/yr	35	40	15	20	35
	HyNetwork	M€/yr	1.5	1.5	1.5	1.5	1.5
	Grid	M€/yr	10.5	10	10.5	10	10
	Land lease	M€/yr	2	2	2	2	1.5
	Maintenance	M€/yr	7	8	9	10	6
	Other	M€/yr	3	3	3	3	3
	Total	M€/yr	24	24.5	26	26.5	22

4.3 Model Description

The model uses the input and system dependent parameters to simulate the operation of the systems over a time span of 20 years. Since these systems must have a viable business case in the real world, the model is created to simulate the operation of the systems. To simulate this operation over a 20-year horizon, the model makes use of a Model Predictive Control (MPC) framework with a receding horizon. The model simulates the main operational strategies of the systems, consisting of hydrogen production and battery charging or discharging. At each time step, the MPC evaluates several predefined operational strategies, or paths, and selects the most profitable option based on forecasted electricity prices, hydrogen demand, and system constraints.

The four operational paths considered in the model are:

- **Path 1 – Battery charging & electricity sales**:
  Charge the battery and sell excess electricity of the contracted PPAs to the grid.
- **Path 2 – Battery discharging & electricity sales**:
  Discharge the battery and sell the energy together with excess PPA electricity to the grid.
- **Path 3 – RFNBO-Compliant hydrogen production**:
  Produce RFNBO-compliant hydrogen and charge the battery with excessive PPA power if possible.
- **Path 4 – Mixed hydrogen production (RFNBO + Low-Carbon)**:
  Produce both RFNBO-compliant and low-carbon hydrogen, and charge the battery with excessive PPA power if possible.

While both systems follow the same operational logic, their internal handling of power, efficiency, and emissions differs significantly. In Path 1, the battery is charged and the electrolyser uses the minimal amount of power. If these demands are met, any surplus of incoming PPA electricity is resold to the grid. First, the system routes available PPA power to the BoP, to ensure that assets remain stand by. If this power is insufficient to meet the BoP's minimum load, grey grid power is used to fulfill this deficit. The remaining PPA power, after BoP needs are met, is used to charge the battery. Any excess PPA electricity is resold to the electricity grid and added to the arbitrage revenue. This operation mode will be selected when electricity prices are high, or will be high in the future, so that revenue is generated through selling electricity. For the Battolyser, the power is internally split between battery charging and hydrogen production based on the state of charge. Hydrogen is produced from the portion of power allocated to the stack, and emissions intensity is computed using any grey power used. In contrast, the battery and electrolyser setup handles charging and hydrogen production separately. Power for the battery is charged using fixed efficiencies, and the stack receives the power requirements to operate on minimum stable load. The GHGE intensity is also calculated, and the hydrogen is categorized accordingly. The main difference between the Battolyser and the system consisting of the electrolyser and battery, lies in the decoupling of the charging and hydrogen production. In Path 2, the system discharges the battery and sells the discharged energy to the grid. Similar to option 1, the incoming PPA power is used for the minimum stable load of the BoP and electrolyser, while the rest is resold to the grid. If the PPAs provide insufficient power, electricity is taken from the grid to meet the BoP and electrolyser requirements. For the Battolyser, discharging the battery means that the change in state of charge impacts future hydrogen production. For the electrolyser and battery system, the electrolyser will run on minimum stable load, while the battery discharges. The assets are co-located and connected through a DC bus. The net amount that will be supplied or drawn from the grid, depends on the power flow of the battery and electrolyser. From an economic point of view, in a co-located system with a battery and an electrolyser, it makes no difference whether the electricity from the battery is used to power the electrolyser or sold to the grid. This is because the revenue from discharging the battery to the grid would be equal to the cost of purchasing electricity from the grid to run the electrolyser. Therefore, the net economic effect remains the same. As explained in Chapter 2.1, the energy contracted through the PPA can be allocated to the electrolyser even though it is physically drawn from the battery or the grid. This operation mode will be selected when electricity prices are high, meaning that more profit can be made with reselling electricity than that can be made with hydrogen. In Path 3, the system aims to produce RFNBO compliant hydrogen using the PPAs and compliant grid electricity. The compliance of grid power is determined based on price thresholds, ETS reference, GHG footprint, or renewable share. If grid power is not compliant, only PPA electricity is used to power the electrolyser, and grey electricity may be used to run the BoP if necessary. Similar to option 1, the Battolyser allocates the power to charging and hydrogen production. If the battery is fully charged, all the incoming power is used for the BoP and hydrogen production. The GHGE intensity is computed using any grid electricity involved, and hydrogen is then classified as RFNBO or grey. In the system consisting of the battery and electrolyser, the electrolyser is prioritized above the battery. All incoming power is used for the electrolyser, if the grid constraint permits any room, the rest of the power is used to charge the battery. In Path 4, power from PPA or the RFNBO-compliant grid is first used to fill the electrolyzer up to the remaining capacity after BoP power is accounted for. If the electrolyzer still has room, additional electricity from the grid is used. In addition to using RFNBO-compliant grid power, the system can incorporate a calculated amount of extra grid power to produce both RFNBO-compliant and low-carbon hydrogen using Equation (3) from Chapter 2.2. The model calculates the allowable grid power input to ensure that the system remains below the 70% GHG emissions reduction threshold. Although the specific interaction between the battery and hydrogen systems may vary depending on the system or configuration, these paths remain consistent across both systems and their configurations. The configurations have different constraints such as the minium stable load, and these will always have to be met. This means that producing grey hydrogen becomes necessary in some scenarios due to the technical constraints of the electrolysers. As discussed in the previous chapter, an ALK electrolyser requires a minimum stable load of 12%, meaning at least 12% of its power demand must be met. If wind and solar parks generate insufficient electricity, grid power must be injected into the system, potentially leading to the production of grey hydrogen due to the MSL constraint.

To calculate the profit of each path, all costs and revenues directly related to operating the electrolyser are considered. This includes the costs for the contracted PPAs, grid offtake costs, and revenues from reselling PPAs and selling hydrogen. The PPAs have a cost per MWh set by Eneco to ensure the financial viability of the associated wind and solar parks. Grid offtake costs are based on the electricity price per MWh at the time of consumption. The PPAs can be resold on the market at a price per MWh that includes Guarantees of Origin (GoOs). Hydrogen revenues vary by classification, such as grey, low-carbon, and RFNBO-compliant, each with a price projected by Eneco. The grey hydrogen price changes annually, with the low-carbon price following the same change with an added premium. Due to uncertainty around future RFNBO-compliant hydrogen prices, Eneco provides projections up to 2030. The hydrogen price is forecasted to 2030, which is adopted as a fixed price, which is used in evaluating the most profitable path.

The model makes use of heuristic Model Predictive Control (MPC), a decision-making process that continuously evaluates the available energy routes based on forecasted electricity prices and system constraints. A heuristic approach is a problem-solving method that uses practical shortcuts to save processing time. Instead of evaluating every possible decision path, heuristics enable the model to make near-optimal choices within a reasonable time frame. At each time step, the MPC algorithm simulates multiple decision paths over a predefined time horizon, as illustrated in Figure 10. Each branch of the decision tree represents a different operational strategy, with projected profits calculated at every stage. The MPC does not attempt to solve the entire problem in one step, because this would mean that the systems would have a perfect forecast, which would not be feasible in real life. Instead, the model employs a receding horizon approach, where it selects the first step of the most profitable path based on the forecasts of the horizon. After executing this step, the model recalculates the optimal path from the new starting point. System dependent parameters such as the state of charge of the battery are also evaluated in the decision making. However, considering every potential path in detail would be computationally demanding. To address this, the code incorporates predefined thresholds that guide the decision-making process by determining feasible operational paths. For instance, a low threshold of €20/MWh is set, ensuring that whenever electricity prices fall below this value, the system will always opt to produce RFNBO-compliant hydrogen. This aligns with one of the approved methods outlined in RED III for generating RFNBO-compliant hydrogen.

In Figure 10, it is illustrated how the price of electricity determines the potential routes of operation. In timestep T, the electricity price is above the low threshold, meaning that all four paths are available. In timestep T+1 and T+2, the electricity price is below the low threshold, meaning that only option three and four can be chosen. The MPC algorithm evaluates these options and selects the most profitable path, which is highlighted in green. Chapter 4.5 will further discuss which assumptions have been taken in the model design.

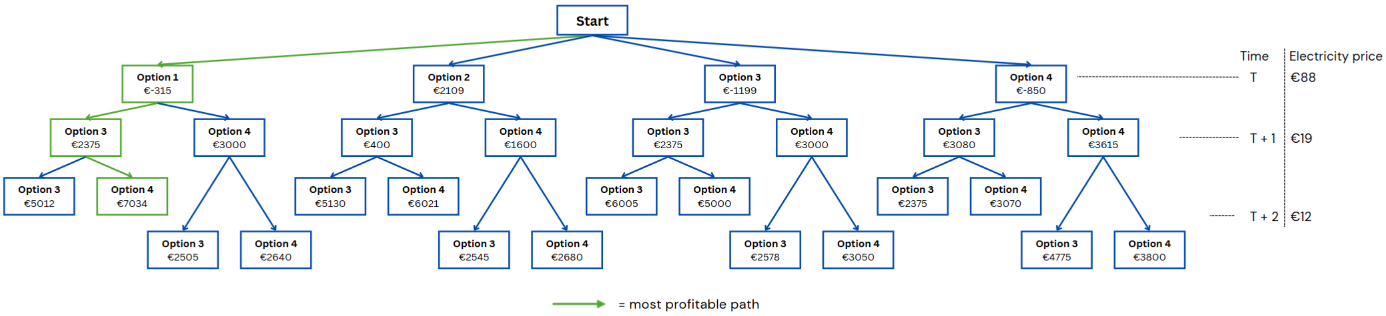


Figure 10: Example of the MPC decision making

4.4 Output

As stated in Chapter 4.3, the Model Predictive Control (MPC) will select the most profitable path. The code will export the values directly related to the electrolyser operation, including electricity costs, electricity revenues, and the amount of produced hydrogen from the optimal path. These values will then be stored for the calculation of the Levelised Cost of Hydrogen (LCOH).

The LCOH is a financial metric used to evaluate the cost-effectiveness of hydrogen production technologies over their entire operational life. It is calculated by dividing the total lifetime costs of a hydrogen production system by the total amount of hydrogen produced during that period. The total lifetime costs include both Capital Expenditure (CAPEX) and Operational Expenditure (OPEX). CAPEX represents the upfront costs required for the construction, installation, and setup of the hydrogen production facility. OPEX includes the ongoing costs associated with running the facility, such as energy consumption, maintenance, labor, and other operational expenses. The calculation of LCOH must incorporate inflation and potential future cost changes, particularly for energy and operational costs. Inflation impacts both the ongoing OPEX and potentially the future replacement costs for components of the system, further influencing the LCOH over the long term. This adjustment ensures a more accurate representation of the true cost of hydrogen production across the system's lifespan. A hurdle rate is implemented in the LCOH calculation. A hurdle rate is the minimum rate of return required for a project to be considered financially viable. It functions as a discount rate, converting future cash flows into present value to account for the time value of money and investment risk. This ensures that long-term investments can be properly evaluated in today's financial terms. In the same way, the total hydrogen output is also discounted to present value. This is done to ensure consistency in the LCOH calculation, as both the costs and benefits of the system must be evaluated over the same financial time frame. Discounting future hydrogen production reflects the reality that output delivered many years into the future carries less economic value today. The total hydrogen production is determined by the system's production capacity, operational efficiency, and expected operational hours over its lifetime. This involves multiplying the system's annual production rate by the number of years the facility is expected to operate, factoring in potential downtime for maintenance or repairs. The formula for calculating the LCOH is the following:

$$\text{LCOH} = \frac{\text{Total Lifetime Costs}}{\text{Total Lifetime Hydrogen Production}}$$

This calculation provides a cost per kilogram of RFNBO compliant hydrogen produced, allowing for comparisons between different hydrogen production technologies. The lower the LCOH, the more competitive the hydrogen production method becomes compared to other methods. For the purposes of this thesis, the LCOH will be evaluated based solely on RFNBO-compliant hydrogen, excluding the amount of low-carbon or grey hydrogen in the calculation. However, the costs associated with producing non-compliant hydrogen will still be considered, as they are an important factor in the business case. For example, when electricity prices rise due to a lack of renewable energy, the electrolyser cannot be easily turned off and must operate at a minimum stable load, leading to the production of hydrogen that does not meet RFNBO requirements. These associated costs will be taken into consideration in determining the LCOH of the system.

The LCOH in this analysis is calculated by discounting all relevant costs and hydrogen production volumes to a reference year of 2025, using a nominal discount rate that incorporates a hurdle rate of 9%, which reflects higher-risk investments. The hurdle rate represents the minimum acceptable rate of return of an investment. An inflation rate of 2% is used to account for inflation over the years. The financial values provided earlier are increased with this inflation rate starting from 2025. The discount rate is used to calculate the Net Present Value (NPV) of the CAPEX and OPEX. The investment timeline assumes that the CAPEX is distributed evenly across the years 2028 and 2029, with payments made quarterly. OPEX are also distributed quarterly, from the start of the project in 2030 through its end in 2050. In addition, the model accounts for one-time replacement costs during the system's lifetime, such as electrolyser and battery replacements, and includes them in the discounted OPEX. Furthermore, the CAPEX is depreciated linearly over the 20 years operational lifetime of the project. The Levelized Cost of Hydrogen is then derived by dividing the total discounted costs (CAPEX, OPEX, and electricity-related costs, minus any revenue from power reselling) by the total discounted volume of RFNBO-compliant hydrogen produced. Inflation is not applied to the hydrogen production volumes. Similarly, no inflation is applied to PPA power costs, electricity grid costs, or arbitrage revenues, since this is already incorporated in the imported electricity prices. As a result, only the discount rate is used to bring all future values to present value with a desired profitability of 9%. In the current framework, the RFNBO hydrogen price is used to enable path selection within the code and thus helps identify viable or optimal production pathways. However, this price is an internal assumption and not a guaranteed revenue stream. As such, it would be inaccurate to calculate tax costs based on assumed revenues. Thus, tax is not included in the LCOH calculation as this LCOH calculation will be evaluated pre-tax.

4.5 Assumptions

To ensure that the simulation model operates within a reasonable computational timeframe and to manage the complexity of certain calculations, several assumptions have been made throughout this thesis. These assumptions are necessary to balance accuracy, data availability, and runtime efficiency. This chapter presents the assumptions made regarding the behavior of the system, the interactions of the components and the creation of the model.

The losses from the additional power electronics are taken into account in the round trip efficiency (RTE) of the battery and the specific energy consumption of the BoP. The RTE of the lithium ion batteries is 85% and 80% for the redox flow batteries, which includes the additional DC converter losses. A study conducted on behalf of Eneco analyzed the energy consumption of the balance of plant (BoP) and compressors of an electrolyser. The results showed that the BoP, excluding compressors, has a specific energy consumption of 2.16 kWh/kgH$_2$. This includes the energy required for sensors, safety systems, control units, and other auxiliary equipment, as well as losses from converters, transformers, and related components. The losses of the additional DC converter are taken into account of the co-located systems where the specific energy consumption is increased with 2%. The total BoP power demand is determined by this fixed consumption together with the energy demand of the compressors, which in turn is dictated by the hydrogen production rate. Therefore, the power allocated to the stacks determines the required BoP power, as the hydrogen flow influences compressor operation. This relationship is reflected in Equations (7) and (8).

$$P_{\text{in}} = P_{\text{BoP}}(P_{\text{stacks}}) + P_{\text{system}} \quad (7) \qquad P_{\text{system}} = P_{\text{BESS}} + P_{\text{stacks}} \quad (8)$$

To calculate the fixed BoP power demand, the specific energy of the compressors must be determined.

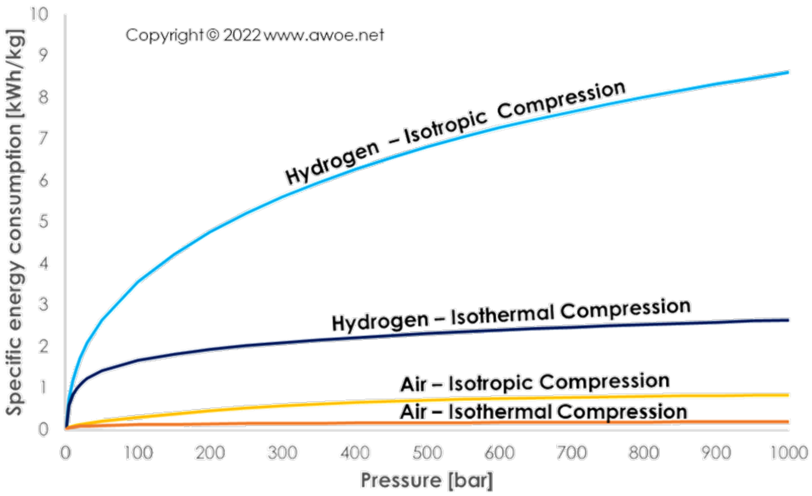


Figure 11: Energy consumption of hydrogen compressor [7]

As shown in Figure 11, the specific energy required to compress hydrogen from 0 to 100 bar is about 3.2 kWh/kgH$_2$ in an isentropic process. For compression from 31 to 100 bar, the energy required is approximately 0.8 kWh/kgH$_2$. While isentropic compression assumes no heat exchange, real-world compressors operate under polytropic conditions, which are a combination of isentropic and isothermal behavior. According to the U.S. Department of Energy (2021), roughly 65% of the compression process is isentropic [133]. The HyNetwork is designing its pipelines to operate at a pressure of 66.2 bar [134]. To compensate for the polytropic process, the isentropic energy demand to compress to 100 bar is used instead of to 66.2 bar. The Battolyser and PEM electrolysers are therefore modeled with a compressor demand of 0.8 kWh/kgH$_2$, while alkaline electrolysers use 3.2 kWh/kgH$_2$. The specific energy demands are used in (6) to determine the BoP power demand.

In real life, the BoP power demand for the systems would be recalculated every time based on the hydrogen flow, which requires multiple iterations. For the Battolyser, the calculation of BoP power demand and state of charge change requires a few iterations due to the nature of the system. The power allocation to the stacks is determined by the change in state of charge, which in turn decides the power demand of the BoP, which impacts the state of charge demand again. To model this, an initial estimate for the BoP power has to be made. The resulting power is then distributed between the battery charging and hydrogen production, based on the battery's state of charge. This in turn redefines the BoP power again, necessitating a new iteration. This iterative process continues until convergence is achieved. However, due to the high computational cost of this approach, a simplification is applied. The BoP power demand is assumed to be constant, set at the value when the electrolyzer operates at full capacity. While this reduces computational load significantly, it slightly overestimates BoP demand at partial loads. As a result, the model may overstate the total power requirement during low hydrogen production periods. In order to be consistent, this simplification is also applied to the battery and electrolyser systems. Nonetheless, this approach can be justified by operational practice. As discussed in Chapter 3.4, B. Okhuijsen from Siemens explained that continuous compressor operation is favorable for equipment longevity. Through the use of recycle lines, the compressors can operate within a 0%–100% operating range while preventing degradation as a result of partial operation. The recycling line ensures that it allows for redirection of compressed hydrogen to the compressor inlet, resulting in a net low hydrogen throughput. Therefore, the assumption of a relatively stable BoP load aligns with practical considerations. Due to the significant simulation time, it is not feasible to simulate the Battolyser or combined battery-electrolyser systems under a dynamic BoP power demand. However, this does not apply to stand-alone alkaline and PEM electrolysers. Therefore, in this thesis, only the stand-alone alkaline and PEM electrolyser are simulated to assess the impact of a constant BoP load. First, both electrolysers were simulated with constant BoP power demands, 10 MW for the alkaline and 5 MW for the PEM electrolyser. Under these conditions, the LCOH was €9.79/kgH$_2$ for the alkaline electrolyser and €9.84/kgH$_2$ for the PEM electrolyser. Next, a simulation was performed where the BoP operates with a minimum stable load of 29%. This corresponds to the maximum turndown range of hydrogen compressors. In this case, the LCOH decreased to €9.47/kgH$_2$ for the alkaline system and to €9.68/kgH$_2$ for the PEM system. Notably, the effect is less significant for the PEM electrolyser as the BoP demand is smaller compared to the alkaline electrolyser. The reduction in LCOH is mainly attributed to decreased arbitrage revenues and increased grid electricity costs. This is in line with the expectations as the operational flexibility of the electrolysers is reduced. Additionally, hydrogen production slightly increased, as partial load operation reduces BoP power requirements, meaning that a greater share of available power can be allocated to the stacks. However, the dynamic BoP simulation does not account for potential increases in maintenance costs or reductions in system lifetime due to partial load operation, which could offset some of the cost benefits. Although the simulations show that a dynamic balance of plant has a noticeable impact on the LCOH, these results are not included in the LCOH comparison across system configurations in this master thesis.

Another simplification is made in the Battolyser code regarding the efficiency and the hydrogen split. For the Battolyser system, the power split between the battery and the electrolyzer stacks depends on both the power input and the battery's state of charge. This creates an additional layer of complexity, since the battery's state of charge affects the overall power distribution. For each state of charge of the battery, the Battolyser has a different efficiency and power split, dictating how much power goes to charging and how much goes to hydrogen production. As this differs during the charging process in the hour, a simplification is made to reduce the computational demand of the code. The model uses the geometric average of the efficiency and hydrogen split associated with the state of charge (SOC) before and after charging to estimate the effective battery performance. Specifically, the characteristics of the initial SOC determine the charging efficiency and hydrogen split, which in turn result in a new SOC. Each of these SoC levels has an associated efficiency and hydrogen split. By taking the geometric average of these values, the model estimates the effective efficiency and hydrogen split used in that timestep, which then updates the SOC accordingly. A similar simplification has been applied to Path 4, where additional electricity is drawn from the grid to increase RNFBO-compliant hydrogen production, along with some low-carbon hydrogen. Equation (3) assumes that all input power is used directly for hydrogen production. However, in the Battolyser system, input power is split between battery charging and hydrogen production, making this assumption inaccurate. Since the amount of additional power drawn affects both the system's efficiency and hydrogen split, an extra simplification is introduced to avoid additional iterative calculations. To ensure that the current calculation method is correct, the MPC ensures that Option 4 is only selected when the majority of the additional power is used for hydrogen production. Data analysis on the simulation results has shown that the equation remains valid when the state of charge of the battery is at least 70% at the start of charging. As a result, partial renewable energy from the grid is only allowed when the state of charge exceeds this threshold. This restriction prevents the addition of another iterative calculation and helps to reduce simulation time.

To improve the computational time of the simulations, a low threshold of €20/MWh is introduced. When electricity prices are below the threshold, producing RFNBO compliant hydrogen is prioritized above selling electricity to the grid. The break even electricity price lies at approximately €159/MWh. For example, with 100 MW of PPA power in one hour (90 MW to the electrolyser stack and 10 MW to the BoP), an electrolyser efficiency of 51 kWh/kgH$_2$, and a hydrogen sale price of €9/kg:

$$H_2 = \frac{90{,}000\ \text{kWh}}{51\ \text{kWh/kg}} \approx 1{,}764.71\ \text{kg} \tag{9}$$

$$\text{Revenue}_{H_2} = 1{,}764.71\ \text{kg} \times 9\ €/\text{kg} = 15{,}882.39\ € \tag{10}$$

$$100\ \text{MWh} \times P = 15{,}882.39 \Rightarrow P = \frac{15{,}882.39}{100} \approx 158.82\ €/\text{MWh} \tag{11}$$

Notably, the conversion price depends on the electrolyser efficiency of the system. For the PEM electrolyser, the break even price is approximately €155.77/MWh at the beginning of the stack life and for the Battolyser approximately €171.52/MWh. As the hydrogen conversion energy of the stack increases over time, the conversion price decreases accordingly. For example, after 10 years of operation, the conversion price for the alkaline electrolyser drops to approximately €142.36/MWh. This price does not indicate that no hydrogen is produced when electricity prices are higher than this conversion point as the MPC will examine and choose the first step of the path with the most cumulative profit. As the low threshold in the code is well below the conversion point, it is not likely that the MPC will choose to sell power to the grid when the electricity price is below €20/MWh. However, in order to confirm this does not have a significant impact on the operation and LCOH of the systems, a simulation has been performed without the low threshold to determine what the impact is. The alkaline and lithium ion battery system, and the PEM and redox flow battery system have been simulated without the use of the low threshold. In both cases the outputs remained nearly identical, while the simulation time increased as a result of the inclusion of additional paths. In both cases, the LCOH remained unchanged, and the discounted hydrogen production decreased by less than 0.02%.

Another assumption relates to the stack degradation and efficiency. A margin of 2% is applied to the base stack efficiency to compensate for dynamic behavior, such as ramping within the hour. Additionally, stack degradation is modeled by increasing the energy demand per kilogram of hydrogen over time, simulating a decline in performance. This means that the hydrogen output remains consistent over time. To compensate, the model assumes that the grid connection capacity must be sufficient to handle the highest expected energy demand from the electrolyser. Based on this, the PEM system requires a connection of 107 MW, the Battolyser requires a connection of 105 MW and the alkaline system requires 110 MW. These values are used as upper limits for grid sizing in the model. This has as result that the battery and electrolyser systems initially have some room to charge the battery if sufficient power is available. Evidently, this does not hold for the Battolyser as the the battery and hydrogen production stack are the same, meaning that there is no interplay between these. The costs associated with a larger grid connection are taken into account in the financial assumptions.

Finally, several assumptions have been made regarding system-dependent cost parameters. The effects of the synergy between the battery and electrolyser are uncertain, especially affecting BoP and EPC costs as they have a significant share of the total investment. Assumptions have been made to estimate costs, with the expertise from Eneco. These assumptions are point values, where the sensitivity analysis will investigate the consequences of the insecurity of these values. For a 100 MW alkaline electrolyzer, the balance of plant is approximately 100 M€. In the case of a lithium-ion battery system, the balance of stacks is estimated at around 16 M€ from the literature research. However, this figure does not yet account for all required supporting infrastructure, such as the additional DC-DC converter. Taking into consideration potential integration of the supporting systems, the BoP for the combined alkaline electrolysers and battery system is estimated at 120 M€. For a redox flow battery, this combined BoP is estimated at €130 million. Similarly, Engineering, Procurement, and Construction (EPC) costs were estimated using internal knowledge at Eneco. Since construction and site preparation form a substantial part of EPC, some synergies can be expected when integrating systems during the construction phase. For a conventional alkaline electrolyzer, EPC costs are estimated at 100 million euro. For the combined systems, EPC costs are expected to rise to €130 million. In the case of a Battolyser configuration, EPC costs are estimated at 115 M€, as no EPC party has yet constructed a large scale Battolyser. This relatively higher cost, compared to a standalone alkaline electrolyzer but lower than a full battery-electrolyzer combination, is attributed to the novelty of the technology. No EPC contractor has yet constructed a large-scale Battolyser installation, which introduces additional uncertainty and contingency, design effort, and project risk. During the lifetime of the system, it is assumed that the CAPEX of the systems is depreciated linearly over the operational lifetime of 20 years. This means that the depreciation does not directly impact the cash flow in the system, so no additional depreciating costs are included in the analysis. At the end of the system's lifetime, the salvage value of materials such as steel, nickel, iron, and platinum is weighed against the decommissioning costs, which include dismantling the system, handling any hazardous materials, recycling components, and restoring the site. Alkaline electrolysers use common, recyclable materials like steel and nickel, and are relatively simple to disassemble, resulting in low decommissioning costs. The same applies to the Battolyser, which consists mainly of nickel and iron, which are also non-toxic and recyclable materials. The nickel can be dissolved in to retrieve the starting materials in the electrodes, which is a fairly easy process. PEM electrolysers are more complex and costly to decommission due to the use of platinum group metals. However, a significant portion of this value is recovered through material recycling. While, this is more difficult to retrieve, the value of iridium is higher than nickel. The system lifetime for a redox flow battery is estimated at 25 years, which means that the system can still be operational after the horizon for this master thesis. However, due to the relatively new nature of such flow battery, the system lifetime cannot be determined with certainty. It is therefore difficult to estimate an end of life value, as no large scale redox flow has existed 25 years yet. Most of the large scale redox flow battery projects in China have been commissioned 15 years ago [135]. Lastly, for the LFP batteries, the materials such as lithium still hold value at the end of life. This is difficult to retrieve, however, the processes involved are likely to become cheaper at the end of life due to the high installed capacity of lithium-ion batteries. For the co-located systems, more converters and power electronics are needed to correctly couple the assets to the grid. This will increase the decommissioning costs as more of these products must be removed at the end of life. Contrary, these power electronics yield again more scrap metals that still hold value. As it is difficult to quantify what the values are of the assets and electronics involved, it is assumed that the end of life value equals the decommissioning costs, which is assumed for all the components of the system. As a result, despite differences in configuration and cost structure, the net end-of-life impact is valued to be zero for all configurations as the end of life value and decommissioning costs are assumed to be equal. This means that no end of life value is taken into consideration in the LCOH calculation. Once more information is gathered about the end-of-life value of the systems, this can be included into the LCOH calculation in future research.

4.6 Verification and Validation

The model developed in this thesis is designed to represent the technical and economic behavior of energy systems producing hydrogen. To ensure that both the logic of the model and its outcomes are reliable, this chapter will discuss the verification and validation methods. Verification focuses on confirming that the model has been implemented correctly and behaves accordingly. THe model can be verified using unit tests and boundary value checks. Validation addresses whether the model accurately reflects real life. Typical validation methods are sensitivity analyses and expert validation. This chapter describes the methods applied to verify and validate several aspects of the model

4.6.1 Verification

The model is verified to confirm that the logic of the model is correctly implemented and that the calculations produce consistent results. Several components of the system, such as hydrogen production, battery operation, grid interaction, and emissions calculations, are each verified with unit testing. During the creation of the model, unit tests were used to confirm the correct functioning of formulas, such as the energy to hydrogen conversion, the partial renewable grid off take calculation, and the GHGE calculation. For instance, the values *1000* and *3600* in Equation (3) are conversions to ensure that the units are correctly altered from kWh to MWh and from kWh to MJ. Moreover, during creation and implementation of the code, constant debugging was used to trace logical errors in the code, such as division by zero errors.

First, it was verified whether the hydrogen production was consistent with the calculation. For instance, when 90 MW of power is directed towards the stacks, approximately 1,765 kilograms of hydrogen per hour should be produced, assuming a conversion efficiency of 51 kWh/kgH_2. This is calculated by dividing the energy in kWh by the efficiency in kWh/kgH_2. These values were verified directly from the simulation output and confirmed through these calculations. These calculations were conducted for multiple time steps to verify that the model correctly calculated the hydrogen output based on the energy input and efficiency. Moreover, it is confirmed that the state of charge (SOC) of the battery always remains within the defined bounds of 0% to 100%, both for the Battolyser and the combined battery and electrolyser configurations. This was verified by examining the SOC output across the entire output and ensuring that it never exceeded 1.0 or dropped below 0.0. Additionally, several moments where the battery was fully charged or completely discharged were checked to confirm that the model correctly limited charging or discharging, and that no extra or too little energy was passed to the grid. Next, several boundary conditions were evaluated using the model results. Both individual functions and the full model were tested using boundary checks. Parameters such as power input, battery capacity, and electricity prices were set to zero or unrealistically large values to check how the model responds. For instance, the battery capacity was set to zero to verify that the model did not perform battery calculations meaning that the battery was excluded from the system. Moreover, the capacity was also set to unrealistically high values to check whether a SOC of 100% was reached. In addition, electricity prices were set to a constant value of €20 to validate that only option 3 and 4 were selected by the MPC. Power and financial consistency checks were also performed. For example, the profit from selling excess power to the grid was traced back using the electricity price and the resale volume. If, in a specific hour, the model reported a profit of €5,000 from power resale and the electricity price was €100 in the same hour, then the excess electricity sold must have been 50 MWh. This value was confirmed by checking the corresponding hour. Next, consistency across system configurations were performed. The model included multiple PPA sources, and it was confirmed that for each time step, the sum of power allocated from these sources remained consistent across all system setups. This was verified by exporting the total PPA allocation per hour and comparing it across different operational modes. It was found that the total contracted energy remained constant, confirming that no energy was created or lost when switching between configurations. A similar verification was performed for other variables such as electricity price and ETS price. The equations used for allocating partially renewable electricity from the grid is also verified. In Option 4, the model calculates the maximum allowable amount of non-compliant grid electricity that could be drawn from the grid, while still producing RFNBO-compliant and low-carbon hydrogen. This calculation is based on the emission threshold and makes use of Equation (3) from Chapter 2.2. The results confirmed that the model consistently calculated the correct amount of power and that the GHGE intensity of the hydrogen never exceeded the threshold. As a result, no grey hydrogen was produced in any instance where Option 4 was selected. This was also verified manually for several time steps using calculations based on grid carbon intensity and the allowable emission margin. Lastly, the degradation behavior of the electrolyser stacks is verified. The initial capacity and annual degradation are verified by examining the stack power capacity over time. For instance, after one year of operation, the degradation was confirmed to be exactly 1.1%, consistent with the model input.

4.6.2 Validation

To assess the accuracy and realism of the model, several validation techniques are applied. These include regulatory constraint checks, expert validation and sensitivity analyses. The goal of these methods is to confirm that the model not only operates correctly in a technical sense but also reflects the behavior, constraints, and expectations of real-world energy systems.

It was tested that the power allocation and logic functioned as intended. For example, when PPA power was insufficient to meet the minimum stable load (MSL) of the BoP, or the grid was RFNBO compliant, the model correctly made use of grid power. This mechanism only occurred under the appropriate conditions, and the amount of drawn electricity was correctly divided between the BoP and stacks. The cost of the electricity was then calculated using the correct spot market price, and the greenhouse gas emissions (GHGE) intensity was updated accordingly, resulting in the production of grey hydrogen when the regulatory threshold was exceeded. This logic was validated through expert input from Eneco, where it was confirmed that allocating grid electricity to cover PPA shortfalls is a realistic operational decision. Moreover, the inflation and discount rate application are in line with how Eneco calculates their business cases. The calculated LCOH is a metric Eneco also uses to asses their electrolyser plants, and the calculation method was validated by a colleague from the financial branch. It is worth noting that the model used in this master thesis is partially derived from an existing internal Eneco model. While this may introduce some bias in the expert validation process, this risk was mitigated by assessing the logic in the code. Therefore, the expert validation still provides meaningful assurance that the model is realistic and applicable in the context of hydrogen production systems. Another common form of validation is comparison with literature values or historical data from similar systems. However, this research explores a relatively novel configuration in which the synergy between a battery and hydrogen production system is evaluated. Therefore, direct comparisons with existing models or case studies are unavailable. However, a sensitivity analysis is an accepted validation method, as it tests whether the model behaves logically and predictably when key input parameters are changed. This helps determine whether outputs remain within reasonable bounds and whether the system responds consistently to shifts in technical or financial parameters. For example, if the CAPEX is increased, the LCOH should also increase as the costs for the system are higher. The sensitivity analysis is discussed in Chapter 6.1.

5 Base Case Simulations of the Different Hydrogen Production Systems

This chapter will show the preliminary results from the base case simulations of the different hydrogen production system configurations. These results form the basis for later analyses and are used to evaluate the cost-efficiency of different hydrogen production systems. The cost breakdown for each configuration is visualised using waterfall charts, which show the contribution of each cost and revenue stream to the overall LCOH.

Figure 12 shows the LCOH breakdown for the alkaline electrolyser system combined with a lithium-ion battery. The system produced a discounted value of 64.83 kiloton of RFNBO hydrogen over its lifetime. Figure 13 shows the average hydrogen production per day over the 20 year period. It can be seen that more grey hydrogen is produced in the winter months. This is in line with the seasonal power profile associated with solar PV, where more electricity is generated in the summer due to the increase in sun hours. The total levelised cost of hydrogen is €10.36/kgH_2. The dominant cost drivers are electricity costs from the PPAs and the OPEX, along with the electrolyser CAPEX. The lithium-ion battery enables moderate arbitrage revenue, helping to offset the electricity grid costs. The discounted arbitrage revenue amounts to approximately 141 million euro across the lifetime. Over the systems lifetime, the electrolyser produced approximately 225.73 kilotons of RFNBO-compliant hydrogen. The potential production over 7,298 operating days (accounting for 2 days of maintenance downtime), with an electrical efficiency of 51 kWh/kg H_2 (due to the 2% safety margin), yields a potential hydrogen production of approximately 308.93 kiloton. The actual production divided by the theoretical production results in a capacity factor of approximately 73.1%. The capacity factor (C_f) increases to 73.6% if the produced grey and low-carbon hydrogen is included as well.

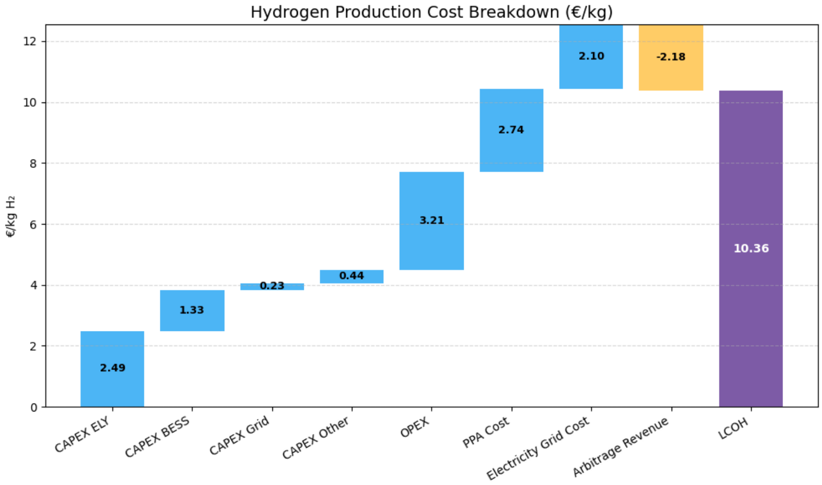


Figure 12: LCOH of a system consisting of an alkaline electrolyser and lithium-ion battery.

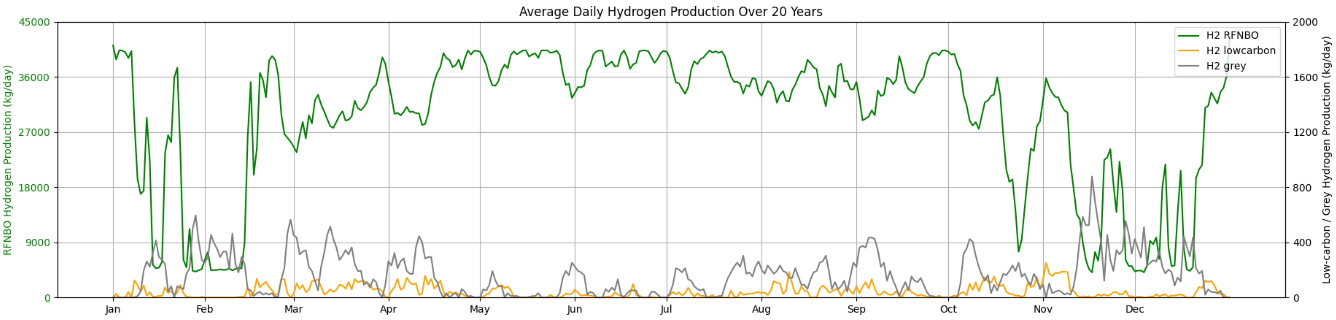


Figure 13: Average daily hydrogen production of the ALK Li-ion system.

The ALK-RF system, depicted in Figure 14, yields the highest LCOH among all cases at €11.31/kgH_2, even though the RFNBO hydrogen production slightly increased to 64.90 kiloton. The cost increase is primarily due to a combination of increased CAPEX and OPEX as a results of the redox flow battery system. While RF storage allows for longer duration energy discharge, the economic return under base case assumptions appears limited. Compared to the Li-ion battery, the arbitrage revenue is decreased and is not able to fully offset the electricity grid costs. The lifetime arbitrage revenue amounts to approximately 135 million euro across the lifetime. The average hydrogen production profile is very similar to the alkaline and lithium ion system, as can be seen in Figure 15. This is in line with the expectation as the electrolysers are similar. Together with the decreased arbitrage revenue, this suggests that an increased battery capacity does not necessarily result in the MPC choosing more often for generating revenue through arbitrage. The capacity factor of the alkaline and redox flow system is approximately 73.2% when focusing on RFNBO compliant hydrogen and the capacity factor increases to 73.7% when the total hydrogen production is evaluated.

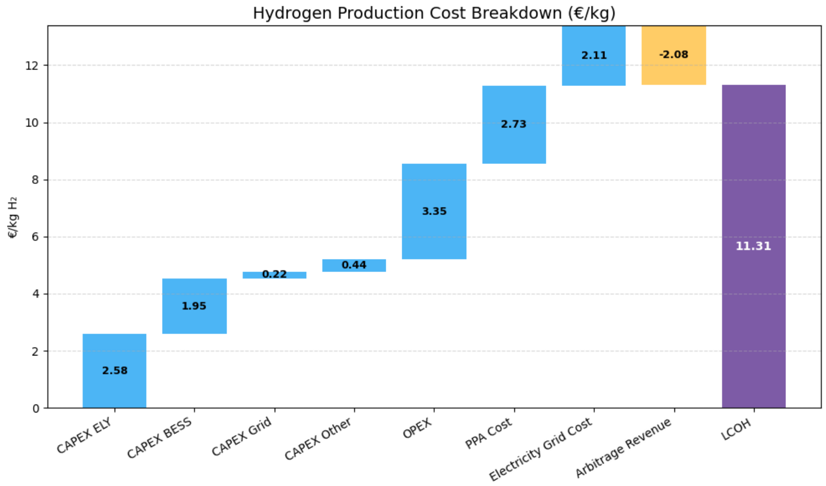


Figure 14: LCOH of a system consisting of an alkaline electrolyser and redox flow battery.

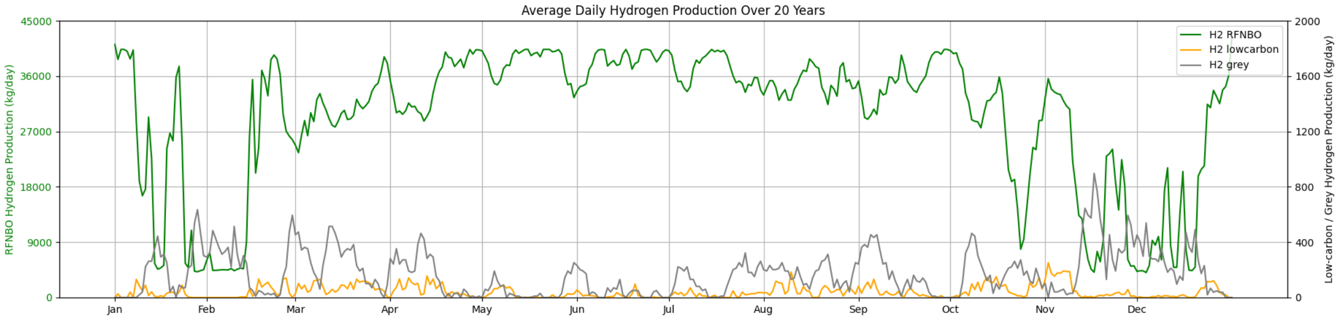


Figure 15: Average daily hydrogen production of the ALK RF system.

As illustrated in Figure 16, the PEM electrolyser paired with a lithium-ion battery achieves an LCOH of €10.15/kgH_2, slightly lower than the alkaline electrolyser system. Like the ALK-Li system, the largest cost contributors are PPA costs and CAPEX. However, the PEM system benefits more from arbitrage revenue, likely due to higher operational flexibility. The arbitrage revenue is approximately 184 million across the lifetime, which is significantly more than the alkaline systems. As can be seen in Figure 17, less grey hydrogen is produced, which can be attributed to the greater operational flexibility as a result of the smaller BoP power demand and lower minimum stable load. The RFNBO hydrogen production is significantly less than of the alkaline electrolysers, as the PEM electrolyser produces a discounted value of 61.72 kiloton. For the PEM electrolyser, the efficiency is 52.02 kWh/kgH_2 due to the 2% safetymargin. This results that the theoretical hydrogen production is 302.94 kiloton. The capacity factor for the PEM Li-ion system is 70.7%, as the total hydrogen production sums up to 241.09 across the lifetime. The capacity factor increases to 70.9% when the grey and low carbon hydrogen is included in the calculation as well.

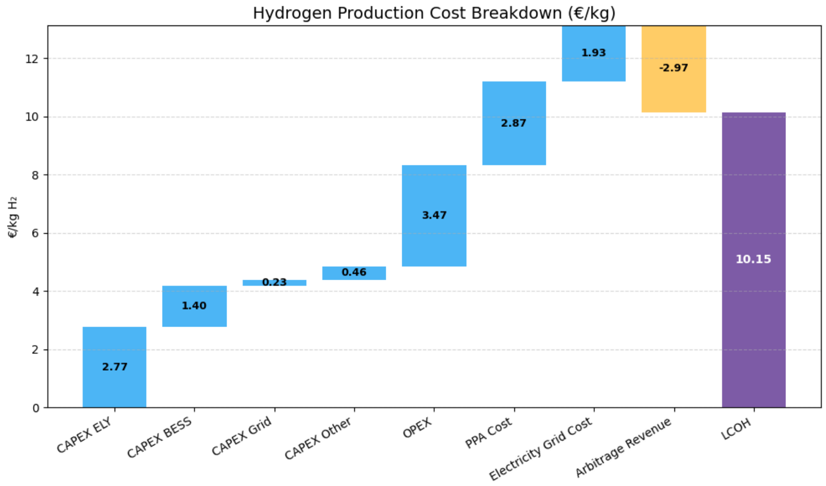


Figure 16: LCOH of a system consisting of an PEM electrolyser and lithium-ion battery.

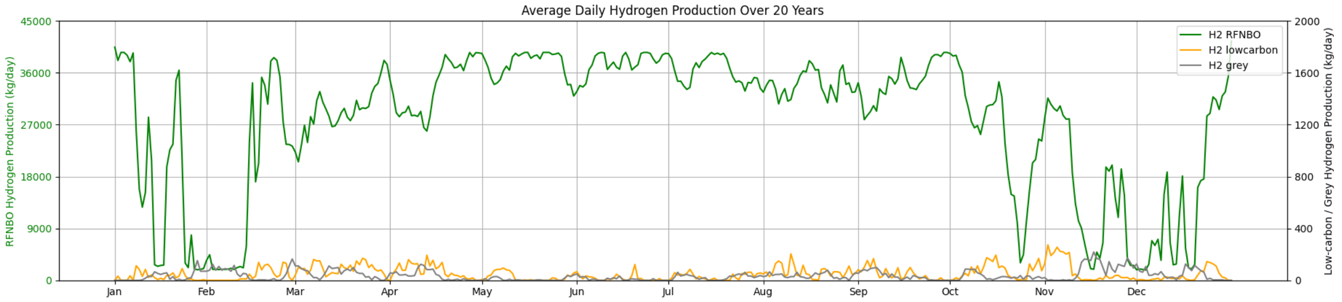


Figure 17: Average daily hydrogen production of the PEM Li-ion system.

Figure 18 shows the waterfall plot of the PEM RF configuration, which results in an LCOH of €11.14/kgH_2. The RFNBO hydrogen production is almost identical to the PEM-Li configuration, with a discounted value of 61.71 kiloton over its lifetime. Figure 18 shows a similar hydrogen production pattern as the lithium ion battery counterpart. Although the cost structure is similar to that of the ALK-RF system, the greater flexibility of the PEM leads to slightly better arbitrage revenue. The arbitrage revenue amounts to approximately 178 million euro over the lifetime. This is less arbitrage revenue compared to the PEM and ALK system, indicating again that a larger battery capacity does not yield more arbitrage revenue. However, the redox flow systems in this context show limited economic benefit, as the higher investment cost is not sufficiently offset by revenue gains. This system produces 213.97 kiloton of RFNBO compliant hydrogen, which results in a capacity factor of 70.6%. The capacity factor rises to 70.9% when the sum of all the hydrogen is used.

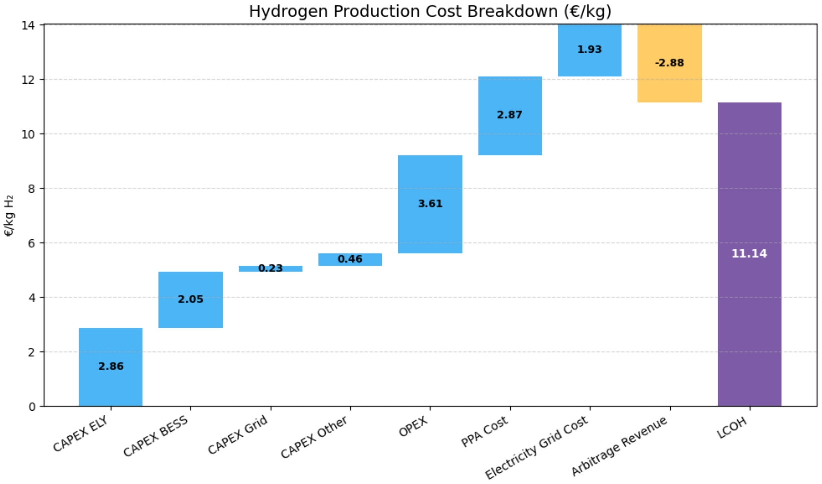


Figure 18: LCOH of a system consisting of an PEM electrolyser and RF battery.

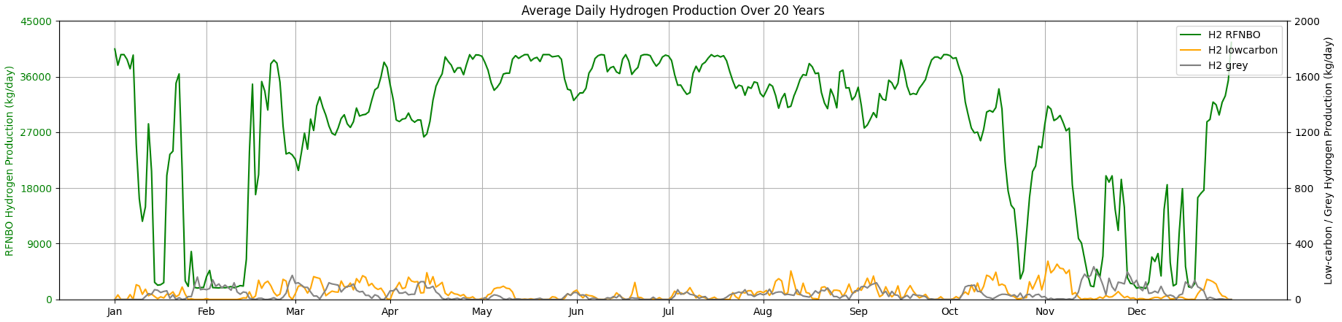


Figure 19: Average daily hydrogen production of the PEM RF system.

The Battolyser configuration, displayed in Figure 20, achieves the lowest LCOH across all simulated systems at €9.96/kgH_2. Despite relatively high upfront investment, the integrated nature of the Battolyser allows for a low OPEX, compared to the other systems. Although arbitrage revenue is lower than in PEM-Li, overall system costs are significantly more controlled. Moreover, the Battolyser has the highest discounted hydrogen production with 69.72 kiloton. This is likely due to the significantly higher efficiency of 46.3 kWh/kgH_2 compared to the other systems (50 - 51 kWh/kgH_2). Figure 21 shows that no grey hydrogen is produced, as the Battolyser is able to go into standby mode. However, the Battolyser has the lowest arbitrage revenue of the systems, with an amount of approximately 92 million euro over the lifetime. An hourly hydrogen production of 1905 kg H_2 can be achieved with an efficiency of 47.23 kWh/kgH_2, as a result of the 2% safety margin. With this efficiency, a theoretical hydrogen production of 333.54 kiloton can be achieved. The Battolyser produces 240 kiloton RFNBO compliant hydrogen across its lifetime, resulting in a capacity factor of 72.0%. The capacity factor rises to 72.3% when all the produced hydrogen is used for the calculation.

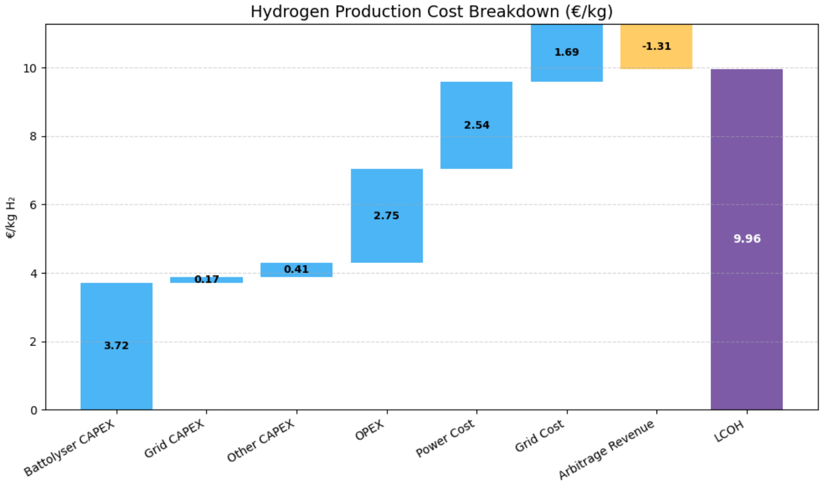


Figure 20: LCOH of a system consisting of a Battolyser.

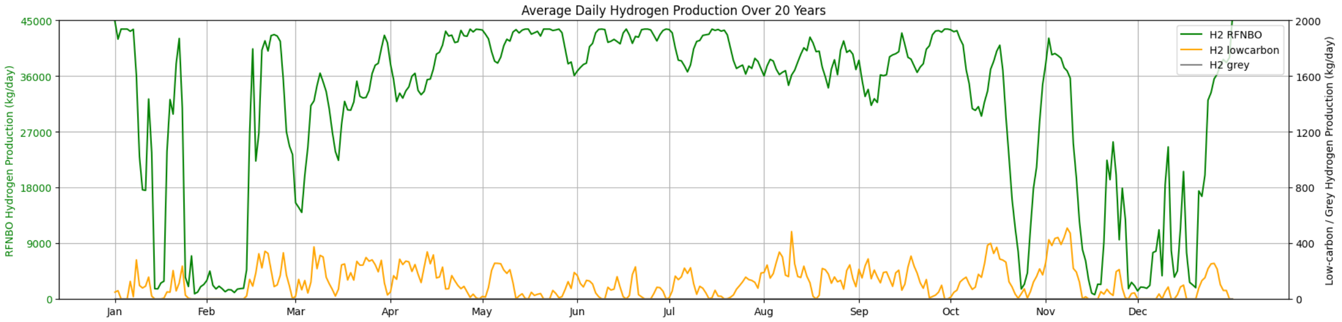


Figure 21: Average daily hydrogen production of the Battolyser system.

In summary, the preliminary simulations reveal clear differences in the levelised costs and hydrogen production. Systems using lithium-ion batteries show lower LCOH values in comparison to the redox flow batteries, primarily due to lower CAPEX and slightly better arbitrage performance. PEM systems achieve slightly lower LCOHs but also yield lower total hydrogen output compared to ALK systems. The Battolyser stands out as the most cost-effective and productive configuration in this scenario, highlighting the potential benefits of lower OPEX due to the integrated design and improved system efficiency, which together contribute to both lower costs and higher hydrogen output. The capacity factors of the systems are relatively similar, and the alkaline system yields the highest capacity factor. The findings are summarized in Table 22.

Table 22: Summary of preliminary results for each system configuration.

System	**LCOH** [€/kgH_2]	**Discounted H_2** [kt over lifetime]	**Discounted Arbitrage** [M€ over lifetime]	**Electrolyser Efficiency** [kWh/kg H_2]	**C_f RFNBO** [%]
ALK + Lithium-ion	10.36	64.83	141.15	50.0	73.1
ALK + Redox Flow	11.31	64.90	134.83	50.0	73.2
PEM + Lithium-ion	10.15	61.72	183.52	51.0	70.7
PEM + Redox Flow	11.14	61.71	177.64	51.0	70.6
Battolyser	9.96	69.72	91.67	46.3	72.0

6 Sensitivity and Scenario Analyses

Several analyses have been performed on the results that have been displayed in the previous chapter. These analyses aim to investigate how variations in several parameters affect overall system performance, to identify statistically relevant relationships, and to explore the system's response to changes in power input profiles. A local sensitivity analysis is first performed to determine how several parameters impact the LCOH of the systems, as well as serving as a validation method mentioned in Chapter 4.6.2. This is followed by a global sensitivity analysis, which is used to capture the main effects and the relation between parameters on the LCOH. Finally, a scenario analysis is performed to evaluate the behaviour of the systems under a different renewable input profiles.

6.1 Local Sensitivity Analysis

A local sensitivity analysis is performed to assess the impact of a 20% variation in CAPEX and OPEX on the levelised cost of hydrogen (LCOH), as shown in Figures 22 and 23. The figures show the variation in LCOH across different system configurations and include the rate of change (RC) in €/kg/€ for each system in the legend. This analysis is performed where a single parameter is changed, while keeping the other parameters consistent with the base case. This analysis has been performed to validate the performance of the model.

From Figure 22, it is evident that a 20% CAPEX variation leads to different impacts on LCOH depending on the system. For example, a 20% reduction in CAPEX for the Battolyser results in an LCOH of 9.10 €/kgH_2, which is lower than that of the standalone alkaline electrolyser (9.16 €/kgH_2). Notably, the systems with a PEM electrolyser in combination with a battery have the steepest slopes, with RCs of approximately 0.0124 €/kg/M€, reflecting a higher LCOH sensitivity to CAPEX changes. Moreover, coupling the system with either a Li-ion battery or a redox flow battery has minimal influence on LCOH sensitivity. The rate of change remains effectively the same for both alkaline and PEM electrolysers, regardless of the battery type used.

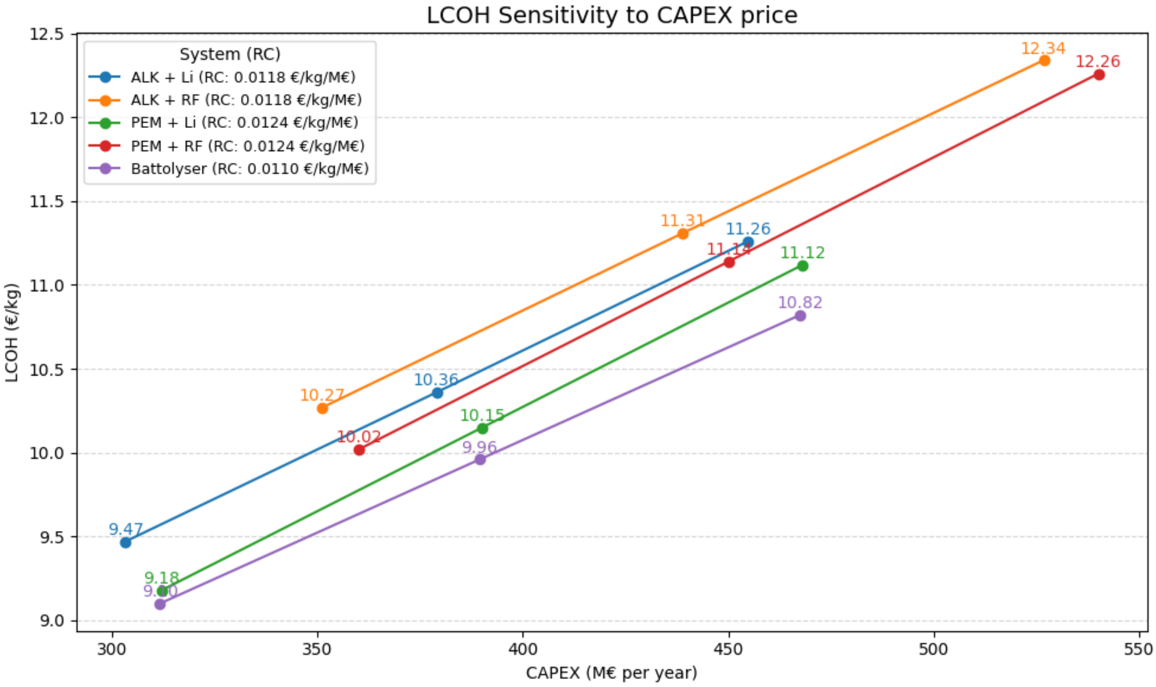


Figure 22: Sensitivity analysis: CAPEX impact on LCOH

From Figure 23, it is clear that variations in OPEX have a more significant effect on LCOH compared to CAPEX. The RC values are significantly higher across all systems, typically in the range of 0.12–0.14 €/kg/M€ per year. This shows that variations of several million euros in OPEX have a greater impact on LCOH than identical changes in CAPEX. The systems combining PEM electrolysers with Li-ion or redox flow batteries exhibit the steepest RCs (up to 0.1418 €/kgH_2/M€ per year), suggesting that these configurations are sensitive to changes in OPEX. In contrast, the alkaline electrolyser has the lowest OPEX sensitivity. Moreover, systems using the same electrolyser type but different battery technologies show slightly different RCs.

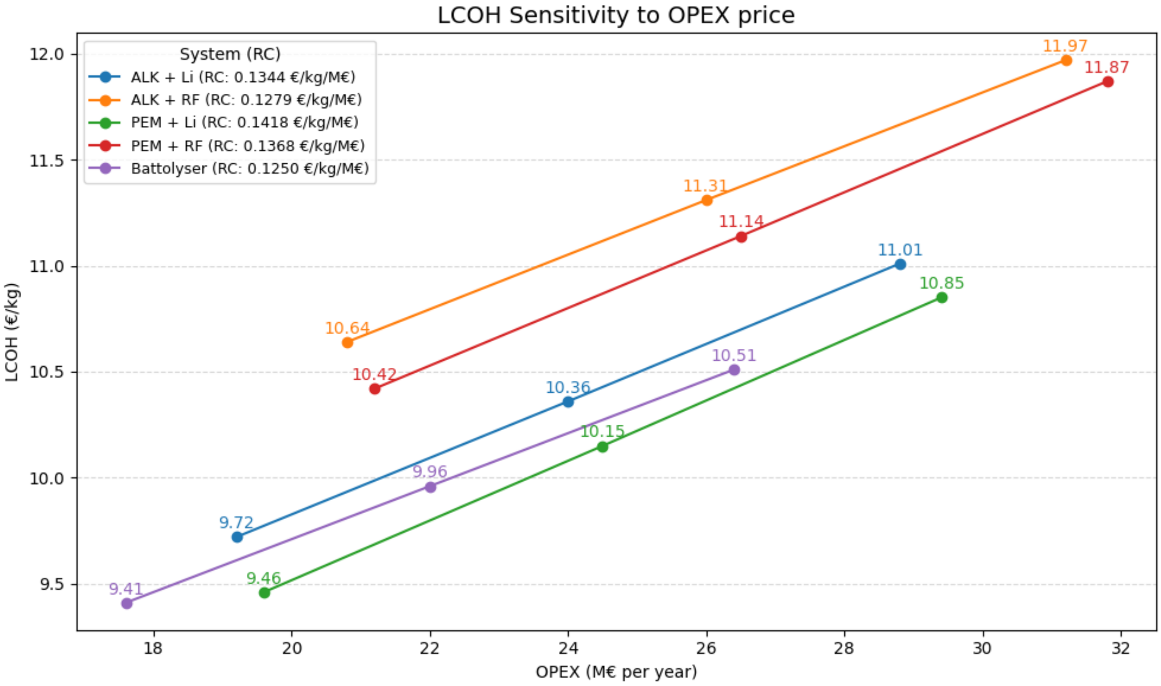


Figure 23: Sensitivity analysis: OPEX impact on LCOH

Another local sensitivity analysis is performed to assess the impact of varying electricity prices on system performance. The input prices are scaled by 20% in both directions, meaning one simulation is run using 0.8 times the original dataset and another using 1.2 times. This ensures that in the increased scenario, the spread in electricity prices is larger, and in the reduced scenario the spread is dampened, which is depicted in Figure 24 As the PPA price is in line with the market electricity prices, the PPA price has also been scaled in this analysis. As stated in Chapter 2.2, grid power can be used to generate RFNBO compliant hydrogen when electricity prices fall below €20/MWh. On the one side, lower electricity prices may result in more hours where this threshold is met, which could increase the production of RFNBO hydrogen. However, battery arbitrage revenue may reduce under these conditions, as the conversion price at which it becomes more profitable to sell stored power than generating hydrogen, is reached less frequently. On the other side, in a scenario with higher electricity prices can lead to fewer RFNBO compliant hours, but the battery may generate more revenue through arbitrage. Since the contracted PPA capacity remains constant across the simulations, changes in market electricity prices can lead to different operational decisions. This analysis can therefore provide insight into the system's operational flexibility and assess whether the relative performance in terms of LCOH changes under different electricity price scenarios.

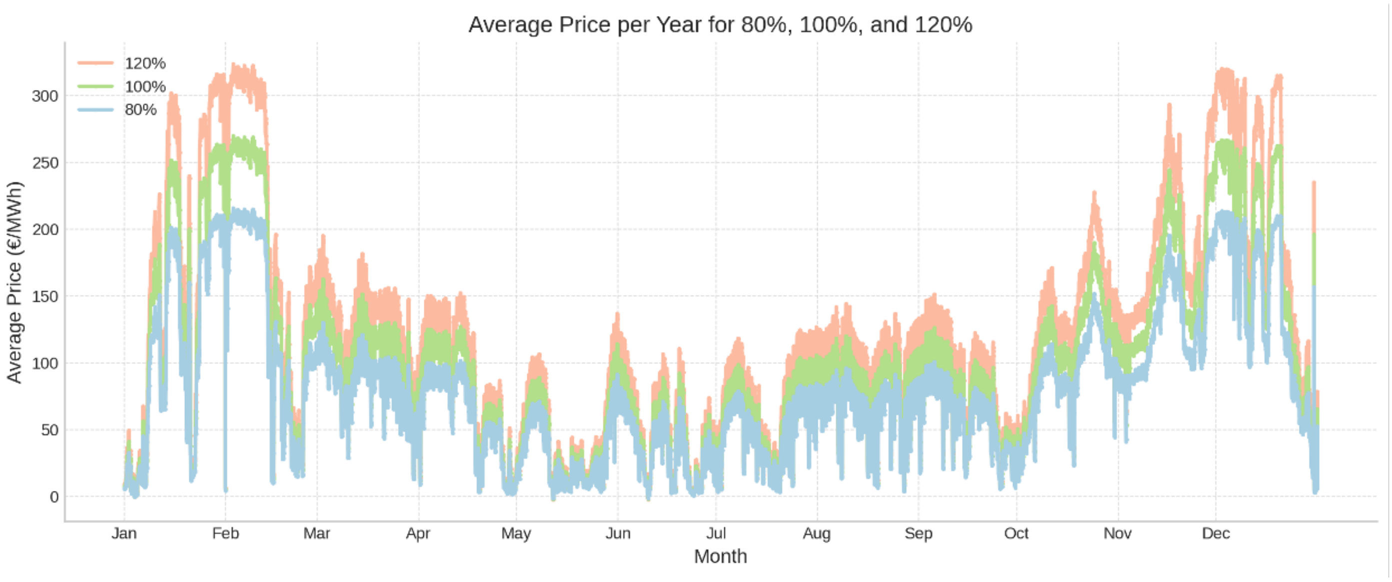


Figure 24: Visual representation of electricity price spread in the different scenarios.

Figure 25 shows the LCOH of all systems under varying electricity price scenarios. When electricity prices are scaled down to 80%, all systems achieve a lower LCOH. The Battolyser shows the largest reduction of 0.96 €/kgH_2, followed by the alkaline systems with reductions of 0.85 €/kgH_2 for the RF configuration and 0.74 €/kgH_2 for the Li-ion configuration. The PEM systems show more modest improvements, with reductions of 0.67 €/kgH_2 for the RF configuration and 0.55 €/kgH_2 for the Li-ion configuration. The systems also respond differently to increased electricity prices. The Battolyser shows the steepest increase in LCOH, increasing by 1.25 €/kgH_2 compared to the base case. The alkaline systems increase with 0.79 €/kgH_2 for the RF configuration and 0.76 €/kgH_2 for the Li-ion configuration. In contrast, the PEM systems are less affected, with more modest increases of 0.55 €/kgH_2 and 0.39 €/kgH_2 for the RF and Li-ion configurations. Notably, the sensitivity to electricity prices causes a change in order of the LCOH system performance. Under reduced electricity prices, the ALK + RF configuration outperforms the PEM + RF setup, changing the order of the base case result. In high electricity price conditions, both the PEM + Li-ion and ALK + Li-ion systems outperform the Battolyser in LCOH performance, indicating that the Battolyser configuration is less resilient to rising electricity costs. In addition, the Battolyser system shows the highest variation in LCOH across the electricity price scenarios, with a range of 2.21 €/kgH_2. This is followed by the alkaline systems, with a range of 1.40 €/kgH_2 for the Li-ion configuration and 1.64 €/kgH_2 for the redox flow configuration. The PEM systems show the smallest variation, with a range of 0.94 €/kgH_2 for the Li-ion setup and 1.22 €/kgH_2 for the redox flow configuration.

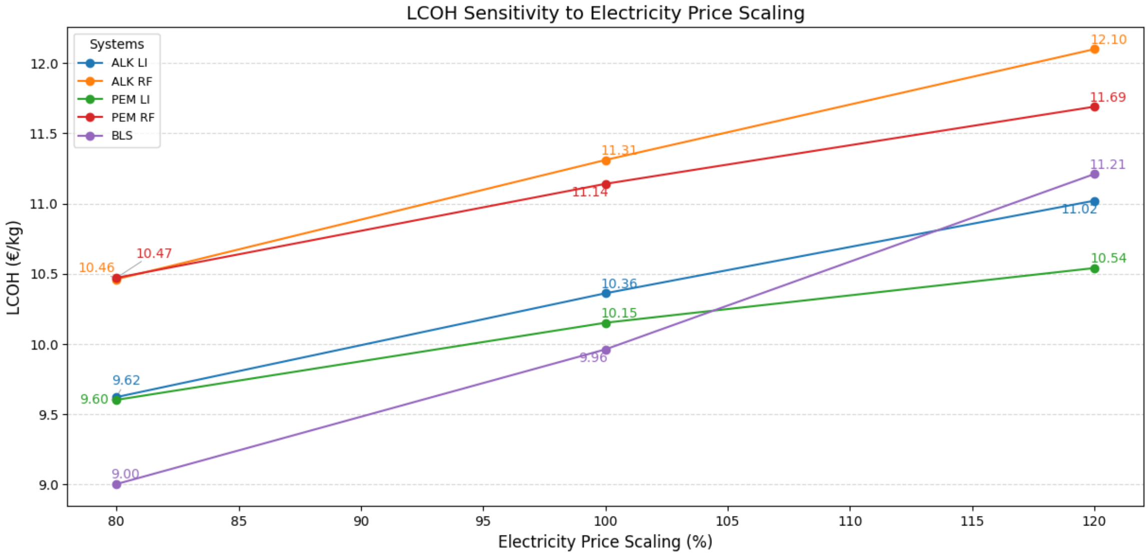


Figure 25: Sensitivity of electricity price variation on LCOH of the systems.

Table 23 shows the LCOH, discounted arbitrage revenue, and discounted hydrogen production across all three electricity price scenarios. As expected, arbitrage revenue increases for each system as electricity prices rise. In contrast, hydrogen production decreases with higher scaling of the electricity price, aligning with the expectation that less RFNBO-compliant hydrogen can be produced when fewer low-price hours are available. Notably, in all scenarios, the configurations with the lithium-ion battery outperform those with the redox flow battery in terms of arbitrage revenue. The decline in hydrogen output is most significant for the Battolyser, with a reduction of 18.07 kt between the lowest and highest electricity price scenarios. The PEM + Li-ion system shows the smallest decrease in hydrogen production, with a drop of 12.11 kt. This is comparable to the variation in hydrogen production of the alkaline and lithium ion battery setup. In addition, hydrogen production is nearly identical for the alkaline and PEM systems in the base case, regardless of the battery used. However, this consistency does not hold in the reduced and increased electricity price scenarios, where differences between the configurations become more significant.

Table 23: Summary of results across electricity price scenarios.

System	**LCOH** [€/kgH_2]			**Discounted Arbitrage** [M€ over lifetime]			**Discounted H_2** [kt over lifetime]			**Discounted Grid Offtake** [M€ over lifetime]		
	80%	100%	120%	80%	100%	120%	80%	100%	120%	80%	100%	120%
ALK + Li-ion	9.62	10.36	11.02	87.28	141.15	208.44	70.71	64.83	58.54	126.19	136.37	141.32
ALK + RF	10.46	11.31	12.10	82.98	134.83	200.43	68.46	64.90	53.98	126.64	136.91	142.49
PEM + Li-ion	9.60	10.15	10.54	110.42	183.52	273.21	70.74	61.72	58.63	112.21	119.06	115.60
PEM + RF	10.47	11.14	11.69	105.27	177.64	264.25	68.59	61.71	54.19	112.46	119.22	116.45
Battolyser	9.00	9.96	11.21	57.71	91.67	136.71	76.52	69.72	58.45	113.24	117.65	88.09

Table 23 also presents the discounted electricity grid costs associated with grid offtake, over the lifetime of the systems. The alkaline systems show a consistent increase in discounted electricity grid offtake cost as electricity prices rise. For instance, the ALK + Li-ion configuration sees its grid cost increase from €126.19 million at 80% electricity prices to €141.32 million at 120%. Similarly, the ALK + RF system increases from €126.64 million to €142.49 million across the same range. This pattern is in line with the characteristics of alkaline electrolyser, which has limited operational flexibility due to higher minimum MSL and BoP power demand. In contrast, the PEM-based systems and the Battolyser show a different trend. Although grid costs increase from 80% to 100% pricing, they decline at 120%, suggesting a change in operational behavior. For example, PEM + Li-ion increases grid cost from €112.21 million (80%) to €119.06 million (100%), but then reduces it to €115.60 million at 120%. The Battolyser has the most significant decrease in grid offtake cost in the increased scenario, falling from €117.65 million at 100% to only €88.09 million at 120%. This significant reduction shows that Battolyser is able to reduce grid consumption during high-price periods and give priority to arbitrage revenue.

To sum up, the sensitivity analysis shows that the Battolyser is the most sensitive to varying electricity prices with a total variation of 2.21 €/kgH_2 in LCOH. This is followed by the alkaline systems and then by the PEM systems, indicating that the PEM systems are most resilient to electricity prices. Discounted arbitrage revenue increases consistently across all configurations as electricity prices are scaled up, while discounted hydrogen production decreases in every case. The costs associated with electricity offtake from the grid vary depending on the system. The least flexible systems (alkaline systems) show a steady increase in costs, while the more flexible systems reduce the grid costs in the increased scenario.

6.2 Global Sensitivity Analysis

A full factorial (FF) design is an approach used to investigate the individual and interactive effects of multiple input parameters by evaluating all possible combinations. In this study, five parameters are selected as drivers of the LCOH: CAPEX, OPEX, battery capacity, electrolyser efficiency and minimum stable load of the electrolyser. These parameters are chosen based on expert knowledge, as these values could impact the LCOH significantly. CAPEX and OPEX directly determine the investment and yearly costs, which are primary components of the LCOH. Electrolyser efficiency relates to the amount of electricity needed per kilogram of hydrogen produced, affecting both operating costs and hydrogen production. Battery capacity determines the amount of arbitrage revenue that can be generated. Finally, the minimum stable load constraint defines the operating flexibility of the electrolyser, impacting electricity costs. Each parameter is modeled at two levels, representing low and high values, leading to a total of $2^5 = 32$ combinations in a full factorial design. It is important to note that the parameter range has an influence on the absolute effect of the respective parameter on the LCOH. Therefore, the ranges have been selected in consultation with experts from Eneco to ensure meaningful variation. The selected values are centered around a base case, allowing the analysis to capture both optimistic and conservative deviations from the assumed system performance. The primary objective of this analysis is to understand how the model responds to changes in each parameter and to assess the sensitivity. To reduce the computational effort required for such an evaluation, a Resolution V fractional factorial design is implemented. A Resolution V FF design ensures that the main effects and low order interactions can be estimated, while reducing the simulation runs by half [136]. The reduction is achieved by defining one parameter (in this case, electrolyser efficiency) as a product of the remaining four parameters. The relation is depicted as $A = B \times C \times D \times E$. The sparsity of effects principle states that, when investigating a large number of effects, only a few are significantly important [137]. In a Resolution V fractional factorial design, the assumption of sparsity of effects allows for the accurately estimation of the main effects in a reduced amount of runs. Aliased (or confounded) effects are effects that cannot be distinguished from each other in the analysis because they are mathematically combined in the design. This means that their individual contributions to the outcome cannot be separately identified. Using the Resolution V approach, the main effects are only co-founded with 4-way interactions or higher. This is done deliberately because this gives good information as higher order interactions have less significance than the main and two-way interaction effects. However, some interactions may still be aliased with other parameters, which could affect interpretation if multiple interactions are active. The resulting 16 data points are used to fit a linear regression model in which LCOH is expressed as a function of the selected parameters and their interactions. This regression model can be used to determine the influence of the parameters on the LCOH. The regression formula fitted on the results of the fractional factorial (FF) design includes an intercept term, α_0, which represents the LCOH, where all parameters are set to their midpoint values. This value reflects the LCOH where the parameters are set as in the base case. The other terms in the formula are the regression coefficients, which indicate how much each parameter influences the LCOH. A positive coefficient means that increasing the parameter leads to a higher LCOH, while a negative coefficient implies the opposite. The formula can be used to quickly estimate the LCOH for different scenarios by filling in coded values (–1 for low, +1 for high). For example, in a very optimistic scenario, all parameters can be set to –1 to predict a best-case LCOH. While this approach provides fast estimated results, it is important to note that this analysis is based on the assumption of linearity and neglects higher-order effects, which are assumed to have negligible impact on the LCOH. This means that the fractional factorial design still has uncertainty and that must be taken into account when using this design to assess the results.

6.2.1 Battolyser

The fractional factorial design has been applied to the Battolyser system. The system is modeled where the parameters are altered between high and low values. The high and low values are determined by adding and subtracting a significant amount from the base value. For the CAPEX, the high and low values correspond to 439.4 and 339.4 M€. The OPEX varies between 20 and 24 M€, and the battery capacity varies between 75 and 105 MWh. As the minimum stable load cannot correspond to a negative value, the high and low values correspond to 0 and 5 percent. Lastly, the electrolyser efficiency ranges between 41.3 and 51.3 kWh/kgH_2. Equation (12) shows the regression formula that is fitted to the fractional factorial design. Notably, the α_0 term in the regression model does not exactly match the LCOH of the Battolyser in the base case simulation, which was 9.96 €/kgH_2. Although the regression formula assumes all parameters vary symmetrically between a low (–1) and high (+1) value, the MSL parameter has a lower bound at 0% and cannot physically go below that. In the base case, MSL is already set to its minimum value (0%), so it cannot adopt a coded value of –1. Consequently, the intercept α_0 reflects the predicted LCOH in the mathematical center of all parameters, which means a midpoint MSL of 2.5%, while the physical base case uses 0%. As mentioned, the interaction terms are aliased with higher order interaction terms. In addition, in a Resolution V fractional factorial design, the intercept is aliased with the fifth order interactive term: $I = A \times B \times C \times D \times E$. Although less likely than the effect of the asymmetrical MSL value, these effects could explain the impact on the intercept of the regression formula. Despite this, the regression model remains a valid estimating tool, as long as these limitation are taken into account.

$$\begin{aligned}\text{LCOH} = \quad & 10.03 + 0.54\,\text{CAPEX} + 0.21\,\text{OPEX} + 0.11\,\text{BatteryCap} + 0.03\,\text{MSL} + 1.30\,\text{Eff} - 0.03\,\text{CAPEX}\cdot\text{OPEX} - 0.01\,\text{CAPEX}\cdot\text{BatteryCap} + 0.03\,\text{CAPEX}\cdot\text{MSL} \\ & +0.12\,\text{CAPEX}\cdot\text{Eff} - 0.02\,\text{OPEX}\cdot\text{BatteryCap} + 0.04\,\text{OPEX}\cdot\text{MSL} + 0.06\,\text{OPEX}\cdot\text{Eff} + 0.03\,\text{BatteryCap}\cdot\text{MSL} + 0.10\,\text{BatteryCap}\cdot\text{Eff} - 0.03\,\text{MSL}\cdot\text{Eff}\end{aligned} \tag{12}$$

Table 24 shows the regression coefficients again without the α_0 term. It can be seen that most of the main effects have a high coefficient, and thus more impact on the LCOH compared to the two-way interactions. Notably, the electrolyser efficiency has the most significant influence on the LCOH of the Battolyser.

Table 24: Regression coefficients of the Battolyser based on the FF Resolution V.

Main Effects	**Coefficient**	**Two-way Interactions**	**Coefficient**	**Two-way Interactions**	**Coefficient**
CAPEX	+0.5375	CAPEX × OPEX	–0.0262	OPEX × MSL	+0.0363
OPEX	+0.2125	CAPEX × Battery capacity	–0.0075	OPEX × Efficiency	+0.0638
Battery capacity	+0.1137	CAPEX × MSL	+0.0287	Battery capacity × MSL	+0.0250
Minimum Stable Load (MSL)	+0.0250	CAPEX × Efficiency	+0.1163	Battery capacity × Efficiency	+0.1025
Electrolyser Efficiency	+1.2975	OPEX × Battery capacity	–0.0175	MSL × Efficiency	–0.0262

The fractional factorial design includes 16 simulation runs and estimates 16 parameters, 15 regression coefficients plus the intercept term α_0. As a result, there are no degrees of freedom left in the model. This means the regression model perfectly fits the data, meaning that $R^2 = 1.0$. This means that the model is saturated and that the number of observations equals the number of estimated parameters. However, without an error left to calculate the variance, it is not possible to calculate standard errors or p-values for the coefficients. Although this means that the regression formula fits the points perfectly, it limits the ability to assess the uncertainty or statistical significance.

In order to be able to test for statistical relevance, more degrees of freedom must be created. This can be achieved by removing parameters that are expected to have limited relevance [137]. This can be done by examining the Pareto chart in Figure 26. This figure shows the absolute effect of each parameter on the LCOH, as well as the cumulative contribution to the LCOH change. This figure is used to remove terms with negligible effects. Even though the coefficient of effect of the MSL is small, the main effects are kept together with the three most significant interactive terms, which are CAPEX:Efficiency, Battery capacity:Efficiency and OPEX:Efficiency. Notably, the three most influential interaction terms are coupled with the electrolyser efficiency parameter.

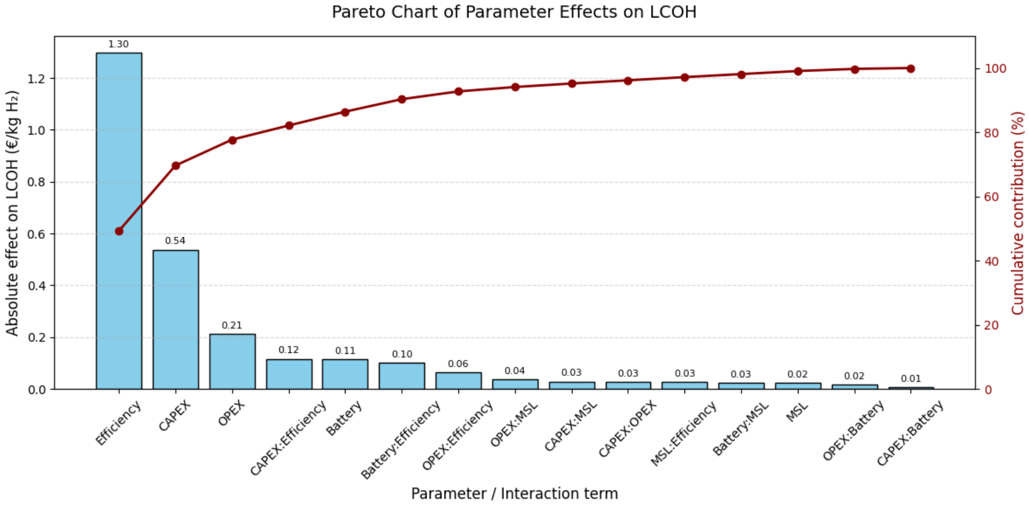


Figure 26: Pareto chart of the effect of the parameters on the LCOH of the Battolyser system.

Another regression model is fit to the results without the use of the seven weak interaction terms. This reduced model has $R^2 = 0.998$, meaning that 99.8% of the variation in LCOH can be explained by the model. This suggests that the removal of these terms has a negligible impact on the estimation of the LCOH, which is in line with the expectation. By removing the seven terms, more degrees of freedom have been created and it becomes possible to calculate p-values for the remaining effects, as shown in Table 25. A p-value indicates if a parameter has a statistically significant impact, where values below 0.05 indicate significance. All three two-way interaction terms in the reduced model involve electrolyser efficiency, indicating that the effect of CAPEX, OPEX, and battery capacity on the LCOH is influenced by the efficiency level. The interaction between CAPEX and efficiency has a positive coefficient (+0.1163), indicating that the combined effect of these two parameters on LCOH is stronger than the sum of their individual effects. The same holds for the interactions OPEX:Efficiency (+0.0638) and Battery Capacity:Efficiency (+0.1025). The table also shows the p-values of all the parameters, where almost all parameters show statistical significance. However, the p-value for the minimum stable load is higher than the threshold of 0.05, indicating that it does not have a significant effect on the LCOH. This is in line with the expectation from the initial regression coefficient.

Table 25: Regression coefficients and p-values of the Battolyser model based on the reduced FF Resolution V design.

Main Effect	**Coefficient**	**P-value**
CAPEX	+0.5375	0.000
OPEX	+0.2125	0.000
Battery capacity	+0.1137	0.003
Minimum Stable Load (MSL)	+0.0250	0.357
Electrolyser Efficiency	+1.2975	0.000

Two-way Interactions	**Coefficient**	**P-value**
CAPEX × Efficiency	+0.1163	0.003
Battery capacity × Efficiency	+0.1025	0.005
OPEX × Efficiency	+0.0638	0.040

Based on the coefficients and p-values of this regression model, electrolyser efficiency has the largest influence on the LCOH, followed by CAPEX and OPEX. All these parameters are statistically significant since the p-value is less than 0.05. Battery capacity and the minimum stable load have a smaller impact compared to the other main parameters. The influence of the MSL on the LCOH is not statistically significant in this model, as indicated by the large p-value.

6.2.2 Alkaline and Li-ion System

The fractional factorial design has also been applied to the system consisting of an alkaline electrolyser and a lithium-ion battery. As with the Battolyser system, high and low values have been assigned to the five system characteristics. The CAPEX varies by 50 M€ from the base value, resulting in input values of 429 M€ and 329 M€. The OPEX changes with 2 M€, giving a range of 22 to 26 M€ per year. Due to the larger battery capacity in this system, the battery size is also varied more widely compared to the Battolyser, namely between 300 and 500 MWh. The minimum stable load (MSL) is set at 5% and 19%, representing a 7% deviation from the base value. Finally, the electrolyser efficiency is varied between 45 and 55 kWh/kgH$_2$. Equation (13) shows the fitted regression formula based on the fractional factorial design of the alkaline and lithium ion system. Similar to the Battolyser, the intercept term α_0 does not correspond to the base case LCOH, which is 10.36 €/kgH$_2$.

$$\begin{aligned} \mathrm{LCOH} = \ & 10.44 + 0.60\,\mathrm{CAPEX} + 0.25\,\mathrm{OPEX} - 0.01\,\mathrm{BatteryCap} + 0.13\,\mathrm{MSL} + 1.06\,\mathrm{Eff} - 0.001\,\mathrm{CAPEX}\cdot\mathrm{OPEX} + 0.004\,\mathrm{CAPEX}\cdot\mathrm{BatteryCap} - 0.01\,\mathrm{CAPEX}\cdot\mathrm{MSL} \\ & + 0.08\,\mathrm{CAPEX}\cdot\mathrm{Eff} - 0.003\,\mathrm{OPEX}\cdot\mathrm{BatteryCap} - 0.004\,\mathrm{OPEX}\cdot\mathrm{MSL} + 0.03\,\mathrm{OPEX}\cdot\mathrm{Eff} + 0.01\,\mathrm{BatteryCap}\cdot\mathrm{MSL} - 0.01\,\mathrm{BatteryCap}\cdot\mathrm{Eff} + 0.02\,\mathrm{MSL}\cdot\mathrm{Eff} \end{aligned} \tag{13}$$

Table 26 shows the coefficients without the interaction term. It can be seen that all the main effects have a significant regression coefficient and similar to the Battolyser, the electrolyser efficiency has the highest absolute effect on the LCOH. In contrast to the Battolyser, increasing the battery capacity results in a lower LCOH, depicted by the negative sign.

Table 26: Regression coefficients of the ALK + Li based on the FF Resolution V.

Main Effects	**Coefficient**
CAPEX	+0.5950
OPEX	+0.2512
Battery capacity	-0.0988
Minimum Stable Load (MSL)	+0.1275
Electrolyser Efficiency	+1.0575

Two-way Interactions	**Coefficient**
CAPEX × OPEX	-0.0013
CAPEX × Battery capacity	+0.0037
CAPEX × MSL	-0.0125
CAPEX × Efficiency	+0.0825
OPEX × Battery capacity	–0.0025
OPEX × MSL	-0.0037
OPEX × Efficiency	+0.0313
Battery capacity × MSL	+0.0113
Battery capacity × Efficiency	-0.0137
MSL × Efficiency	+0.0200

The fractional factorial design does not have any degrees of freedom left with $R^2 = 1.0$. Therfore, the Pareto chart in Figure 27 is used to determine which parameters are left out of the regression model to increase the degrees of freedom. The five main effects are kept, together with the three interactive terms with the highest absolute effect on the LCOH. These are CAPEX:Efficiency (+0.0825), OPEX:Efficiency (+0.06313) and MSL:Efficiency (+0.0200). Notably, these interaction terms are all coupled with the electrolyser efficiency parameter.

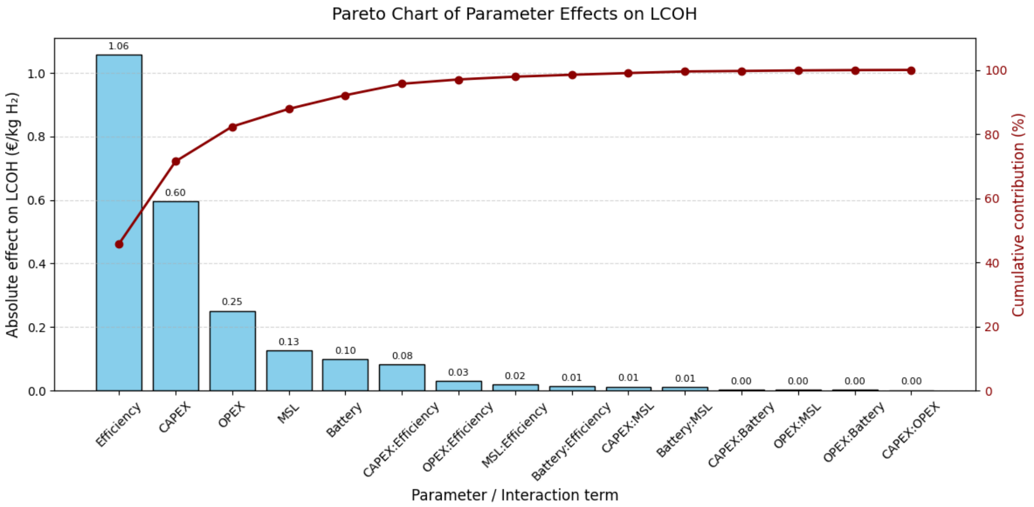


Figure 27: Pareto chart of the effect of the parameters on the LCOH of the ALK Li system.

A second regression model is fitted to the results with the eight kept parameters. The reduced model has a $R^2 = 0.999$, which means that 99.9% of the variation in LCOH is accounted for in the reduced regression model. P-values can now be investigated to assess the statistical significance of these parameters on the LCOH. Table 27 show the coefficients and p-values of the reduced regression model. A parameter is statistically significant if the p value is lower than 0.05. Evidently, all parameters are statistically significant, although the MSL:Efficiency interaction term is borderline significant.

Table 27: Regression coefficients and p-values of the ALK Li system based on the reduced FF Resolution V design.

Main Effect	Coefficient	P-value
CAPEX	+0.5950	0.000
OPEX	+0.2512	0.000
Battery capacity	–0.0988	0.000
Minimum Stable Load (MSL)	+0.1275	0.000
Electrolyser Efficiency	+1.0575	0.000

Two-way Interactions	Coefficient	P-value
CAPEX × Efficiency	+0.0825	0.000
MSL × Efficiency	+0.0200	0.051
OPEX × Efficiency	+0.0313	0.008

To sum up, increasing battery capacity results in a lower LCOH. The other parameters in the reduced regression model result in the worsening of the LCOH. All the main effects are statistically significant regarding the LCOH of the alkaline and lithium ion system. The three interaction terms are also statistically significant, while the MSL:Efficiency is borderline significant.

6.2.3 PEM and Li-ion System

A fractional factorial design has been performed for the PEM and lithium ion battery system. Similar to the previous analyses, the five parameters have been assigned high and low values. The CAPEX ranges between 340.1 and 440.1 million euros, as the base case corresponds to 390.1 million euros. The OPEX ranges between 22.5 and 26.5 million euros per year, and identical to the ALK and Li-ion systemm, the battery capacity ranges between 300 and 500 MWh. The minimum stable load ranges between 0% and 10% and the efficiency varies between 46 and 56 kWh/kgH_2. Equation (14) shows the regression formula that is fitted to the data set. The base case LCOH of the PEM and Li-ion system is 10.15 €/kgH_2, while the intercept term α_0 equals 10.25€/kgH_2.

$$\begin{aligned}\mathrm{LCOH} = \;& 10.25 + 0.62\,\mathrm{CAPEX} + 0.26\,\mathrm{OPEX} - 0.13\,\mathrm{BatteryCap} + 0.10\,\mathrm{MSL} + 1.00\,\mathrm{Eff} - 0.00\,\mathrm{CAPEX}\cdot\mathrm{OPEX} + 0.01\,\mathrm{CAPEX}\cdot\mathrm{BatteryCap} - 0.01\,\mathrm{CAPEX}\cdot\mathrm{MSL} \\ & + 0.09\,\mathrm{CAPEX}\cdot\mathrm{Eff} - 0.00\,\mathrm{OPEX}\cdot\mathrm{BatteryCap} - 0.00\,\mathrm{OPEX}\cdot\mathrm{MSL} + 0.04\,\mathrm{OPEX}\cdot\mathrm{Eff} + 0.01\,\mathrm{BatteryCap}\cdot\mathrm{MSL} - 0.02\,\mathrm{BatteryCap}\cdot\mathrm{Eff} + 0.02\,\mathrm{MSL}\cdot\mathrm{Eff}\end{aligned} \tag{14}$$

The regression coefficients are shown in Table 28 without the intercept. Similar to the previous analysis, all five main effects have a more significant contribution to the LCOH than the interaction terms, which is in line with the expectation. The electrolyser efficiency has the highest absolute contribution to the LOCH, followed by the CAPEX and OPEX. Similar to the alkaline and Li-ion system, an increase in battery capacity results in a reduced LCOH, which is indicated by the negative sign in the table.

Table 28: Regression coefficients of the PEM+ Li based on the FF Resolution V.

Main Effects	Coefficient
CAPEX	+0.6231
OPEX	+0.2644
Battery capacity	-0.1269
Minimum Stable Load (MSL)	+0.0994
Electrolyser Efficiency	+1.0006

Two-way Interactions	Coefficient	Two-way Interactions	Coefficient
CAPEX × OPEX	–0.0006	OPEX × MSL	–0.0019
CAPEX × Battery capacity	+0.0081	OPEX × Efficiency	+0.0369
CAPEX × MSL	–0.0106	Battery capacity × MSL	+0.0119
CAPEX × Efficiency	+0.0906	Battery capacity × Efficiency	–0.0169
OPEX × Battery capacity	–0.0006	MSL × Efficiency	+0.0194

Figure 28 shows the Pareto chart that is used to determine which parameters to keep, and which parameters to leave out of the reduced regression model. The five main effects are kept, as well as the following interaction terms: CAPEX:Efficiency, OPEX:Efficiency and MSL:Efficiency. These interaction terms are kept as they have the highest absolute contribution to the LOCH. The other interaction terms are not taken into account in the reduced regression model in order to create additional degrees of freedom.

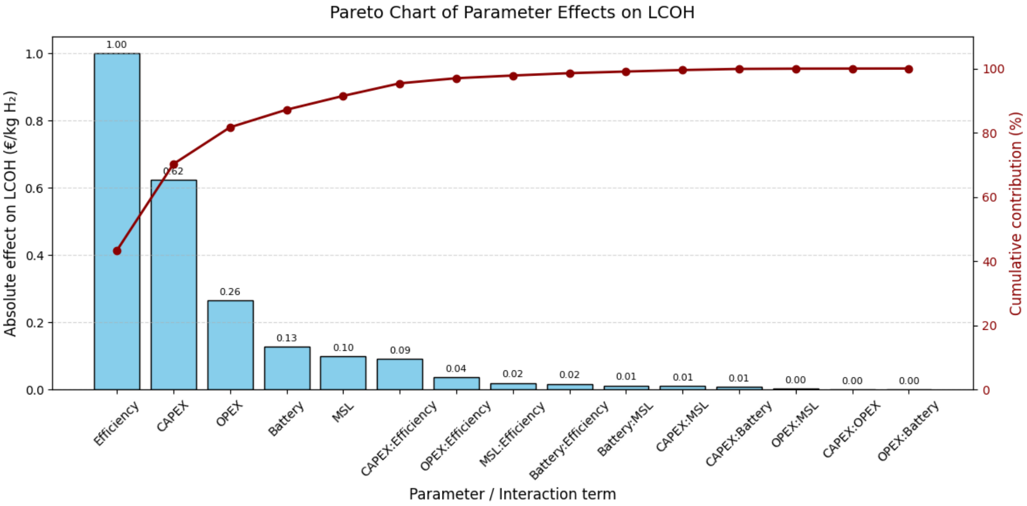


Figure 28: Pareto chart of the effect of the parameters on the LCOH of the PEM Li system.

A second regression model is fitted to the results with the eight kept parameters. The reduced model has a $R^2 = 0.999$, which means that 99.9% of the variation in LCOH is accounted for in the reduced regression model. P-values can now be investigated to assess the statistical significance of these parameters on the LCOH. Table 31 shows the coefficients and p-values for the reduced regression model. Similar to the alkaline system, the main effects are all statistically significant as the p-value is below 0.05. The CAPEX:Efficiency and OPEX:Efficiency interaction terms are also statistically significant. However, the MSL:Efficiency interaction term is not statistically significant, meaning that there is insufficient evidence to conclude that this parameter has a reliable or consistent effect on the LCOH.

Table 29: Regression coefficients and p-values of the PEM Li system based on the reduced FF Resolution V design.

Main Effect	**Coefficient**	**P-value**
CAPEX	+0.6231	0.000
OPEX	+0.2644	0.000
Battery capacity	–0.1269	0.000
Minimum Stable Load (MSL)	+0.0994	0.000
Electrolyser Efficiency	+1.0006	0.000

Two-way Interactions	**Coefficient**	**P-value**
CAPEX × Efficiency	+0.0906	0.000
MSL × Efficiency	+0.0194	0.076
OPEX × Efficiency	+0.0369	0.006

The regression analysis show similar results to the alkaline and lithium ion battery system. All five main effects are statistical significant with the electrolyser efficiency contributing the most to the LCOH, followed by the CAPEX and OPEX. Increasing the battery capacity results in a reduced LCOH. The interaction terms are also statistical significant except the MSL:Efficiency term, for which the p-value exceeds the 0.05 threshold.

6.2.4 Alkaline and Redox flow System

Just like the lithium-ion configurations, the redox flow configurations have been evaluated using a global sensitivity analysis. For the alkaline and redox flow system, the CAPEX varies by 100 million euros around the base case of 439 million euros, and the OPEX varies by 2 million euros around the base value of 26 million euros. Due to the larger battery capacity in redox flow systems, its variation is also greater (150 MWh) compared to the lithium-ion setup (100 MWh variation). The variation in the minimum stable load (MSL) is identical to that of the alkaline configuration, with a 7% range around the base value of 12%. Similarly, the electrolyser efficiency ranges between 45 and 55 kWh/kgH$_2$, consistent with the alkaline systems. The regression equation resulting from the global sensitivity analysis is shown in Equation (15). The base case LCOH is 11.31 €/kgH$_2$, while the intercept of the regression model is slightly higher at 11.36 €/kgH$_2$.

$$\begin{aligned}\mathrm{LCOH} = \;& 11.35 + 0.60\,\mathrm{CAPEX} + 0.25\,\mathrm{OPEX} - 0.06\,\mathrm{BatteryCap} + 0.09\,\mathrm{MSL} + 1.19\,\mathrm{Eff} - 0.00\,\mathrm{CAPEX}\cdot\mathrm{OPEX} + 0.00\,\mathrm{CAPEX}\cdot\mathrm{BatteryCap} - 0.01\,\mathrm{CAPEX}\cdot\mathrm{MSL} \\ & + 0.09\,\mathrm{CAPEX}\cdot\mathrm{Eff} - 0.00\,\mathrm{OPEX}\cdot\mathrm{BatteryCap} - 0.00\,\mathrm{OPEX}\cdot\mathrm{MSL} + 0.03\,\mathrm{OPEX}\cdot\mathrm{Eff} + 0.01\,\mathrm{BatteryCap}\cdot\mathrm{MSL} - 0.01\,\mathrm{BatteryCap}\cdot\mathrm{Eff} + 0.01\,\mathrm{MSL}\cdot\mathrm{Eff}\end{aligned} \tag{15}$$

Table 30 shows the regression coefficients without the intercept term. Similar to the other analyses, the main effects have a higher absolute contribution to the LCOH than the interaction terms. The electrolyser efficiency has the highest absolute contribution, followed by the CAPEX and the OPEX. The battery capacity has a negative coefficient, which means that a larger battery capacity reduces the LCOH, as expected.

Table 30: Regression coefficients of the ALK RF system

Main Effects	Coefficient	Two-way Interactions	Coefficient	Two-way Interactions	Coefficient
CAPEX	+0.5969	CAPEX × OPEX	–0.0019	OPEX × MSL	–0.0044
OPEX	+0.2519	CAPEX × Battery capacity	+0.0006	OPEX × Efficiency	+0.0344
Battery capacity	–0.0581	CAPEX × MSL	–0.0144	Battery capacity × MSL	+0.0081
Minimum Stable Load (MSL)	+0.0894	CAPEX × Efficiency	+0.0844	Battery capacity × Efficiency	–0.0106
Efficiency	+1.1931	OPEX × Battery capacity	–0.0044	MSL × Efficiency	+0.0119

The Pareto chart in Figure 29 is used to identify which parameters to keep in the reduced regression model. The five main effects, along with the three most significant interaction terms, are kept for the reduced regression formula. The interaction terms CAPEX:Efficiency, OPEX:Efficiency, and CAPEX:MSL are retained. Notably, the CAPEX:MSL interaction has a greater absolute effect on the LCOH than the Battery:Efficiency interaction term, which is in contrast to the previous results.

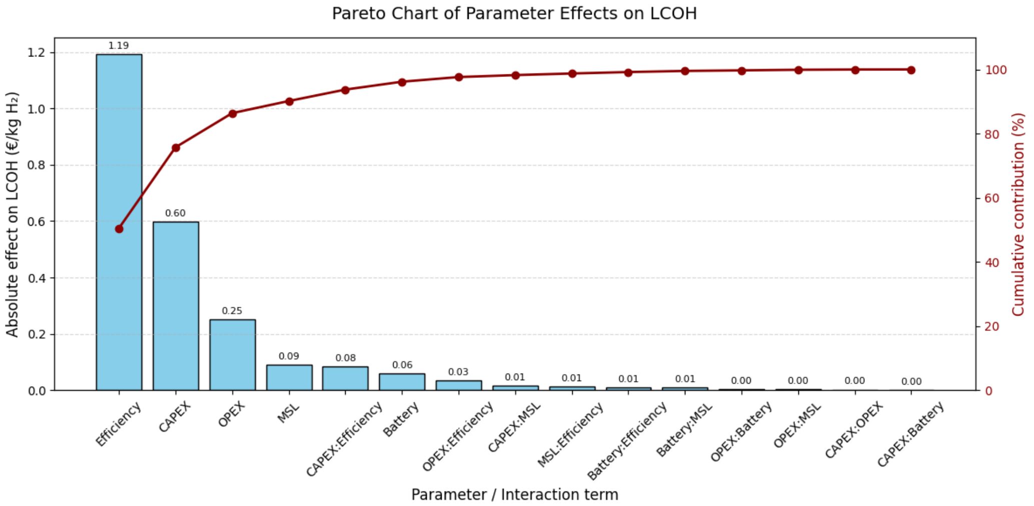


Figure 29: Pareto chart of the effect of the parameters on the LCOH of the ALK RF system.

Another regression model is fit to the results without the use of the seven weak interaction terms. This reduced model has $R^2 = 0.999$, meaning that 99.9% of the variation in LCOH can be explained by the model. This suggests that the removal of these terms has a negligible impact on the estimation of the LCOH, which is in line with the expectation.

Table 31: Regression coefficients and p-values of the ALK RF system based on the reduced FF Resolution V design.

Main Effect	Coefficient	P-value
CAPEX	+0.5969	0.000
OPEX	+0.2519	0.000
Battery capacity	–0.0581	0.000
Minimum Stable Load (MSL)	+0.0894	0.000
Efficiency	+1.1931	0.000

Two-way Interactions	Coefficient	P-value
CAPEX × Efficiency	+0.0844	0.000
OPEX × Efficiency	+0.0119	0.002
CAPEX × MSL	-0.0144	0.086

The regression analysis yields results consistent with the analysis of the previous systems. All five main effects are statistically significant, with electrolyser efficiency having the strongest influence on the LCOH, followed by CAPEX and OPEX. An increase in battery capacity leads to a lower LCOH, although its absolute impact is smaller than in the lithium-ion configurations. Most interaction terms are statistically significant, except for the CAPEX:MSL interaction, which has a p-value above the 0.05 threshold. Unlike earlier analyses, not all significant interaction terms in the ALK + RF system involve electrolyser efficiency.

6.2.5 PEM and Redox flow System

The final global sensitivity analysis is performed on the PEM and redox flow system. Similar to the other systems, the CAPEX ranges with plus and minus 50 million from the base value of 450.1 million euro. The OPEX varies with 2 million around 26.5 million euro, showing the highest OPEX value of the systems. Similar to the alkaline and redox flow system, the battery capacity ranges between 650 and 950 MWh. The minimum stable load set to 0% and 10% of the stack capacity. Finally, the efficiency varies between 46 and 56 kWh/kgH_2. Equation (16) shows the regression formula fitted to the data set. Similar to the other configurations, the intercept term α_0 is slightly higher than the base case LCOH of €11.14/kgH_2.

$$\begin{aligned}\mathrm{LCOH} = \; & 11.21 + 0.63\,\mathrm{CAPEX} + 0.26\,\mathrm{OPEX} - 0.08\,\mathrm{BatteryCap} + 0.08\,\mathrm{MSL} + 1.15\,\mathrm{Eff} - 0.00\,\mathrm{CAPEX}\cdot\mathrm{OPEX} + 0.00\,\mathrm{CAPEX}\cdot\mathrm{BatteryCap} - 0.01\,\mathrm{CAPEX}\cdot\mathrm{MSL} \\ & + 0.09\,\mathrm{CAPEX}\cdot\mathrm{Eff} - 0.00\,\mathrm{OPEX}\cdot\mathrm{BatteryCap} - 0.00\,\mathrm{OPEX}\cdot\mathrm{MSL} + 0.04\,\mathrm{OPEX}\cdot\mathrm{Eff} + 0.01\,\mathrm{BatteryCap}\cdot\mathrm{MSL} - 0.01\,\mathrm{BatteryCap}\cdot\mathrm{Eff} + 0.01\,\mathrm{MSL}\cdot\mathrm{Eff}\end{aligned} \tag{16}$$

Table 32 shows the regression coefficients of the formula, without the intercept term. The main effects show the highest absolute contribution to the LCOH variation. The electrolyser efficiency has the largest contribution, followed by the CAPEX and OPEX. As expected, the battery capacity has a negative influence on the LCOH, meaning that an increase in battery capacity leads to a reduction in the LCOH.

Table 32: Regression coefficients of the PEM RF system

Main Effects	**Coefficient**
CAPEX	+0.6263
OPEX	+0.2637
Battery capacity	–0.0763
Minimum Stable Load (MSL)	+0.0825
Efficiency	+1.1488

Two-way Interactions	**Coefficient**	**Two-way Interactions**	**Coefficient**
CAPEX × OPEX	–0.0025	OPEX × MSL	–0.0037
CAPEX × Battery capacity	+0.0025	OPEX × Efficiency	+0.0375
CAPEX × MSL	–0.0113	Battery capacity × MSL	+0.0063
CAPEX × Efficiency	+0.0925	Battery capacity × Efficiency	–0.0125
OPEX × Battery capacity	–0.0025	MSL × Efficiency	+0.0113

The Pareto chart in Figure 30 is used to reduce the number of coefficients and increase the degrees of freedom. The eight terms that are kept for the reduced regression analysis are the five main effects and the three highest contributors of the interaction terms. These are the CAPEX, OPEX and battery capacity terms in combination with the electrolyser efficiency.

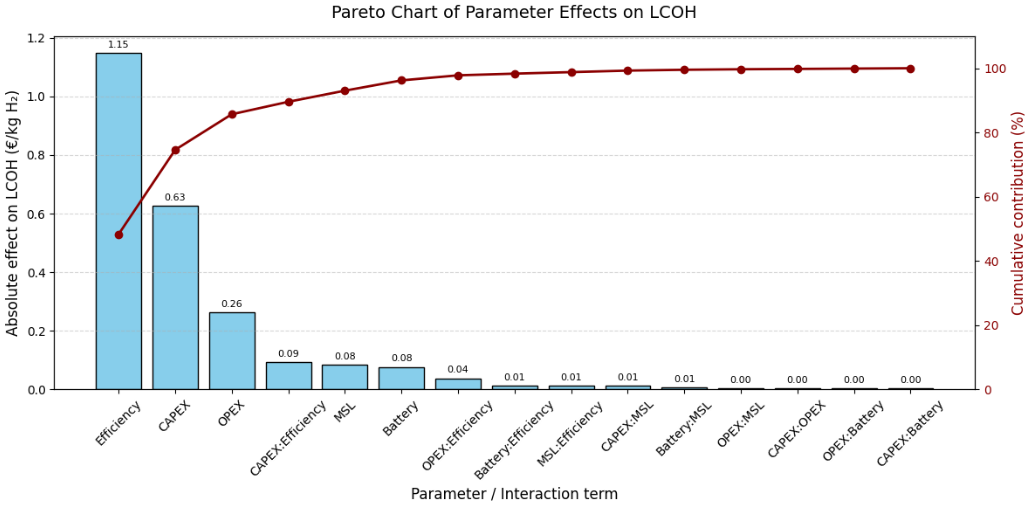


Figure 30: Pareto chart of the effect of the parameters on the LCOH of the PEM RF system.

The reduced regression formula has an $R^2 = 0.999$, meaning that 99.9% of the variation in LCOH can be explained with this reduced formula. Similar to the other systems, this indicates that the removal of the other interaction terms has a very small impact on the estimation of the LCOH. Table 33 shows the coefficients of the reduced regression model.

Table 33: Regression coefficients and p-values of the PEM RF system based on the reduced FF Resolution V design.

Main Effect	**Coefficient**	**P-value**
CAPEX	+0.6263	0.000
OPEX	+0.2637	0.000
Battery capacity	–0.0763	0.000
Minimum Stable Load (MSL)	+0.08925	0.000
Efficiency	+1.1488	0.000

Two-way Interactions	**Coefficient**	**P-value**
CAPEX × Efficiency	+0.0925	0.000
OPEX × Efficiency	+0.0375	0.001
Battery capacity × Efficiency	-0.0125	0.109

The table shows results consistent with previous systems. All main effects have statistical significance based on their p-values. However, the interaction between battery capacity and electrolyser efficiency is not statistically significant. Unlike the ALK + RF system, all significant interaction terms in this model are related to electrolyser efficiency. The absolute impact of battery capacity variation is similar to that seen in the alkaline and redox flow systems, and is lower than that seen in the lithium ion systems.

6.3 Scenario Analysis

Currently, the systems are modeled on renewable energy provided by a mix of solar and wind on land. This mix is based on the Eneco portfolio. However, the expansion of onshore wind energy is facing growing challenges in the Netherlands. As a result, onshore wind development has slowed, while offshore wind energy is experiencing significant growth. The Dutch government has set target to increase offshore wind capacity from 4.5 GW in 2025 to 21 GW by 2032, aiming to supply approximately 75% of the country's electricity demand from North Sea wind farms [138]. According to RED III, RFNBO compliant hydrogen requires renewable energy installations to be commissioned within 36 months prior to the electrolyser's operation. The combination of solar and wind on land provides a relatively constant power input towards the systems, with daily power peaks provided by the solar profile. Given the strong expected growth in offshore wind, it is therefore interesting to evaluate how the LCOH of the different systems behave when the system is powered solely by offshore wind.

Currently, the Levelised Cost of Electricity (LCOE) for offshore wind ranges between 90 and 100 €/MWh. However, Ørsted expects that the LCOE can be reduced to between 60 and 70 €/MWh by 2040 through joint efforts [8]. This projected cost reduction is shown in Figure 31. It is important to note that the LCOE represents the cost of producing electricity and does not necessarily reflect the PPA prices. Operators of offshore wind parks must also make a profit, meaning that PPA prices are expected to be higher than the LCOE. Since this thesis focuses on the period from 2030 to 2050, a reduction in electricity costs is expected, but the exact reduction remains uncertain. To account for this, several PPA price scenarios were modeled to assess their impact on the LCOH across the different system configurations.

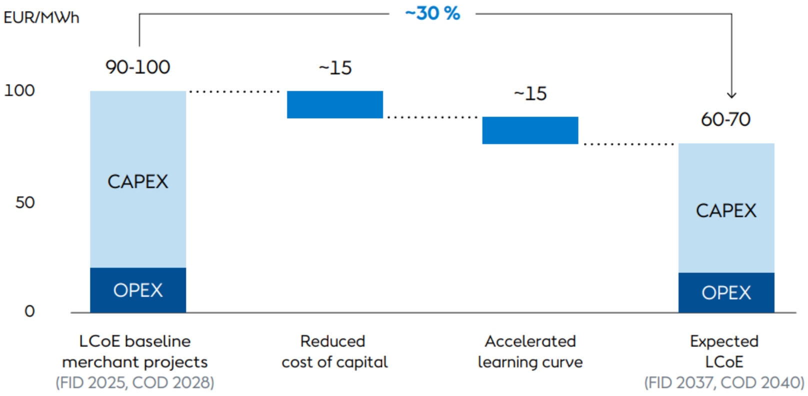


Figure 31: Cost reduction trajectory offshore wind.[8]

For this scenario, a hypothetic offshore wind farm is used as power input for the systems. An offshore power input curve is used from Eneco to simulate the power input of the hypothetical wind park. In order to ensure a fair comparison with the base scenario, the total electricity generation of the offshore wind park must match. The total electricity generation of the wind on land and solar PV parks in the base case scenario sum up to 7556347 MWh over the course of 18 years. By incorporating a compensating factor, the total electricity generation of the offshore wind park amounts to the same sum. Therefore, any variation in system performance will depend on the PPA price or the structure of the power profiles, such as intermittency and power peaks, as the total amount of generated electricity is identical.

Figure 32 depicts the LCOH of the systems for different PPA prices. The systems show different LCOH values based on the offshore wind profile in relation to the base case. However, the effect of the offshore power input differs per system. In the base case scenario, the contracted PPA prices are approximately 70 €/MWh. Compared to this scenario, the systems obtain similar or lower LCOHs depending on the system and PPA price. For instance, the LCOH of the alkaline and lithium ion system is identical for the base case with a PPA price of 75 €/MWh. The ALK + RF system performs slightly better, with an LCOH of 11.26 €/kgH$_2$ compared to 11.31 €/kgH$_2$ in the base case. Moreover, the Battolyser performs better with this PPA price, decreasing from 9.96 €/kgH$_2$ to 9.84 €/kgH$_2$. Conversely, the PEM systems perform slightly worse compared to the base case: the LCOH of the lithium ion system increases from 10.15 €/kgH$_2$ to 10.18 €/kgH$_2$, and from 11.14 €/kgH$_2$ to 11.17 €/kgH$_2$ for the redox flow system.

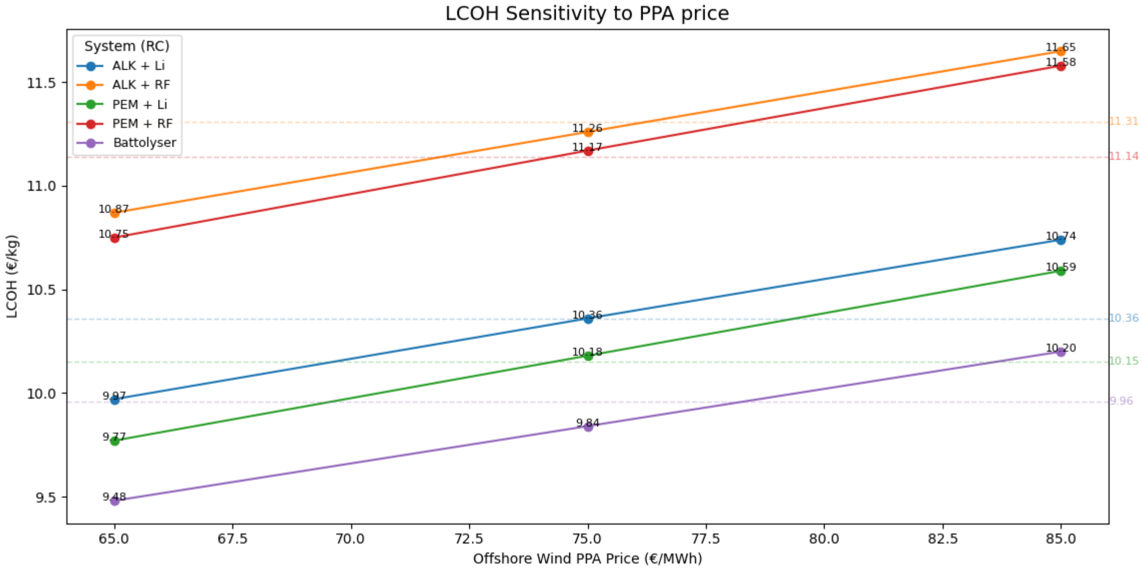


Figure 32: LCOH of the systems simulated with an offshore wind power profile with different PPA prices.

In addition, the hydrogen output increases for the Battolyser and for the alkaline systems, while the PEM systems decrease in RFNBO-compliant hydrogen output. For instance, Table 34 shows that the hydrogen output of the alkaline + Li-ion system increases slightly from 64.83 kiloton in the base case to 65.28 kiloton in the offshore wind scenario. The Battolyser shows a more significant increase, from 69.72 to 71.15 kiloton discounted hydrogen. In contrast, the PEM + Li-ion system shows a minor decrease from 61.72 to 61.52 kiloton of RFNBO-compliant hydrogen. The PEM + redox flow battery system shows a similar decrease. The arbitrage revenue increases significantly for all systems compared to the base case. The redox flow battery systems have the larges increase, where the discounted arbitrage revenue of the alkaline + RF system increases from €134.83 million to €150.35 million. Similarly, the PEM + RF system increases from €177.64 million to €192.88 million. Within the offshore wind scenario, the different PPA prices do not influence the operational strategies of the systems. Regardless of the price, the hydrogen production and arbitrage revenue remain almost identical for all the systems.

Table 34: Comparison of base case and offshore wind scenario.

System	**Discounted Arbitrage** [M€]		**Discounted H_2 Output** [kt]	
	Base Case	Offshore	Base Case	Offshore
ALK + Li-ion	141.16	153.24	64.83	65.29
ALK + RF	134.83	150.38	64.90	65.21
PEM + Li-ion	183.52	196.53	61.72	61.53
PEM + RF	177.64	192.77	61.71	61.38
Battolyser	91.67	94.99	69.72	71.15

Figure 33 shows the average daily power profile for each month. This means that the average daily power profile is shown for a month until the grey line, then the average day of the new month begins. The offshore wind profile (blue) is more stable and shows fewer extreme values compared to the more volatile onshore wind + solar PV profile (orange), which fluctuates strongly throughout the year, especially during the summer. The increased stability of offshore wind power may lead to more continuous hydrogen production, as seen in the Battolyser and alkaline systems. It can also create greater potential for arbitrage revenue when electricity prices are high. A more consistent PPA power input before hours with high electricity prices allows the battery to be charged in preparation for profitable resale.

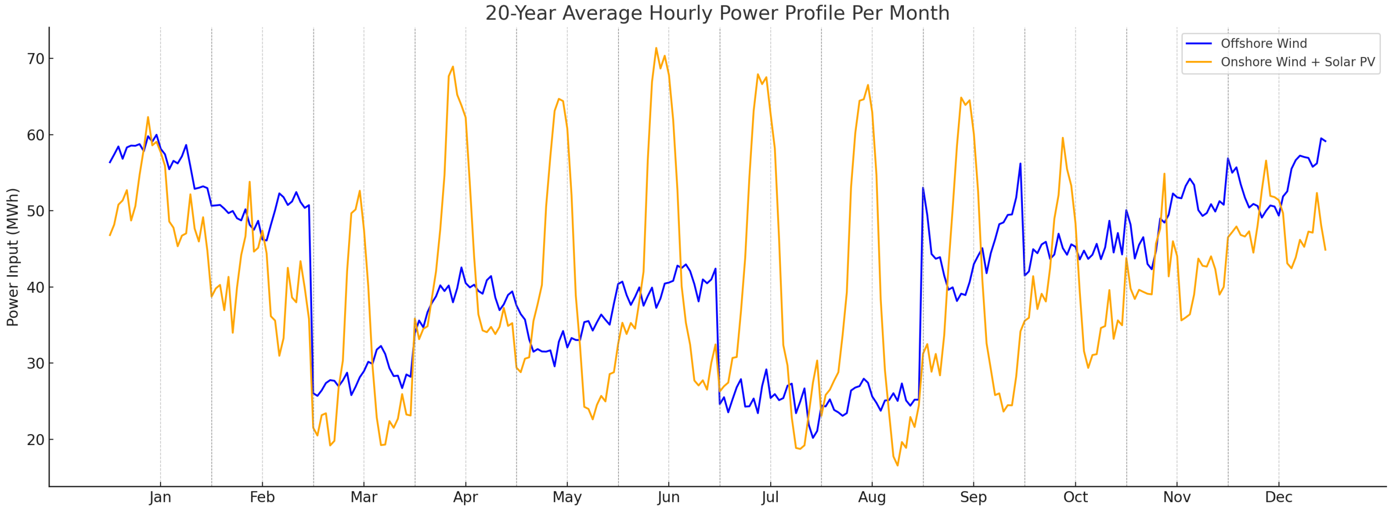


Figure 33: Average daily power profile for each month.

Overall, the Battolyser shows the most improvement in both hydrogen output and arbitrage revenue, whereas the systems with a redox flow battery benefit more from arbitrage opportunities. The PEM systems show a slight drop in hydrogen production. The relative ranking of the systems in terms of LCOH remains the same across all PPA price levels, with the Battolyser consistently performing best. Although offshore wind can improve performance, it does not change the performance order between configurations.

7 Discussion

This chapter discusses the main findings of the simulations performed in this master thesis. The LCOH is used as a key metric to evaluate system performance and compare the configurations. First, the preliminary results are discussed to provide an overview of how the different system setups perform under the base case assumptions. After that, the results of the local and global sensitivity analyses are discussed to evaluate how changes in input parameters affect the LCOH. This helps to identify which parameters are most important for each system and how sensitive the outcomes are to changes in electricity prices, CAPEX, efficiency, and other factors. Next, the chapter looks at a scenario where electricity comes from offshore wind to see how the systems perform under a different energy supply. The performance of the systems is then compared with that of standalone electrolysers. After this, the environmental effects of each system are discussed. The results are then brought together in a comparison section to show general patterns and differences across all systems and analyses. Finally, the assumptions used in the model are discussed, followed by a summary of the main contributions of this research. The chapter ends with recommendations for future work.

7.1 Interpretation of the Base Case Simulations

The base case results show differences in LCOH performance between the five system configurations. The Battolyser system results in the lowest LCOH at 9.96 €/kgH_2, followed by the PEM + Li-ion system at 10.15 €/kgH_2. The alkaline and Li-ion system achieves a LCOH of 10.36 €/kgH_2. In contrast, both redox flow systems result in significantly higher LCOH values, with the ALK + RF system reaching €11.31/kgH_2 and the PEM + RF reaching €11.14/kgH_2. The results show that the battery type has a significant influence on system economics, particularly through CAPEX, OPEX and arbitrage revenue.

The Battolyser system has the highest system efficiency (46.3 kWh/kgH_2), which increases hydrogen output and reduces the LCOH. In addition, the Battolyser does not require a minimum stable load (MSL), which allows the system to shut down during periods of high electricity prices with only consuming little power for BoP operation. This reduces both electricity costs and grey hydrogen production. These characteristics contribute to the lower LCOH of the Battolyser, despite its relatively modest arbitrage revenue compared to the ALK/PEM + Li-ion systems. The PEM + Li-ion system has a lower LCOH than the ALK + Li-ion system, likely because of the combination of greater operational flexibility and higher arbitrage revenue because the CAPEX and OPEX are higher than those of the alkaline system. This is supported by the lower grey hydrogen production and higher arbitrage revenue in the PEM case. The ALK system has a slightly higher capacity factor. This is the result of a more favorable electrolyser efficiency, but it can also suggest that alkaline electrolysers tend to operate more consistently over time, even when electricity prices are less favorable. This is directly related to the higher minimum stable load as this results in a higher hydrogen output, but also in increased electricity usage and grid costs. The PEM systems, in contrast, have lower hydrogen output but higher arbitrage potential due to the ability to better respond to price fluctuations. Moreover, due to the ability to produce pressurized hydrogen, the BoP power demand is lower than an alkaline electrolyser. Together with a lower minimum stable load, the PEM electrolyser has a higher operational flexibility which enables the system to better optimize for hydrogen production or arbitrage revenue. This additional flexibility seems to offset the higher CAPEX, OPEX and electrolyser efficiency compared to the alkaline electrolyser.

In addition, the capacity factor (C_f) provides insight into the overall operation of the electrolyser systems. The alkaline systems show slightly higher capacity factors (up to 73.2%) compared to PEM systems (around 70.6–70.9%). This difference is consistent with the higher total hydrogen output observed in alkaline configurations, while the Battolyser has a capacity factor of 72.0%. The narrow range of capacity factors (70–73%) in all systems shows that the power profile created by Eneco is well constructed. The slightly higher capacity factors in alkaline systems can be attributed to the lower operational flexibility and higher electrolyser efficiency, which leads to more continuous operation regardless of market conditions. This results in more total hydrogen production, but at the cost of reduced flexibility in acting on electricity prices. In contrast, PEM systems can better optimize revenue generation, resulting in more frequent operation at minimum stable load and, thus, lower overall capacity factors. The Battolyser offers the highest load range flexibility, however, due to its integrated stacks, it has lower arbitrage revenues. The capacity factor is often used as an indicator of system utilization where a higher capacity factor relates to more operation at nominal capacity. The original intention behind producing green hydrogen is to absorb excess renewable electricity that would otherwise be curtailed or lost. In general, a high capacity factor can also imply that the system is operating during periods when electricity is more carbon-intensive or less abundant, potentially drawing from fossil-based generation. This reduces the environmental benefit of hydrogen production and may conflict with RFNBO compliance objectives. A lower capacity factor can indicate that the electrolyser more closely follows the availability of renewable power, especially under a PPA with variable output, aligning with the original intention of producing green hydrogen using surplus renewable electricity. In this framework, the chosen PPA power input reflects a sustainable operational strategy, as hydrogen is produced primarily during periods of renewable availability.

Furthermore, the systems using redox flow batteries (ALK + RF and PEM + RF) perform the worst in terms of LCOH. Although redox flow batteries have larger storage capacities and lower degradation over time, it shows that these benefits do not compensate for their higher CAPEX and lower round-trip efficiency. The results show that a larger battery capacity does not necessarily lead to higher arbitrage revenue in this scenario. Redox flow batteries have larger energy storage capacities, however, the simulation results show that arbitrage revenue from redox systems are lower than those from lithium-ion batteries in the base case. This counterintuitive result could be explained by a limitation in the model. As all the systems have a grid limitation, the advantage of a redox flow battery lies in the ability to discharge for a longer period of time. However, the additional storage capacity can remain underutilized in the short horizon. While the RF battery is able to fully discharge in 8 hours, the horizon only looks at 3 hours in advance. Together with a lower round trip efficiency, this could explain why lithium-ion batteries appear to outperform redox flow batteries.

Overall, the results suggest that lithium-ion batteries are the more cost-effective option in a grid-connected setup under current assumptions because of their lower cost and sufficient arbitrage potential. Redox flow batteries may be more suitable in systems where long-duration storage is more valuable. The Battolyser stands out due to its high efficiency and integrated design, which increases hydrogen and reduces the LCOH. However, its lower arbitrage revenue suggests that the integrated nature of the system limits its flexibility in allocating power solely for arbitrage purposes.

It is important to note that these results are based on point value assumptions for parameters such as CAPEX, OPEX, and efficiency. In reality, these parameters are uncertain due to technological advances, market fluctuations, and regional differences. For example, the data sets provided by Eneco are continuously updated as new information becomes available. However, the systems are evaluated using a fixed power input profile and electricity price forecast. As a result, the reported LCOH values represent specific conditions. While these values provide a useful baseline for comparison, some of the observed differences, especially those within a few tenths of a euro per kilogram, should be interpreted with caution. Small variations in LCOH may not be practically meaningful when parameter uncertainty is taken into account.

7.2 Local Sensitivity Analysis

The first local sensitivity analysis is used to validate the functionality of the model. The increase in CAPEX and OPEX yields an increase in LCOH for all the systems, as expected. This validates that the model correctly deals with price changes in the simulations. The percentage based variations in costs are correctly translated to the model, as systems with a higher initial CAPEX benefit more from a percentage based reduction, due to a larger absolute cost reduction. Moreover, when comparing CAPEX and OPEX sensitivity, it becomes clear that OPEX changes have a much greater impact on LCOH than equivalent CAPEX changes. This suggests that reducing ongoing operational costs could be more effective in lowering hydrogen production costs than reducing upfront investments.

The results of the second local sensitivity analysis show important insights into how each system configuration responds to fluctuations in electricity prices. As expected, lower electricity prices lead to lower LCOH values across all systems, while higher prices result in increased LCOHs. However, the degree to which each system is affected varies significantly.

The Battolyser shows the largest LCOH variation across scenarios, with a spread of 2.21 €/kgH$_2$. This high sensitivity indicates that its LCOH performance is strongly related to the electricity prices. The Battolyser benefits the most from low electricity prices due to its high hydrogen conversion efficiency of 46.3 kWh/kgH$_2$ and the ability to turn to standby mode during high-price hours. However, the Battolyser is shown to be vulnerable to a higher and larger electricity price spread because the Battolyser cannot decouple the operation of the battery and the electrolyser due to the integrated design. The integrated stacks ensure that hydrogen generation and battery charging always occur simultaneously when the state of charge is below 100%. This limits the system's ability to fully exploit price fluctuations, as it lacks the flexibility to prioritize one operational mode over the other. In contrast, the alkaline and PEM configurations are co-located systems that have separate batteries. This allows the systems to allocate power either to hydrogen production or battery (dis)charging, based on the electricity prices. When the spread in electricity prices is large, the PEM + Li-ion system can take full advantage of this flexibility by dynamically shifting its operation. For example, the system can produce hydrogen at nominal capacity during one hour, switch to battery discharging the next hour when electricity prices are high, and then switch back to hydrogen production at nominal capacity. This level of operational decoupling allows the system to optimize revenue streams from both hydrogen production and electricity arbitrage independently. In addition, the data shows that arbitrage revenue increases across all systems as electricity prices rise, but the scale of this increase differs per system. The battery capacity in the co-located systems is decoupled from the electrolyser stack size, in contrast to the Battolyser. This contributes to the higher arbitrage revenues observed in the PEM and alkaline systems compared to the Battolyser. In all the scenarios, the lithium ion battery outperforms the redox flow battery in terms of arbitrage revenue. This can be attributed to the larger round trip efficiency. This indicates that a larger battery capacity does not result in more arbitrage revenue in this framework. Chapter 7.8 will further discuss the impact of the model.

Another important factor influencing system response is the minimum stable load (MSL) of the electrolyser. The alkaline systems operate with an MSL of 12%, the PEM systems with 5%, and the Battolyser with 0%. A lower MSL allows the electrolyser to minimize power consumption from the grid during high-price hours. This flexibility specifically benefits the PEM + Li-ion system. In this configuration, the LCOH experiences a modest increase as electricity prices increase. The PEM systems show the smallest variation, with a range of 0.94 €/kgH$_2$ for the Li-ion setup and 1.22 €/kgH$_2$ for the redox flow configuration. The stability in LCOH for the PEM systems likely stems from their higher operational flexibility as a result of the lower minimum stable load, which allows them to better adapt to changing market conditions without significant decrease hydrogen production. The alkaline systems, which have a higher MSL, experience a larger LCOH increase under higher electricity prices, with a range of 1.40 €/kgH$_2$ for the Li-ion configuration and 1.64 €/kgH$_2$ for the redox flow configuration. They are more sensitive than PEM systems but less so than the Battolyser. This ensures that the alkaline + RF system outperforms the PEM + RF system in the reduced electricity price scenario. Moreover, the PEM electrolyser and Battolyser produce pressurised hydrogen, in contrast to the alkaline electrolyser, which decreases their minimum BoP power demand and contributes to the flexibility. Although the Battolyser has a MSL of 0%, the LCOH of the system rises significantly, with an LCOH range of 2.21 €/kgH$_2$. This indicates that although the MSL proves to be an important factor in the resilience against electricity prices, the decoupling nature of the co-located scenarios provide an advantage when electricity prices increase. This is confirmed by the fact that while the Battolyser has similar CAPEX structure as the PEM + Li-ion system, the LCOHs of the system do not respond in a similar way. This can be attributed to the higher arbitrage revenue of the PEM system, as the hydrogen production is approximately the same for both systems.

Overall, this sensitivity analysis shows that the Battolyser performs best under favorable price conditions but performs significantly worse with increased electricity prices. This is in contrast to the PEM systems as they experience less sensitivity and more predictable performance. These findings also show the importance of flexibility in terms of BoP power demand and MSL, since increased flexibility results in less variation in LCOH. More importantly, regardless of the system, LCOH performance is significantly sensitive to electricity market conditions.

7.3 Global Sensitivity Analysis

The fractional factorial design is an efficient method to estimate the influence of key parameters on the LCOH. However, the FF design assumes that the interactions are linear. This means the model captures only main effects and selected two-way interactions, and ignores potential nonlinear or higher-order effects. For this reason, the regression model should be used for estimating LCOH within the defined parameter range and not extrapolated beyond it. It is important to note that the absolute size of each regression coefficient is influenced by the range selected for each parameter in the design.

7.3.1 Battolyser

For the Battolyser, electrolyser efficiency has the strongest influence on the LCOH (+1.2975). This is expected as better efficiency also increases total hydrogen output, which reduces the LCOH by spreading fixed costs like CAPEX and OPEX over more hydrogen. This is shown in the unit of the LCOH, which is €/kgH$_2$. Interestingly, the battery capacity shows a positive coefficient (+0.1137), indicating that a larger battery increases the LCOH. This can be explained by the way electricity is allocated between hydrogen production and battery charging. A larger storage capacity causes the state of charge to rise more slowly, as the power rating stays identical. In the Battolyser system, the power allocation depends on the state of charge of the system. This means that a slower change in SOC reduces power allocated to the electrolyser, lowering hydrogen production. Because all system costs are divided by the total hydrogen output, hydrogen production can significantly increase the LCOH.

The main effect of the MSL (+0.0250) was found to be statistically insignificant in the reduced model ($p = 0.357$). The parameter range used in the design was limited to 0%–5%, which may not fully reflect the impact MSL can have on the system. Additionally, since the base case already included the lower bound (0%), the FF design does not account for scenarios where MSL could decrease and increase significantly. Even though the model suggests that the MSL has limited influence on LCOH, a difference should be made in statistical relevance and practical relevance. In real-world implementations, MSL constraints can strongly influence how an electrolyser can respond to electricity prices. Although the current model suggests limited influence within the narrow range used, the importance of MSL may be underestimated, and a further analysis or expanded parameter range would be required to fully assess the effect of varying the MSL.

Moreover, all two-way interaction terms that were kept because of the absolute effect on the LCOH, involve the electrolyser efficiency parameter. Since efficiency in this model is expressed in kWh/kgH$_2$, a higher value (+1) reflects a lower-performing electrolyser. The positive coefficients of these interaction terms, therefore, indicate that a worse efficiency increases the negative impact of other parameters on the LCOH. For example, the interaction between CAPEX and efficiency (+0.1163) suggests that capital costs have a more significant effect when the electrolyser is less efficient. Similar results are found for the OPEX in combination with electrolyser efficiency (+0.0638). Similarly, the interactions with battery capacity and OPEX (+0.1025) show that both the negative effects associated with storage capacity and operational costs worsen in combination with a less beneficial electrolyser efficiency. These results again suggest that the electrolyser efficiency has a significant influence on the LCOH. This is not only for its direct impact on energy consumption and hydrogen output, but also since all system costs are divided by the total hydrogen output.

7.3.2 Alkaline and Li-ion System

The fractional factorial design has also been performed for the ALK + Li-ion system. The intercept of the regression model (10.44 EUR/kgH$_2$) represents the predicted LCOH when all five parameters are set at their nominal values. This means that if all the parameters are set at 0 instead of -1 or +1, the intercept will correspond to the center of the model. In this case, the actual simulated LCOH at the base-case is 10.36 EUR/kgH$_2$, resulting in a small variation of 0.08 EUR/kgH$_2$ compared to the model's α_0. This difference can be explained by several factors that are associated with the fractional factorial design and regression model. First, the regression model is based on a linear approximation of the system. If the parameters do not have a completely linear relationship with the LCOH, the non-linearity will not be captured in this design. As a result, the intercept determined by the model may not perfectly match the actual center LCOH from the base case. Second, the intercept in a Resolution V fractional factorial design is aliased with the five-factor interaction term. The high-order interactions are assumed negligible, however, they are not necessarily zero. Even a small non-zero five-way interaction can result in an intercept that is biased. In addition, the aliasing between two- and three-factor interactions may also play a role in the offset. If the three-way interactions have some influence, they can slightly affect the two-way interaction estimates, which in turn can shift the intercept as well.

For the alkaline and lithium-ion system, electrolyser efficiency again has the strongest influence on the LCOH, as reflected by the largest main effect coefficient (+1.0575). This is expected, since a more efficient electrolyser produces more hydrogen per unit of electricity consumed. Additionally, because the LCOH is calculated in EUR/kgH$_2$, improvements in hydrogen output also spread the costs across a larger production volume, resulting in a lower LCOH. In contrast to the Battolyser system, the battery capacity has a negative main effect in this case (–0.0988), meaning that increasing the battery size results in a lower LCOH. This is in line with the expectation, as a larger battery capacity enables the system to charge and discharge more energy. In contrast to the

Battolyser, the battery and electrolyser stacks are not the same, meaning that the hydrogen production and battery charging are not inherently connected with each other. This additional operational flexibility enables the system to generate more revenue with an increased capacity. The MSL shows a positive coefficient (+0.1275), indicating that a higher MSL increases the LCOH. This aligns with expectations, since a higher MSL restricts the flexibility of the electrolyser and limits its ability to reduce power offtake during moments with high electricity prices. However, unlike in the Battolyser system, the MSL effect is statistically significant in this model (p = 0.000). This can be explained by the wider parameter range (5–19%) used in the FF design, which better captures the change in performance.

All three interaction terms in the reduced model again involve the electrolyser efficiency. This in line with the Battolyser and stresses the fact that efficiency not only has a large impact on its own, but also in combination the effects of other parameters. The coefficient between CAPEX and efficiency (+0.0825) indicates that high CAPEX together with a unfavorable efficiency have a larger impact than the parameters individually. The same holds for the OPEX and Efficiency interaction term (+0.0313). The MSL and Efficiency interaction (+0.0200) is borderline significant (p = 0.051). However, it suggests that a high MSL becomes more costly when the system is also inefficient.

7.3.3 PEM and Li-ion System

For the PEM and Li-ion system, the regression results show that the electrolyser efficiency has the strongest influence on the LCOH (+1.0006). As in the other systems, this is expected because higher efficiency leads to greater hydrogen output for a given energy input, thereby lowering the LCOH. Battery capacity again shows a negative regression coefficient (-0.1269), meaning that increasing the size of the battery leads to a reduction in the LCOH. This finding aligns with the result from the alkaline and Li-ion system and is in contrast with the Battolyser system, where a larger battery increased the LCOH. The influence of MSL is positive (+0.0994), suggesting that a higher MSL increases the LCOH. This result expected as a higher MSL reduces the operational flexibility and forces the electrolyser to draw more power from the grid when this is unfavorable.

All three kept interaction terms involve the electrolyser efficiency, which again highlights the role of electrolyser efficiency in determining the LOCH. The statistically significant interaction between CAPEX and efficiency (+0.0906) indicates that the cost impact of the CAPEX is strengthened when the electrolyser has a worse efficiency. A similar result can be found in the OPEX and Efficiency interaction (+0.0369) where the operational costs contribute more heavily to the LCOH when efficiency is low. These interaction effects show that efficiency not only has a large direct effect on the LCOH, but also strenghten the influence of other parameters in combination. The interaction between MSL and electrolyser efficiency (+0.0194) is not statistically significant in this case.

Finally, the order of the main effects has changed in relation to the alkaline and lithium ion system. In the previous system, the MSL had a larger absolute effect on the LCOH than the battery capacity. In the PEM + Li-ion system, the order of these absolute effects are reversed. This could be attributed to the different size in BoP power demand and/or the different range in MSL variation for the fractional factorial design. Moreover, the interaction term α_0 is not identical to the LCOH of the base case. This can be explained by the fact that the intercept term is aliased with a higher order term. Although it is assumed that these are negligible, it shows that this assumption does not always hold.

7.3.4 Alkaline and Redox flow System

The regression results for the ALK + RF configuration show that the electrolyser efficiency is the most influential factor on LCOH (+0.1931). CAPEX and OPEX also have significant influence on LCOH, with the CAPEX coefficient (+0.5969) more than double that of OPEX (+0.2519). The Minimum Stable Load (MSL) also shows a significant positive coefficient (+0.0894), indicating that increasing MSL negatively impacts cost performance by limiting the electrolyser's ability to reduce grid offtake during high-price periods. The battery capacity in the ALK + RF system has a negative effect on LCOH, meaning that increased storage reduces hydrogen costs. This aligns with expectations, as co-located systems can independently optimize battery operation and hydrogen production. However, the absolute effect of battery capacity is smaller than in the lithium-ion configuration. This is possibly the result from the under-utilization of the long-duration advantage of the redox flow battery, caused by the limited 3-hour MPC horizon. This model might limit the added value of the RF battery, which will be further discussed in Chapter 7.8.

Interestingly, the interaction terms retained in the reduced model are not all linked to efficiency, unlike in previous configurations. The interaction between CAPEX/OPEX and efficiency was found to be statistically significant, suggesting that the cost sensitivity increases when efficiency is lower. This shows that the cost-effectiveness of the system depends on how well the electrolyser performs. However, the additional inclusion of the CAPEX and MSL interaction term is not statistically significant (p = 0.086), meaning that no conclusions can be drawn from this.

Finally, the intercept term of the regression model is estimated slightly higher than the LCOH in the base case. This can be explained by the fact that the terms in the regression formula are aliased with higher order terms, which are assumed to be zero. The differing intercept indicates that this assumption does not fully hold in this case, and that some aliasing with higher-order terms may be influencing the intercept estimate.

7.3.5 PEM and Redox Flow System

The regression results for the PEM + RF configuration again identify electrolyser efficiency as the most influential factor on the LCOH with an absolute contribution of +1.1488. CAPEX and OPEX are also significant contributors, with CAPEX (+0.6263) showing a stronger influence than OPEX (+0.2637), consistent with trends observed in the other system configurations. The Minimum Stable Load (MSL) shows a moderate effect on LCOH (+0.0825), suggesting that higher minimum operating constraints reduce system flexibility and thereby increase hydrogen production costs. The battery capacity shows a negative influence on LCOH (-0.0763), indicating more arbitrage revenue with increased energy storage. However, the magnitude of this effect is relatively small compared to other main effects in this system.

The interaction terms involving efficiency are statistically significant, such as CAPEX and Efficiency ((+0.0925) and OPEX and Efficiency (+0.0375). This shows that high CAPEX or OPEX has a more pronounced impact when efficiency is lower. Among the terms retained in the reduced regression model, the Battery Capacity and Efficiency interaction term is not statistically significant ($p = 0.109$). This indicates that the interaction between storage size and electrolyser performance does not consistently influence cost outcomes within the studied range. Notably, all statistically significant interaction terms in this configuration involve efficiency.

Lastly, the intercept term is slightly higher than the base-case LCOH of €11.14/kgH_2, which can again be explained by aliasing effects. The regression assumes higher-order terms are negligible, however, the deviation in the intercept suggests some degree of interaction with higher-order terms may be present.

7.3.6 Cross-System Trends

Across all system configurations, several trends become evident from the global sensitivity analysis. The most obvious trend is the dominant role of electrolyser efficiency in determining the LCOH. In all systems, efficiency is the largest main effect and appears in every statistically significant interaction term in the reduced regression model. This highlights that efficiency not only directly reduces electricity consumption and increases hydrogen output but also strengthens the influence of other parameters like CAPEX, OPEX, and MSL when performance is suboptimal. CAPEX and OPEX also have significant impact on LCOH across the systems. The absolute influence of the battery capacity and MSL is significantly lower, indicating that while they contribute to cost optimization, their impact is less significant compared to the electrolyser efficiency and cost components. This global analysis suggests that improvements in efficiency, capital investment, and operational expenditures should be prioritized, while battery sizing and MSL flexibility play less distinctive roles in reducing LCOH.

Battery capacity shows contrasting effects depending on the system design. In the Battolyser, increasing battery size raises the LCOH. This is because a larger battery takes longer to reach full charge, resulting in smaller changes in state of charge and thus less power direction towards hydrogen production. In contrast, in co-located systems, the battery capacity has a small LCOH reducing effect. Larger batteries in these systems improve arbitrage revenue without directly reducing hydrogen production, resulting in a slight improvement in LCOH. The absolute effect on the LCOH varies with battery type, where the lithium-ion batteries have a slightly larger influence.

The minimum stable load (MSL) also has a consistent but system varying impact on LCOH. In all systems, a higher MSL increases the LCOH by reducing flexibility and forcing the system to consume power even when prices are unfavorable. However, the statistical significance of this main effect depends on the parameter range. In the Battolyser, where MSL varies between 0%–5%, the effect was statistically insignificant. In contrast, in the co-located systems where MSL had a larger range, the effect was both stronger and statistically significant. This suggests that while MSL is relevant operationally, its statistical significance can depend on the chosen parameter range.

Finally, the intercept term of the regression model, which predicts LCOH at nominal parameter values, consistently overestimates the actual simulated base-case LCOH. This small bias (typically less than 0.1 €/kgH_2) can be explained by the aliasing of higher-order interaction terms and the linear assumptions of the fractional factorial design. This shows that the fitted regression model should not be trusted blindly, and further investigation is needed. Nevertheless, the regression model remains a valid estimation tool.

7.3.7 Influence of Parameter Ranges on Results

In a fractional factorial design, the regression coefficients represent the relative impact of a parameter across its defined range. This means that the sensitivity of a parameter is not only determined by its physical or economic significance but also by the magnitude of the variation range. A wider range results in a larger influence on the output, while a narrower range reduces this.

Electrolyser efficiency consistently shows to be the most influential parameter in all systems. The range assigned to efficiency varies slightly between systems. In the Battolyser configuration, the efficiency varies from 41.3 to 51.3 kWh/kgH_2, with a midpoint of 46.3 kWh/kgH_2. This corresponds to a relative variation of approximately 10.8%. The lower bound is very optimistic, approaching the thermodynamic minimum of around 39.4 kWh/kgH_2, and represents a scenario that may not be practically achievable. For the alkaline systems, the efficiency range is chosen between 45 to 55 kWh/kgH_2, which translates to a variation of approximately 10%. This is a realistic range as this captures both current alkaline electrolyser performance and possible improvements. In the PEM-based systems, the efficiency range is set between 46 and 56 kWh/kgH_2, with a midpoint of 51, resulting in a variation of approximately 9.8%. While all three electrolyser types show high sensitivity to efficiency, the Battolyser's slightly wider and more optimistic range leads to a higher regression coefficient. This indicates that the dominance of electrolyser efficiency in the model is not only due to its economic relevance but also due to the width of the range.

The other parameters have similar percentage variations, although their influence in the regression models appears to be lower. CAPEX, for instance, varies by 50 million euros across different systems. In the Battolyser, the base value is 389.4 million euros, leading to a relative variation of around approximately 12.8%. For the PEM and alkaline systems, the base CAPEX is between 390 and 450 million euros, resulting in variations between approximately 11% and 13%. The OPEX range is a bit smaller as it varies by 2 million euros around base values of 22 to 26.5 million euros. This corresponds to a relative variation of about 7.5% to 9.1%. Battery capacity shows more variation depending on the system. In the Battolyser, the range is 75 to 105 MWh with a base value of 90 MWh, giving a relative variation of 16.7%. For the lithium-ion batteries, the capacity ranges from 300 to 500 MWh which is a 25% variation. Redox flow systems vary between 650 and 950 MWh, resulting in a relative change of approximately 18.75%. Despite these relatively large ranges, the influence of battery capacity on the LCOH remains moderate, indicating that the effect of battery sizing is limited on the LCOH. This is in contrast to OPEX for instance, where the smaller range still indicates a large effect on LCOH. Finally, the minimum stable load (MSL) parameter is physically constrained at the lower bound of 0%. For the alkaline electrolyser, the 5%–19% range is centered around 12%, resulting in a variation of 58%. For the PEM electrolyser, the MSL ranges between 0% and 10%, while the Battolyser has a range of only 5%. Regardless of the larger percentile difference, the impact of the MSL on LCOH is shown to be smaller.

To sum up, the sensitivity results are both determined by their technological or economic influence as the parameter ranges defined in the fractional factorial design. A broader range naturally results in a stronger apparent effect on the LCOH, while a narrower range limits the influence. The ranges used in this analysis were selected based on practical considerations in consultation with experts from Eneco, with the goal to assess the sensitivity on the systems. These ranges do not necessarily reflect precise forecasts but are also designed to explore the system's sensitivity. For instance, in the Battolyser system, the efficiency range from 41.3 to 51.3 kWh/kgH_2 includes a lower bound that is close to the theoretical limit. Although this may not be achievable, it is valuable to explore how strongly system economics respond to efficiency improvements over time, as the LCOH can be estimated when efficiencies approach best-case potential. However, it is important to note that a different selection of ranges could shift the balance between parameters. Therefore, the results should be interpreted in combination with other insights from this study.

7.4 Scenario Analysis

The scenario analysis is used to investigate whether the systems behave differently under varying power input profiles, and what would cause the potential change. The LCOH, hydrogen production, and arbitrage revenue from the base case are compared to the results obtained from the offshore wind scenario. The total generated energy over the 18 years has been kept constant between the scenarios to ensure that the differences in LCOH are the result of the characteristics of the power profiles.

For a similar PPA price, both the Battolyser and alkaline electrolyser systems show similar or improved performance in terms of LCOH compared to the base case. In contrast, the PEM electrolyser systems perform slightly worse under the same conditions. This contrast in performance can probably be attributed to the structure of the offshore wind profile, which offers a more stable and consistent power supply. In the base case more intermittent renewable sources such as onshore wind and solar PV are used, meaning that the operational flexibility of the PEM electrolyser provides a significant advantage. However, with offshore wind, the steadier power profile reduces the need for this level of flexibility. As a result, the efficiency of the electrolyser becomes a more influential factor in determining the overall LCOH. Since alkaline and Battolyser systems have a better efficiency than PEM systems, they benefit more from the stable offshore wind supply. In addition, the Battolyser shows the most significant improvement across all metrics. The hydrogen output increases from 69.72 to 71.15 kiloton and depending on the PPA price, the LCOH reduces compared to the base case. Moreover, the discounted arbitrage revenue increases from 91.67 million euros to 94.99 million euros over the lifetime. The alkaline systems also show slight improvements in hydrogen output and LCOH. The alkaline + Li-ion system, performs almost identical in terms of LCOH compared to the base case at 75 €/MWh PPA pricing. Similar to the Battolyser, the offshore wind profile results in a slight increase in hydrogen production. The same holds for the arbitrage revenue, as this is increased for all the systems. In contrast, the PEM systems have a slight decrease in hydrogen output under the offshore wind profile. As discussed in Chapter 4.5, the conversion price at which it becomes more profitable to sell electricity instead of producing hydrogen, is influenced by the electrolyser efficiency. The PEM electrolyser operates with a less favorable efficiency, meaning that the system reaches the lower conversion price for favoring electricity resale sooner than the other systems. This could explain why the MPC opts for electricity resale in PEM-based systems, whereas hydrogen production is more favorable for the other systems under similar conditions. In addition, Figure 33 shows that the average PPA input is higher during the winter months. During these months, the electricity prices are on average higher, which explains the increase in arbitrage revenue across all systems.

The battery type also plays a role in system performance in terms of arbitrage. Systems with a redox flow batteries see the largest increases in arbitrage revenue across all configurations. For example, the alkaline + redox flow system discounted arbitrage revenue increases from €134.83 million to €150.35 million. This is likely due to the larger capacity of the redox flow battery, allowing them to store and sell larger amounts of electricity. In comparison, lithium-ion systems have less significant gains due to their limited capacity. However, the increased arbitrage revenue does not result in a more favorable LCOH compared to the lithium ion systems.

Whether offshore wind is a more favorable energy source compared to a mix of onshore wind and solar depends on the PPA price. The base case assumes a PPA price of approximately 70 €/MWh. At this price level, the systems perform better when powered by offshore wind, due to the increased power stability. This suggests that the systems perform more efficiently when powered solely by offshore wind, compared to a combination of onshore wind and solar energy. This can be explained due to the higher and more consistent capacity factors of offshore wind farms. Offshore wind typically achieves capacity factors between 45% and 60%, whereas onshore wind and solar PV in the Netherlands average around 25–35% and 10–15% [139, 140]. A higher capacity factor allows the electrolyser systems to operate more consistently near their design capacity, which significantly improves hydrogen production and lowers the LCOH. As noted earlier, system efficiency is higher at nominal capacity due to the relatively constant power demand of the BoP components. In contrast, the combination of onshore wind and solar results in more variable power supply, especially at night or during periods of low wind, leading to partial-load operation or grey hydrogen production. While this is beneficial for battery operation, hydrogen production reduces as power is used to set the system up for arbitrage. Additionally, offshore wind profiles have fewer extreme low-wind periods compared to onshore wind, resulting in a more stable power input to the systems [141]. As Ørsted projects, offshore wind LCOE may decline to 60–70 €/MWh around 2040 [8]. If this forecast is accurate, offshore wind could become more advantageous for all systems. Until then, the base scenario results in lower LCOH values. This outcome is as expected, as the Eneco power mix was specifically designed to align well with hydrogen production systems.

Despite the variations regarding the base case, the relative LCOH ranking among systems remains unchanged, with the Battolyser performing best of the hybrid systems. This indicates that the operational flexibility of the co-located electrolyser and battery systems offers limited benefit under the stable offshore wind profile. Although the systems can allocate power independently, these systems show less significant improvement in hydrogen output compared to the Battolyser, potentially indicating the importance of electrolyser efficiency.

7.5 Comparison Between Hybrid and Standalone Electrolyser Systems

Although this thesis focuses on hybrid systems consisting of an electrolyser and a battery, a standalone configuration consisting of only an alkaline or PEM electrolyser has also been simulated for comparison. The goal of this comparison is to evaluate whether the addition of a battery leads to an LCOH improvement in the current framework. By comparing the hybrid systems to standalone electrolysers, it becomes possible to assess whether the battery component adds value in a grid-connected context with a battery operating on the day-ahead market. In addition, this comparison could provide further insight into the performance of the Battolyser, helping to clarify whether its unique advantage lies in the arbitrage potential or in the improved efficiency.

The general input parameters are identical to the previously modeled systems. Similar to the other systems, the financial input values are based on vendor data provided by Eneco. The input parameters and LCOH plots are depicted in Appendix A. The LCOH of the alkaline electrolyser is 9.79 €/kgH_2 and 9.84 €/kgH_2 for the PEM electrolyser. The alkaline electrolyser produces 239.47 kiloton across its lifetime, while the PEM electrolyser yields 233.32 kiloton. The arbitrage revenue for these systems is €45.40 million for alkaline and €63.17 million for PEM. It is important to note that these systems do not include a battery, meaning that the arbitrage revenue is a result of reselling PPA power to the grid rather than energy storage. Table 35 summarizes these performance characteristics for all system configurations discussed so far, including the standalone alkaline and PEM systems.

Table 35: Summary of preliminary results for each system configuration.

System	**LCOH** [€/kgH_2]	**Discounted H_2** [kt over lifetime]	**Discounted Arbitrage** [M€ over lifetime]	**Electrolyser Efficiency** [kWh/kg H_2]	**C_f RFNBO** [%]
ALK + Lithium-ion	10.36	64.83	141.15	50.0	73.1
ALK + Redox Flow	11.31	64.90	134.83	50.0	73.2
PEM + Lithium-ion	10.15	61.72	183.52	51.0	70.7
PEM + Redox Flow	11.14	61.71	177.64	51.0	70.6
Battolyser	9.96	69.72	91.67	46.3	72.0
ALK	9.79	70.44	45.40	50.0	77.5
PEM	9.84	69.17	63.17	51.0	77.0

The results show that the standalone alkaline and PEM electrolysers achieve lower LCOH values than any of the hybrid systems evaluated, with the alkaline electrolyser performing best. These systems also yield higher capacity factors (over 77%) than the hybrid systems. This can primarily be attributed to the fact that all incoming power is allocated to hydrogen production rather than also to battery charging, allowing for more continuous operation. As the arbitrage revenue is limited to electricity resale during high-price hours, the PEM system has significantly more revenue, due to its lower minimum stable load and smaller balance of plant power demand. This means that less power needs to be reserved for the electrolyser and more power can be directed towards the grid. The standalone systems appear more cost-effective in the base case, although they offer less operational flexibility. They may be more exposed to losses during periods of low renewable output and high electricity prices if there is no storage available to sell additional power to the grid. Batteries may also be more valuable under scenarios with greater electricity price volatility or in cases where the power supply is less stable.

To verify these trends, a local sensitivity analysis on electricity prices was also performed for the standalone ALK and PEM systems. Figure 34 presents the results when both the electricity price dataset and PPA price are scaled by 80% and 120%. As expected, in the reduced price scenario, both standalone electrolysers still outperform the hybrid configurations due to their higher capacity factors and lower cost structures. The alkaline electrolyser performs better than the PEM in both the reduced and base scenarios, primarily due to its higher hydrogen output resulting from a better electrolyser efficiency. However, in the increased electricity price scenario, the operational flexibility of the PEM system becomes more advantageous. This allows it to outperform the alkaline electrolyser under these less favorable market conditions. These results show that standalone electrolysers are sensitive to electricity price variations. Interestingly, under increased electricity prices, the PEM + Li-ion system outperforms both standalone configurations. This is attributed to the additional arbitrage revenue enabled by the battery, which becomes more valuable when the price volatility is higher.

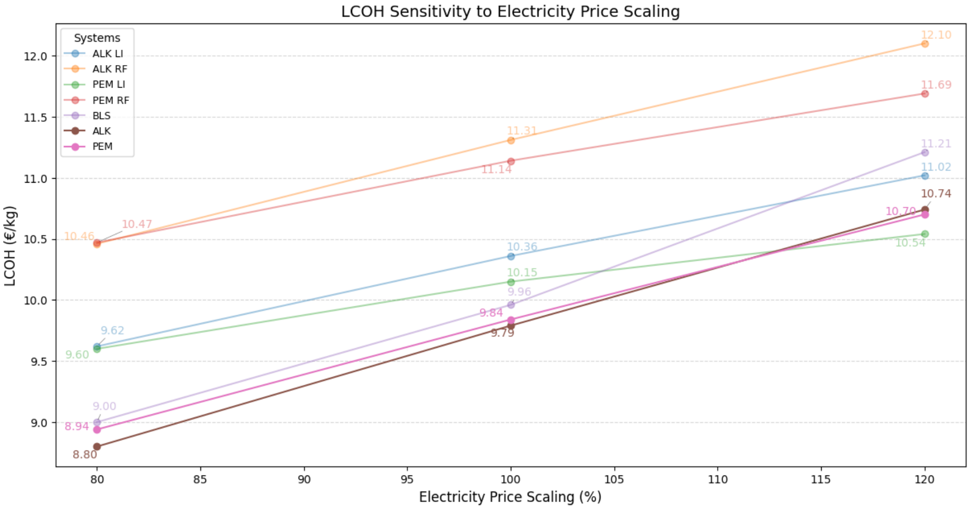


Figure 34: Sensitivity of electricity price variation on LCOH of the systems.

In addition, the standalone alkaline and PEM electrolysers were simulated using an offshore wind power profile as the PPA input. This analysis is identical with the scenario study in Chapter 6.3, where the PPA price was varied to reflect the uncertainty surrounding the levelised cost of electricity (LCOE) from offshore wind. Figure 35 presents the LCOH for each system across a range of various PPA prices. The results show that both standalone systems benefit from the higher and more stable capacity factor associated with offshore wind, leading to lower LCOH values compared to the base case using an onshore wind profile. As expected, the alkaline electrolyser consistently outperforms the PEM system due to the higher efficiency and greater hydrogen output. This analysis reinforces earlier findings that system efficiency plays a dominant role when power availability is high and stable. It also shows that that the economic competitiveness of each configuration depends on the assumed PPA price.

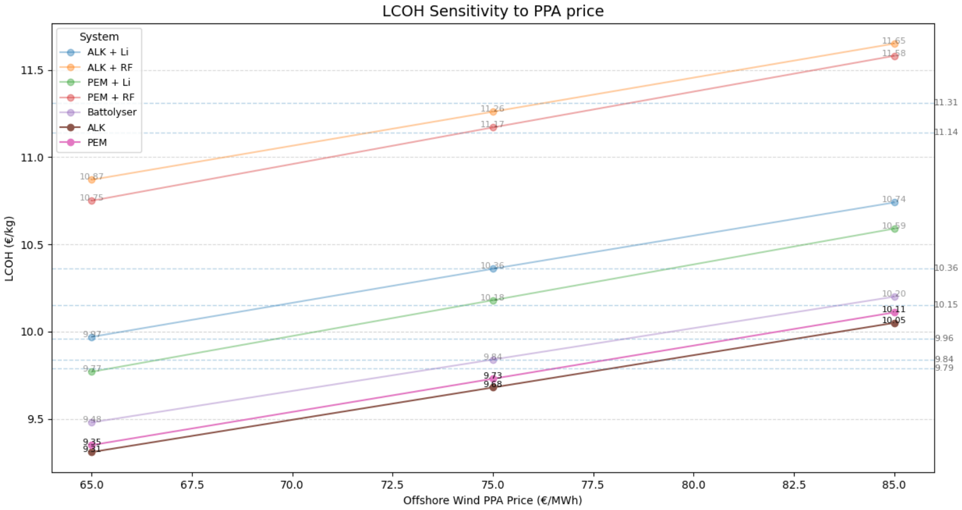


Figure 35: LCOH of the systems simulated with an offshore wind power profile with different PPA prices.

Overall, the comparison indicates that hybrid configurations do not automatically guarantee a lower LCOH than simpler standalone systems. In this model, the battery is only used within a day-ahead market framework. As a result, the battery may not be fully used to its potential, especially if the frequency response and intraday markets can add value. This limited use of battery potential means that the difference in performance between hybrid and standalone systems remains relatively small under the current assumptions. While batteries do provide additional arbitrage revenue, this does not directly reduce the LCOH. However, under high electricity price scenarios, battery integration becomes more advantageous. This is evident in the local sensitivity analysis, where the PEM and lithium-ion system outperforms both standalone electrolysers due to its operational flexibility and added arbitrage income. The benefits of battery integration could become more pronounced in models that incorporate broader market access, which is further discussed in Chapter 7.8 and 7.10. In addition, electrolysers must comply with evolving grid regulations, such as those outlined by ACER, which may influence operational behavior and system degradation. While the addition of a battery can help mitigate these effects, such regulatory constraints and system impacts are not captured by the LCOH metric.

7.6 Environmental Considerations

The research questions in this thesis are of quantitative nature, while qualitative aspects such as the environmental impact are not taken into account in the LCOH. All configurations are producing hydrogen from renewable power via PPAs or RFNBO compliant grid power, which means direct carbon emissions during hydrogen production are minimal. However, upstream components such as battery and electrolyser manufacturing still have environmental impact. Alkaline electrolysers do not rely heavily on scarce or precious metals, which makes them less environmentally intensive than other technologies. However, scarce metals can be added to improve the performance of alkaline electrolysers, which in turn makes them less environmental friendly. PEM electrolysers depend on scarce materials such as iridium and platinum. These rare earth elements involve energy-intensive mining processes and are associated with recyclability problems and geopolitical risks. Moreover, lithium-ion batteries also have environmental concerns related to mining and recycling, especially concerning cobalt and lithium. LFP batteries eliminate the use of cobalt, however still require lithium and phosphate. Mining these materials uses significant energy and water, which poses problems in the regions where these minerals are located. Redox flow batteries may offer longer lifetimes and better recyclability, but require large quantities of vanadium. Although vanadium is often found as a byproduct in mining other minerals such as uranium, the extraction of this has a significant environmental impact.

Recent geopolitical and regulatory developments make these issues more important. In January 2025, the European Commission confirmed plans to ban PFAS in consumer products, and there is growing pressure to also restrict industrial uses such as electrolyser membranes [142]. PFAS breakdown products like trifluoroacetic acid (TFA) are increasingly being found in European waterways, adding to the problem of PFAS use [143]. This could cause major challenges for PEM and VRFB technologies that rely on PFAS-based membranes like Nafion. At the same time, metals as iridium remain in short supply. Most iridium is mined in South Africa, and growing demand from hydrogen and automotive industries could drive prices up further after 2030. This makes PEM electrolyser costs uncertain in the future. Moreover, the copper and lithium supply is expected to drop in the coming years, while the supply is expected to rise. This could influence the costs for the LFP batteries and the power converters. As the co-located systems require more materials for the additional power electronics, the price of these systems are more sensitive to price changes of raw materials. These rising material prices could encourage increased mining activities in new regions. This can lead to greater environmental impacts, such as more deforestation, water pollution, and higher carbon emissions. In addition, the expansion of mining operations often occurs in politically unstable regions, which increases geopolitical risks. This could affect the long-term availability and sustainability of critical raw materials, especially if these systems will be deployed on a large scale.

These environmental and supply chain issues create extra risk for technologies that depend on scarce metals or PFAS-based components. The Battolyser is less affected by these risks because they use more common and recyclable materials and are less exposed to sudden changes in regulations or geopolitical events. The Battolyser's integrated design also reduces its dependence on extra components, making it less sensitive to raw material price swings and long-term supply problems. In addition, using abundant materials like nickel and iron means the Battolyser could have a higher end-of-life recycling value. In contrast, technologies that use small amounts of iridium or platinum remain hard to recycle, although this could improve once more capacity is installed and recycling systems develop. As a result, the Battolyser is less sensitive to material price fluctuations and long-term availability concerns. This makes the technology more environmentally sustainable and also better suited for large-scale deployment, especially in a European context where PFAS regulation is becoming increasingly important.

These environmental and geopolitical impacts are difficult to quantify and have not been taken into account in the LCOH. Therefore, future environmental assessments, such as life-cycle analyses (LCA), are recommended to further research these impacts and compare hybrid and standalone setups beyond the economic performance.

7.7 Comparative Analysis

Several patterns become evident from the analyses regarding how different system configurations perform under varying conditions. These trends help identify how the systems perform under certain circumstances, and what the effects are of the differences in efficiency, flexibility, and system complexity.

A first key takeaway is that the Battolyser configuration generally shows the lowest LCOH. This is largely due to its high hydrogen conversion efficiency and the low minimum stable load of 0%, allowing the system to reduce grid consumption in unfavorable conditions without being forced into inefficient grey hydrogen production. However, the integrated nature of the Battolyser also becomes its weakness in the increased and more volatile electricity price scenario. The system cannot independently optimize for battery arbitrage or hydrogen production, which results in reduced flexibility compared to the co-located setups. This makes the Battolyser particularly sensitive to electricity price fluctuations, as shown in the local sensitivity analysis. While the Battolyser benefits most from low electricity prices, it also sees the steepest increase in LCOH when prices rise. This can be attributed to the decreased hydrogen production and relatively low arbitrage revenue. In addition, increasing the battery capacity in the Battolyser leads to higher LCOH values, as became evident in the global sensitivity analysis. This occurs because the larger battery capacity delays the battery reaching full charge, reducing the power available for hydrogen production, and thereby lowering total hydrogen output. Since fixed costs are spread over fewer kilograms of hydrogen, the LCOH is impacted by this.

PEM systems, in contrast, are the most resilient to changes in electricity prices. Their low minimum stable load and lower balance of plant demand allows the system to minimize electricity costs and improve arbitrage performance, even though hydrogen production is lower. This operational flexibility allows PEM systems to perform consistently across scenarios, especially in the lithium ion configuration. The alkaline systems produce slightly more hydrogen due to a better efficiency and higher MSL, however, they also show a greater LCOH increase in less favorable market conditions, due to the lower flexibility in reducing energy offtake during high-price periods. In these co-located systems, a larger battery capacity has a more beneficial effect as became evident from the global sensitivity analysis. The decoupled nature allows additional storage to increase arbitrage revenue without directly limiting hydrogen production. However, the impact remains limited and highly dependent on market conditions.

Furthermore, it becomes evident that battery type plays a key role. Lithium-ion batteries outperform redox flow batteries in this framework. This is primarily due to their higher round-trip efficiency and more favorable cost structure (CAPEX and OPEX). The advantage of the redox flow battery, which is the larger battery capacity and reduced degradation, is underutilized in this framework as a result of the short receding horizon. Since the redox battery's full potential lies in long-duration storage, the limited foresight of the MPC means the system doesn't fully exploit its longer discharge window. As a result, the RF batteries do not provide increases in arbitrage revenue and do not improve LCOH compared to lithium-ion systems. The current modeling setup therefore favors systems with high efficiency and short-term flexibility, rather than larger storage duration. This is expanded on in Chapter 7.8.

Another clear trend across all configurations is the dominant role of electrolyser efficiency in determining the LCOH. This observation is supported by both the global sensitivity analysis, where it consistently had the highest main effect and significant interaction terms, and the local sensitivity analysis, where systems with beneficial efficiency perform better under a less large electricity price spread. Systems with better efficiency not only consume less electricity per unit of hydrogen but also increase hydrogen output, which spreads fixed costs over more kilograms of production. This makes efficiency twice as important: reducing both operational costs and increasing the LCOH denominator. In all systems, efficiency interacts strongly with other parameters such as CAPEX and OPEX, amplifying their effects when performance is lower. Electrolyser efficiency also proves to be more important under different power input structures. The scenario analysis showed that offshore wind, with its higher and more stable capacity factors, improves system performance across all the systems. Although the relative differences are limited, the Battolyser still outperforms the other hybrid configurations. This suggests that although more stable power profiles help all systems, they do not change the order of performance between them. The main advantage of the PEM electrolyser, which is its flexibility due to lower BoP demand and MSL, becomes less important when operating with a stable power profile. In this case, the efficiency of the electrolyser becomes more pronounced, which means the PEM system shows less improvement compared to the other systems.

The comparison between hybrid and standalone electrolyser systems provides an important perspective on the assumed benefits of integrating batteries. Under base-case conditions, both the standalone alkaline and PEM systems result in lower LCOH values than any of the hybrid configurations. This is due to their higher capacity factors and lower cost structures, which can be attributed to directing all available power solely toward hydrogen production. Without a battery, these systems avoid splitting power between competing objectives. As a result, they produce more hydrogen over the lifetime, improving cost efficiency. While hybrid systems add flexibility through arbitrage, this does not necessarily translate into lower LCOH, as the CAPEX and OPEX rise. The battery introduces an alternative income stream, but it does not directly enhance hydrogen productivity or efficiency. If the battery discharges into the electrolyser, the system essentially "buys" its own electricity at the opportunity cost of lost arbitrage revenue. Economically, this is equivalent to purchasing power at market price, making the net gain zero. The only real advantage in this exchange might lie in avoiding grid tariffs or taking advantage of behind-the-meter configurations. Therefore, the synergy between battery and electrolyser is limited in this framework. Arbitrage revenue does help offset costs and can reduce LCOH slightly, but it acts like a parallel income source. Nevertheless, the benefits of hybrid configurations become more apparent in less favorable electricity price conditions. In the increased electricity price scenario, the PEM + Li-ion system was found to outperform both standalone electrolysers. This suggests that under high and volatile electricity prices, the operational flexibility and added arbitrage revenue of hybrid systems can outweigh their lower hydrogen output. Furthermore, the comparison between hybrid and standalone systems raises the question of whether LCOH alone is sufficient to evaluate system performance. Even though the LCOH is a useful metric for comparing the cost of hydrogen production, it inherently favors configurations that maximize hydrogen output. This introduces a bias against systems with a more battery-focused approach, where more electricity is diverted toward storage for arbitrage rather than hydrogen production. Since LCOH is calculated per kilogram of hydrogen, a reduction in hydrogen output can increase the LCOH as the fixed costs will be spread out over a less large amount of hydrogen, even if total system revenue improves through electricity resale. As a result, the economic value of arbitrage may appear limited, because it does not directly influence the LCOH denominator. One could therefore argue that the LCOH metric may undervalue the contribution of the battery operation in this framework. However, LCOH remains a relevant performance indicator in the context of an emerging hydrogen market since producers with the lowest LCOH are best positioned to enter this market. As the market volume and price for renewable hydrogen is still uncertain, minimizing hydrogen costs remains a critical strategy for competitiveness in the market. A clearer outlook on future hydrogen prices is essential to improve the accuracy of these assessments. Once such prices become more established, future studies could enhance the evaluation of hybrid configurations by incorporating broader financial metrics, such as net present value (NPV), that capture both hydrogen productivity and broader economic benefits.

Finally, it is important to reflect on the LCOH values presented in this study in relation to the estimated RFNBO hydrogen market price. The forecast by Eneco is that the estimated market price is approximately €9/kgH_2 for RFNBO-compliant hydrogen. All the different system configuration in this thesis result in a higher LCOH than this market estimation, with values ranging from €9.79/kgH_2 to over €11/kgH_2 in the base case. This spread in this LCOH range is small, especially considering the high contingencies and price uncertainties. Notably, only the Battolyser and standalone systems are able to reach the threshold of €9/kgH_2 in the reduced electricity price scenario. This suggests that under current technological and market assumptions, the majority of configurations remain dependent on external financial support to become viable. The gap between the LCOH and the estimated market price highlights the potential need for subsidies to bridge the cost gap and enable the deployment of green hydrogen production systems. Moreover, this highlights the importance of technological improvements to lower the LCOH and reduce reliance on subsidies over time.

Overall, the comparative analysis shows that efficiency and operational flexibility remain the most critical drivers of performance. Less desirable efficiency strengthens the effects of CAPEX and OPEX, meaning that the effect of high CAPEX is more pronounced when the efficiency is not optimal. Batteries can add value, but depending on the system and configuration, the impact differs. In this framework, their benefit is limited, and the assumed synergy between battery and electrolyser is less pronounced than expected, looking at the LCOH performance. This results that the Battolyser performs best under ideal conditions, while also being more sensitive to varying scenarios. Contrary, the PEM and Li-ion systems offers a more robust performance. The trade-off between robustness and optimality is important for real world scenarios, where the market conditions are often uncertain. In addition, a full life cycle analysis of the environmental impact of the systems will contribute to the system trade-off in the real world as the LCOH performance is fairly similar. To further understand the systems, more advanced modeling is required, which is discussed further in Chapter 7.8 and 7.10.

7.8 Model Limitations

The simulation model created in this master thesis is based on Eneco's operational strategy, which evaluates electrolysers on predefined operational paths. The four defined paths represent the most relevant operational modes. Path 3 and 4 focus on generating revenue through hydrogen production, while Path 2 focuses on revenue through electricity sale. Path 1 is an intermediate strategy that is applicable when high electricity prices are expected, but too high to generate revenue through producing hydrogen. It is acknowledged that this model has several limitations that result in the fact that the simulations do not represent real life operation. This chapter will discuss the limitations of the model used in this master thesis.

First, an important limitation is that the model currently only considers the day-ahead electricity market to prepare for arbitrage opportunities. Although this market is useful for modeling for a long-term horizon, it does not reflect the full range of revenue potential available to battery systems in real-world operations. Currently, batteries generate the most revenue from participating in markets such as frequency response and intraday trading. These markets operate on shorter time frames, with fast responses and higher price volatility, which can significantly increase the economic value of energy storage. By excluding these additional revenue streams, the model may underestimate the potential benefit of including a battery in the system, particularly for lithium-ion and redox flow configurations. This could help explain why hybrid systems do not show a significant cost advantage over standalone electrolysers in the current results. If the model were expanded to include frequency services or intraday price signals, it is possible that the arbitrage revenue would increase. However, this also raises new questions about the operational synergy between the battery and electrolyser. Participating in short term markets requires the battery to respond quickly to external signals. This could potentially conflict with the steady power demand of when the electrolyser is in operation. Moreover, the grid connection constraint cannot be exceeded, limiting the total power flow. In this case, allocating power between hydrogen production and electricity trading becomes very complex. Electrolysers cannot respond as quickly as batteries, meaning that a part of the grid connection capacity would have to be reserved for electricity trading. To mitigate this, the battery and the electrolyser can work together behind the meter as the energy can be consumed directly on-site, avoiding grid fees. This could shift the battery's role from external market arbitrage to internal optimization, such as managing peak demand, reducing curtailment, or smoothing variable generation. While the inclusion of short-term markets such as frequency response and intraday trading could increase the revenue potential of battery systems, it is important to recognize that these opportunities may not scale indefinitely. As battery penetration in the grid continues to grow, the available revenue from such services is expected to decline due to market saturation. For example, increased competition in frequency markets can lead to lower prices and shorter availability windows, reducing profitability for new entrants. This means that while battery value streams may appear attractive under current conditions, their contribution to LCOH may diminish over time as the market matures. In addition, it is worth noting that the long-term value of battery systems will depend not only on current market design but also on how electricity markets evolve. New market mechanisms may emerge such as capacity markets that change the revenue opportunities for batteries. In such cases, the most valuable services may shift away from short-term arbitrage toward grid stability or integration support. This introduces uncertainty in projecting long-term LCOH impacts from battery integration. Therefore, while the current model offers valuable insight under present market structures, future research could explore different market scenarios to assess the robustness of hybrid system performance over time.

Second, the receding horizon helps to compensate for the limited horizon of the MPC by recalculating the paths at every time step. However, the MPC can still fail to prepare the systems for events outside of the horizon. For instance, if high electricity prices are expected in hour 4, it will not be considered at the first time step. This could result that the MPC will not select to charge the battery yet, even though this could mean more profits later in time. At the next time step, the MPC will recognize the high electricity prices and can react by selecting to charge the battery. This means that the system has a reactive behavior instead of proactive behavior, which could lead to suboptimal performance. The impact is particularly relevant for the redox flow battery, which has an 8-hour storage duration, compared to 4 hours for the Li-ion battery. Because long-duration storage assets like redox flow batteries rely on identifying extended high-price windows, the 3-hour MPC horizon inherently restricts their economic potential. As a result, the 3-hour MPC horizon may be sufficient for the Li-ion system but inadequate for the redox flow system, since more than half of its capacity lies outside the decision window. A mitigation strategy could be to increase the length of the horizon. A longer horizon would allow the MPC to better adjust for future market opportunities such as high electricity prices. For example, if the horizon is 12 hours, the MPC would able to recognize high electricity prices well in advance, setting the system up for more optimized operation. However, increasing the horizon would significantly increase the simulation time of the model. In the current simulation, a horizon of three time steps has been used, meaning that the profit is calculated for T, T+1 and T+2, on which the path selection is based. In order to evaluate what the consequences are of this horizon, another simulation is conducted with a horizon of four time steps. All the co-located systems have been evaluated, and the extended horizon has resulted in a slightly decreased LCOH. Appendix B shows the waterfall charts of the simulations. As can be seen in Table 36, hydrogen production and the capacity factor stay relatively constant while the arbitrage revenue increases significantly. This indicates that the increased horizon allows the MPC to better act on future electricity prices and improve the arbitrage revenue. The absolute change in LCOH is larger for the redox flow battery configurations compared to the Li-ion configurations, suggesting that the greater storage capacity of the redox flow systems is increasingly being utilised. However, the overall reduction in LCOH is maximal 2% for all systems, which is not a substantial amount. Nevertheless, given the close range of the LCOH values across the systems, this change is notable in the context of the preliminary results.

Table 36: Comparison of simulation results across different horizon lengths.

Metric	Unit	ALK + Li-ion		ALK + RF		PEM + Li-ion		PEM + RF	
		Horizon 3	Horizon 4	Horizon 3	Horizon 4	Horizon 3	Horizon 4	Horizon 3	Horizon 4
LCOH	[€/kgH_2]	10.36	10.22	11.31	11.16	10.15	10.01	11.14	10.97
Discounted H_2	[kt over lifetime]	64.83	64.37	64.90	64.54	61.72	61.10	61.71	61.13
Discounted Arbitrage	[M€ over lifetime]	141.16	153.91	134.83	146.98	183.52	197.31	177.64	193.53
C_f RFNBO	[%]	73.1	72.6	73.2	72.8	70.7	70.0	70.6	69.9

Ideally, a 24-hour horizon should be used, matching the timeframe of the Dutch day-ahead market. This would allow the systems to fully optimize their operation across the full daily price curve. However, a longer simulation horizon was not feasible using the current simulation method due to computational limitations. The area of complexity was the modeling of the BoP power demand. In this thesis, BoP demand was modeled using an iterative approach, rather than an analytical one. This decision was made because the BoP depends on the amount of power directed toward the electrolyser stacks, which in turn depends on the change in the battery's SOC. The SoC change influences the charging power efficiency, which again feeds back into the overall system efficiency and the power flow toward the stacks. Because these parameters are interdependent and form a loop, solving the BoP demand analytically would require a complex formula that might also demand significant computational time. Future work could explore whether a (simplified) analytical formulation is possible, especially if it enables longer simulation horizons without significant increasing computational time.

Third, the model in this master thesis is based on the approach of using the four predefined paths mentioned before, instead of using a continuous optimization to dynamically allocate power between battery charging and hydrogen production. This choice was made to simulate the main operational strategies while also keeping the model computationally efficient. Not all the possible operational strategies will be captured using this approach. Partial operation, where power is split dynamically (e.g. 50% to the battery and 50% to the electrolyser), is not captured by these simulation paths. Situations could exist where it would be more beneficial to partially charge the battery to set the system up for arbitrage, while still producing some hydrogen. While this is not applicable to the Battolyser, such partial operation could offer value for the co-located battery-electrolyser system. However, the system's economics are largely determined by a conversion point: below the conversion electricity price hydrogen production is more profitable; above it, selling electricity to the grid results in greater revenue. This creates a division between operational modes, which means that the transition periods in which partial operation might offer an advantage are limited. Situations can occur where it will be more beneficial to prepare for arbitrage by partly allocating power to the battery instead of the stacks below the conversion point. These partial operations could provide small improvements by dynamically splitting power and generate more revenue. However, it is expected that this is limited because the system's performance is mostly influenced by price forecasts and system constraints, which have a larger impact on decision making than the added flexibility provided by partial operation.

Lastly, an important overarching consideration of the model is that the combination of a short optimization horizon, predefined operational strategies, and reliance on a single set of electricity price data do not eliminate the possibility of finding a local rather than a global optimum. The limited horizon reduces the system's ability to anticipate longer-term market dynamics or prepare for upcoming periods of low electricity prices, while the fixed set of operational paths restricts flexibility in how power is allocated between battery charging and hydrogen production. Even though the performed analyses test the robustness of the systems across different configurations and input variations, they are ultimately constrained by the underlying model structure. As a result, the system may adopt operational strategies that perform well under these specific short-term conditions but miss more optimal strategies over longer time frames. This also affects the arbitrage revenues, particularly for long-duration storage like redox flow batteries. Moreover, a short horizon constrains the ability to align hydrogen production with periods of excess renewable generation, which is the key motivation for the need for green hydrogen systems. In real-life energy systems, renewable curtailment is becoming increasingly common, and a hydrogen system that can respond to these surplus events could prevent the need for curtailment of these assets. Without a longer foresight, the model may occasionally favor operation during hours dominated by non-renewable electricity generation if this appears to be the most profitable option within the limited horizon. This may partially undermine the objective of producing renewable hydrogen aligned with RFNBO standards.

7.9 Contribution To Existing Research and Broader Impacts

This study makes several contributions by filling the knowledge gap in the hydrogen production literature and providing insights for both industry and policy. It is a novel study that offers a quantitative comparison between the Battolyser and a conventional configuration of a co-located battery and electrolyser, using the Levelised Cost of Hydrogen (LCOH) as the decision metric. Previous research had not directly compared these two approaches, and by analyzing four different battery–electrolyser combinations alongside the Battolyser, this thesis aimed to investigate the cost-effectiveness of these hybrid systems in the Dutch energy market. The framework captures realistic market behavior by modeling operations on an hourly basis with projected Dutch electricity market prices from 2030 to 2050. The model also incorporates the temporal constraints introduced by EU RFNBO regulations. Unfortunately, the techno-economic model developed in this study cannot be reused, as it is confidential and the property of Eneco. However, the structure of the framework, the modeling approach, and the underlying assumptions can still provide valuable insights for other researchers.

The comparative analysis identifies some key drivers of hydrogen production cost and system performance. Most notably, electrolyser efficiency proves to be the most influential factor affecting LCOH across most scenarios. Higher electrolyser efficiency directly lowers the energy required per kilogram of hydrogen, thereby reducing both operational costs and spreading fixed costs over more hydrogen. This insight can guide project developers and investors, such as Eneco, to prioritize high-efficiency electrolysers. Electricity price volatility also plays a significant role in determining the relative advantages of different system configurations. Under increased and volatile electricity prices, systems with decoupled storage and hydrogen stacks can better exploit arbitrage opportunities by dynamically shifting between charging, discharging and hydrogen production. This information shows which systems are best suited for different market conditions. Furthermore, the small spread in LCOH observed in the base case simulations suggests that system performance is similar across all configurations. As a result, companies like Eneco could base their decision-making on secondary considerations such as environmental impact, material sustainability, and the availability of technologies within the European market.

Starting from 2030, a minimum share of renewable hydrogen will be required in sectors such as transport and industry, as set by European legislation. This will create an offtake market for renewable hydrogen, which is currently still limited. A market study by Eneco investigated the willingness-to-pay for renewable hydrogen in 2030, and it is expected that renewable hydrogen can be imported for 9 €/kgH_2. As becomes evident from the LCOH analysis, none of the modeled system configurations is able to reach this expected market price under current assumptions. Therefore, significant cost reductions or supportive measures (e.g. subsidies, tax credits, or increased ETS prices) will be required to make RFNBO-compliant hydrogen competitive with import in the 2030–2050 time frame. At the same time, the current political climate in Europe and the Netherlands is shifting toward more right-leaning politics, leading to tighter budgets for renewable energy support. If these trends continue, the likelihood of support schemes for green hydrogen projects may decrease, making it even more challenging for local renewable hydrogen to become competitive. Supporting local production could strengthen energy independence and reduce reliance on foreign supply, while increased dependence on imports may expose the country to geopolitical risks, as seen during the recent energy crisis involving Russia. However, if support measures are the only way to make renewable hydrogen cost-competitive in the Netherlands, an important question can be raised: should public resources focus on innovation and subsidies for domestic production, or would investing in hydrogen imports be more effective?

Finally, environmental considerations are a key reason why renewable hydrogen is being pursued. Although the focus of this thesis is on economic performance, the integrated design of the Battolyser could reduce the need for physical infrastructure and potentially result in a smaller environmental footprint. In contrast, co-located systems often require more space, more components, and greater resource use, particularly when they rely on materials such as vanadium for redox flow batteries or critical metals for PEM electrolysers. A broader sustainability assessment is needed to fully understand the wider impacts of these systems, including carbon intensity, resource depletion, recyclability, and end-of-life disposal. This will help show whether systems that look cost-effective today will also be truly sustainable at scale.

7.10 Recommendations for Future Work

Building on the key findings and limitations discussed above, the following recommendations are provided for future research. This section outlines recommendations for future research aimed at both improving the model's accuracy and exploring broader questions about the feasibility and scalability of hydrogen production. The recommendations are grouped into two categories: (A) Model improvements and system optimization and (B) Broader hydrogen production and deployment research.

A. Model Improvements and System Optimization

1. Increase the MPC horizon to match day-ahead market structure.
Currently, the model operates with a limited receding horizon (3 time steps) to ensure the model remains computational efficient. However, in the European market, day-ahead electricity prices are published at noon for the entire following day [144]. To fully simulate the potential of the systems, future models should adopt a 24-hour optimization horizon. This would allow the model to adapt proactively and better exploit high electricity prices. This would also allow for better utilization of the long-duration discharge capability of redox flow batteries. These simulations should assess whether extending the horizon affects the relative ranking and robustness of system configurations.

2. Add dynamic power allocation between battery and electrolyser.
The current framework uses predefined operating paths for computational efficiency. While this is a good starting point for the comparison of the hybrid systems, the static allocation prevents the system from dynamically reallocating power between battery charging, discharging, and hydrogen production. Changing the model for dynamically allocation of power split could improve synergies and reveal whether such flexibility actually improves system performance and lowers LCOH.

3. Include more market opportunities beyond day-ahead arbitrage.
In reality, batteries participate in multiple electricity markets, including intraday, balancing, and frequency containment reserves (FCR). These markets often offer higher revenue streams than the day-ahead market. The current model excludes these markets, underestimating the potential value batteries could bring. Future research should simulate multi-market participation to estimate additional battery revenues. This will better simulate the synergy between batteries and electrolysers.

4. Consider variable Balance of Plant (BoP) and compressor dynamics.
In the current model, BoP power consumption is a fixed parameter. In reality, BoP power demand varies with hydrogen production rate, and part-load operation may lead to higher energy consumption or mechanical wear. Future models should incorporate dynamic BoP functions and investigate the operational implications of frequent ramping and part load operation. Future research could explore the possibility of using an analytical formula to determine the interdependent parameters per time step. Moreover, battery and electrolyser components degrade over time, especially under high cycling frequencies or part-load operation. While this thesis assumes fixed lifetime and performance, a more accurate approach would include degradation models for both batteries and electrolysers, including impacts on efficiency, capacity, and OPEX. Modeling this dynamic behavior will provide more accurate estimates of energy use and maintenance needs.

5. Investigate the synergies in hybrid setups.
In this framework, limited synergy between battery and electrolyser in grid-connected setups has been found. Drawing power from the battery to produce hydrogen effectively means buying electricity at the market price. Current synergies exist only in CAPEX and OPEX reductions. Future work should test whether more integrated strategies (e.g., joint dispatch, thermal coupling, or flexible grid connection contracts) can improve synergy and create economic advantages. In combination with the exploration of more battery market opportunities, this could also reveal that a separate battery and electrolyser setup may lack operational synergy and perform better alone.

6. Expand the comparison of the systems.
The focus in this research is on the comparison of the LCOH as a result of the production of RFNBO compliant hydrogen. While this is a valid performance metric, it can create a bias toward hydrogen output as the only measure. To develop a more comprehensive assessment, future research should expand the scope of evaluation criteria. It is recommended that future research includes a full life cycle analysis to investigate the environmental impact of the systems, from material extraction to end of life impact. Additionally, other economical indicators such as net present value and internal rate of return could be investigated to further capture the financial viability of the systems from a business perspective.

B. Broader Hydrogen Production and Deployment Research

7. Investigate the impact of regulatory frameworks and policy incentives.
This thesis highlights the significant influence of regulatory (RFNBO) compliance on technology choice and operational strategies. Given the dynamic nature of policy developments, future research should explicitly examine how potential changes in EU hydrogen regulations, subsidy mechanisms, and market incentives could affect the competitiveness of hydrogen production systems. This could include modeling scenarios with various subsidy levels or carbon pricing to better inform strategic decisions for industry stakeholders and policymakers.

8. Investigate the viability of producing renewable hydrogen in the Netherlands.
Under current techno-economic assumptions none of the evaluated system configurations are able to produce renewable hydrogen at or below the projected willingness to pay in the Netherlands. This indicates that domestically produced renewable hydrogen may remain economically uncompetitive in the short to medium term. It may be more cost-effective to import hydrogen produced in regions with more favorable renewable energy conditions, such as higher solar irradiance or lower land and electricity costs. Therefore, future research should compare the domestic production route with international import strategies, considering not only cost but also energy security, infrastructure requirements, and geopolitical factors.

9. Explore the impact of large-scale deployment of batteries and electrolysers on the availability of key materials.
The widespread deployment of batteries and electrolysers at industrial scale could place significant pressure on global supply chains for critical raw materials. For example, lithium, nickel, cobalt, and vanadium are essential for many battery chemistries, while electrolysers require materials such as platinum group metals (for PEM), PFAS, iridium, or rare earth elements (for power electronics and magnets). Large-scale expansion may lead to resource bottlenecks, geopolitical dependencies, and increased costs due to scarcity or extraction constraints. Future research should examine the material intensity of hydrogen systems across different technology choices. This includes assessing availability, recyclability, environmental impact, and the potential for circular economy strategies.

8 Conclusion

Producing renewable hydrogen in a way that is both cost-effective and compliant with RFNBO (EU) standards is crucial for industrial decarbonization, energy system flexibility, and enabling seasonal renewable storage. One technology that addresses this challenge is the Battolyser, which integrates a battery and an electrolyser into a single system. By combining hydrogen production with electricity arbitrage, it aims to achieve a low levelised cost of hydrogen (LCOH). The LCOH is a key metric for evaluating hydrogen production systems, as a lower LCOH enhances their competitiveness and market potential. An alternative approach is a co-located system consisting of a separate electrolyser and battery energy storage system (BESS). While such a system can also leverage arbitrage revenue, a direct comparison with the Battolyser had not previously been conducted.

This thesis addressed this gap by answering the central research question:

> **How does the Battolyser compare to a system with a separate battery and electrolyser in achieving the lowest levelised cost of hydrogen (LCOH) compliant to RFNBO (EU) standards?**

To approach this main research question, several sub-questions were formulated and answered:

SQ1: What processes should be considered in determining the LCOH for hydrogen production?
Several key processes involved in hydrogen production were identified and analyzed to establish an objective framework for evaluating the LCOH. This framework included not only the electrolysis process itself but also supporting processes such as hydrogen compression and transport to the end user. Hydrogen storage was excluded, as the analysis assumed a pay-as-produced agreement with the hydrogen offtaker. Additionally, auxiliary equipment including hydrogen dryers and power electronics was considered to capture the full energy and cost profile. The model also incorporated a detailed representation of renewable power input, accounting for its availability, associated costs, and its temporal alignment with hydrogen production.

SQ2: Which technical and financial aspects need to be evaluated to make a meaningful comparison between both systems?
The evaluated system configurations included both alkaline and PEM electrolysers, each paired with either lithium-ion or redox flow batteries, and were compared against the Battolyser. A range of technical and financial parameters was identified and assessed to determine point values for the base case simulations. Key technical characteristics included electrolyser and battery efficiency, minimum stable load, and system capacity. Additional components such as hydrogen compression electricity consumption and losses from power electronics were also considered to determine the total balance-of-plant power demand. Moreover, financial parameters were established through internal expertise at Eneco and data from vendors. These included capital and operational expenditures (CAPEX and OPEX), grid connection costs for large-scale systems, and expenses related to land lease.

SQ3: How does a model for evaluating the hydrogen production systems look like?
The system configurations were evaluated using a techno-economic model that simulates the operational strategies in a consistent framework based on EU regulatory compliance in the Dutch electricity market. The techno-economic simulation model operates at an hourly resolution over a twenty-year project lifetime and was designed to capture the operational behavior of hydrogen production systems under RFNBO (EU) compliance and Dutch electricity market conditions. It simulates the interaction between electrolyser and battery systems in response to hourly electricity prices, renewable power availability, and system-level constraints. By incorporating a horizon of three hours ahead, the model allows the systems to anticipate market conditions and optimize their operations accordingly. Key components of the model include hydrogen production calculations, power input and reselling from PPAs of renewable sources and the grid, battery charge-discharge dynamics, and the enforcement of regulatory rules such as temporal correlation between renewable input and hydrogen production. The model simulates the different system configurations in a consistent framework, allowing for objective comparison across scenarios. The primary objective was to simulate the operational behavior of each configuration and calculate the LCOH, incorporating the associated costs.

SQ4: How do variations in relevant parameters affect the LCOH of the systems?
The global sensitivity analysis showed strong interactions between efficiency, CAPEX, and OPEX. Lower electrolyser efficiency not only reduced hydrogen output but also amplified the impact of financial parameters, resulting in significantly higher LCOH. From this analysis, it was found that the dominant factor across all systems was electrolyser efficiency. Higher efficiency increased hydrogen output, reducing LCOH by spreading fixed and variable costs across more kilograms of production. A steady PPA input such as an offshore wind profile further enhanced this effect, as operational flexibility became less important and efficiency more pronounced. Additionally, the local sensitivity analysis revealed that systems with a low minimum stable load and low BoP power demand showed greater adaptability to volatile electricity prices. The PEM electrolyser combined with a lithium-ion battery demonstrated the best and most robust performance of all the systems when electricity prices were high and more variable. Its operational flexibility enabled the system to minimize grey hydrogen production and achieve high arbitrage revenues. Although the LCOH of the co-located systems is slightly higher in the base case, both lithium ion configurations outperform the Battolyser in high electricity price scenarios. In contrast to the Battolyser, the co-located system can operate at nominal hydrogen capacity one hour, switch to battery discharging the next hour when electricity prices are high, and return to hydrogen production afterward.

SQ5: What is the recommended system for hydrogen production that minimizes the LCOH when coupled with renewable energy generation?
The findings showed that the Battolyser achieved the lowest LCOH in the base case scenario (9.96 €/kgH_2), primarily due to its high hydrogen efficiency and zero minimum stable load. These characteristics enabled the Battolyser to avoid grey hydrogen production

and capitalize on high electricity prices by discharging its integrated battery to the grid. However, its integrated design introduced limitations, as it could not independently optimize hydrogen production and battery arbitrage. Consequently, the Battolyser was more sensitive to volatile market conditions, showing the steepest LCOH increases when prices were less favorable. From an environmental perspective, the Battolyser also presented advantages, as it avoided the use of scarce or critical raw materials found in PEM electrolysers and lithium-ion batteries, potentially making it more sustainable for large-scale deployment. In contrast, in high electricity price scenarios, a PEM electrolyser combined with a lithium-ion battery demonstrated the best performance among the systems, thanks to its low balance-of-plant demand and low minimum stable load. Furthermore, redox flow battery configurations consistently resulted in higher LCOH values, largely due to higher CAPEX and lower round-trip efficiency. Their long discharge duration was also underutilized in the model's three-hour planning horizon. Interestingly, standalone alkaline and PEM electrolysers outperformed hybrid systems in the base case due to their low cost structure and ability to direct all available power to hydrogen production. However, these systems lacked flexibility, making them less resilient under volatile electricity prices. It is important to note that the differences in LCOH between the configurations of the system were relatively small: the spread was within €1.5/kgH$_2$ when including redox flow battery systems and narrowed to within €0.5/kgH$_2$ when excluded. Additionally, all simulated systems resulted in an LCOH above the estimated RFNBO hydrogen market price of €9/kgH$_2$. This cost gap underscores the likely need for subsidies or other support mechanisms to make green hydrogen production economically viable under current market conditions.

In conclusion, the Battolyser achieves the lowest LCOH among the hybrid systems under RFNBO (EU) compliance when electricity market conditions are favorable and relatively stable. This can be attributed to the best electrolyser efficiency of the system. From an environmental perspective, the Battolyser also presents advantages as it avoids the use of scarce or critical raw materials found in PEM electrolysers and lithium-ion batteries. However, in a more volatile electricity price scenario, a co-located system combining a PEM electrolyser and a lithium-ion battery may offer a more suitable solution due to the ability to respond to the fluctuating prices. The batteries contribute additional value through electricity arbitrage, but their impact on LCOH remains modest in this framework as the standalone electrolysers outperform the hybrid systems. Furthermore, the LCOH values of the systems lie fairly close to each other, as the spread in LCOH is within 1.5 euros including the redox flow configurations, and withing 0.5 euros without. This narrow range suggests that the economic performance is comparable despite technological differences, especially considering the uncertainties in future asset prices and policy developments. It is also important to note that all simulated systems yield an LCOH higher than the estimated RFNBO hydrogen market price of €9/kgH$_2$. This cost gap highlights the likely need for subsidies or support mechanisms to make green hydrogen production economically viable under current assumptions.

For Eneco, the findings of this research offer more insight into the trade-offs between system efficiency, operational flexibility, and economic performance. The results show that electrolyser efficiency is the most important driver of LCOH, suggesting that Eneco could benefit from prioritizing vendors focused on improving electrolyser efficiency. The assumed synergy between batteries and electrolysers in hybrid configurations appears limited in the modeled framework, as the two components largely generate value independently. The contribution of batteries is through day-ahead electricity arbitrage, which proves to be modest. This is further confirmed when looking at the comparison of the hybrid systems with the stand alone electrolysers, where the electrolyser outperform them in both the base case and in combination with offshore wind power profile. Since the LCOH differences between systems are relatively small, it is further recommended that the final system selection be guided by additional factors such as environmental impact and the availability of technologies within the European market. The Battolyser's reliance on abundant and recyclable materials gives it an environmental advantage over PEM electrolysers and lithium-ion batteries. Both the Battolyser and the associated power electronics use less impactfull materials and are more easily to recycle. This aligns with Eneco's long-term sustainability and supply chain goals. Therefore, a pilot project with the Battolyser would enable validation of the simulated performance in a real-world operational context.

Finally, this research was conducted to investigate the potential for producing cost-effective, RFNBO-compliant hydrogen to stimulate the energy transition. Reducing the cost of renewable hydrogen is essential, as significant investments from governments and industries are needed to accelerate the energy transition. This thesis explored whether combining battery storage with electrolysis could lower production costs through electricity market arbitrage. However, a cost gap remains between the modeled production costs and the expected market willingness to pay. Therefore, future research should aim to improve the modeling framework by extending the optimization horizon, enabling dynamic power allocation, and simulating participation in electricity markets beyond the day-ahead level to improve the accuracy of the LCOH comparison. In addition, the availability of raw materials, supply chain challenges, and the viability of domestic production versus imports should be further explored to evaluate the long-term impact of electrolysis and the renewable hydrogen market.

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A Simulation of standalone electrolysers

This appendix presents the technical assumptions, financial parameters, and resulting LCOH outcomes for the standalone alkaline and PEM electrolyser configurations. These systems are simulated under the same economic and operational assumptions as the hybrid systems discussed in the main chapters. The purpose is to establish a consistent baseline for comparing the performance of standalone and hybrid electrolyser-battery systems. The arbitrage revenue indicated in the data stems from reselling the incoming PPA to the grid, meaning that no energy storage system is involved.

An inflation rate of 2.0% is applied to CAPEX and OPEX starting from 2025. A hurdle rate of 9.0% is used to discount future costs and hydrogen production to their 2025 values for the LCOH calculation. Financial inputs are based on literature and project data provided by Eneco.

A.1 Alkaline electrolyser

Table 37 shows the characteristics and financial data used in the simulation of the alkaline electrolyser. Figure 36 shows the LCOH of the alkaline electrolyser.

Table 37: Technical and financial specifications for the ALK system.

Function	Component	Value	Unit
Electrolyser	Stack capacity	90	MW
	Stack efficiency	50	kWh/kgH$_2$
	Stack MSL	12	%
	Stack degradation	1.1	%/yr
	Stack replacement	10	yr
	BoP capacity	10	MW
System	Grid connection	110	MW

Category	Component	Value	Unit
CAPEX	Electrolyser stacks	23	mEUR
	BoP (system)	100	mEUR
	Grid connection	15.5	mEUR
	HyNetwork connection	3	mEUR
	Labor, EPC, etc.	116	mEUR
	Devex and other	6	mEUR
	Contingency	25	mEUR
OPEX	Stack replacement	16	mEUR
	HyNetwork	1.5	mEUR/yr
	Grid	10	mEUR/yr
	Land lease	1.5	mEUR/yr
	Maintenance	5.7	mEUR/yr
	Other	2	mEUR/yr

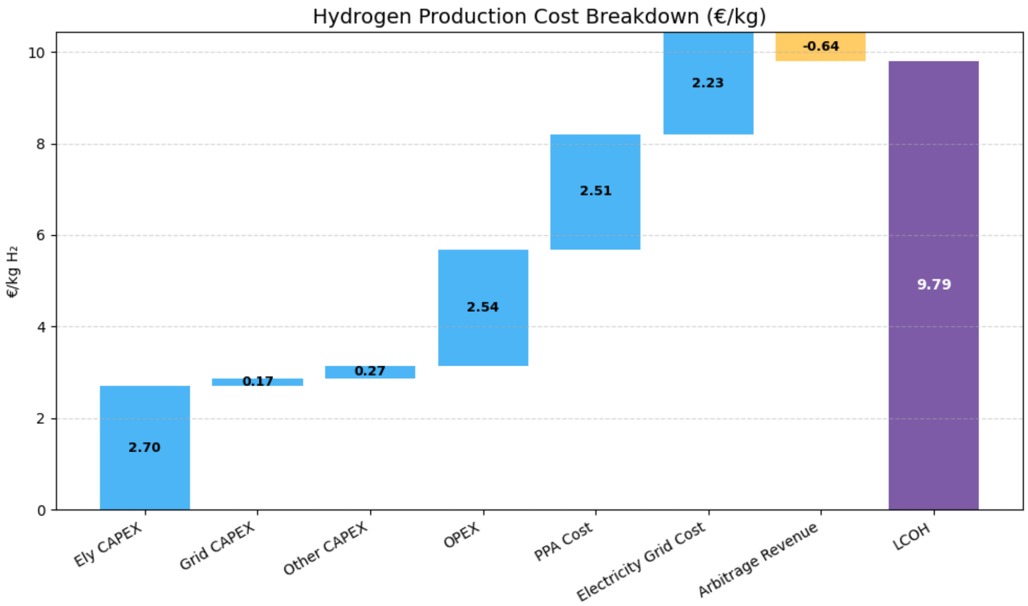

Figure 36: LCOH of a grid connected alkaline electrolyser.

A.2 PEM electrolyser

Table 38 shows the data used in the simulation of the PEM electrolyser. Figure 37 shows the LCOH of the PEM electrolyser.

Table 38: Technical and financial specifications for the PEM system.

Function	Component	Value	Unit
Electrolyser	Stack capacity	90	MW
	Stack efficiency	51	kWh/kgH_2
	Stack MSL	5	%
	Stack degradation	1.1	%/yr
	Stack replacement	10	yr
	BoP capacity	5	MW
System	Grid connection	107	MW

Category	Component	Value	Unit
CAPEX	Electrolyser stacks	35	mEUR
	BoP (system)	100	mEUR
	Grid connection	15.5	mEUR
	HyNetwork connection	3	mEUR
	Labor, EPC, etc.	121	mEUR
	Devex and other	6	mEUR
	Contingency	25	mEUR
OPEX	Stack replacement	20	mEUR
	HyNetwork	1.5	mEUR/yr
	Grid	10	mEUR/yr
	Land lease	1.5	mEUR/yr
	Maintenance	7	mEUR/yr
	Other	2	mEUR/yr

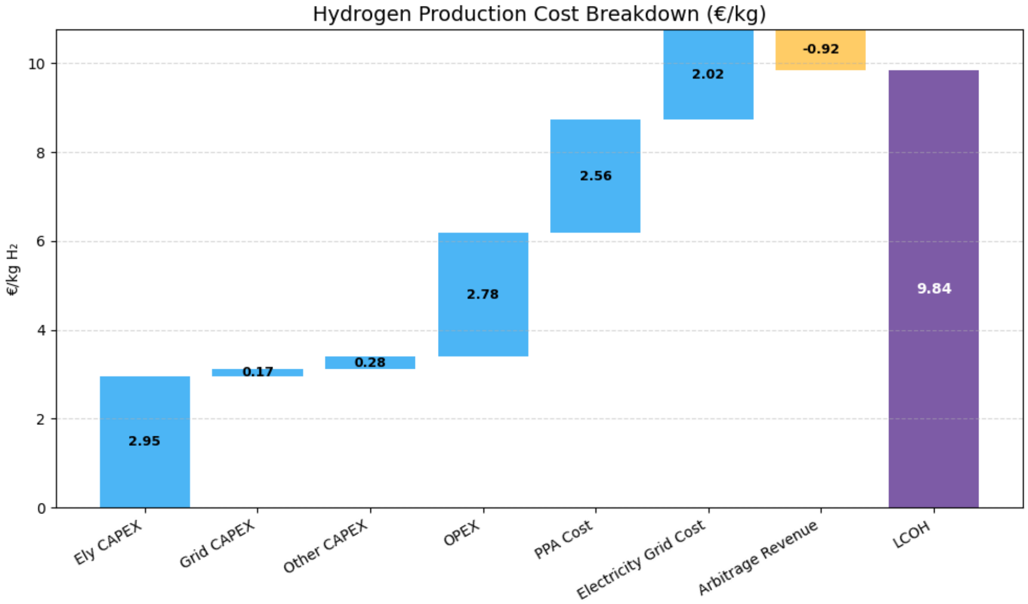

Figure 37: LCOH of a grid connected PEM electrolyser.

Summary

The alkaline system reaches an LCOH of €9.79/kgH_2, while the PEM system results in €9.84/kgH_2, as shown in Figures 36 and 37. These results indicate that under the current assumptions, standalone systems can outperform hybrid configurations in terms of cost per kilogram of hydrogen, primarily due to their higher hydrogen output and reduced costs. The comparative findings are further discussed in Chapter 7.5.

B Simulation of the co-located systems with a horizon length of 4 hours.

This appendix shows the waterfall charts of the co-located systems with a horizon length of 4 hours. These findings are summed in Table 36 in Chapter 7.8.

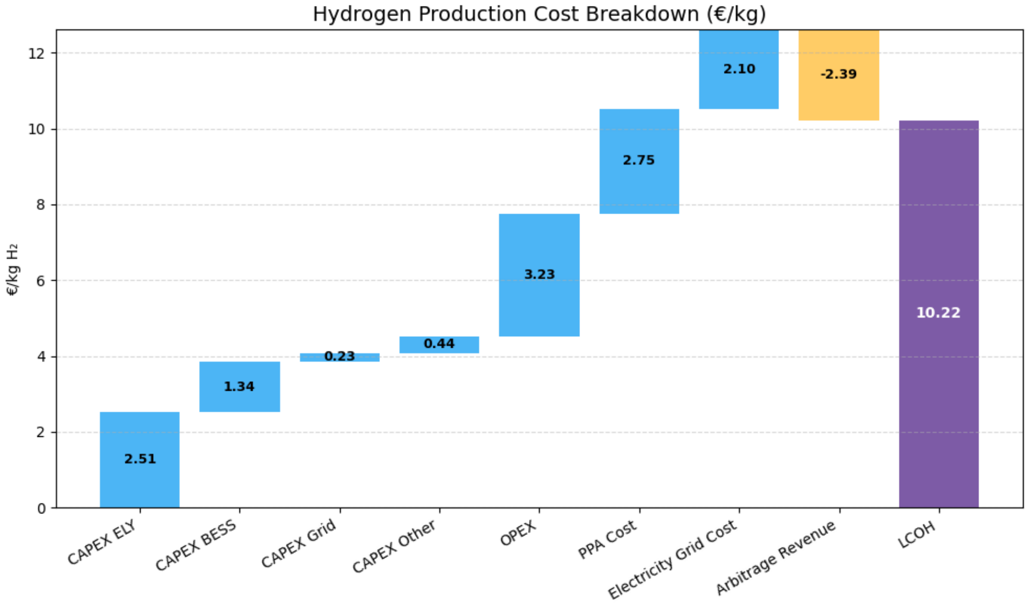

Figure 38: LCOH the ALK + Li system with horizon length of 4 hours.

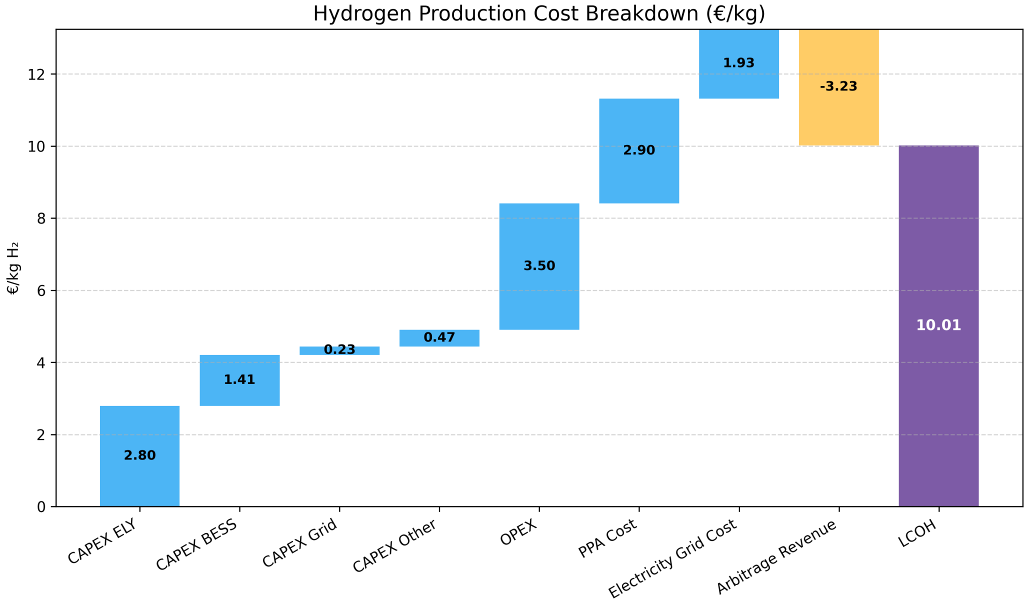

Figure 39: LCOH the PEM + Li system with horizon length of 4 hours.

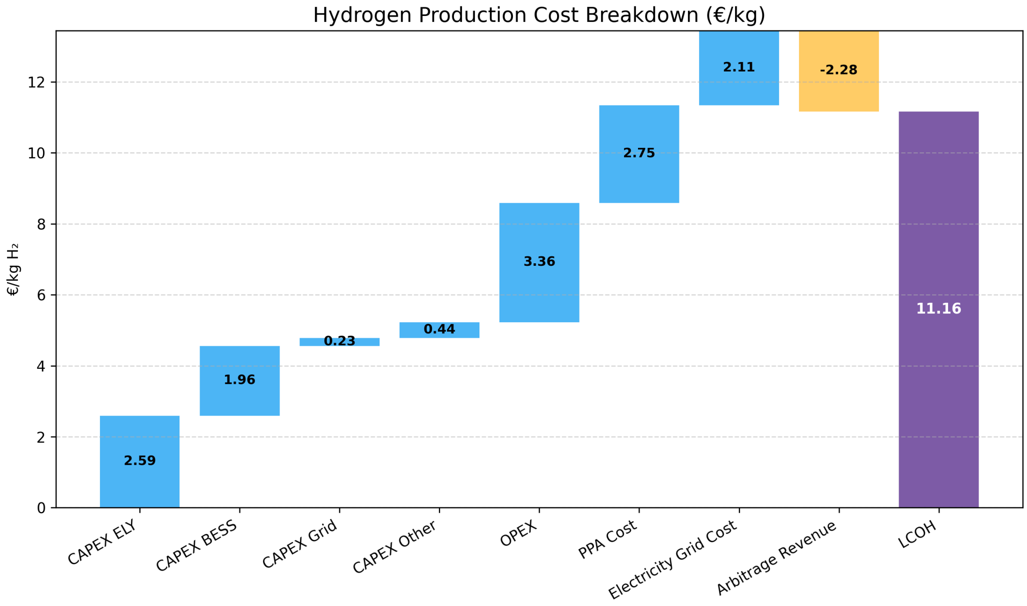

Figure 40: LCOH the ALK + RF system with horizon length of 4 hours.

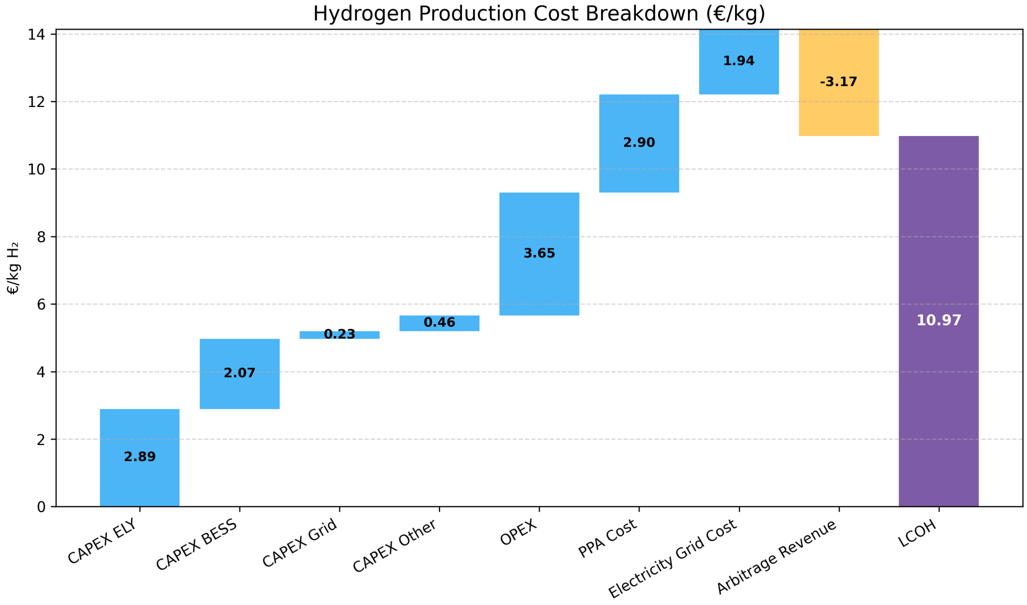

Figure 41: LCOH the PEM + RF system with horizon length of 4 hours.