Techno-economic assessment of offshore hydrogen production in the Dutch North Sea

Comparative analysis of offshore hydrogen and electrical infrastructure with green hydrogen import using standardized breakdown and open-source cost model

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by

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Preface

Before you lies my thesis, marking the concluding chapter of my studies in Delft and of completing my master's degree in Hydraulic Engineering at the Faculty of Civil Engineering and Geosciences, Delft University of Technology. Researching this dynamic and rapidly evolving topic was both exhilarating and challenging, offering numerous rewarding moments and valuable lessons. This study has ignited my passion for the energy transition and strengthened my commitment to contributing to our collective need for sustainable energy solutions. This enthusiasm is fueled in part by the energy and dedication of everyone involved in this project, and I would like to extend my gratitude to several individuals in particular.

Firstly, I would like to thank Mark van Koningsveld, who has been integral in providing critical insights and motivating me to reach this study's full potential by posing challenging questions, thereby elevating the quality of the research tremendously. While a great deal of effort and time was dedicated to model development, Mark ensured that I effectively conveyed the academic relevance in this report, resulting in a sharply formulated presentation of our research.

Secondly, I would like to thank Gerben de Boer for his dedication to our weekly meetings, providing invaluable guidance when necessary, yet always gave me the freedom to shape my own thesis - or as Gerben would jokingly say, my "100,000 euro project". His balance of support and independence provided me with rewarding lessons, extending beyond the scope of this study. I would also like to thank Walter Sieval, who consistently kept me motivated and, more importantly, inspired me with insights into the latest developments in the offshore wind and hydrogen industry. Whether sharing his own expertise or inviting me to presentations by other experts, his support was invaluable.

Thirdly, I would like to thank George Lavidas for sharing his vast knowledge of renewable energy. His emphasis on key elements within the literature encouraged me to critically assess my approach and helped me see the broader context of my work. He continuously emphasized the importance of literature, ensuring the academic depth of the research. And I would also like to thank Poonam Taneja for her unwavering support, always motivating me to persevere through challenges. Her confidence in my approach, positive attitude, and detailed views were invaluable.

Lastly, I would like to thank my family, friends and girlfriend for their unconditional support and believe, which has brought me to the point of writing this final page.

M.J. (Maarten) Bakker
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Abstract

To stay on track for the 1.5°C pathway of the Paris Agreement, an accelerated energy transition is essential. Efficient offshore energy infrastructure planning, incorporating novel methods, is crucial and requires transparent, industry-wide discussion. However, two main challenges emerge: (i) the often-overlooked integration of energy islands in literature and (ii) the lack of a standardized techno-economic comparison method. A comprehensive review of offshore wind supply chain feasibility studies highlighted the need for explicit implementation of standardization, syntax and semantics in model development. Detailed assessment of international and industry standards revealed that no single standard fully covers the study's scope. Nevertheless, one ISO standard showed significant similarities in component definitions, with which this study's component definition is maximally aligned. The developed open-source model enables automated supply chain configuration generation, eventually calculating economic metrics such as the Levelized Cost of Hydrogen (LCOH). Applying the developed techno-economic model to the 19.5GW case study hub North in the North Sea Energy programme demonstrated its applicability and the techno-economic advantages of integrating an offshore energy island. The key finding is that island-based configurations are economically more efficient for hydrogen production compared to platform or onshore setups. Comparison with other studies on hydrogen import indicates that the calculated LCOH range of 8.54 - 10.40 €/kg has the potential to compete with hydrogen imports, which often have overly optimistic estimates ranging from 4 to 9 €/kg. Ultimately, in this way, a standardized, transparent method for industry-wide collaboration is presented.

Executive summary

The Paris Agreement aims to limit global warming by reducing greenhouse gas emissions, with offshore wind being a key strategy for the Netherlands. Optimizing energy efficiency and transmission costs for distant wind farms presents challenges, and the inherent variability of wind power affects grid stability, leading to curtailment. This issue is expected to grow as the Netherlands plans to expand offshore wind capacity from 4.7 GW to 21 GW by 2032, an enormous challenge - which is often underestimated.

While batteries can manage daily fluctuations, ammonia and hydrogen present viable options for large-scale, long-term energy storage, aligning with the European Commission's REPowerEU plan for large-scale domestic production and import of green hydrogen by 2030. In this context, exploring novel methods for efficient offshore energy transport to shore and subsequent storage is crucial, with offshore artificial energy islands being a prime example. However, these are often not explicitly studied in literature, resulting in overlooking the concept in offshore energy infrastructure planning, potentially leading to a sub-optimal offshore energy system design, presenting the first research gap.

To stay on track for the 1.5°C pathway, an acceleration of the energy transition is required. However, the confidential and competitive nature of the offshore wind and hydrogen markets hinders necessary knowledge sharing among stakeholders, leading to a sub-optimal environment for collaborative design. This process could greatly benefit from a transparent discussion by adoption of a standardized method for comparing alternative offshore wind to hydrogen concepts, which is not available yet. Van den Haak (2023) made a significant advancement into developing such a standardized method. However, it could benefit significantly from enabling automated supply chain configuration generation, further detailing of components, inclusion of various configuration types, and commissioning years as an uncertainty factor rather than design parameter. Together, they present the second research gap.

This results in this study's two-fold objective: (i) develop a standardized comparison method for the offshore wind industry and create an offshore artificial energy island cost estimation tool; (ii) apply these models to the hub North case study within the North Sea Energy (NSE) programme to evaluate the feasibility of an energy island concept in detail. This approach enhances the potential of the model to be valued and adopted by the industry, showcasing the proof of concept and relevance of an industry-wide, transparent, standardized techno-economic model for efficient offshore energy infrastructure planning. Moreover, it offers crucial insights into the feasibility of integrating an energy island, thereby informing the NSE programme. Five sub-questions and the following main research question are formulated:

How can the evaluation of offshore wind supply chain configurations be standardized to enhance industry-wide collaboration? And how can this standardized approach be applied to evaluate the feasibility of energy island concepts for the hub North case study in the North Sea Energy programme compared to hydrogen import?

To understand the current landscape of feasibility studies within the offshore wind supply chains, a review was conducted, indicating that techno-economic assessments are the common method. These assessments typically utilize constant cost rates, net present value calculations, and the levelized cost of hydrogen (LCOH). The review also indicates that efforts into "softer" aspects such as standardization, industry-wide implementation, and stakeholder engagement are not addressed in these techno-economic studies, as well as transparency in presenting assumptions, input, and methodologies. This lack of transparency and the diversity in assumptions across studies makes meaningful comparisons challenging, diminishing the significance of study outcomes. Explicit integration of these aspects would extend current knowledge and improve the reliability and comparability of the studies.

To address this challenge of developing an industry-wide approach effectively, the importance of explicit incorporation of syntax and semantics into the model is studied, as well as standardization. A common pitfall in model development is the creation of ad hoc representations of a system without explicitly considering concepts such as domain semantics, metamodels, and ontologies, leading to misunderstanding. To enhance model consistency and utilization, the study contains explicit recommendations for future model development regarding implementation of model taxonomies and ontologies.

Additionally, a comprehensive assessment of international and industry standards indicated that no single standard comprehensively covers this study's scope. Consequently, an alternative method for efficient study comparison was adopted: the LCOH. Despite its challenges, particularly concerning the discount rate, after careful considerations this study employs the weighted average cost of capital (WACC) to ensure more accurate and meaningful comparisons. In this context, international standardization might hold the solution for this challenge of a correct, yet realistic and engaging, utilization of the discount rate. Consequently, the resulting LCOH becomes more comparable and insightful than if a uniform discount rate were applied. Lastly, the physical breakdown structure (PBS) of ISO standard 19008:2016 exhibits high similarities with the scope of this study, leading to the design choice of maximally aligning this study's component definition with the standard's PBS.

Implementation of these identified elements led to model development with integration of standardization, enabling automated supply chain generation, detailing of components, including commissioning as uncertainty and extending supply chain options. The model utilizes the common practices of techno-economic studies yielding techno-economic metrics such as Levelized Cost of Total Energy, Hydrogen, and Electricity (LCOTE, LCOH, and LCOE). Moreover, to focus on energy island-based configurations, a cost estimation model for offshore artificial energy islands has been developed.

By applying the developed techno-economic model to the 19.5 GW case study hub North in the NSE programme, the model's applicability is demonstrated, showcasing the technical and economic advantages of integrating an energy island into offshore energy infrastructure. The key finding from this application is that, for the study's setup, island-based configurations are more economically efficient for hydrogen production compared to platform or onshore setups. Considering co-production of hydrogen and electricity, at both 50%, island-based configurations have a lower weighted LCOH of 8.86 €/kg (range of all unique scenarios of $n = 4374$ between 8.54 - 10.40), versus 10.55 €/kg (range 10.13 - 11.44 for $n = 729$) for platform-based and 9.94 €/kg (range 9.52 - 11.06 for $n = 729$) for onshore-based configurations.

From the model results that this advantage for island-based compared to platform-based is due to lower operational and capital expenses for electrical and electrolyzer systems, along with longer electrolyzer stack lifetimes and reduced efficiency degradation rates (EDR), outweighing the higher initial investment of the energy island. Although offshore foundation structures like jackets typically entail lower investment costs, their decentralized nature poses other challenges. It is difficult to maintain a constant direct current base load, leading to increased electrolyzer EDR. Additionally, the marine environment and harsh weather conditions lead to higher investment costs compared to onshore or island facilities.

Lastly, a detailed review of studies on hydrogen import indicates a LCOH ranging from 4 to 9 €/kg. In these studies, import terminals and temporary storage are often omitted. Additionally, their assumed electrolyzer costs are often considerably low compared to this study's electrolyzer cost estimate from preliminary data of the NSE programme. This leads to the fact that in literature, the presented values of LCOH are often overly optimistic. Based on the calculation of 4374 unique island-based scenarios, the LCOH ranges from 8.54 - 10.40 €/kg, leading to the conclusion that there is potential to compete with hydrogen import. Especially given the potential subsidies for North Sea-produced hydrogen and the often overly optimistic estimates in literature.

This study addresses the need for a transparent, standardized techno-economic method to compare various offshore wind supply chains by developing an open-source model with automated configuration generation. Applying this model to the hub North case study explicitly demonstrates its proof of concept and the feasibility of integrating energy islands for the NSE programme, ensuring this concept is not overlooked. By utilizing the model, industry players can input their latest cost and efficiency values, resulting in more accurate calculations. This could enhance the recognition of its proof of concept, further leading to industry-wide efforts into collaborative design methods to overcome the challenges of the competitive hydrogen and wind market. Finally, an outlook suggests concrete advises for the NSE program, directing bodies, and the broader offshore wind industry.

- By this study's proof of concept, the Ministry is suggested to stimulate standardized, open-source, industry-wide model development to overcome the industry's challenging isolated dynamics
- This study has demonstrated the energy island's techno-economic feasibility, with significant potential for further optimization in areas such as location, construction methods, and logistics
- Identification of additional benefits - not yet reflected in the LCOH - would further strengthen the concept of offshore energy islands

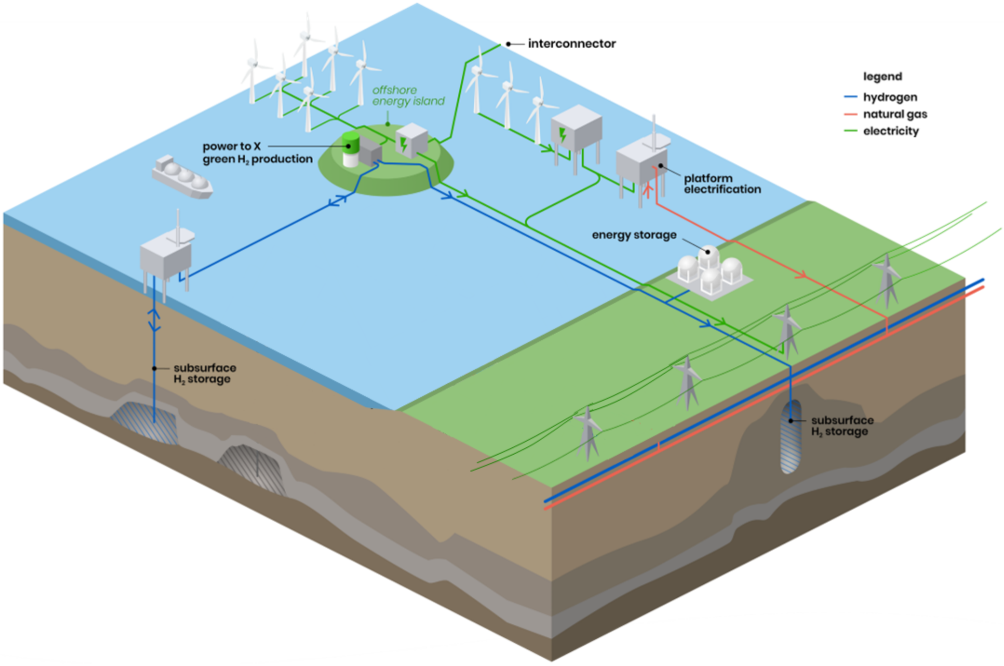

Figure 1: Graphical summary of co-production of hydrogen and electricity on an offshore artificial energy island, alongside a supply chain dedicated to transporting electricity to shore via an offshore substation, adopted and modified from IRO (2022)

Contents

Abbreviations

Abbreviation	Definition
AEL	Alkaline Electrolysis
AC	Alternating Current
CAPEX	Capital Expenditures
COR	Code of Resource
DC	Direct Current
DECEX	Decommissioning Expenditures
DPB	Discounted Payback Period
ESDL	Energy System Description Language
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current
LCOTE	Levelized Cost of Total Energy
LCOE	Levelized Cost of Energy
LCOH	Levelized Cost of Hydrogen
LCOHP	Levelized Cost of Hydrogen Production
LCOHT	Levelized Cost of Hydrogen Transport
LVDC	Low Voltage Direct Current
NPV	Net Present Value
NSE	North Sea Energy programme
OPEX	Operational Expenditures
PBS	Physical Breakdown Structure
PEMEL	Proton Exchange Membrane Electrolysis
SAB	Standard Activity Breakdown
SOEC	Solid-Oxide Electrolysis Cell
W2H	Wind-2-Hydrogen
W2P	Wind-2-Power
WACC	Weighted Average Cost of Capital
WBS	Work Breakdown Schedule

1 Introduction

1.1. Motivation and relevancy

In subsection 1.1.1 the reader will be guided through the dynamic field of offshore wind. The section highlights the growing relevance of integrating artificial energy islands into offshore energy infrastructure for enhanced cost and energy efficiency, as well as their positive impact on creating a resilient and robust energy system. However, these benefits are frequently under-addressed in existing studies, which may result in the energy island concept being overlooked in offshore energy infrastructure planning. In subsection 1.1.2, the relevance of system thinking to facilitate efficient and optimal offshore energy infrastructure design is explained, in which standardization holds a key component.

1.1.1. Motivation and relevancy - energy island and hydrogen production

Current plans wind energy in the Dutch North Sea

The Paris Agreement commits all parties to reduce emissions, adapt to climate change impacts, and strengthen efforts over time, aiming to limit global warming to well below 2°C above pre-industrial levels, with a target of 1.5°C (UNFCCC, 2015). Achieving this requires ambitious greenhouse gas reduction targets and a transition to renewable energy sources like wind and solar, in which wind energy is vital to the Netherlands' sustainable energy strategy. Due to limited land and public resistance to onshore turbines (Jarvis, 2022), the focus has shifted to offshore wind development. Offshore wind farms benefit from higher wind speeds (Bilgili et al., 2011), leading to higher production factors compared to onshore turbines (CBS, 2022). Despite offshore wind turbine's transmission losses for long-distance transport to the mainland (Eeckhout et al., 2009) and high capital expenditures (Brändle et al., 2021), the Dutch market is increasingly prioritizing offshore wind energy initiatives.

Offshore wind energy involves placing wind turbines at sea to generate electricity. For direct cable supply to onshore grids, the energy efficiency is optimized (Srinil, 2016). Initially, Dutch offshore wind farms were located nearshore, enabling highly efficient energy systems. Alternating current (AC) power transmission over short distances is a straightforward process, and by stepping up the voltage to high voltage AC (HVAC) with transformers, active energy losses are significantly reduced (Apostolaki-Iosifidou et al., 2019). HVAC is compatible with the Dutch national grid, allowing direct supply (TenneT, 2024b). However, as capacity increases and farms move further offshore, challenges such as high cable infrastructure costs and increased energy losses arise (Zhao et al., 2020; Jin et al., 2019).

To overcome the high energy transmission losses of AC power over long distances, high voltage direct current (HVDC) transmission is used (Figure 1.2). Converting AC wind power to HVDC is complex and costly compared to handling AC voltages with transformers (Härtel et al., 2017). However, after conversion to HVDC, transmission is highly efficient, incurring minimal active losses. HVDC transmission only incurs active losses, which can be minimized with very high voltages. For instance, a 320 kV HVDC cable loses about 0.3% of power over 200 km, compared to 6.5% for HVAC (Apostolaki-Iosifidou et al., 2019). Studies commonly acknowledge that for distances well beyond 100 km, HVDC is more efficient (Torres et al., 2014). Despite this, HVDC conversion remains costly and must be converted back to HVAC to supply the onshore grid (EMV, 2024), impacting the cost of electricity for distant wind farms.

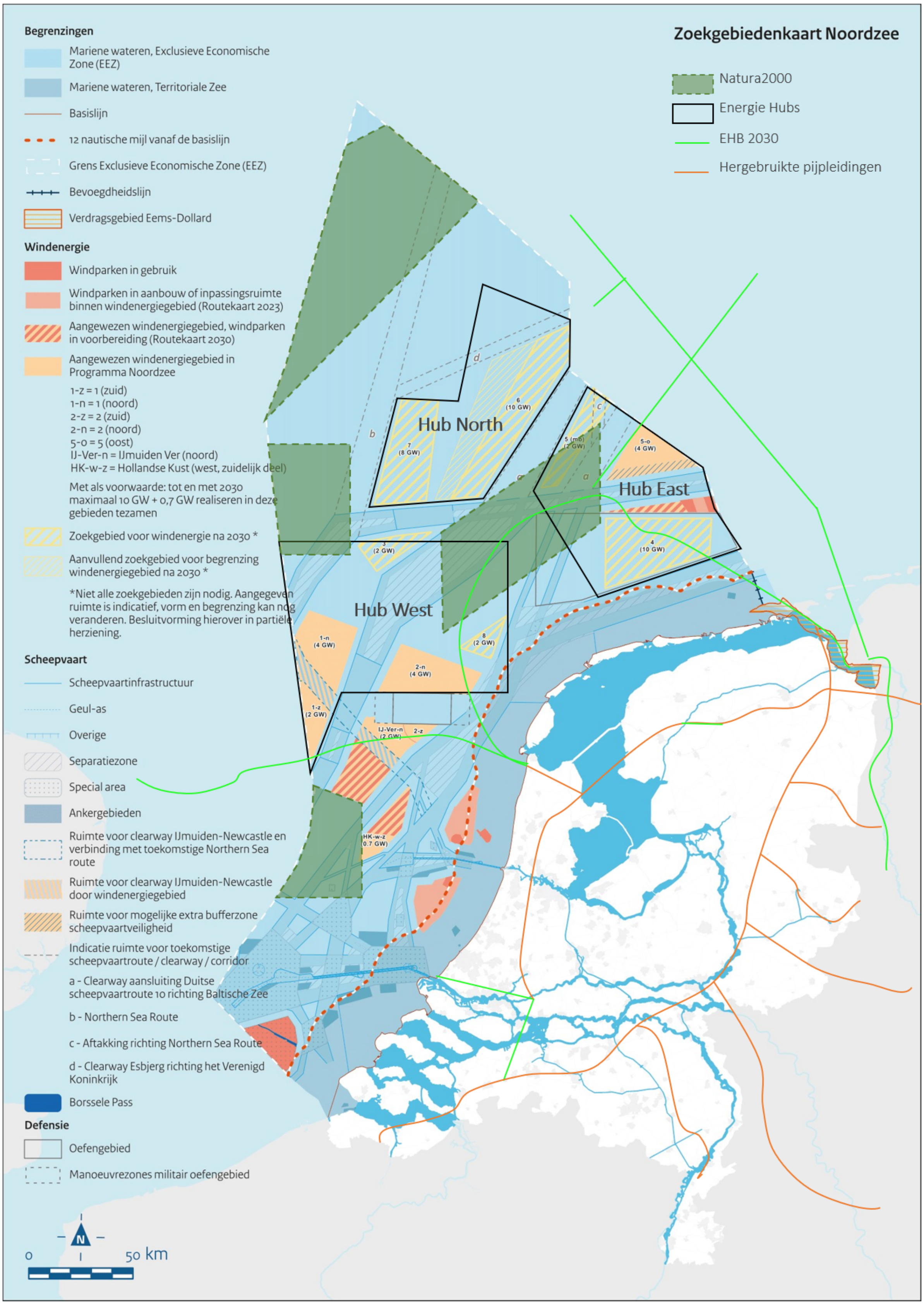

Figure 1.1: Search Areas North Sea - Map 4 North Sea Program 2022-2027 (NL: "Zoekgebiedenkaart Noordzee - Kaart 4 Programma Noordzee 2022 - 2027"), adopted and modified from Rijksoverheid (2022)

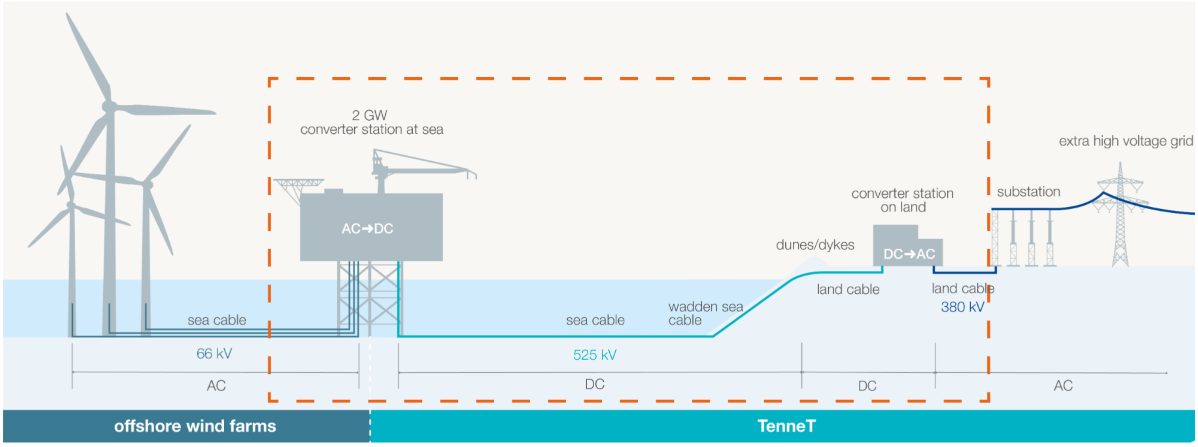

Figure 1.2: Proposed new standard for offshore grid connection systems with standardized 2 GW HVDC converter stations by TenneT, adopted from TenneT (2024a)

An additional challenge arises from integrating fluctuating offshore wind energy into the national electricity grid. The variable nature of wind energy makes it difficult to balance supply and demand. Existing grid infrastructure may struggle to accommodate sudden changes in electricity generated by offshore wind farms, leading to congestion and inefficiencies. Consequently, some companies are currently being excluded from connecting to the national electricity grid (Netbeheer Nederland, 2024). The government recently announced a €25 billion loan for TenneT to expand the national grid (Rijksoverheid, 2024). However, construction will not commence until 2030, further delaying commissioning. Currently, during periods of low energy consumption and high energy production, it is necessary to curtail wind energy from sea to alleviate pressure on the energy grid, resulting in the wastage of renewable energy.

Future plans to expand offshore wind capacity will exacerbate existing grid constraint challenges. This expected continuous increase in offshore wind energy capacity will only escalate pressure on the current energy infrastructure system. The Netherlands' offshore wind energy ambitions in the North Sea are enormous, with current installations at 4.7 GW, plans to reach 21 GW by 2032, and projections of 70 GW by 2050 (Netherlands Enterprise Agency, 2024). Figure A.1 depicts the cumulative growth of global offshore wind capacity, with a total capacity of 67.4 GW in 2023, indicating the immense magnitude of the 70 GW in the Dutch North Sea alone by 2050. The commercial availability of advanced wind turbines like the 13 MW Haliade-X (GE Vernova, 2024) and the 14 MW SG 14-222 DD (Siemens Gamesa, 2024; Adnan Durakovic, 2024) underscores the scale of upcoming installations. This implies that within eight years, an additional exorbitant number of 1,100 improved Haliade-X or SG 14-222 DD wind turbine models need to be installed.

The increasing distance of offshore wind farms from shore, coupled with the relatively higher costs associated with HVDC power transmission infrastructure compared to HVAC transmission, underscores the necessity for optimizations in this domain. Moreover, the existing capacity constraints in the national onshore electricity grid render the straightforward connection of offshore wind energy unfeasible. Therefore, a primary objective lies in optimizing offshore wind energy efficiency and transmission costs while ensuring grid stability, amidst various other challenges.

Necessity of energy storage systems

Another aspect, but in line with the purpose of alleviating the constraint national electricity grid, is the crucial storage of offshore wind energy (Mohler & Sowder, 2017). Wind energy holds great potential for generating electricity, however, its natural occurrence is characterized by fluctuating behavior, which poses significant challenges for the grid (Stangro, 2015). The variability of wind speed and direction can cause sudden and unpredictable changes in the output of wind turbines (Valdés Lucas et al., 2016; Ren et al., 2017). This intermittency leads to an imbalance between supply and demand, often necessitating curtailment, where excess wind energy is intentionally discarded to prevent grid overload (Biggins & Brown, 2022). However, curtailment comes at a cost, as it means wasting valuable renewable energy resources. For example, a study found that in Great Britain, increased wind deployment could lead to curtailment of up to 17% of annual variable renewable electricity generation (Villamor et al., 2020).

Implementing energy storage systems is crucial for harnessing the full potential of wind power and reducing curtailment rates (Yousefi et al., 2023), which enhances the utilization and profitability of offshore wind farms (Chen et al., 2022). These systems store surplus wind energy during high production periods and release it when demand exceeds supply, thereby smoothing out the fluctuations and ensuring a more reliable and stable grid operation (Martínez de León et al., 2024).

To address daily fluctuations in supply and demand, batteries are effective (Martínez de León et al., 2023). However, managing weekly and seasonal variations requires different strategies (Pellow et al., 2015; Chatenet et al., 2022). Energy storage systems can be categorized into several types, including electrochemical and battery storage, thermal storage, thermochemical storage, compressed air storage, pumped hydroelectric storage, magnetic storage, chemical storage, and hydrogen storage. For long-term storage, the most viable options currently available are batteries, pumped hydroelectric storage, compressed air storage, and hydrogen storage (Koohi-Fayegh & Rosen, 2020).

As wind power integration into the grid grows, effective weekly and seasonal energy storage systems become crucial (Ozarslan, 2012). These systems enhance both energy stability and security, specially in light of the Netherlands' energy vulnerabilities highlighted by recent global conflicts, underscoring the need for self-reliant domestic energy production. While batteries manage daily fluctuations, longer-term variations require alternative solutions. In this context, the utilization of ammonia and hydrogen emerges as a technical and economical realistic, yet crucial, potential for efficient long-term energy storage (Brey, 2021). Based on Ozarslan (2012), hydrogen emerges as the most suitable technology for large-scale, long-term storage.

Hydrogen within the energy system

Hydrogen stands out as a promising energy storage solution due to its seasonal storage capability and versatility in producing zero-emission fertilizers and chemicals (Saeedmanesh et al., 2018). When hydrogen is generated via electrolysis, a process that uses electricity to split water molecules into hydrogen and oxygen, and this electricity is sourced from renewable energy such as wind, it is known as green hydrogen (IEA, 2019). This method presents a sustainable approach for producing and storing renewable energy. Hydrogen's applications extend to the petroleum industry, chemical synthesis, transportation, and power generation. It can be stored in tanks, salt caverns, or repurposed old gas fields, making it a versatile long-term energy storage option (Lysyy et al., 2021).

Alongside green hydrogen, green ammonia cannot be overlooked, composed of nitrogen and hydrogen (NH_3). Traditionally produced using the carbon-intensive Haber-Bosch process (Adeli et al., 2023), green ammonia offers a carbon-neutral alternative by using green hydrogen and atmospheric nitrogen (Arora et al., 2016). It has multiple promising applications: reducing emissions in fertilizer production, serving as a cleaner transportation fuel, and efficiently storing and transporting renewable energy (Bora et al., 2024). Green hydrogen and green ammonia can be reconverted to electricity via fuel cells or used directly as energy sources. Hydrogen releases only water vapor as a byproduct, while ammonia releases primarily water vapor and nitrogen gas, making both clean and versatile energy carriers. The existing global infrastructure for ammonia production, storage, and transportation provides a head start for expanding the use of green ammonia, leveraging existing assets while minimizing the need for entirely new infrastructure investments (Bora et al., 2024). Green ammonia's potential underscores the importance of green hydrogen production.

The imperative of producing hydrogen as an energy storage system perfectly aligns with the objectives of the REPowerEU plan proposed by the European Commission to produce and import large quantities of hydrogen by 2030 (European Commission, 2022). The plan should serve as a strategy that reinforces energy security while encouraging Europe's transition to cleaner energy sources. The strategy includes annual domestic production of 10 million tonnes and also import of 10 million tonnes of renewable hydrogen by 2030 (European Commission, 2022). The imperative also aligns with the Dutch National Climate Agreement's ambition to scale up electrolysis to 3-4 GW of installed capacity by 2030 (Rijksoverheid, 2020), or the ambition within the Dutch Hydrogen Roadmap of 6-8 GW (NWP, 2022), equivalent to approximately 0.25 - 0.35 million tonnes per annum (mtpa) and 0.50 - 0.70 mtpa, respectively, depending on the number of full load hours.

Another important incentive is the benefit of acquiring one's own energy supply, as recent global conflicts have shown. In any case, advocating for a diverse energy supply can be supported. Which would, in the case of hydrogen, consist of a domestic offshore wind to hydrogen production, import of for example liquid ammonia in port of Rotterdam (Brauer et al., 2022) and import of hydrogen with pipelines from the solar-rich countries in Southern Europe (Timmerberg & Kaltschmitt, 2019).

The Hydrogen Roadmap, proposed by the National Hydrogen Program, outlines the collaborative efforts of public and private stakeholders to achieve the Netherlands' hydrogen ambitions and climate goals, establishing the country and Rotterdam as a hydrogen hub (NWP, 2022). Leveraging its experience with hydrogen, natural gas infrastructure, port facilities, and offshore wind capabilities, the Netherlands is well-positioned for large-scale hydrogen development (Roland Berger & Royal HaskoningDHV, 2022). Rapid action will enable Dutch companies to secure key positions in various sub-markets, ensuring its strong position in the international hydrogen industry.

Hydrogen can be produced through various methods, including electrical, thermal, biochemical, photonic, and electro-thermal processes (Dincer & Acar, 2015). For import, the common hydrogen carriers for shipping are liquid hydrogen (LH_2), ammonia (NH_3), and liquid organic hydrogen carriers (LOHC). For transport by pipelines, gaseous hydrogen (GH_2) is typically used (Wijayanta et al., 2019). This study focuses on producing green hydrogen using offshore wind energy. Multiple supply chain configurations are possible: the electrolyzer can be located onshore, centralized on an artificial energy island, centralized on an new (Konrad, 2014) or repurposed (Kok et al., 2018) offshore platform or decentralized on multiple offshore platforms. Additionally, there are initiatives to place smaller electrolyzers within individual wind turbines for a decentralized offshore system (Singlitico et al., 2021). Evaluating these supply chains for efficiency and economic feasibility is crucial, especially for offshore artificial energy islands as the current literature is still relatively limited on this (Lüth et al., 2023).

Offshore artificial energy island - the concept

The term 'offshore artificial energy island' has been previously mentioned in the context of offshore electrolysis, but it requires further elaboration. The concept of energy islands gained momentum around 2016, initially proposed by the North Sea Wind Power Hub (NSWPH) consortium for the Dogger Bank (NSWPH, 2024). Denmark further embraced this concept in 2020, announcing plans for two energy islands in the North Sea and the Baltic Sea. This spurred interest in other countries such as Norway (Zhang et al., 2022), Belgium, and Germany. The idea aligns with the European Commission's vision to expand offshore wind power as a key element of the energy system transformation (European Commission, 2020). Figure 1.3 presents an overview of potential energy hubs around the North Sea.

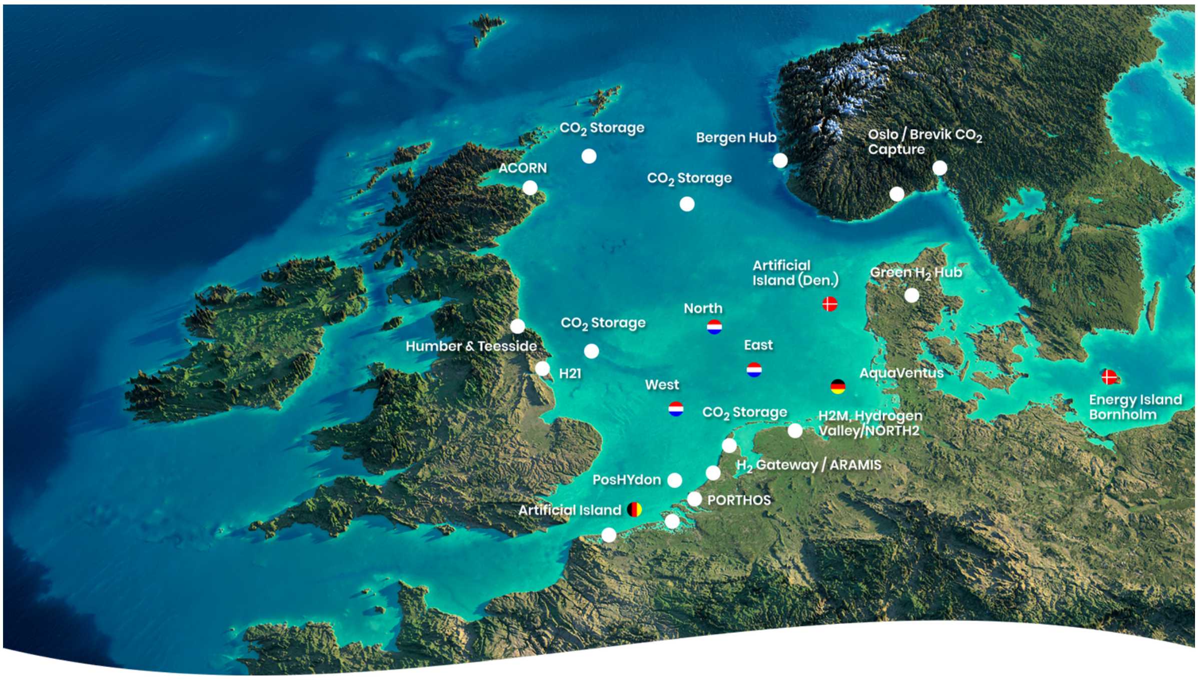

Figure 1.3: Locations of Energy Hubs at and around the North Sea. Search Areas for Hubs in the North Sea Energy Program are Highlighted: Hub West, Hub East, and Hub North, adopted from NSE Programme (2024)

By growing offshore wind power production capacity, offshore energy transmission infrastructure must also be expanded. Integrated offshore grids, potentially with meshed structures (Gea-Bermúdez et al., 2018), offer a promising solution by enhancing interconnection, stabilizing renewable energy systems (Strbac et al., 2014), and increasing overall social welfare through efficient renewable energy use (Schlachtberger et al., 2017; Egerer et al., 2013). Power link islands, which bundle large wind resources, are considered efficient components of these grids and precursors to energy islands. These energy islands are defined by their offshore location, large surrounding wind capacities, cable connections to land, and potential storage and conversion technologies (Lüth, 2022).

Currently, an energy island is under construction off the coast of Belgium – the Princess Elisabeth Island, the world's first artificial energy island (Elia Group, 2024). The energy island will house almost exclusively transmission infrastructure, combining HVDC and HVAC, improving the system's energy efficiency. As the offshore wind sector expands, countries are exploring increasingly sophisticated methods of connecting wind farms to the mainland. Whereas previously only radial (from A to B) connections were used, more complex approaches are now being adopted. Europe is striving to establish meshed offshore networks, with energy islands playing a key role. As the world's first energy island, Princess Elisabeth Island fully dovetails with this new strategy (Elia Group, 2024).

Despite technological advances and declining transmission costs, transferring electricity from offshore wind farms via sub-sea cables remains expensive (IRENA, 2019b). One way to reduce cable use is to convert some of the generated electricity into hydrogen and transport it to shore via less costly hydrogen pipelines (Singlitico et al., 2021). This concept is central to discussions about energy islands, which act as interconnected conversion and storage hubs at large offshore wind farms (Tosatto et al., 2022; Lüth, 2022). Although energy islands for hydrogen production have not yet been commissioned, the Danish government and industrial consortia are exploring integrating hydrogen production from offshore wind on potential energy islands (North Sea Energy Island Consortium, 2024). A well-designed policy framework is needed due to the project's scope, long investment cycles, and market uncertainties.

As illustrated before, transmitting electricity from distant offshore wind farms is challenging due to high costs and efficiency losses over long distances (Apostolaki-Iosifidou et al., 2019). Moreover, the current supply of wind energy is already straining the onshore grid, leading to capacity issues that will only worsen in the future. In this context, hydrogen production becomes an increasingly attractive method to alleviate grid constraints and improve curtailment utilization (Park et al., 2023). For example, a study by Durakovic et al. (2023) calculated that without an energy hub and hydrogen production, the average curtailment of all offshore wind farms in the North Sea in 2050 will be 24.9%. In contrast, with both an energy hub and hydrogen production, curtailment is reduced to 9.6%, significantly addressing the potential of centralized offshore hydrogen production. The perception of the economic feasibility of offshore artificial energy islands has shifted over time. Initially deemed too expensive and technologically complex, recently, there has been a growing recognition of the challenges in transporting offshore wind energy over long distances, making energy islands a more viable solution (Jansen et al., 2022; Rogeau et al., 2023; Lüth et al., 2024).

Energy islands offer significant potential for large-scale, centralized offshore electrolysis (Jansen et al., 2022), enabling cost-efficient, high-capacity hydrogen transport via large pipelines (Wingerden et al., 2023). Doubling the diameter of hydrogen pipelines increases transport capacity quadratically while keeping investment costs proportional. In contrast, large-scale electricity transport is limited by cable capacity (AC cables have maximum at around 350 MW and DC cables at around 2 GW) (Wingerden et al., 2023). In contrast, a single 48-inch hydrogen pipeline would enable 16.9 GW of energy transport, indicating its huge potential and economic attractiveness for larger capacities, supporting a planned hydrogen backbone network in the North Sea (Wang et al., 2021). Additionally, landing electrical cables in countries like the Netherlands and Germany is challenging due to protected nature areas along coastlines. (Wingerden et al., 2023). Bundling cables is difficult due to electromagnetic induction constraints, but pipelines, with their higher transport capacity, require less space for onshore landing.

Although the previous analysis has demonstrated the promising potential for offshore hydrogen production on energy islands, and the benefits of integrating energy islands within large-scale offshore wind power production are increasingly recognized, the literature on this topic remains limited (Lüth et al., 2023). This poses a significant challenge, as comprehensive studies are essential to elevate the concept's visibility and facilitate its integration into offshore energy infrastructure design. Consequently, we might risk that the integration of energy island concepts into offshore infrastructure is overlooked.

1.1.2. Motivation and relevancy - system thinking and standardization

Necessity of large-scale system thinking

The anticipated increase in offshore wind capacity, longer transmission distances, higher energy losses, and need for seasonal energy storage present an enormous challenge. Nevertheless, the magnitude of this energy transition is often underestimated (McKinsey, 2023b), and acknowledging the complexities involved is crucial. Successfully navigating it requires bold, innovative measures and a reevaluation of traditional offshore energy systems, which can only be achieved through industry-wide collaboration.

Exploring novel methods for offshore energy transport to shore reveals the challenge of accurately assessing developments made in individual components (e.g. electrolyzers and pipelines) and translate these developments into total system costs or energy prices. Developers focus on optimizing individual performance and cost-effectiveness without considering the broader energy system context. Additionally, manufacturers may hesitate to share performance metrics, costs or design details due to competitive concerns (Kusiak, 2016). This isolated company-specific approach risks investing heavily in individual concepts which pose a part of the solution but may not be feasible from a larger system perspective.

For instance, electrolyzer manufacturers may focus on maximizing hydrogen output through efficiency optimization, which feels intuitive as their primary objective. However, in practice, electrolyzers solely optimized for hydrogen output might be impractical within the larger offshore system context. If the system design prioritizes processing otherwise curtailed offshore wind peaks instead of a dedicated hydrogen production, the electrolyzer design should focus on operational flexibility, rapid ramp-up times, and minimal efficiency degradation due to highly variable input. Without focusing on these aspects, the electrolyzer might malfunction for its intended purpose and degrade rapidly, leading to a significantly shorter economic lifetime. Consequently, replacement frequency and costs would increase dramatically.

Stakeholders, including wind farm developers and government bodies, often focus on their components, neglecting broader system needs. In the early stages of green hydrogen project development, a systemic perspective is crucial. Collaboration across the supply chain can mitigate risks, share knowledge, and foster innovation. Neglecting to examine the larger system perspective may lead to concepts being (incorrectly) deemed unfeasible, as seen with the energy island example (Bloomberg, 2023).

Facilitate large-scale system thinking through standardized method

Establishing a collaborative ecosystem where supply chain players share insights and best practices fosters efficient energy system design. To enhance this system thinking ideology, Van den Haak (2023) developed a transparent, open-source model, allowing for offshore infrastructure concept comparison through the LCOH. This facilitates industry-wide discussions and enhance exploration of concepts, improving decision-making processes in the energy transition.

The applicability of the method was demonstrated through a case study. However, despite significant advancements toward an industry-wide, transparent comparison model, it could benefit from further technical component detailing and validation by industry players. Currently, the supply chain configurations within the model are generated manually, and only a limited number of configuration types are supported for calculations. This limitation hinders its attractiveness and reduces the likelihood of first-mover adoption by industry players.

Absence of standardization in comparison studies

Van den Haak (2023) observes in his study that no research has yet been done to standardize a method whereby every possible W2H concept can be compared in a transparent and equal way, while it would help stakeholders to better understand possible offshore W2H concepts, and the effect of components' prices on the total cost of a project. In this context, the LCOH is the most common method used to compare hydrogen concepts, but discrepancies exist due to variations in assumptions. While some researchers attempted to develop models for the techno-economic evaluation of offshore W2H concepts, these models did not consider stakeholder adoption and contribution (Dinh et al., 2021; Yan et al., 2021). The developed method and model by Van den Haak (2023) could serve as a standardized method using the LCOH method, functioning as a benchmark for existing in-house comparison models.

Herdem et al. (2024) similarly concluded that while numerous studies have been published on various green hydrogen production systems, a systematic comparison approach is lacking. The industry is flooded with numerous reports that separately address different aspects of hydrogen production, utilization, storage, and economics (Yukesh Kannah et al., 2021; Yue et al., 2021; Gabriel et al., 2022). The standardization approach suggested by Herdem et al. (2024) would greatly benefit the offshore W2P and W2H industries by providing a consistent method for evaluating different green hydrogen production systems.

1.2. Research Problem

To stay on track for the 1.5°C pathway of the Paris Agreement, the current speed and scale of the energy transition would need to increase significantly. The European Union would now need to triple its current pace of renewable-energy-source deployment to avoid a less orderly transition (McKinsey, 2023a). In parallel, considering the ambitious REPowerEU and Dutch Hydrogen Roadmap targets, there is an imminent need for a supported acceleration of the energy transition. However, in the current landscape, the confidential and competitive nature of the offshore wind and hydrogen markets hinders knowledge and concept sharing among stakeholders, which is essential to determine the optimal offshore energy infrastructure design in terms of cost and energy efficiency. Industry-wide cooperation is sub-optimal, with various parties vying for their own methods without considering the larger system perspective. Potentially resulting in less efficient and organized setups in the larger system perspective. Furthermore, the limited number of studies on high-potential concepts like energy islands could lead to their oversight and underinformed decision-making. As a result, the required acceleration of the energy transition may fall short, jeopardizing the goal of staying within the 1.5°C pathway.

In order to ascertain the most viable offshore wind energy concept for the North Sea, and to facilitate decision and policy making for directing bodies, it is essential that all stakeholders engage in a transparent discussion. Facilitating this discussion could greatly benefit from the adoption of a transparent method for comparing alternative offshore wind to hydrogen concepts. However, two distinct challenges emerge in this context. Firstly, there is a deficiency in research of the feasibility of innovative supply chain methods, with energy islands being a prime example. No calculation model is present yet. This may result in energy islands being neglected in offshore energy infrastructure planning, potentially leading to sub-optimal solutions. Secondly, as observed by Van den Haak (2023), no research has yet been done to standardize a method whereby potential offshore W2H concepts can be compared in a transparent and equal way. In his study, a significant advancement was made into a standardized method, facilitating efficient concept comparison. Nevertheless, the current method might benefit significantly by improving its technical features, facilitating its industry-wide adoption and valuation.

With the potential recognition, industry and government could start guiding developments towards industry-wide collaborative design methods, overcoming the challenges of the competitive hydrogen and wind market and truly igniting the required acceleration of the energy transition.

1.3. Research Gap

In this section, the research gap will be addressed through a comprehensive literature review, comprising of three elements, namely: (1) general literature review, (2) detailed analysis of feasibility studies within the offshore wind industry and their characteristics, and (3) detailed analysis of the current standardized method by Van den Haak (2023). Given that offshore W2H is a relatively novel concept marked by ongoing developments and emerging insights, the focus is exclusively on papers published after 2018.

1.3.1. Literature review offshore wind & hydrogen import

This subsection reviews the literature across four key areas: the offshore (i) wind-to-power, (ii) wind-to-hydrogen, (iii) wind-to-hydrogen including energy island concepts and (iv) global hydrogen import.

(i) Offshore wind-to-power

Offshore wind energy has received significant attention as a viable option for decarbonizing power generation. This led to detailed cost modeling of offshore wind-to-power (W2P) projects, often comparing HVAC and HVDC power transmission to shore (Xiang et al., 2016). Resource assessments play a crucial role in identifying optimal energy production locations and estimating global potential and associated costs. Previous studies have conducted resource assessments for W2P (Elsner, 2019; Patel et al., 2022; Arenas-López & Badaoui, 2022). Site selection methodologies are commonly employed to pinpoint suitable areas for wind power projects, with some studies coupling site selection with economic evaluation to produce economically attractive resource curves (Dupré la Tour, 2023; Caglayan et al., 2019; Hundleby et al., 2017). It is worth noting that the modelings of costs used in resource assessment studies are often simplified, taking into consideration only part of all the expenditures presented above or adopting simplified models (Rogeau et al., 2023).

(ii) Offshore wind-to-hydrogen

In contrast, hydrogen production from offshore wind farms is a relatively new area of research (Rogeau et al., 2023). Some studies examined the current situation of wind-to-hydrogen (W2H) (Calado & Castro, 2021; Ibrahim et al., 2022; Luo et al., 2022) and identified three main supply chain configurations for such projects, namely onshore, centralized offshore, and decentralized offshore electrolysis. Singlitico et al. (2021) also considered these connection schemes for an offshore wind case study in the North Sea considering a parallel power-hydrogen export connection. Similarly, Lüth et al. (2023) evaluated the most economical option between hydrogen and power connection for an energy island considering grid infrastructure and capacity expansion. Lucas et al. (2022) estimated the economics of hybridizing an existing W2P project and analyzed the impact of electricity price fluctuations on the levelized cost of hydrogen (LCOH). Kim et al. (2023) studied three configurations of offshore wind farms for hydrogen generation and compared the LCOH for optimized sites and designs. Similarly, Jiang et al. (2022) performed sizing optimization of offshore hydrogen generation wind farms. In all these works, no real site characteristics are considered and the wind farms configurations are theoretical.

Some studies integrate geographic analysis with the economic evaluation of W2H projects. For instance, Komorowska et al. (2023) conducted a case study in Poland focusing solely on onshore electrolysis. Dinh et al. (2023) assessed the LCOH for W2H projects in Ireland, considering a centralized offshore connection scheme. Additionally, Giampieri et al. (2024) explored the potential of using offshore electricity for hydrogen production via different transport methods in a case study based in the UK. They employed a learning rate in their analysis, referring to the rate at which costs decrease with increased production due to gained efficiencies and improved methods. The techno-economic study by Wolf et al. (2024) uses a stochastic approach with Monte Carlo simulations to analyze the potential LCOH in Germany, Norway, Spain, Algeria, Morocco, and Egypt for 2050. The analysis includes the concept of economy of scale, highlighting cost advantages from increased production, which is vital for future electrolyzer cost reduction. Additionally, they emphasize the importance of using country-specific weighted average cost of capital for discounting in LCOH calculations instead of a uniform value for all countries. However, a harmonized comparison of onshore electrolysis considering HVAC and HVDC export and offshore electrolysis including both centralized and decentralized options is still lacking (Rogeau et al., 2023).

(iii) Offshore wind-to-hydrogen including energy islands

Even less studied is the integration of offshore artificial energy islands within offshore wind energy and electrolysis (Lüth et al., 2023). Singlitico et al. (2021) were the first to analyze combining electricity and hydrogen production from offshore wind on large energy islands, finding that prioritization of hydrogen production can make offshore placement cost-competitive with fossil fuel hydrogen. Jansen et al. (2022) examined the North Sea Wind Power Hub, showing that large connected wind generation capacities can make an energy island profitable, based on exogenous capacity assumptions. In contrast, Lüth et al. (2023) used an integrated capacity model to endogenise the decision of connecting energy islands by cable or pipeline and at what capacity.

Lüth et al. (2023) explored the design and planning of offshore energy infrastructure, focusing on energy islands and the trade-offs between offshore electricity and hydrogen infrastructure. Their research question addresses how energy islands can be integrated with onshore energy systems and the system implications of such integration. In a related study, Lüth et al. (2024) assessed operational patterns, market results, and prices incorporating uncertainties of electricity production. A two-stage stochastic optimisation model was developed that solves the day-ahead and balancing market-clearing problems for bidding zones. They considered case studies of proposed energy islands by the North Sea Wind Power Hub consortium, the Danish Energy Island, and Bornholm.

(iv) Global hydrogen import

Li et al. (2019) concluded that the most cost-effective method for importing hydrogen was to that date unclear. In response, Lanphen (2019) examined this issue in greater detail, providing insights into which energy carrier is most efficient for various distances. Numerous studies have followed, assessing various hydrogen transportation options. For instance, Hong et al. (2021) found that compressed H_2 via pipeline has the lowest energy penalty and cost for distances up to 2000 km. Conversely, Cui and Aziz (2023) concluded that ship transshipment is the least expensive option for shipping ammonia and methanol. Additionally, Rong et al. (2024) also examined the storage and determined that both liquid hydrogen and liquid organic hydrogen carriers (LOHC) are suitable for long-distance transport with large volumes. In their study ammonia was not included as an energy carrier.

Makepeace et al. (2024) studied the entire supply chain, including H_2 generation, conversion, transport, and carbon pricing, concluding that shipping is the most likely and cost-effective H_2 export method for long distances. Specifically, ammonia, methanol, and LOHC were identified as the most viable hydrogen carriers for the Australia to Japan route in 2030.

A study by d'Amore Domenech et al. (2023) examined hydrogen delivery scenarios for three sea transport alternatives: liquefied hydrogen (LH_2) shipping, compressed hydrogen (cH_2) shipping, and pipeline transport. Focusing on transport costs, including packing and unpacking, but excluding hydrogen production and local distribution, the study analyzed scenarios with mass flow rates from 0.1 mtpa to 10 mtpa over distances of 100 km to 5000 km. The findings indicated that there is no "silver bullet" for mass hydrogen transport, with each alternative performing better under specific conditions. For instance, pipelines are best for short distances (100 km), cH_2 shipping is optimal for 2500 km with 0.1 mtpa, and LH_2 shipping is preferable for 10 mtpa. All levelized costs were under 2 USD/kg, suggesting that countries with low-cost renewable energy could become significant green hydrogen exporters.

Schuler et al. (2024) conducted a comprehensive review analysis focusing on comparing shipping cost projections for various hydrogen-based derivatives from a wide range of recent international publications. While transportation costs in literature reveal a consistent picture for liquid ammonia, projections for liquid hydrogen, LOHCs, and, surprisingly, also for methanol and liquid methane differ significantly. Cost projections for hydrogen (derivatives) diverge as large-scale shipping is not established yet. Discrepancies are mainly attribute to the ship's speed, lifetime and CAPEX assumptions.

Summary

In short, it can be summarized that:

- There is a deficiency in techno-economic feasibility studies focusing on offshore hydrogen production including the energy island concept
- Global hydrogen transport is most likely to be cost-effective for ammonia, methanol and LOHC, with a consistent picture in literature for transport costs estimations of liquid ammonia. However, there is no "silver bullet" in mass hydrogen transport; each alternative excels under specific combinations of distance and hydrogen flow rates and should be assessed individually

1.3.2. Methods in academic literature

Detailed examination of feasibility studies in literature provides Table 1.1, in which for each study the characteristics are checked, including whether an energy island is included, what the economic assessment method is, if efficiencies are specified, if a standard is included to enhance industry-wide collaboration and if the methods are open-source. Below, the key observations are listed.

Table 1.1: Overview of previous research in the field of techno-economic analyses on utilization of wind energy for electrolysis

Author	Island	Dedicated	Economic ass. meth	Financial assump.	Costs specified	Efficiencies specified	Standards specified	Stochastic approach	Open-source
Giampieri et al. (2024)	No	Co-prod.	LCOH	• r = 7% • no inflation • T = 40 yrs	All but turbines & foundations	All included	No	No	No
Dinh et al. (2023)	No	100% H_2	LCOH	• r = 5% • no inflation • T = 25 yrs	CAPEX, OPEX, DECEX	None	No	No	No
Lüth et al. (2023)	**Yes**	Co-prod.	-	• r = 4% • no inflation • T = 30 yrs	Poorly	Transport losses not included	ELMOD model	No	Yes
Phan-Van et al. (2023)	No	100% H_2	LCOH, NPV, DPB	• WACC unclear • no inflation • T = 30 yrs	CAPEX, OPEX, DECEX	Transport losses not included	No	No	No
Jang et al. (2022)	No	100% E & 100% H_2	LCOH, NPV	• r = 8% • no inflation • T = 20 yrs	CAPEX, OPEX, DECEX	All included	No	Yes NORM distr.	No
Rogeau et al. (2023)	**Yes**	100% H_2	LCOH	• r = 5% • no inflation • T = 25 yrs	CAPEX, OPEX, DECEX	All included	No	No	No
Singlitico et al. (2021)	**Yes**	Co-prod.	LCOH, LCOE	• r = 5% • no inflation • T = 30 yrs	CAPEX, OPEX	Transport losses not included	No	No	No
Superchi et al. (2023)	No	100% H_2	LCOH	• r = 5% • no inflation • T = 20 yrs	Poorly	Only for electrolyzers; transport losses not included	No	No	No
Komorowska et al. (2023)	No	100% H_2	LCOH	• r = 4;6;8% • no inflation • T=20 & 30 yrs	Poorly	Only for electrolyzers; transport losses not included	No	Yes, PERT distr.	No
Roos (2021)	No	Co-prod.	LCOH, LCOE, NPV	• WACC=3;6;10% • infl. inc.	CAPEX, OPEX	Only for electrolyzers; transport losses not included	No	No	No
Groenemans et al. (2022)	No	100% H_2	LCOH	• None	Poorly	None	No	No	No
Yan et al. (2021)	No	100% E & 100% H_2	LCOH, LCOE, NPV	• r = 6% • no inflation • T = 25 yrs	CAPEX, OPEX	Only for electrolyzers; transport losses not included	No	No	No
Lucas et al. (2022)	No	100% H_2	LCOH, NPV	• r = 10% • no inflation • T = 20 yrs	CAPEX, OPEX	All included	No	No	No

McDonagh et al. (2020)	No	Co-prod.	LCOH, LCOE, NPV	• r = 6% • no inflation • T = 25 yrs	CAPEX, OPEX, DECEX	Transport losses not included	No	No	No
Dinh et al. (2021)	No	100% H_2	NPV, DPB	• r = unknown • no inflation • T = unknown	CAPEX, OPEX	Only for electrolyzers; transport losses not included	No	No	No
Franco et al. (2021)	No	100% H_2	LCOH, NPV	• r = 7% • infl. incl. • T=25 yrs	CAPEX	Transport losses not included	No	No	No
Benalcazar and Komorowska (2022)	No	100% H_2	LCOH	• WACC = 6;8;10% • infl. incl. • T=20;30yrs	Poorly	Transport losses not included	No	Yes, PERT distr.	No
Di Lullo et al. (2022)	No	100% H_2	No formula presented	• r = 10%; • infl. incl. • T=25 yrs	CAPEX, OPEX	None	No	Yes, MC simulation	No
Tang et al. (2022)	No	100% H_2	LCOH	• CoC = 6%; • no inflation. • T=20 yrs	CAPEX, OPEX	No	No	No	No
Wingerden et al. (2023)	No	100% H_2	no Eq. for LCOH	• WACC = 10% • no inflation • T=20 yrs	CAPEX, OPEX	All included	No	No	No
North Sea Energy (2018)	**Yes**	Co-prod.	NPV	• WACC = 10% • no inflation • T=40 yrs	CAPEX, OPEX	Only for electrolyzers; transport losses not included	No	No	No

Based on Table 1.1, several key observations highlight the potential elements to include in this study's objective. Addressing these research gaps will support more reliable and comprehensive analyses.

- **Limited number of studies focus on offshore hydrogen production on energy islands:** this presents a problem as it limits the understanding of the unique technical and economic benefits an energy island might offer, additionally, this might lead to the concept being overlooked
- **None of the techno-economic assessment methods applied international standards:** absence of standardization might lead to inconsistencies and reduced comparability between studies. Adopting standardized frameworks would enhance the reliability and transparency of these assessments, facilitating better study comparison
- **No open-source techno-economic assessment method available, except for one by Lüth et al. (2023):** the very limited availability of open-source studies represents a notable gap in the current literature. Open access to research findings and methods is essential for promoting transparency, reproducibility, and collaboration within the scientific community
- **No harmonized comparison of various supply chain configurations for offshore W2P and W2P within one study:** the absence of standardized comparisons between onshore and offshore electrolysis methodologies presents a significant research gap. While some studies have examined the cost implications of different electrolysis configurations, there is a lack of harmonized approaches that consider HVDC, hydrogen or co-production export options, as well as infrastructure placement on offshore platforms, energy island and onshore locations
- **Limited number of studies consider all efficiency factors associated with energy conversion and transmission:** another critical gap in the literature relates to the oversight of transmission efficiencies in techno-economic feasibility studies While these studies typically account for CAPEX and OPEX, transmission losses are often omitted from the analysis. This oversight can lead to inaccuracies in cost projections and undermine the validity of study findings

1.3.3. Current methods standardized techno-economic comparison model

Since Van den Haak (2023) presented a first advancement towards a transparent comparison method to facilitate industry-wide collaboration, it is studied in further detail to determine where the model might be enhanced. The model already has a robust basis of financial features. However, despite the comprehensive financial features, several other components are identified for improvement.

- **Detailing of individual components:** the level of detailing provides in certain scenarios trivial answers regarding the output techno-economic performance metrics. Crucial components are absent such as depth-dependent costs of offshore platform substructures and differentiation in CAPEX and OPEX for onshore, island and platform-based conversion and/or transmission installations
- **Manual supply chain generation employed in the model:** to facilitate efficient techno-economic assessment studies, the model should allow for automated generation of supply chain configurations and include all relevant options. Therefore, the model would benefit greatly from automatizing and inclusion of more supply chain configuration options
- **Component supply chain breakdown:** the method employs an intuitive supply chain breakdown schedule, corresponding with Singlitico et al. (2021). However, industry adoption of the method could be improved by explicitly aligning the supply chain breakdown with international or industry standards rather than relying solely on academic studies, making it more relatable and practical for industry professionals
- **Basic cost estimation of offshore artificial energy island:** given the focus on energy island-based supply chain configurations, current methods could significantly benefit from a detailed cost estimation tool for energy islands. Such a tool is essential for accurately assessing the feasibility and performance of offshore energy islands
- **Wind farm commissioning as design parameter:** in the current method developed by Van den Haak (2023), the influence of differentiating wind farm commissioning years on the economic performance is studied. However, without including financial risks and penalties this would give a misleading view of the system, since delayed commissioning would be beneficial due to the discounting mechanism. While in reality, a delay is associated with financial penalties

Specifically addressing these shortcomings and implementing improvements into the standardized model and method will lead to better accuracy of results, flexibility, and usability of the techno-economic feasibility study. Through this iterative process of improvement, the study aims to provide more robust and reliable insights into the feasibility and economic viability of offshore wind-to-hydrogen supply chains, contributing to the advancement of sustainable energy solutions.

1.4. Thesis objective and scope

This paragraph provides a definition of the research's purpose and field. The research objective is formulated based on the identified research problem and the existing research gap.

1.4.1. Thesis objective

To accelerate the required energy transition effectively, a standardized comparison method is urgently needed to facilitate transparent, industry-wide collaboration. This approach would enrich the industry with valuable knowledge, insights, and experiences that are currently lost in the one-sided, isolated development structure prevalent in the industry. Leading to this study's two-fold objective: (i) develop a standardized comparison method for the offshore wind industry and create an offshore artificial energy island cost estimation tool; (ii) application of this standardized comparison method and energy island cost tool to the hub North case study within the NSE programme to evaluate the feasibility of an energy island concept in detail, a topic not frequently addressed in academic literature. This approach would enable the NSE programme to make better-informed decisions.

1.4.2. Thesis scope

This research will focus on improving the current standardized model with technical features to be able to perform more accurate techno-economic analyses into greenfield developments of offshore W2H concepts in the North Sea, with a focus on offshore artificial energy islands. Full offshore wind power utilization is considered rather than electricity grid utilization. Several supply chain configurations emerge in this context, namely: full H_2 production and transmission, full electricity production and transmission, and co-production and transmission of both, at the shares 30/70, 50/50 and 70/30%.

Repurposing old gas pipelines for hydrogen transport is excluded from this study. However, it should be noted that current operators are planning to repurpose the NOGAT (Northern Offshore Gas Transport) and NGT (Noordgastransport) pipelines in the future (NOGAT, 2022). The decision of excluding it comes from the substantial risks associated with such re-purposing efforts, such as embrittlement. Moreover, various studies indicate that for re-purposed gas infrastructure the technical limit concentration of hydrogen is relatively low and that for the accomplishment of substantial decarbonization benefits high concentration levels are required (Marcogaz, 2019; Erdener et al., 2023).

The research will concentrate on the pre-feasibility stage of a project, where a high-level detailed model is unnecessary as costs and concepts are not yet fully defined. The primary goal is to identify which supply chain configurations show the most potential relative to each other rather than finding a ′perfectly′ correct LCOH or LCOE. Different assumptions can lead to varied results, each potentially valid within the context of their assessment. By comparing different configurations in a harmonized manner, aligning assumptions and methodologies, a realistic comparison of different supply chain configurations is enabled. This approach ensures that the focus is on the configuration's performance metrics relative to each other, facilitating the determination of the best performing supply chain configuration for energy transmission from offshore wind farms.

The accuracy of techno-economic feasibility studies using the standardized model depends on the accuracy of the estimated values for the cost and energy-efficiency. These values are derived from publicly accessible data and benchmarked with values available within Van Oord and the NSE programme. Based on the writer's judgement, small modifications to cost estimates are made to align relative differences between onshore, island and platform-based installations, for example.

The improvements to the standardized model and the development of the artificial energy island module are implemented in modelling language python. This facilitates collaboration while leveraging existing libraries and open-source tools. Additionally, python preserves the model's transparent character.

1.5. Research questions

The main research question is formulated as follows:

How can the evaluation of offshore wind supply chain configurations be standardized to enhance industry-wide collaboration? And how can this standardized approach be applied to evaluate the feasibility of energy island concepts for the hub North case study in the North Sea Energy programme compared to hydrogen import?

To address the main research question, the study explores five sub-questions. The first sub-question examines the current literature on techno-economic assessments in the offshore wind system, identifying gaps and areas for extending existing knowledge.

1. How are feasibility assessment studies for offshore wind production supply chains and global hydrogen import typically conducted in literature, how can the current knowledge be extended?

The first sub-question provides insights into the current literature on offshore wind systems and global hydrogen import, highlighting areas for further research. This knowledge is used to enhance the standardized model development. To address the model development in a structured approach, the following sub-question is formulated to integrate modeling concepts explicitly:

2. How can explicit implementation of standardization, syntax and semantics into the standardized techno-economic model enhance effective study comparison, allowing for industry-wide adoption?

In alignment with question 2, this one is method-related. While exploring the research gap, it was identified that the current techno-economic model could significantly benefit from an automated the supply chain configuration generation and incorporating a detailed energy island cost estimation tool. To explore this, the third sub-question is formulated:

3. How can automating the supply chain generation and development of an offshore artificial energy island cost estimating tool better facilitate efficient supply chain comparison?

To explore the potential future hydrogen market and assess the techno-economic feasibility of domestic hydrogen production using wind energy from the North Sea, it is crucial to evaluate the generally estimated costs of hydrogen import. Therefore, the third sub-question is:

4. What are the estimated costs of hydrogen import for the Netherlands and Europe in literature and who would be the end-user?

Eventually, based on the knowledge gained on the status quo of offshore wind literature and the beneficial aspects of explicit integration of standardization, syntax and semantics into the techno-economic model, the methods of Van den Haak (2023) are extended by improving the current standardized model and developing a cost estimating tool for offshore artificial energy islands. With these two models, it is enabled to conduct a comprehensive techno-economic feasibility assessment of the hub North case study within the NSE programme. The techno-economical performance metrics can be determined for different supply chain configurations in a harmonized manner. The following question addresses this:

5. How are the techno-economical performance metrics of different energy transmission methods for offshore wind-to-hydrogen and wind-to-power systems evaluated in a harmonized way using this study's developed model, focusing on the hub North case study in the North Sea Energy programme?

By obtaining answers to these five sub-questions, the main research question can be answered. This approach enables the study to achieve its initial objective of (i) developing a standardized comparison method for the offshore wind industry and to create an offshore artificial energy island cost estimation tool; and the (ii) application of this standardized comparison method and energy island cost tool to the hub North case study within the NSE programme to evaluate the feasibility of an energy island concept in detail.

1.6. Report Outline

The report outline provides a systematic examination across various chapters. Beginning with Chapter 1, the introduction provides the motivation of the study, research objectives, and research questions, followed by an extensive literature study covering feasibility assessment methods for the offshore wind industry and standardization in Chapter 2. Additionally, the benefits of explicitly integrating syntax and semantics in future model development are addressed, touching upon aspects such as ontology and taxonomy. Chapter 3 delves into the breakdown of an offshore wind supply chain. In Chapter 4, the methodology is addressed for improving and developing the standardized techno-economic model, leading to Chapter 5's application of the model to the case study hub North in the North Sea Energy programme. Here, the results of the techno-economic assessment for the case study are presented. Chapter 6 delves into estimating the typical costs associated with hydrogen import, serving as a benchmark for comparing the feasibility of potential domestic hydrogen production in the North Sea. Chapter 7 provides a detailed discussion on the study findings, uncertainties and limitations. Chapter 8 concludes with summarizing the key findings, providing recommendations, and outlining pathways for further research.

2

Review of existing methods and standards in industry

This chapter reviews existing feasibility assessment methods in the offshore wind industry. It covers standardization in model development and model-based systems engineering, providing valuable insights and context for developing the subsequent techno-economic model.

2.1. Literature overview

In this section, feasibility assessment studies within academic literature in the offshore wind industry are analyzed. Common methods within the industry are examined and identified.

2.1.1. Feasibility assessment methods within literature

Techno-economic assessments are a common method for evaluating the feasibility of offshore W2P or W2H projects. These assessments consider technical factors like system efficiency and geospatial data, as well as economic factors such as costs, cash flows, and discounting, often referred to as part of economic assessment studies.

Cash flow analyses

To address supply chain component costs, a common method involves defining a constant cost rate in €/MW (BVG Associates, 2019; Giampieri et al., 2024), which scales linearly with capacity. Typically, two types of costs are delineated for all components in the supply chain: CAPEX and OPEX, in which the OPEX is often expressed as a percentage of the CAPEX (Rogeau et al., 2023; Singlitico et al., 2021). The OPEX, usually estimated at 2% of the CAPEX, recurs annually. A characteristic value for the CAPEX of a wind turbines is around 1,000,000 €/MW, while for AC substations lower CAPEX values are exhibited at around 50,000 €/MW (BVG Associates, 2019).

Component costs are calculated by multiplying the constant cost rate by the capacity, resulting in the total CAPEX. Subsequently, the OPEX is calculated based on CAPEX. For each year the net project cash flow can be determined by summation of all cash flows, including CAPEX, OPEX, and revenues. Typically, CAPEX is incurred in the initial project years, while OPEX recurs annually (WFO, 2022).

The time value of money principle states that a euro today holds more value than a euro in the future due to factors like inflation, opportunity cost, and risk. At the core of financial analysis lies the calculation of the Net Present Value (NPV), which compares the present value of cash inflows and outflows associated with an investment or project. To calculate the NPV, analysts discount future cash flows back to their present value using an appropriate discount rate (Myers, 1974).

In parallel, the inflation rate measures the rate at which prices for goods and services rise over time, thereby diminishing the purchasing power of money. It erodes the real value of cash over time, impacting both the cost of capital and the future purchasing power of cash flows (MAN Group, 2021). In techno-economic assessment studies found in literature, the treatment of inflation is often less transparent and explicitly addressed compared to the discount rate. This lack of clarity makes it difficult to efficiently compare outcomes across different studies, since differing inflation accounting can significantly impact results like the LCOH.

In summary, the cash flow analyses, discount rate and inflation rate are fundamental and often applied elements in techno-economic assessment studies. Additionally, the constant cost rate for components is often employed, and functions as a transparent and convenient method for cost estimations.

Levelized cost of hydrogen

One commonly used metric for techno-economic analyses in the hydrogen sector is the Levelized Cost of Hydrogen (LCOH) (Hurtubia & Sauma, 2021). It is determined by comparing the discounted present value of produced and transported energy to that of costs. It can also be viewed as the energy rate that allows investors to break even by covering capital returns and expenses incurred over a technology's lifespan (Dinh et al., 2023). However, despite its widespread use for comparing different hydrogen concepts, discrepancies in research papers often arise due to varying assumptions. As the LCOH and Levelized Cost of Electricity (LCOE) depend on the produced energy that is transported onshore, supply chain efficiency has a large influence on these two metrics. Therefore, losses over the supply chain should be carefully considered and are an import metric to compare energy projects.

To calculate the levelized costs, Eq. 2.1 is used to compare the present value of discounted incomes with the present value of discounted expenses. The discounted incomes are represented by the left side of the equation while the discounted expenses are shown on the right side (IEA, 2020).

$$\sum_{t=1}^{n} P \times E \times (1+r)^{-t} = \sum_{t=1}^{n} (\text{CAPEX}_t + \text{OPEX}_t) \times (1+r)^{-t} \tag{2.1}$$

where,

- n is the final project year,
- P is the energy price, could be in [kWh], [kg], [MJ], etc., as long as consistently applied,
- E is the amount of energy produced annually, unit in accordance with P,
- $(1+r)^{-t}$ is the real discount rate corresponding to the cost of capital,
- CAPEX_t is the total capital expenditures in year t,
- OPEX_t is the total operational expenditures in year t.

When we assume the energy price P to be constant over time, it can be brought out of the summation and Eq. 2.1 can be transformed into Eq. 2.2 for the LCOH,

$$LCOH = P_{H_2} = \frac{\sum_{t=1}^{n} \frac{\text{CAPEX}_{t,H_2} + \text{OPEX}_{t,H_2}}{(1+r)^t}}{\sum_{t=1}^{n} \frac{\text{H}_2 \text{ at shore}_t}{(1+r)^t}} = \left[\frac{€}{\text{kg}}\right] \tag{2.2}$$

and into Eq. 2.3 for the LCOE.

$$LCOE = P_E = \frac{\sum_{t=1}^{n} \frac{\text{CAPEX}_{t,E} + \text{OPEX}_{t,E}}{(1+r)^t}}{\sum_{t=1}^{n} \frac{\text{E at shore}_t}{(1+r)^t}} = \left[\frac{€}{\text{kWh}}\right] \tag{2.3}$$

where,

- P_{H_2} is the hydrogen price in [€/kg]; P_E is the electricity price in [€/kWh],
- CAPEX_{t,H_2} is the total capital expenditures for the hydrogen supply chain in year t,
- H_2 at shore$_t$ is the amount of hydrogen received at shore in [€/kg], after energy transmission & conversion losses and application of capacity factor.

Understanding the nuances in Eq. 2.2 and Eq. 2.3 requires careful attention to Eq. 2.1. At first sight, these equations might imply that energy itself is being discounted. However, the constant value P (price) can be factored out from the summation of the revenues. By dividing both sides of Eq. 2.1 by this revenue summation, it becomes clear that it is not the physical energy (in kg or kWh) being discounted, but the revenue derived from that energy. This distinction is crucial because the discounted value accounts for the economic worth of the output, reflecting the principle that revenue earned today is valued higher than future revenue due to time preference in cost-benefit accounting (IEA, 2020).

Pros and cons of levelized cost of hydrogen

The application of LCOH and LCOE for financial feasibility assessments of projects has both advantages and disadvantages, which are discussed here. One widely acknowledged advantage of using levelized cost metrics is their simplicity. LCOE is a straightforward analysis method that simplifies complex financial calculations. Another advantage is clarity, as LCOE distills the entire project into a single, easily understood data point, namely the cost of electricity. Lastly, LCOE is prevalent and widely used, with data often readily available or easily calculable, making it a common metric for comparing energy systems globally (Energy for growth hub, 2020; Friedl et al., 2023).

Despite the significant advantages of levelized cost analysis, it has several limitations. Firstly, levelized cost is most effective for comparing similar systems in similar contexts and regions, such as one offshore wind farm against another of the same type in the same location. Costs, revenues, and renewable energy availability can vary significantly between regions, making average LCOE values potentially misleading. Therefore, levelized cost should be applied to compare similar projects within the same context, which aligns with this study's focus on different supply chain configurations for an offshore wind farm in the Dutch North Sea region (Sklar-Chik et al., 2016; Energy for growth hub, 2020).

Moreover, levelized cost analysis lacks contextual nuance. For example, solar, wind, and nuclear projects typically have higher capital costs but lower operating costs than coal or natural gas projects. A higher interest rate in LCOE calculations can unjustly favor low-capital projects like natural gas plants by discounting future cash flows, diminishing the weight of future operating expenses and thus concealing the relatively higher OPEX of natural gas projects. Therefore, it's essential to consider these limitations to ensure accurate and meaningful comparisons (Sklar-Chik et al., 2016; Energy for growth hub, 2020).

2.2. Requirement of standardization in model development

Chapter 1 discussed the benefits and necessity of incorporating standardization within techno-economic assessment studies, which enhances efficient comparison across studies. This section examines international and industry standards in further detail within the offshore wind sector.

2.2.1. Standardization within the offshore wind industry

The importance of standardization has been addressed by Van den Haak (2023) and Herdem et al. (2024), initiating an examination of international standards applicable to the offshore wind industry. A fundamental challenge in the field of international standard application to an industry, is the absence of a single international standard that encompasses the entire scope of the supply chain specific to the offshore W2H industry. This realization is not merely a theoretical concern but a practical barrier to efficient communication and collaboration among stakeholders. Studying the relevant international standards in the industry revealed several major international standards that could be applicable to the offshore wind industry, which are separately addressed below:

- Oil and Gas Industry standard ISO 19008:2016 (ISO, 2016)
- Industrial Systems standard IEC 81346-1:2022 (ISO, 2022)
- Industry Foundation Classes standard ISO 16739-1:2018 (ISO, 2018)
- Cost Estimate Classification System by AACE International 18R-97 (AACE, 1997)
- Energy System Description Language ESDL (industry standard) (TNO, 2023)

Oil and Gas Industry standard ISO 19008:2016

ISO 19008:2016 outlines a standard cost coding system used primarily in the oil and gas industry (ISO, 2016). It is a standard system for classification and coding of costs according to entities (physical units), activities (durations), and physical quantities (weight, length, volume, flow rate, etc.). It covers the life cycle of oil and gas production and processing facilities, and is extended to cover offshore wind components. The system includes three hierarchical classification structures: the Physical Breakdown Structure (PBS), Standard Activity Breakdown (SAB), and Code of Resource (COR).

The PBS categorizes all physical project elements, ensuring systematic project planning and cost estimation. The SAB focuses on the activities or tasks required to complete the project, breaking it down into manageable activities and sub-activities to provide a clear overview of the sequence, duration, and interdependencies of tasks. The COR classifies project resources like equipment and labor, enabling accurate tracking and cost control. Together, these structures facilitate detailed project planning, execution, and cost management.

Industrial Systems standard IEC 81346-1:2022

The IEC 81346-1:2022 standard establishes general principles for structuring industrial systems, installations, equipment, and industrial products (ISO, 2022). It provides guidelines for the formulation of unambiguous reference designations, which identify objects for the purpose of creating and retrieving information. This standard is applicable across various technical areas such as mechanical engineering, electrical engineering, construction engineering, and process engineering. It includes rules for reference designation, recommendations for metadata in design structure management, and requirements for sector-specific parts of the standard. This standard aims to ensure consistency and clarity in reference designations, facilitating better communication and documentation across different systems and industries.

Industry Foundation Classes standard ISO 16739-1:2018

ISO 16739-1:2018, known as Industry Foundation Classes (IFC), defines a standardized data model to describe building and construction industry data (ISO, 2018). IFC facilitates interoperability and information sharing among software applications used in architecture, engineering, construction, and facility management. For example, an architect using a design software can create a building model, and the structural engineer can use a different software to analyze it, both using IFC to ensure compatibility and data consistency. This standard improves collaboration and reduces errors by ensuring that all stakeholders work with the same data.

Cost Estimate Classification System by AACE International 18R-97

The cost estimate classification system by AACE International presents a comprehensive cost estimate classification system for the process industries, providing a structured approach to categorizing cost estimates based on the level of project definition. The system is divided into five classes, each corresponding to a different stage of project maturity. Class 5 estimates, with 0-2% project definition, are used for concept screening and strategic planning, with an accuracy range of -50% to +100%. In contrast, Class 1 estimates, covering 50-100% project definition, are prepared for final bid/tender purposes and offer the highest accuracy range of -10% to +15%. This system standardizes estimating practices and improves project cost management.

Energy System Description Language (ESDL)

In the landscape of model development and standards in the energy industry, TNO introduced the Energy System Description Language (ESDL), a novel method for describing comprehensive energy systems in a uniform format (TNO, 2023). ESDL aims to address practical challenges. TNO's use case-driven approach in developing ESDL offers flexibility and adaptability, beneficial in the rapidly evolving offshore W2H industry. It enables detailed representation of energy system components and their interconnections, integrating aspects like energy production, consumption profiles, physical locations, and cost assessments. This standardized approach enhances interoperability between ESDL-based tools. Features in ESDL include potential Python integration, an extensive energy data repository and allows for spatial information with the MapEditor, all beneficial for comparison studies in the energy industry.

To assess the alignment between this study's intended offshore W2P and W2H supply chain components and the aforementioned standards, a detailed analysis and comparison are conducted. The results are presented in Table 2.1.

Table 2.1: Overview of this study's supply chain components and their potential alignment with ESDL and ISO standard 19008:2016, IEC 81346-1:2022, ISO 16739-1:2018 and AACE International 18R-97, names have been shortened for readability purposes

	ISO 19008:2016		ESDL	IEC 81346-1:2022	ISO 16739-1:2018	AACE 18R-97
Study's component definition	**Code**	**Name**	**Name**	**Name**	**Name**	**Name**
Foundation & cable	AWAB	*WTG foundations*	×	×	×	×
Turbine	AWAA	*WTG - wind turb. gen.*	*WindTurbine*	×	×	×
AC collection cable	AEGA	*Cables*	*ElectricityCable*	×	×	×
AC substation foundations	AWBB	*Substation foundations*	×	×	×	×
LVDC converter foundations	AWBB	*Substation foundations*	×	×	×	×
HVDC converter foundations	AWBB	*Substation foundations*	×	×	×	×
Electrolyser foundations	AWBB	*Substation foundations*	×	×	×	×
Artificial island	×	×	×	×	×	×
AC substation topside	AWBA	*Substation topside*	*Transformer*	×	×	×
HVDC converter topside offshore	AWBA	*Substation topside*	×	×	×	×
HVDC converter topside island	BDDH	*Trafos, rectif. & conv.*	×	×	×	×
HVDC converter topside onshore	BDDH	*Trafos, rectif. & conv.*	×	×	×	×
LVDC converter topside offshore	AWBA	*Substation topside*	×	×	×	×
LVDC converter topside island	BDDH	*Trafos, rectif. & conv.*	×	×	×	×
LVDC converter topside onshore	BDDH	*Trafos, rectif. & conv.*	×	×	×	×
Electrolyser topside offshore	×	×	*Electrolyzer*	×	×	×
Electrolyser topside island	×	×	*Electrolyzer*	×	×	×
Electrolyser topside onshore	×	×	*Electrolyzer*	×	×	×
Desalination unit	BHD	*Freshwater supply*	×	×	×	×
Compressor unit	AEAJ	*Booster stations*	*Pump*	×	×	×
Storage unit	BACAA	*Gas storage*	*GasStorage*	×	×	×
Compressor after storage	BAAABBD	*Sales gas compres. sys.*	*Pump*	×	×	×
DCAC converter	BDDH	*Trafos, rectif. & conv.*	×	×	×	×
HVDC export cable	AEFA	*Cables*	*ElectricityCable*	×	×	×
H2 pipeline	ADKA	*Pipelines*	*Pipeline*	×	×	×
Export cable landing	ADEL	*Shore approach*	×	×	×	×
Export pipeline landing	AEAL	*Shore approach*	×	×	×	×
	Coverage	85%	40%	0%	0%	0%

Reflection on utilization of ESDL

Since ESDL is developed by TNO, a Dutch independent research institute supporting the Dutch government, and presented as the new Dutch industry standard for the energy sector, it holds all potential to become the standard for the North Sea energy transition. Therefore, the industry standard deserves special attention, which is addressed in this subsection.

TNO is a leading partner in the NSE program, which is dedicated to designing and planning an efficient, robust, and resilient offshore energy system to accelerate the energy transition. This strategic position allows TNO to address the needs of all Dutch supply chain players within the ESDL industry standard, thereby facilitating industry-wide collaboration and enhancing knowledge, concept, and experience sharing. An open and transparent environment is crucial for designing an efficient and robust offshore energy system, and TNO's role in the NSE program positions it well to foster such an environment.

TNO recognized a fundamental challenge: the lack of a single ISO standard covering the entire offshore W2H supply chain. This gap creates practical barriers to efficient stakeholder communication and collaboration. Using multiple ISO standards to cover the entire domain risks conflicts and overlaps, complicating the energy landscape depiction. Consequently, TNO decided to develop its own language, which offers a significant feature. Unlike established ISO standards, which require adherence to stringent rules and processes, ESDL's company-developed nature allows for easier modification and updates. Since it is maintained by a single entity, it can be more responsive and adaptable to industry needs, bypassing the lengthy certification processes associated with large, international organizations such as ISO.

On the other hand, exactly this single company-developed and maintained nature also has its drawbacks. This dependence on one company subjects users to the developer's decisions and changes, contrasting with the slower but more predictable processes of an ISO committee. Despite ESDL's ambition to fill gaps in component definitions and allow for rapid modifications to meet industry demands, it currently falls short of being an industry standard that is attractive to all industry players. This limitation hinders its potential to be widely adopted across the entire supply chain, thereby limiting its ability to enhance industry-wide collaboration.

During the examination of available international and industry standards, ESDL was evaluated as a method for efficient study comparison. However, several challenges emerged during the implementation and adaptation of ESDL, which are crucial to address for its industry-wide adoption.

- **Insufficient supply chain component detailing:** there is no distinction between DC and AC cables based on physical breakdown within the model. The difference can only be attributed by explicit naming within the specific modeled energy system, which might lead to confusion or misunderstanding. New users might inadvertently create physically "impossible" supply chains. The substantial differences between AC and DC should not be left to just naming
- **Absence of explicit standard activity breakdown modeling:** the model does not allow for specific modeling regarding the SAB, limiting its ability to accurately reflect the timelines and dependencies of various activities
- **Insufficient detailing on resource integration:** resources, such as vessels for installation operations, are simply incorporated within the CAPEX, which discourages contractors from using the model due to the lack of detailed resource allocation and scheduling
- **Absence of open-source techno-economic modeling:** ESDL is primarily a language and does not perform calculations, necessitating use of other models for techno-economic analysis, which are not always widely available. This limits its functionality for users seeking a comprehensive modeling tool
- **User-unfriendly integration with pyESDL:** the integration with pyESDL is not user-friendly, posing a barrier for users who wish to leverage Python for advanced data analysis and automation

By addressing these limitations, TNO could enhance the industry-wide adoption of ESDL, solidifying its status as the Dutch industry standard. With this approach, ESDL has the potential to become the (Dutch) industry standard for offshore energy infrastructure development, actively utilized within the NSE program to facilitate transparent, industry-wide discussions. This collaboration would foster efficient innovation, coordinated efforts, and informed decisions, all of which are crucial for accelerating the energy transition.

2.2.2. Implications for model development in current study

To improve the current method for assessing the techno-economic feasibility of offshore W2H systems, several key areas need enhancement. From the examination in subsection 1.3, several distinct, concrete components were identified for improvement, including the current absence of international standards in techno-economic assessments. The assessment of international standards led to the results in Table 2.1. The implications of all these elements for this study's model development are presented below.

Not one single applicable standard for model development

Upon examining international and industry standards to determine if an all-encompassing standard exists for developing a standardized model in the offshore wind industry, it became clear that none meet this criterion. Standards such as AACE 18R-97 offer valuable insights into the practical implications of different project maturity stages. For example, first project stage estimates have an accuracy range of -50% to +100%, while final project stage estimates achieve the highest accuracy range of -10% to +15%. However, AACE 18R-97 lacks a physical or component breakdown schedule applicable to the offshore wind industry, reducing its attractiveness as a comprehensive standard. Using it would necessitate additional standards to cover the physical breakdown schedule, with the risk of conflicts and overlaps.

In addition to the AACE standard, there are ISO 19008:2016 and ESDL, both offering a structure for a physical breakdown of the offshore wind supply chain. ISO 19008:2016 is particularly comprehensive as it also includes a standard activity breakdown and a code of resource, aspects that ESDL lacks, making ISO 19008:2016 more attractive for a holistic approach. Nevertheless, it does not have a 100% coverage of the intended supply chain. Table 2.1 indicates that the standard covers 85% of the intended component definition in this study, but lacks the definition for an energy island and electrolyzer. However, exactly these two components significantly impact the offshore energy system's costs due to their expected high CAPEX, limited experience and absence of large-scale deployment.

Consequently, it can be concluded that within the offshore wind industry, there is no universally adopted standard, leading to varied practices. This inconsistency can also explain why, as noted in section 1.3, the literature review reveals that none of the studies incorporate a single standard. However, the absence of an all-encompassing standard does not imply that standards should be disregarded. Explicitly incorporating standardization into techno-economic model development significantly enhances usability, enabling efficient comparisons with other studies, fostering industry-wide collaboration, and improving overall consistency and accuracy.

Therefore, the author developed its own interpretation of the physical offshore wind supply chain breakdown, but aligned it as closely as possible with the physical component definitions of ISO Standard 19008:2016, enhancing comparability and facilitating industry-wide comparisons. In this way, the concepts of the standard's PBS are explicitly incorporated in this study's model development to improve consistency and comparability with existing practices. On the other hand, due to time and scope limitations, the SAB and COR are not explicitly incorporated in this study's model development. Those two aspects will be addressed through qualitative recommendations for future model development.

Firstly, the benefits of explicit integration of the SAB in a techno-economic model are explained qualitatively. The SAB systematically organizes the activities required to complete a project, breaking them down into manageable sub-activities. This detailed breakdown enhances resource allocation by making it easier to determine the specific personnel, equipment, and materials needed at each stage, optimizing resource utilization. Additionally, it improves cost estimation by allowing for precise assignment of costs to each activity, leading to a more accurate overall project budget and enabling the identification of cost-saving opportunities. Furthermore, the SAB facilitates clear communication and coordination among stakeholders, as it serves as a common reference point that outlines roles and responsibilities, ensuring better collaboration and reducing misunderstandings. Integrating the SAB into the model thus ensures a structured approach to project management, enhancing efficiency and accuracy across all stages of the project.

Secondly, the benefits of explicit integration of the COR in a techno-economic model are explained qualitatively. The three hierarchical classification structures within ISO Standard 19008:2016 each have their specific applications. The benefits of applying the PBS are straightforward, as it systematically organizes physical elements of a project. In contrast, the applications of the COR may be less intuitive, warranting an example for clarity. For instance, for contractors involved in installing components within the offshore supply chain, it is crucial to be able to specify the resource component, such as a specialized vessel, in a standardized model. Because these vessels, which are essential for the long term North Sea strategy, are the major long term investment for contractors. Absence of these resources in a model excludes the potential input of contractors and undermines their business case, preventing their valuable input from being leveraged, hindering industry-wide implementation. Hence, resource selection should be enabled in a future version of the standardized techno-economic model, rather than incorporating the resource (i.e., specialized vessel) as a percentage of a windfarm's investment costs. This will ensure that all stakeholders can include their input at similar levels of detail and at similar stages of a project.

Concluding, through examination of standards it became apparent that efficient study comparisons cannot be achieved solely through the explicit integration of standardization, as none of the standards showed 100% similarities. Hence, another comparison method must be found. For this purpose, the levelized cost is the most viable option. It is a commonly used metric in techno-economic studies within the offshore wind industry due to its simplicity and clarity. It distills the entire project into a single, easily understood data point, namely the cost of hydrogen or electricity. However, due to the nature of the LCOH calculation, it is very responsive to the applied discount rate and initial investment costs.

Application of LCOH for efficient study comparison

In order to calculate the LCOH, future hydrogen-related cash flows are discounted by the discount rate r to their present value. The discount rate reflects the time value of money, the risk associated with the investment, and the opportunity cost of capital. The appropriate discount rate to use depends on the specific context of the analysis. It could be the company's weighted average cost of capital (WACC) in the case of evaluating a project or investment within a specific company, or it could be a different rate reflecting the risk and return profile of the specific investment being considered.

Employing the WACC is a method for companies to appraise a project. It reflects the risk of the future cash flows received by an organisation from its operations (DePamphilis, 2022). If two companies are expected to produce the same future cash flows but company A has a lower WACC, then for company A the future cash flows will be more valuable due to the discounting with a lower value. This is because the company with a lower WACC is seen as having less risk attached to the cash it will generate in the future (Kaldellis, 2022). If the business environment changes, for example with the government issuing regulations impacting the ability to generate cash leading to a higher WACC of a company, then the value of the company (and its shares) will decrease.

The theory behind using the weighted cost of capital to appraise projects is that the WACC is the cost that the business pays for the capital it uses to invest in its operations. Given the risks of the company's position, investors want the company to give them at least this return, or the risk of investing in the company is not worth bearing. So in order for a project to be worthwhile, it must return at least the WACC (Deloitte, 2014).

The WACC presents the actual cost of capital for a company. It is a company-specific value, often employed by financial managers in capital budgeting decisions to discount cash flows for evaluating potential investments or projects (Brealey et al., 2017). It can be used as the discount rate when calculating the NPV of a project. Discounting with the WACC would accurately reflect their financing conditions as the WACC includes the mix of debt and equity within a company, reflecting their actual weighted average cost of capital, resulting in a more realistic financial feasibility method for companies.

In summary, while the WACC is a specific type of discount rate used in capital budgeting to evaluate projects and investments within a company, the discount rate is a broader concept that can be tailored to the specific risk and return characteristics of an investment or project.

Application of r or WACC in LCOH calculation

With this understanding, it becomes clear that for individual players in the offshore wind industry conducting a techno-economic feasibility assessment would be more realistic and useful if a company-specific WACC is used for discounting, rather than a general discount rate. It would accurately reflect the financing conditions of each player in the supply chain, e.g., wind farm operators, energy island developers or hydrogen pipeline manufacturers. Consequently, using the WACC as discount rate in NPV calculations offers a more precise estimation for a specific company of a project's or asset's financial feasibility.

However, given the scope of the current study, which encompasses the entire supply chain including multiple specific industries such as offshore wind, electrolyzers, and electricity, and a diverse array of companies, it is impractical and unrealistic to apply a single WACC value to the entire system. This approach would assume a homogeneous financial environment, which does not accurately reflect the diverse nature of the industries involved. Such an assumption could lead to misinterpretation, falsely suggesting that the debt-to-equity ratio for the entire industry is known, which is evidently not true. This could result in inaccurate conclusions and undermine the credibility of the study. Therefore, it is crucial to recognize the heterogeneity of financial conditions across different sectors and companies within the supply chain to ensure accurate and credible analysis.

These two elements pose a significant challenge. It is a nuanced consideration to choose between using the WACC or a general discount rate. For a broad and correct implementation, it is more appropriate to use a 'general' discount rate, which can be consistently applied across various industries and scenarios. However, using the WACC would enable more precise NPV calculations, tailored to the specific financial conditions of individual companies. This precision makes the model more attractive and relevant for companies, encouraging them to engage with and apply the model. By incorporating the WACC, companies can accurately reflect their cost of capital based on their financial considerations regarding debt-to-equity ratios, leading to more reliable and applicable results. Balancing the general applicability of the model with the need for precise, company-specific financial metrics is crucial for the model's credibility and usefulness in real-world applications.

Since the techno-economic model is developed to enhance industry-wide collaboration and comparison, it is considered more valuable to allow for the implementation of the WACC. Subsequently, the WACC is uniformly applied across the entire supply chain. However, it is important to acknowledge that for a uniform discount rate across the supply chain, a general discount rate would be more appropriate than a uniform WACC. The WACC implies knowledge of a company's capital structure, which is not available and not homogeneous for the entire supply chain. Despite this, the model development decision to incorporate the WACC is made to improve the accuracy and relevance of the model for individual stakeholders.

One method to address this complexity would be to apply industry-specific differentiation for the WACC values used for different components rather than a uniform WACC for the entire supply chain. For instance, the electrolyzer industry, characterized by higher uncertainties and risks, would warrant a higher WACC value. Conversely, the cable-laying industry, being more mature, would have a lower WACC. This approach would better justify the application of the WACC as a discount rate. By defining the WACC per supply chain component, it could be calculated in greater detail and with more accuracy, leading to a more effective use of WACC in the context of the entire supply chain system. This ensures that the financial conditions and risk profiles of each industry segment are appropriately accounted for.

Identified elements to implement in model development

To enhance the applicability and value of this study, it would benefit from enabling better comparison with other studies in academia and industry. For this reason, in this study's model development the physical breakdown structure of the supply chain components has been aligned with the international ISO standard 19008:2016 as much as possible. In this way, the concepts of ISO 19008:2016's PBS are explicitly incorporated to improve consistency and comparability with existing practices. On the other hand, due to time and scope limitations, the SAB and COR are not explicitly incorporated in this study's model development. Those two aspects will be addressed through qualitative recommendations for future model development.

2.3. Syntax and semantics in model development

A common pitfall in model-development is creating ad hoc representations of a system without explicitly considering fundamental modelling concepts such as domain semantics, metamodels, and ontologies. This oversight can lead to confusion and misunderstanding. For example, in an initial version of a techno-economic model, specific components required for a particular supply chain configuration, such as a full HVDC power transmission configuration via converters on offshore platforms, are included. While the model is designed with the particular purpose of calculating this specific configuration, it does not have the capabilities yet to calculate other supply chain configurations as well. To calculate an onshore-based full H_2 configuration, new elements are added separately during modifications to the model. However, this approach may result in a suboptimal and less intuitive model framework, as the original setup was tailored to fulfill the particular purpose of calculation of the platform-based full HVDC configuration. This ad hoc model representation and development could introduce confusion, misunderstanding, and misalignment among modeling study results.

2.3.1. Model-Based Systems Engineering (MBSE)

A classic example of a catastrophic failure due to ad hoc model representations is the Mars climate orbiter in 1998 (NASA, 2024). Designed to study Mars from orbit and serve as a communications relay for other deep space vehicles, the Mars climate orbiter was unsuccessful due to a navigation error caused by a failure to translate English units to metric (NASA, 2024). Confusion over units led to the incorrect commanding of the vehicle during orbit insertion. Rather than achieving its intended orbit, the orbiter instead fell into the Mars atmosphere and disintegrated. Problems also occur when the same term is used differently by different subject matter experts. Consider the term “bandwidth” which can mean “bits per second” to a computer person but to a signal processing person is the difference between the upper and lower frequencies in a continuous band of frequencies (Sievers, 2020).

To prevent such catastrophic failures in extraordinarily situations, and more commonly to aviod ambiguities, the concepts of Model-Based Systems Engineering (MBSE) were introduced (Sievers, 2020). Domain semantics, metamodels, and ontologies are foundational concepts that make possible the primary benefits of MBSE: design collaboration among all stakeholders, model sharing, model reuse, terminology consistency, and reduction of ambiguity and unnecessary redundancy (Sievers, 2020).

Domain semantics assigns meaning to system concepts, i.e., the “physics” behind system components and their interaction. It defines shared terminology within a specific area (Munir & Sheraz Anjum, 2018). For instance, in soccer, terms like “offside” and “striker” have well-defined meanings, and are officially documented in the laws of the game. To address the situation of offside, it is documented by the International Football Association Board that for such a situation the term “offside” should be used. Contrary, terms in spacecraft domains, like “reaction wheel assembly” and “solar array”, vary among stakeholders and regions, and are not universally used by the space flight community. This variation extends to units of measure and terminology, leading to potential confusion. For example, what one group calls a “spacecraft”, another might label an “observatory” or “collection segment”, adding complexity to communication and collaboration (Sievers, 2020). These examples address the significance of explicit specification of domain semantics, which is relatively straightforward in the case of soccer. There is an acknowledged controlling authority that determines the terminology. Conversely, as with many engineering endeavors, a universally agreed upon semantic domain may not be possible, and often, attempts at creating one can cause unresolvable disputes. Still, in situations of heterogeneous semantics, one should explicitly address such concepts to avoid ambiguities.

Ontologies are the controlled vocabularies that comprise agreed-upon sets of explicitly enumerated, unambiguous, and non-redundant terms, relationships, and constraints necessary for building and interpreting models (Gruber, 1993). These vocabularies are established with inputs from domain experts and are configuration managed by a controlling authority. Ontologies are foundational to MBSE and essential in model scoping, creation, and usage. As shown in Figure 2.1, presenting an example of a wind turbine ontology, common components of ontologies are concepts, relationships, instances, restrictions, and rules. Correct application of ontologies facilitates consistent communication within a semantic domain. Although the terms taxonomy and ontology are sometimes used interchangeably, the terms are fundamentally different. Taxonomies are hierarchically ordered and used to name, describe, and classify terms in a domain. Taxonomy ordering is determined by a set of consistent and unambiguous rules. Conversely, ontologies link domain concepts with relationships in ways that support deeper understanding. Ontologies have many uses, including sharing a common understanding of how information is structured and named among stakeholders and enforcing the need for explicit domain assumptions reducing ambiguities (Sievers, 2020).

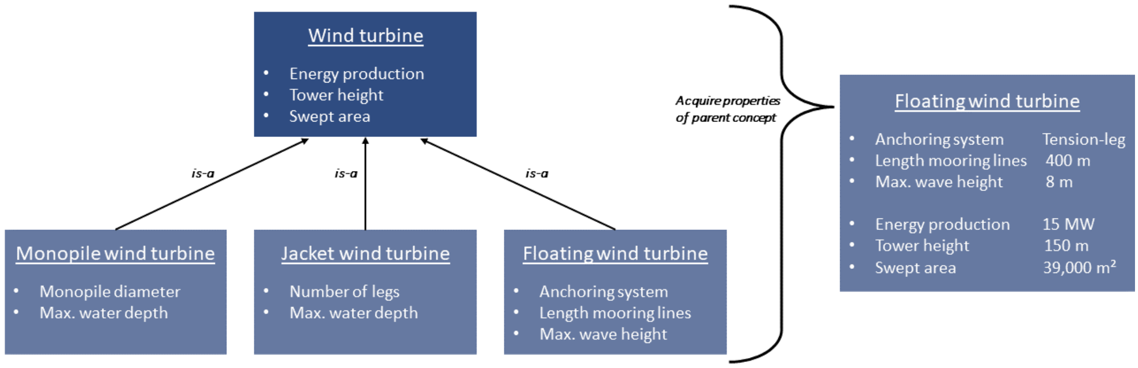

Figure 2.1: Example wind turbine ontology

Taxonomies are hierarchically ordered and used to name, describe, and classify terms in a domain (Madni & Sievers, 2018). Figure 2.2 presents an example for renewable energy production installation methods. With taxonomy questions can be answered regarding what are the types of offshore wind turbines? On which the answer could be “Monopile wind turbines”, “Jacket wind turbines” and “Floating wind turbines”, for example. However, it cannot provide insights on what the capacity of a floating wind turbine is. Taxonomies are limited to hierarchical orders of components, in contrast, ontologies include concepts and relationships for a specific domain and are more information-rich. In the case of wind turbines, providing information on the energy production capacity, tower height and swept area of a wind turbine. Figure 2.1 presents an example of a wind turbine ontology. It shows an ontology using *is-a* relationships in which the subconcepts “Monopile wind turbine”, “Jacket wind turbine” and “Floating wind turbine” acquire the properties of the parent concept, “Wind turbine”.

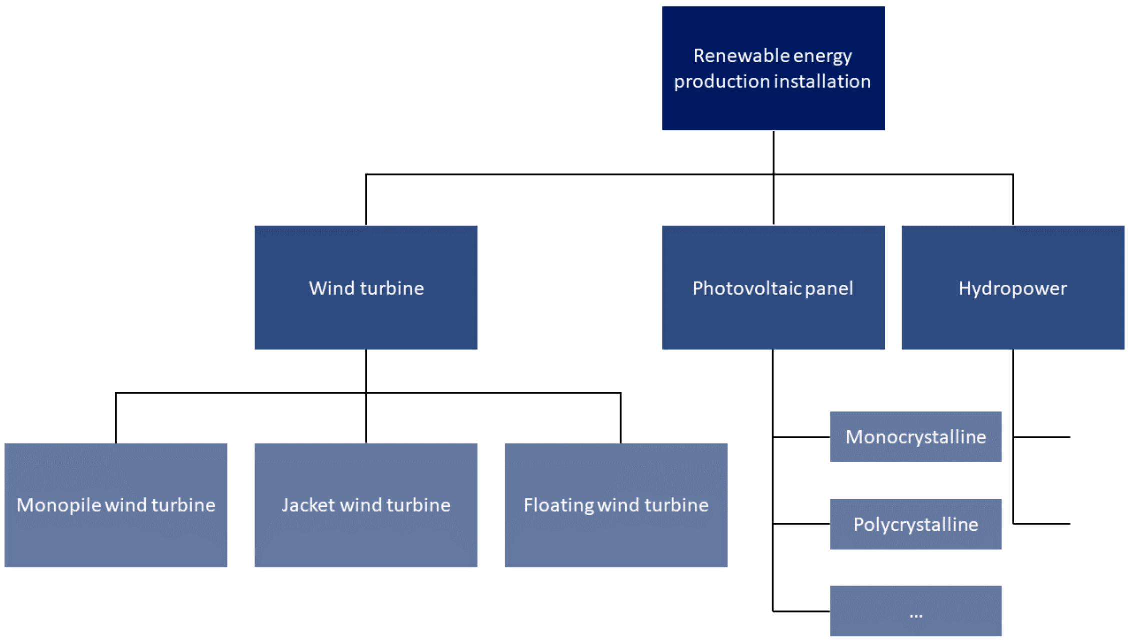

Figure 2.2: Example renewable energy production installation taxonomy

2.3.2. Implications of explicit integration of MBSE

To illustrate, the explicit implementation of taxonomy in future development of the techno-economic model would enable the inclusion of specific products. At a certain level of detail, a real product could be defined as supply chain component in the techno-economic model with its actual properties. For example, a specific wind turbine model from a manufacturer could be included with precise component details, enhancing the model's accuracy and relevance. This structured and clear integration of taxonomy would ensure that the specific model is effectively incorporated into the supply chain, improving the overall clarity and consistency of the model.

Explicit implementation of ontologies in the future development of the techno-economic model would greatly enhance the model's clarity. By requiring each component to have a specific set of properties, the model becomes more structured, prevents inconsistent component definitions, and ensures that all components have complete and accurate properties. This structured approach would prevent that certain properties - crucial for accurate modeling - are overlooked or remain unspecified. For example, in order to be able to create or define a "Wind turbine" within the model, it is required to provide at least the component's properties such as energy capacity, capacity factor, and economic lifetime. With this approach, it is enforced to adhere to a certain structure, making the model more consistent, reliable and maintainable. Within the integration of ontologies in the model, there could be benefited from the programming concept of *Abstract Base Class* (Python Software Foundation, 2024). This concept can be considered as a blueprint for other classes. It allows to create a set of methods that must be created within any child classes built from the abstract class. Ultimately, incorporating ontologies ensures that all stakeholders can easily understand and contribute to the model, promoting industry-wide collaboration and more informed decision-making.

Concluding, by explicit integration of these MBSE concepts in future development of the techno-economic model, confusion, misunderstanding and misalignment among study results can be prevented. The techno-economic model will be able to represent the offshore energy system in a structured, standardized way using Python as modeling language regarding syntax. This approach ensures clarity, consistency, and accuracy to facilitate optimal decision-making processes for policymakers involved in offshore wind policies. It further enhances the model's value, positioning it to potentially become a benchmark tool within the industry.

3
Offshore wind supply chain - A breakdown

In the pursuit of a standardized method for comparison studies in the offshore wind industry, it is important to be clear about the used terminology in these concepts. Electricity generation and hydrogen production from offshore wind involve a complex supply chain, best understood by breaking it down into defined sub-systems. This study's method for component definition is closely aligned with the PBS of ISO standard 19008:2016 as addressed in Chapter 2. This chapter addresses different components in further detail.

3.1. Physical Breakdown Structure (PBS) offshore wind

This section provides a detailed examination of the physical components and infrastructure associated with offshore wind projects. By decomposing the various elements involved in offshore wind installations, this section aims to provide a comprehensive understanding of the structural framework essential for the development and operation of offshore wind farms.

3.1.1. Offshore wind turbine

Offshore wind turbines stand as pivotal components within offshore wind parks, engineered to capture the massive energy of wind and convert it into electricity. Distinguished by their larger scale and intricate design compared to onshore counterparts, these turbines endure harsh environmental conditions at sea (Khare et al., 2020; Esteban et al., 2011). Comprising rotor blades, rotor hub, nacelle, and tower, these turbines are crafted for aerodynamic efficiency, with rotor blades typically crafted from fiberglass or composite materials, and the nacelle housing the generator and electrical components (Bahaj et al., 2017). While offshore wind turbines possess the capacity to generate significant power, their output relies on various factors including wind speed, rotor size, and turbine efficiency. The maintenance and repair of these turbines are crucial for ensuring their continued safe and efficient operation, a task often compounded by the remote and inaccessible nature of offshore locations (Bahaj et al., 2017).

Offshore wind turbines can generate large amounts of electricity, with models SG 14-222 DD and Haliade-X of up to 15 MW expected soon commercially available on the market (GE Vernova, 2024; Siemens Gamesa, 2024). The amount of power generated by an offshore wind turbine depends on several factors, including the wind speed, the size of the rotor, and the efficiency of the turbine. Offshore wind turbines require regular maintenance and repair to ensure they continue to operate safely and efficiently. This can be challenging in offshore environments, as turbines may be located in remote locations that are difficult to access (Bahaj et al., 2017).

3.1.2. Foundation & cables

In offshore wind parks, foundations provide the necessary stability for turbines against harsh open sea conditions. Inventory data indicates that investment in foundations accounts for 20-30% of the total cost of a typical offshore wind farm (Gasch & Twele, 2011), contributing to the higher costs compared to onshore turbines (Gasch & Twele, 2011). Therefore, selecting a suitable foundation type is crucial for effective offshore wind energy exploitation.

Various foundation types are used in offshore wind parks, including mono-piles, jackets, tripods, and floating platforms (Gasch & Twele, 2011). Mono-piles, the most common, are single steel piles anchored into the seabed, suitable for depths up to 30 meters (Wu et al., 2019). Jackets, lattice steel structures, are ideal for deeper waters due to their load-bearing capacity (Thomsen, 2014). Tripods, with three legs, are used in depths up to 25 meters (Wu et al., 2019). Floating platforms, anchored with mooring lines, are suitable for even deeper waters (Wu et al., 2019).

The Dutch portions of the North Sea exhibit water depths ranging from 25 to 50 m, rendering them well-suited for the implementation of diverse offshore wind energy initiatives. This advantageous characteristic positions the North Sea as a promising powerhouse for Europe's renewable energy sector, offering ample opportunities for sustainable energy generation and contributing significantly to the continent's energy transition efforts.

Inter-array cables link individual turbines to one another and to the AC substation. Buried in the seabed for protection and to minimize visual impact, these cables exhibit efficiency rates typically ranging from 97% to 99%, depending on the cable length (Apostolaki-Iosifidou et al., 2019). AC power is transmitted through the cables, allowing for easy handling and efficient transport for relatively shorter distances, which is the case within an offshore wind farm. Subsequently, electricity from offshore turbines is further transported to the onshore electricity system (Figure 1.2 shows an overview).

3.1.3. Offshore topside structures

The topside of an offshore station is the above-water portion of a fixed or floating offshore structure, serving as the operational hub. It accommodates personnel, equipment installation, maintenance operations, and control systems. For the offshore wind industry, topside units might includes HVDC converters, AC substations, electrolyzers and hydrogen compressors (BVG Associates, 2019). These components are essential for converting, managing, and transporting energy generated by the wind turbines, ensuring efficient integration with the onshore grid and supporting various operational needs. Because offshore substations are located in marine environments that are subject to extreme weather conditions, such as heavy winds and waves, and have to remain operational for many years, they are designed to withstand the harsh marine environment and are installed using a method known as subsea installation.

(a) Float-over installation of topside

(b) Lift and set installation of topside

Figure 3.1: Impression of offshore topside installation methods

In the float-over method, the topside modules are fabricated onshore and transported to the offshore site on a barge or vessel. Once positioned adjacent to the substructure, the modules are floated over and carefully lowered onto the substructure using ballasting techniques. This method is commonly used for fixed platforms and tension leg platforms. In the lift and set method, the topside modules are fabricated onshore and transported to the offshore location, where they are lifted and set onto the substructure using heavy lift vessels or cranes. This method is suitable for fixed platforms and compliant towers.

3.1.4. Offshore topside structures - AC substation

An offshore substation is a facility that is used to transmit electricity from offshore generation sites to onshore power sources, increasing efficiency of the transmission process (Apostolaki-Iosifidou et al., 2019). An AC substation is a facility that is used to collect the medium voltage alternating current (AC) electricity generated by the wind turbines (often at 66 kV) and to convert it to a higher voltage, which is done using a large transformer. These substations are usually located near the offshore wind farm to limit transmission energy losses, typically positioned above sea level on a fixed or floating platform. Key functions of an AC topside structure include voltage regulation, power conversion, grid connection and control & monitoring (Lei et al., 2024).

Overall, the AC topside plays a critical role in the efficient and reliable generation, conversion, and transmission of electricity from offshore wind farms to onshore consumers, contributing to the integration of renewable energy sources into the broader power grid.

3.1.5. Offshore topside structures - HVDC converter

A HVDC converter station is a critical component in power transmission systems, converting alternating current (AC) electricity into high-voltage (HV) direct current (DC). This conversion is particularly beneficial for long-distance electricity transmission due to DC's high transmission efficiency over extended distances (Lei et al., 2024). Additionally, the constant voltage characteristic of DC electricity is ideal for electrolysis units, which require stable voltage and current inputs for optimal performance (Lange et al., 2023).

(a) Transport DolWin2 HVDC platform

(b) Operation DolWin2 HVDC platform

Figure 3.2: Impression of an offshore HVDC converter station, both topside and substructure, adopted from ABB (2018)

3.1.6. Offshore topside structures - Electrolyzer

Although not often deployed yet, electrolyzers can be installed on offshore platforms. The first such project is the Sealhyfe initiative by Plug Power and Lhyfe, featuring a 1-megawatt electrolyzer on a floating offshore platform (Lhyfe, 2023). This pioneering project, located off the coast of Saint-Nazaire, France, is designed to produce green hydrogen from offshore wind power, paving the way for future offshore hydrogen production facilities in the North Sea and beyond.

3.1.7. Collection cable

AC collection cables are essential components in offshore wind farms, used to transmit the electrical power generated by wind turbines to a central offshore substation (Lei et al., 2024). These cables operate using AC and are designed to handle the variable power output from the turbines. The substation then steps up the voltage for efficient transmission to the onshore grid. While AC collection systems are effective for relatively short distances, their efficiency diminishes over longer distances due to reactive power losses and other electrical inefficiencies. Consequently, as offshore wind farms are situated farther from shore, the industry is exploring and increasingly adopting HVDC systems to overcome these limitations (Apostolaki-Iosifidou et al., 2019).

3.1.8. HVDC cable

HVDC export cables are a crucial technology for transmitting electricity generated by offshore wind farms to the onshore grid. HVDC systems are preferred for long-distance power transmission due to their superior efficiency compared to AC systems (Apostolaki-Iosifidou et al., 2019). HVDC cables minimize energy losses over vast distances, which is essential as offshore wind farms are increasingly located farther from shore. These cables convert the AC power produced by wind turbines into DC, transmit it to the shore, and then convert it back to AC for integration into the grid. This technology enables the connection of remote offshore wind farms to national grids, facilitating the delivery of large-scale renewable energy to meet growing demands.

3.1.9. Electrolyzer unit

An electrolyzer is an electrochemical device in which DC electricity drives a chemical reaction. For water electrolysis, the aim is to split the water molecule to extract mainly the hydrogen component (Lange et al., 2023). This splitting reaction ideally requires at least 9 L of water & 33.3 kWh of energy per kg of hydrogen produced. However, in practical higher water (10 - 30 L) and energy (55-63 Kwh) requirements per kg of hydrogen produced can be found (WEF, 2023; Franco & Giovannini, 2023).

Proton Exchange Membrane Electrolysis (PEMEL), Alkaline Electrolysis (AEL), and Solid-Oxide Electrolysis Cell (SOEC) are three distinct methods used for hydrogen production through electrolysis, each with unique advantages and disadvantages (Lange et al., 2023). PEMEL uses an acidic solid electrolyte, resulting in a smaller footprint and the fastest response time among the three. However, it requires rare or noble metals, making it more expensive and less environmentally friendly, and has a relatively shorter stack lifetime (Nami et al., 2022). AEL, on the other hand, operates with an alkaline electrolytic medium, allowing the use of inexpensive materials like Ni/Fe. It boasts the lowest CAPEX and the longest lifespan but suffers from slower response times and larger footprints compared to PEMEL (Lange et al., 2023). SOEC employs solid ceramic-based electrolytes and operates at high temperatures, offering the highest electrical efficiency (Nechache & Hody, 2021). Despite its potential, SOEC is still in the demonstration phase, with limited flexibility and the lowest technology readiness level among the three, and requires a source of high-temperature heat. Each method's suitability varies depending on specific operational needs and economic considerations, with PEMEL excelling in dynamic applications, AEL in cost-sensitive and long-term deployments, and SOEC in high-efficiency, high-temperature environments. Table 3.1 presents an overview.

Table 3.1: Performance comparison of PEMEL, AEL and SOEC electrolysis technologies Lange et al. (2023)

Element	PEMEL	AEL	SOEC
Footprint	Smallest	Larger	Moderate
Current Densities	Highest	Lower	Moderate
Load Range	Highest	Lower	Limited
Response Time/Dynamics	Fastest	Slow	Limited
Pressurized H_2 Delivery	$\approx$ 30 bar	1-30 bar	1-15 bar
CAPEX	Moderate	Lowest	High
Lifespan	Short	Longest	Limited
Materials	Precious metals	Abundant resources	Non-noble catalysts
Operating Temperature	Moderate	60-90°C	> 700°C
Electrical Efficiency	Moderate	Lowest	Highest
Flexibility	High	Moderate	Limited
Technology Readiness Level	High	High	Lowest

3.1.10. Desalination unit

A desalination unit is crucial for electrolysis processes, particularly when using seawater as a feedstock (Delpisheh et al., 2021). Electrolysis requires high-purity water to function efficiently and prevent damage to the system components (IRENA, 2020). Desalination units remove salts and other impurities from seawater, ensuring that the water used in electrolysis meets the necessary purity standards. Common desalination technologies include reverse osmosis and distillation. By providing a reliable source of high-purity water, desalination units enhance the efficiency and longevity of electrolysis systems, making them essential components in the production of green hydrogen from offshore renewable energy sources. In literature, the relative cost of desalination compared to other supply chain components is considered low (Singlitico et al., 2021)

3.1.11. Hydrogen pipeline

Submersed hydrogen pipelines, intended for transporting hydrogen produced by offshore wind farms, are a relatively new concept and have yet to be implemented on a large scale on the seabed. These pipelines would play a crucial role in the hydrogen supply chain, enabling the efficient transport of green hydrogen from offshore production sites to onshore facilities. The development of submersed hydrogen pipelines faces several technical and regulatory challenges, including material selection to prevent hydrogen embrittlement, ensuring pipeline integrity under high pressure and harsh marine conditions, and establishing international standards for underwater hydrogen transport. Despite these challenges, the potential benefits of submersed hydrogen pipelines drive ongoing research and pilot projects aimed at making this innovative infrastructure a reality (Wang et al., 2021).

3.1.12. Offshore artificial energy island

In recent years, the term “energy island” - or similar variations like “electricity island” or “power link island” - has been used by academics, industry, and governmental reports to describe different understandings of energy isolation in a wide range of contexts and scenarios, leading to contradicting interpretations of the term (Rettig et al., 2023). It can refer to physically isolated islands with self-sufficient electricity systems, such as Cyprus and Iceland (Proedrou, 2012; Shortall & Kharrazi, 2017). It also describes countries that isolate their electricity systems for political reasons, like Israel and South Korea (Fischhendler et al., 2015). Additionally, the term applies to communities, cities, or regions using technologies like microgrids to voluntarily disconnect from the main grid (Warneryd & Karltorp, 2022). Currently, the primary use of “energy island” refers to artificial islands at sea or in remote areas that serve as hubs for electricity generation and distribution, often focusing on renewable energy (Singlitico et al., 2021; Lüth, 2022; Jansen et al., 2022; Rogeau et al., 2023). In this study, ’energy island’ exclusively refers to these artificial hubs for electricity generation and distribution.

Energy islands are large-scale offshore hubs that facilitate the massive scaling needed for the next generation of offshore wind deployment. By combining proven technologies in an innovative and larger-scale manner, they enable cost-efficient integration of offshore wind. Energy islands address three main challenges to offshore wind expansion (Copenhagen Energy Islands, 2024):

- **Enable significant cost savings:** energy islands reduce costs through scaling benefits. For instance, hosting multiple GWs of offshore wind on one island is cheaper than using multiple HVDC converters on platforms (Witteveen+Bos, 2022), simply because building each additional steel substructure is more expensive than each additional m^2 on an island (Copenhagen Energy Islands, 2024). Additionally, island-based hydrogen production also lowers transmission costs, as hydrogen pipelines are significantly cheaper than HVDC cables (Wingerden et al., 2023)
- **Accelerate rate of deployment:** expanding offshore wind energy can be accelerated by utilizing the existing local supply chain for offshore infrastructure like harbors and bridges, supporting quick mobilization and expansion. Constructing an energy island for multiple GWs of capacity is also faster and more efficient than building multiple offshore converter platforms (Copenhagen Energy Islands, 2024)
- **Reduce grid constraints:** island-based hydrogen production reduces grid constraints by optimizing power cable utilization, minimizing the need for grid expansion and lowering offshore wind curtailment. It maximizes wind resource market value by producing hydrogen when power prices are low and exporting power when prices are high (Copenhagen Energy Islands, 2024)

The challenges of constructing an energy island include high CAPEX, minimal experience in building offshore artificial islands, and the constant development of scour around the island, which complicates cable and pipeline landings. Additionally, the large scale of such islands presents complex logistical challenges as well as the construction duration and working season limitations.

For an offshore artificial energy island, several distinct implementation methods exist, including a sandy rock or concrete revetment island, a sandy caisson island, and a floating barrier barge island. This study considers these three methods, but many other approaches can be envisioned. For example, hybrid islands could feature a sheltered area protected by a (submerged) breakwater for floating, modifiable units. These diverse methods offer various advantages and challenges, allowing for tailored solutions to specific environmental and operational requirements.

(a) Offshore artificial rock revetment energy island, adopted from reve (2024)

(b) Offshore artificial caisson energy island, adopted from Danish Energy Agency (2022)

Figure 3.3: Artist impression of offshore artificial energy island types

3.1.13. Hydrogen storage

Hydrogen storage is a critical component in the realm of green hydrogen production, serving as a method to alleviate grid constraints and ensure a stable energy supply (Elberry et al., 2021). In the context of renewable energy, hydrogen can be produced during periods of excess electricity generation, particularly from variable sources like wind and solar. This hydrogen is then stored in various forms, such as compressed gas, liquid hydrogen, or in chemical carriers, to be utilized later when energy demand is high or renewable generation is low (Yousefi et al., 2023).

Hydrogen storage systems help balance the grid by absorbing surplus electricity that would otherwise be curtailed, thus maximizing the utilization of renewable energy resources (Ershadnia et al., 2023). Additionally, stored hydrogen can be converted back into electricity via fuel cells or turbines, providing a reliable power supply during peak demand or grid instability. This not only enhances grid stability but also supports the integration of higher shares of renewable energy into the energy mix. Advanced storage technologies and infrastructure development are essential to realizing the full potential of hydrogen as a key player in a sustainable and resilient energy future.

3.2. Standard Activity Breakdown (SAB) offshore wind

Next to the PBS of offshore wind infrastructure in Section 3.1, this section addresses the SAB for the offshore wind industry, with Figure 3.4 presenting the activities in an offshore wind project.

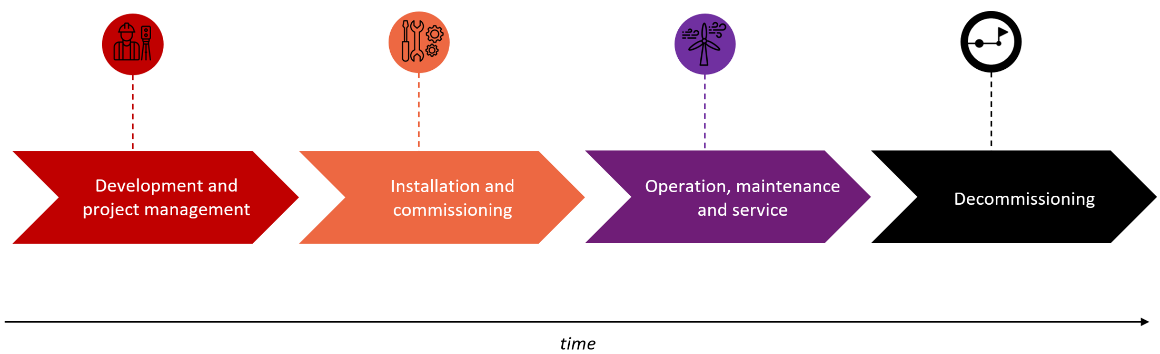

Figure 3.4: Activity Breakdown Schedule for an offshore wind project

3.2.1. Development and project management

Development and project management covers the activities up to the point of final investment decision (FID). This includes activities required to secure planning consents such as the environmental impact assessment, and activities required to define the design and engineering aspects. On average, this activity is budgeted at €140 million, at an exchange rate of £1/€1.18 (European Central Bank, 2024a), for a 1GW wind farm (BVG Associates, 2019). This includes development and consenting services, environmental surveys, resource and metocean assessment, geological and geotechnical surveys, engineering and consultancy. It also includes development expenditure incurred by lost projects.

3.2.2. Installation and commissioning

This activity includes all installation and commissioning (I&C) of balance of plant and turbines, including land- and sea-based activity. For offshore activities, the process starts by transporting components from the nearest port to manufacture to either a construction port or straight to site. Activities are complete at the wind farm construction works completion date, where assets are handed over to operational teams. The installation and commissioning operations generally cost about €760 million for a 1GW wind farm (BVG Associates, 2019). This includes the installation of the balance of plant and turbines, with related offshore logistics. It also includes developer's insurance, construction project management and spent contingency. Today, the typical process for installing a wind farm, with overlaps where possible, involves the following sequence: onshore substation and onshore export cables, foundations, offshore substations, array cables, offshore export cables, and turbines.

3.2.3. Operation, maintenance and service

Operation, maintenance and service (OMS) are the combined functions which, during the lifetime of the wind farm, support the ongoing operation of the wind turbines, balance of plant and associated transmission assets. OMS activities formally start at the wind farm construction works completion date. The focus of these activities during the operational phase is to ensure safe operations, to maintain the physical integrity of the wind farm assets and to optimise electricity generation. On average, this aspects costs about €90 million per year for a 1GW wind farm. This includes insurance, environmental studies, compensation payments and other internal asset owner costs. The focus of OMS is to maximise the financial return from the owners' investment. Owners aim to optimise the balance between operational expenditure and turbine yield. By scheduling downtime during the low wind speed summer months, owners can secure high availability during the winter months when wind speeds and energy outputs are typically higher. Contractual arrangements, which award energy production, are increasingly common.

3.2.4. Decommissioning

Removal or making safe of offshore infrastructure at the end of its useful life, plus disposal of equipment. The decommissioning of a 1GW offshore wind farm will cost around €350 million (gross, excluding any resale value of equipment removed). At the end of the nominal design life of an offshore wind farm, several options are available: extending the operational life through risk assessments, inspections, regulatory compliance, and some component replacements; repowering the site with new, larger turbines, which involves decommissioning existing turbines, foundations, and array cables but possibly extending the life of electrical transmission assets; or fully decommissioning the site. Properly financed decommissioning plans typically are required as part of gaining planning approval to construct the wind farm. In practice, permission is likely to be sought to deviate from decommissioning plans as the sector matures decommissioning techniques. UK Government acts as decommissioner of last resort so is ultimately responsible. As a result, it takes security for decommissioning.

3.3. Code of Resource (COR)

The COR within the offshore wind industry is crucial for various reasons, including effective fleet investment management. Installation of wind turbines and associated infrastructure requires highly specialized vessels. These vessels, such as jack-up rigs and heavy-lift ships, are tailored for specific tasks like turbine installation, cable laying, and maintenance. Accurate classification and tracking of these resources ensure that the right assets are available when needed, optimizing operational efficiency and cost management. The COR framework supports detailed planning and allocation of these specialized resources, which is vital for the successful execution of offshore wind projects. However, despite its importance, the COR is not explicitly integrated into the techno-economic model development. Consequently, the breakdown of the COR within the offshore industry is not assessed in further detail.

3.4. Cost Breakdown

To better understand the cost breakdown of an offshore wind farm project, Figure 3.5 presents a comprehensive overview from the development and project management phase up to decommissioning. This breakdown clarifies the major cost contributors within an offshore wind project, facilitating further reading and discussion in the report. The overview reveals that the largest expenses are associated with the offshore wind turbine itself and the Balance of Plant (BoP). The former includes the purchase and installation costs of turbines, while the latter encompasses infrastructure such as substations, grid connections, and foundations. Following closely is the Installation and Commissioning (I&C) phase, which can be particularly costly due to logistical challenges and the need for specialized equipment. On average, the Operation, Maintenance and Service (OMS) phase, along with the development & project management, and decommissioning phases, contribute less to the overall costs. Data is based on a study by BVG Associates (2019).

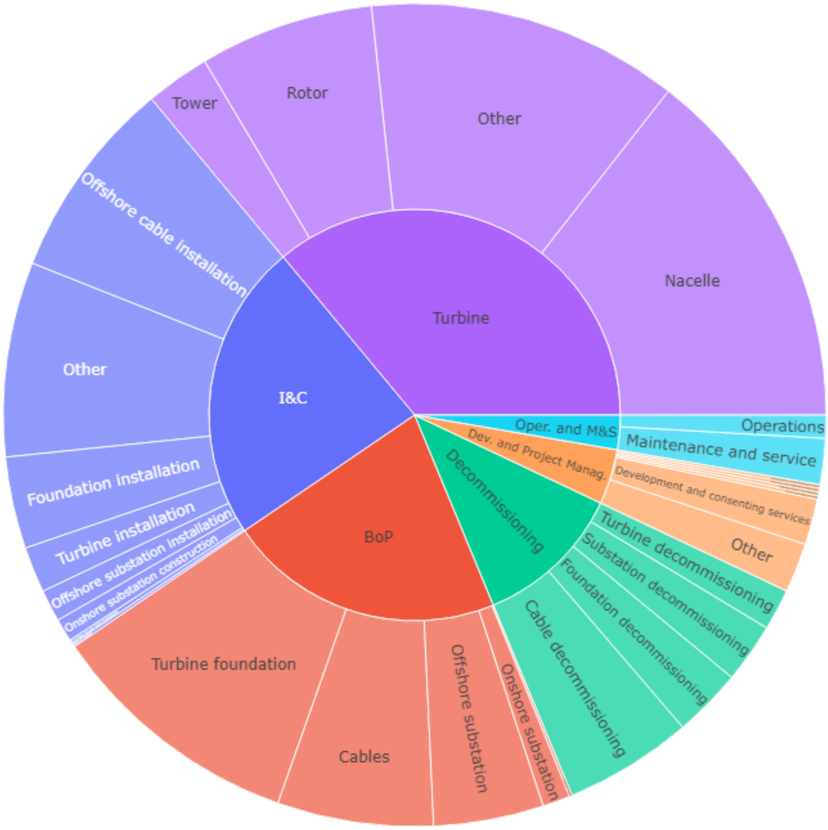

Figure 3.5: Cost breakdown of an offshore wind farm during lifetime, data adopted from BVG Associates (2019) and processed by the author

4 Methodology - standardized techno-economic model

This chapter outlines the structured approach used to develop a comprehensive and standardized model for assessing the techno-economic feasibility of offshore wind projects. Building on identified areas for improvement from the former methods by Van den Haak (2023) and identified gaps within the current literature on techno-economic assessment methods in the offshore wind industry, this chapter outlines the methodology employed in this study. It explains the systematic process of designing the model and incorporating key parameters to ensure robustness and reliability in evaluating various supply chain configurations.

4.1. Areas for improving the techno-economic model

This section addresses two aspects: (1) the areas identified for improvement based on the former version of the model and (2) the the areas identified for improvement based on the extensive literature study.

4.1.1. Former version standardized model

In this study, the methodologies introduced by Van den Haak (2023) are extended. Leveraging the expertise of MTBS, a financial feasibility expert in the maritime sector, Van den Haak (2023) provided detailed financial analyses that facilitated accurate assessments. While the financial aspects were thoroughly addressed, the technical components in the model, including supply chain component detailing, energy loss estimates, and geospatial data implementation, could benefit from further improvement. Therefore, while adopting the financial methodologies of Van den Haak (2023), this study focuses on refining, improving, and extending the technical elements to ensure a comprehensive analysis.

The following elements are selected from the former version of the techno-economic model and are preserved due to their adequate level of detail:

- Net cash flow analysis for all the supply chain components
- Method for calculation of the divestment value based on the principle of depreciation
- NPV calculation by discounting with the WACC, applied to CAPEX, OPEX and revenues
- Escalating yearly net cash flows with a constant inflation rate
- Method for calculating the LCOH, LCOE and LCOTE

Next to the elements that are preserved due to their adequate level of detail, elements in the methodology of Van den Haak (2023) are identified which would benefit from further improvement:

- The lack of features for dynamic adjustments to input variables, such as the number of wind farms and multiple potential starting years, highlights the need for flexibility in the model. The model will be enhanced to allow for dynamic adjustments to key input variables, accommodating various scenarios and timelines.

- The limited number of supply chain configurations available in the former version of the model shows potential for expansion. To enable a more comprehensive analysis, the model is expanded to include a broader range of supply chain configurations, including (different types of) energy island configurations, full HVDC transmission, and centralized and decentralized offshore platform conversion and transmission systems.
- The absence of a comprehensive cost estimation model for offshore energy islands points to a significant gap in financial assessment capabilities for this novel supply chain configuration. A detailed cost estimation model specifically for offshore energy islands will be developed and integrated into the model, ensuring accurate financial assessments.
- The inadequate detailing of supply chain components indicates a need for more thorough evaluation of each component. The model will be enhanced by further detailing supply chain components, including costs of various offshore platform foundations, differences in CAPEX and OPEX for platform, island and onshore-based installations, and electrolyzer performance, among other factors.
- The insufficient inclusion of geospatial data in the previous model suggests the need for location-specific analysis. Geospatial data will be incorporated into the model to better account for location-specific factors and optimize the placement and logistics of offshore wind projects, including aspects such as water depth and cable distances.

In addition to the identified areas for improvement, a similar approach is applied as in the former methods regarding the aggregated cash flow analysis of all supply chain components. The specific supply chain components included in the calculation depend on the type of supply chain configuration. Figure 4.3 provides an overview of the components included in the calculation applicable to the full island-based hydrogen (H_2) production configuration. For each component, factors such as CAPEX, construction duration, OPEX and lifetime are utilized to generate yearly cash flows. Subsequently, all individual cash flows are aggregated to produce one total project cash flow. The NPV of total costs is derived by summing all the discounted (by the WACC) cash flows. Based on the NPV of the total project costs and the discounted quantities of hydrogen and/or electricity production, economic metrics such as LCOH can be calculated.

4.1.2. Elements identified for improvement based on literature study

In subsection 1.3, a comprehensive literature study was conducted to identify areas for improvement in the new version of the techno-economic model. Based on the identified areas for improvement, the following explicit implications for developing the new version of the techno-economic model are defined.

- The small share of offshore energy island W2H focused studies compared to offshore W2P, highlights the need for balanced consideration and increased efforts in the domain of offshore energy island W2H systems. Enhanced research will improve the mapping of benefits from offshore W2H on energy islands and facilitate the identification of high-potential elements for optimizing these systems.
- The lack of detailed analysis of the cost estimation for offshore artificial energy islands indicates a significant gap in financial assessment. The objective is to integrate a thorough cost estimation model for offshore artificial energy islands into the assessment framework.
- The absence of standardization within techno-economic studies suggests a need for uniform methodologies. The objective is to implement standardization practices within the model to enhance comparability and reliability of results across different studies.
- The lack of harmonized comparison of different supply chain configurations points to a gap in comprehensive benchmark analysis. The objective is to develop a harmonized framework that allows for consistent comparison of various supply chain configurations within the offshore wind industry.
- The unavailability of open-source models restricts accessibility and collaborative development. The objective is to develop and distribute open-source models to improve transparency and collaborative enhancements in techno-economic assessments.
- The absence of detailed transmission efficiencies and costs in existing models indicates a need for more precise analysis. The objective is to incorporate detailed data on transmission efficiencies and costs to improve the accuracy of the techno-economic evaluations.

Together with the elements identified in subsection 4.1.1, these factors are incorporated into the techno-economic model development in this study. The following sections outline the methodology employed.

4.2. Energy island cost estimation model

In the methods of the former techno-economic model set-up, there was no comprehensive method for estimating costs related to offshore energy islands. This deficiency hindered the accurate assessment of overall project economics for supply chain configurations involving an offshore artificial energy island. Without a detailed cost estimation method specific to energy islands, crucial factors such as depth-dependent island costs, different island types and island footprint in m^2/MW were not adequately accounted for, potentially leading to inaccuracies in financial feasibility assessment. Addressing this gap in the techno-economic assessment methodology is essential for the accuracy of modeling offshore energy projects including energy island concepts, enabling stakeholders to make more informed and financially sound strategic choices in energy infrastructure planning and development. This section addresses the general setup, assumptions, input and output of the energy island cost estimation model.

4.2.1. General setup of cost estimation model

Ideally, the offshore energy island model should be able to quickly provide a first estimation for the costs of an offshore energy island based on a small set of governing input variables. Literature studies and enquiries within Van Oord and TNO (NSE program), led to the insights that the input variables required for cost estimation of an offshore energy island within the scope of this study are the water depth, island footprint (in m^2/MW) and expected energy capacity on the island (in MW).

Using a standard data repository on costs, including those for rock revetments, sand fill, and quay walls, an initial estimation of the CAPEX of an energy island can be made by simply specifying the water depth, footprint, and expected energy capacity. For other input variables, the model will default to the standard repository unless specified otherwise, enhancing its usability. The island model is enabled with the possibility to estimate the costs for three different island types, namely: (I) a rock revetment sand fill island, (II) a caisson sand fill island, or (III) a floating hybrid island with floating barrier. As the energy island cost model is intended for use in the pre-feasibility stage of offshore energy infrastructure development, the objective of the energy island cost estimator is specified as follows:

Develop a comprehensive and efficient tool to accurately estimate the total investment costs for an offshore artificial energy island, with sufficient detail for informed decision-making

Table 4.1: Associated components in the energy island cost estimation model per island type

Element	**Type I** Rock revetment	**Type II** Caisson	**Type III** Floating
Heavier side rock/concrete revetment	×		
Lighter side rock/concrete revetment	×		
Caisson		×	
Rock berm under caisson		×	
Sand in caisson		×	
Breakwater (harbour protection)	×	×	
Sand inside island and harbour	×	×	
Quay wall	×	×	
Submerged breakwater			×
Sand body below submerged breakwater			×
Floating barrier			×
Floating barges			×
Cable landing facilities	×	×	×

Based on the defined footprint and required capacity of the island, the necessary island area can be calculated. This area accommodates the transmission and conversion energy infrastructure. Including a harbor area provides the total island area. The perimeter can then be calculated, determining the required length of the rock revetment or caisson sections. The water depth at the project site determines the required height of these structures. Greater water depth increases costs (in €/m) of the revetment or caisson sections until a certain depth, where a ”sand pancake” is added to elevate the seabed, as used in the study by North Sea Energy (2022). The required volume of sand needed for both the sand pancake (if necessary) and the sand fill within the island can be calculated.

4.2.2. Technical assumptions for energy island cost estimation model

To make an initial estimation of the costs for constructing an artificial offshore energy island, several simplifications and technical assumptions are necessary, which are outlined below.

Technical feasibility

Rough conditions and significant wind heights on the North Sea (Weisse et al., 2012) make constructing an artificial island in the North Sea challenging. Additionally, the phenomenon that there are two primary wave directions on the North Sea adds complexity (van Leeuwen & de Wit, 2024). The operational waves are a combination of swell and wind, influenced by the current. Swell waves primarily originate from the Nordic regions of the North Sea, while wind waves mainly come through the Strait of Dover. During extreme wave conditions, most waves still come from the Strait of Dover, but the heaviest waves are from the Nordic waters (van Leeuwen & de Wit, 2024). This phenomenon poses a significant challenge for the construction of an energy island, as there is no single dominant wave direction and robust revetments are required on multiple sections. The varying wave directions, combined with the strong currents and the impact of scour, create substantial difficulties for maintaining the stability and integrity of the island.

Nevertheless, currently, an energy island is under construction off the coast of Belgium – the Princess Elisabeth Island, the world’s first artificial energy island (Elia Group, 2024). Princess Elisabeth Island will be built on concrete caissons filled with sand at an average depth of 18-20 meters, covering 6 hectares. Despite the rough North Sea conditions, the ongoing construction demonstrates the feasibility of the energy island concept at these depths (Elia Group, 2024). Additionally, in Denmark, tendering began for an energy island, with Sweco appointed as the technical advisor for the Danish Energy Agency through the tendering, design, construction, and final handover phases (SWECO, 2024). Although the tender was postponed due to high costs, it was not halted because of technical difficulties (Reuters, 2023), suggesting that calculations during the tendering phase confirmed the island’s technical feasibility.

Given the concept’s established feasibility at water depths of 27-30 meters (Danish Energy Agency, 2024), it is reasonable to start considering its technical feasibility at depths of 40-50 meters, relevant for the NSE program hub North. Specialists support this reasoning, noting that wave energy is significantly reduced at these depths. Elevating the seabed with sand and protecting it with scour protection would provide a foundation upon which the proven 27-meter water depth concept could be further developed, a concept earlier introduced by North Sea Energy (2022).

Moreover, it is important to acknowledge that this study focuses on the pre-feasibility stage of offshore renewable energy infrastructure projects, assessing the techno-economic feasibility of various supply chains. Within this scope, based on the aforementioned reasoning, expert judgment, and the proven concepts of the Belgian and Danish islands, it is reasonable to presume that offshore artificial energy islands can be constructed at such water depths. The technical feasibility, coupled with reduced wave energy and proven engineering techniques, provides a strong foundation for further exploration and development of energy islands in deeper waters.

In conclusion, constructing an energy island appears technically feasible, particularly within the study’s scope. However, it is crucial to acknowledge that the technical feasibility has not been assessed in detail for the specific water depths relevant to the case study. Comprehensive studies are necessary to confirm the feasibility of the technical assumptions, construction methods, and island types in the North Sea. Lastly, presenting another perspective: Without techno-economic feasibility studies demonstrating a viable business case for an island, it is unlikely that detailed studies into the technical feasibility at such depths, including real site conditions and metocean data, will be conducted. This underscores the necessity of this study, which assesses and compares the business case for an energy island with other methods, proving its viability.

Bottom layer island

For waves, the orbital motion and wave energy decrease in deeper water. Below a depth of half the wavelength ($D = 1/2L$), water is practically unaffected by the wave energy (Ross, 1970). It is therefore assumed reasonably for waves in the North Sea, that at water depths of more than 30 m, the wave energy is relatively small. From this depth, it is not required to have a robust rock revetment in place; instead, the water depth can be covered with a ”sand pancake” protected by scour protection. This method, also employed by North Sea Energy (2022), involves layering sand to create a stable base, upon which the actual rock revetment and island fill are placed. This assumption leads to a situation where for depths larger than 30 m, the costs do not increase proportionally as there is no rock revetment required up to that depth, but a protected sand pancake suffices.

Construction duration

The construction of the energy island itself is assumed to take one year. Given the challenges posed by the storm season, it is desired to complete the protection works within a single season. This is an ambitious assumption and might prove unrealistic. However, considering the substantial challenges ahead, a bold approach is necessary. By mobilizing the entire fleet of multiple contractors in the Netherlands and working on multiple fronts simultaneously, it is assumed that efficient and rapid construction can be achieved, making this timeline feasible. Additionally, since construction works are not expected to start immediately, ample time is available for preparations such as fleet investment management and logistical planning, which can further ensure the feasibility of this aggressive timeline.

Nessen (2023) studied the construction process, logistics, and construction costs associated with an offshore pumped storage hydropower plant of 5 km in diameter in the North Sea. The study showed that by optimizing the work method and phasing based on the sheltering effects and governing wave directions, the construction time can be reduced from 9 years and 2 months to only 3 years and 6 months. Based on the hydropower plant with a diameter of 5 km, the required perimeter for caissons can be determined. Referring back to the required caisson length for the energy island considered in this study, the construction time is estimated to be about one year.

The techno-economic model does allow for different values for construction duration. However, a longer construction period would necessitate building the island over multiple working seasons, requiring a different approach, which is why a one-year construction duration is considered in the current model. Acknowledging the optimistic construction timeline for the caissons is crucial. Further detailed design of the offshore artificial energy island is necessary to ensure feasibility and address potential challenges.

Scour protection and cable landings

In the study of van Leeuwen and de Wit (2024), it was concluded that metocean conditions are of great importance for design and construction of offshore projects and that design and conditions cannot be separated, calculation of a platform should differ from that for an island. Large, rigid objects, such as energy islands, enforce interaction between structure and wave and current conditions, resulting in significant scour development around the island. Robust scour protection measures and cable landing sites are essential, along with constant monitoring and maintenance to ensure the island’s stability and functionality. The expected scour formation is significant and unprecedented on this scale, introducing uncertainty that must be specifically addressed in future designs of potential energy islands.

Availability of sand

It is assumed that there is a sufficient supply of sand available in close proximity to the construction site. This assumption minimizes transportation costs and logistical challenges, as sourcing sand locally is more efficient and cost-effective. The proximity of the sand supply is crucial for maintaining the project’s feasibility and budget.

4.2.3. Input for energy island cost estimation model

As previously described, the setup of the energy island module must facilitate easy calculation of the island's CAPEX. By specifying the water depth, island footprint (in m2/MW), and expected energy capacity (in MW), the model should be able to perform the calculations. The costs for individual energy island components, such as a rock revetment, are extracted from a database. While modifying the cost specifications of all components is possible, it is not mandatory in order to run the energy island cost estimation model. To develop this database, the experience of Van Oord is utilized on cost estimates for installation and materials for an offshore energy island. Detailed collaboration has been conducted to determine the individual investment costs for the different energy island components.

The cost estimates for the energy island components provided by Van Oord are confidential. These values were used to calculate the estimates for the artificial energy island costs and compared with publicly available data, such as those in the study by North Sea Energy (2022). The values appeared to be in the same order of magnitude. Therefore, the cost estimations for the energy island components referred to in this report are based on the publicly available study by North Sea Energy (2022) rather than Van Oord's internal data.

Application to a 4,000 MW type I (rock revetment) energy island, at 30 m water depth and with a footprint of 80 m2/MW, the key figures and total costs would be as depicted in Table 4.2. The required components correspond with the ones as defined in Table 4.1. The required No. units presented in Table 4.2 is based on the calculation methods of the developed energy island cost estimation model, as explained in Subsection 4.2.1. Key cost figures are derived from publicly available data from North Sea Energy (2022). These figures are used as indicative values in this report but are not utilized in the actual island cost calculations in Chapter 5. Instead, internal confidential data is used for these calculations, which corresponds with the publicly available data.

Table 4.2: Input components and their corresponding costs applicable to a type I island in the energy island cost estimation model. The presented key figures are illustrative and indicative, primarily based on public data of the NSE program 2020-2022 (North Sea Energy, 2022). The required No. are based on calculations of the energy island cost estimation model.

Element	**Key figure**	**Unit**	**Req. No.**	**Unit**	**Total costs** [m€]
Heavier side rock/concrete revetment	450,000	€/m	1,200	m	540
Lighter side rock/concrete revetment	300,000	€/m	800	m	240
Breakwater (harbour protection)	320,000	€/m	320	m	102
Sand inside island and harbour	7.5	€/m^3	14,290,000	m^3	107
Quay wall	125,000	€/m	600	m	75
Cable landing facilities	45,000,000	€	1	[pc]	45
				Total	**1,109**

4.2.4. Output for energy island cost estimation model

Utilizing the indicative values for the required number of meters (m) and cubic meters (m^3), along with indicative costs sourced from North Sea Energy (2022), as inputs for the energy island cost model, facilitates the generation of the cost distribution depicted in Figure 4.1. This distribution offers insights into the allocation of costs across various components within a rock revetment sand fill energy island, indicating the significant share of costs of the rock revetment on the total island costs.

Given that the required length of the breakwater, roughly corresponding to the circumference or perimeter of a potential island, does not increase proportionally to the available m^2 for expanding the island size, it becomes advantageous to implement larger energy islands rather than multiple smaller ones. Figure B.9 illustrates the estimated trend of energy island costs for increasing capacity for island type I (rock revetment) and type II (caisson).

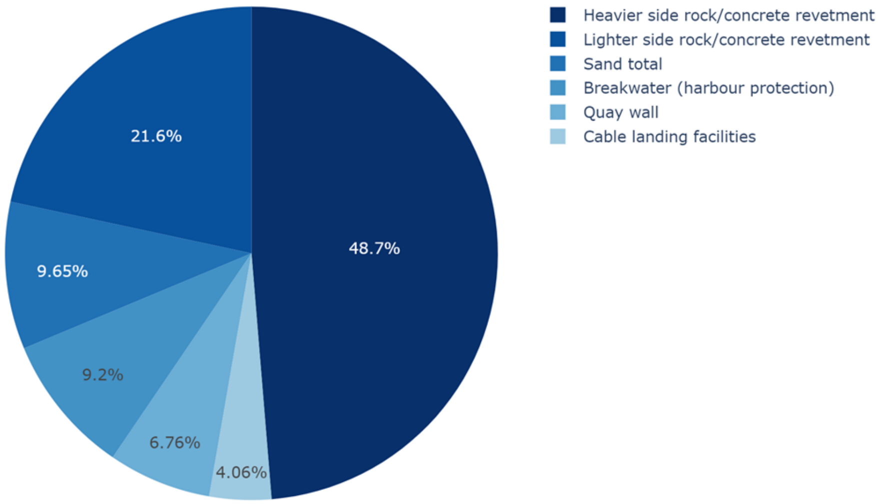

Figure 4.1: Indicative example of the distribution of costs for a 4,000 MW type I energy island at 30 m water depth and a footprint of 80 m^2/MW

Conducting a sensitivity analysis for the two key governing input variables of the island cost model—footprint and water depth—provides valuable insights. The 'base' scenario involves the hub North configuration with 19.5 GW of island capacity, 45m water depth, and a footprint of 80 m^2/MW, resulting in a total cost of roughly €2.8b. By varying both variables by +/- 50%, the sensitivity analysis reveals that the footprint has the most significant impact on the total cost. A footprint of 120 m^2/MW (increase of 50%), results in a 27.1% higher total cost, while an increase of 50% for the water depth leads to a 21.8% higher total cost. This indicates that changes in the footprint parameter greatly influence the overall project expenses.

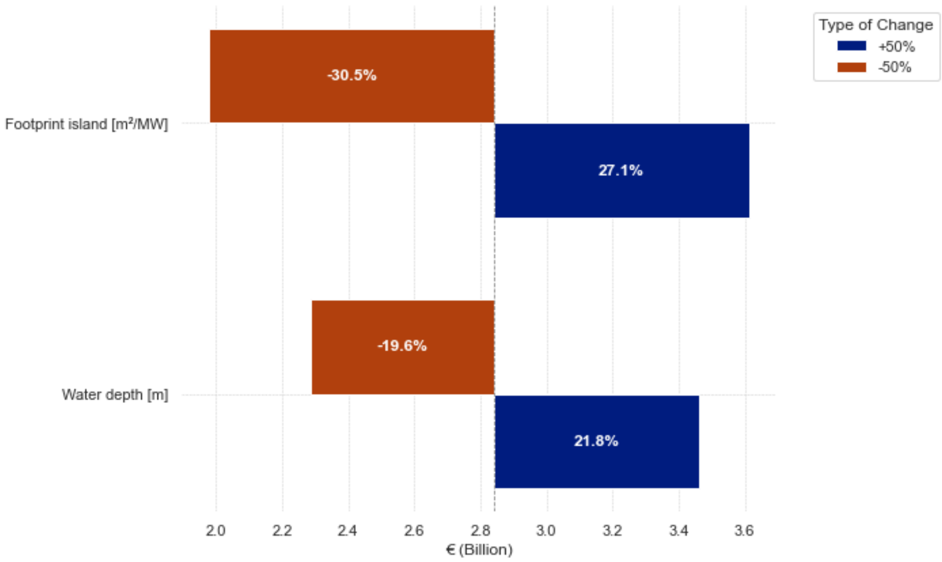

Figure 4.2: Sensitivity analysis for a base case of a 19.50 GW type I energy island at 45 m water depth and a footprint of 80 m^2/MW, varying the water depth and footprint input variables by 50%

4.3. Supply chain components

As offshore wind farms move further from shore, traditional HVAC transmission becomes less suitable. HVDC transmission is more efficient for long distances due to lower energy losses. Additionally, offshore hydrogen production and subsequent hydrogen transport is emerging as an alternative for energy transport to shore. These methods represent different supply chain configurations that should be modeled in the techno-economic model to ensure a “harmonized comparison”, as defined by Rogeau et al. (2023).

Based on recent techno-economic assessments in the offshore W2P and W2H industry (Singlitico et al., 2021; Dinh et al., 2021; Yan et al., 2021; Jang et al., 2022; Terlouw et al., 2022; Rogeau et al., 2023; Lüth et al., 2023; Giampieri et al., 2024), relevant supply chain configurations for this study are identified. These configurations include full dedicated hydrogen production, full dedicated electricity production, and co-production of both (share of H_2/E of 30/70, 50/50 and 70/30%). Additionally, each of these options can be based on offshore platforms, islands, or onshore, resulting in a total of nine supply chain configurations. However, for the onshore-based full electricity production (HVDC) configuration, power would already be converted on an offshore platform to HVDC for efficient energy transmission, leading to an identical configuration with the offshore platform-based full HVDC configuration. Therefore, the onshore-based option is excluded, leaving eight potential supply chain configurations:

1. **Full H_2 Platform**: H_2 production infrastructure situated on an offshore platform structure
2. **Full HVDC Platform**: HVDC infrastructure situated on an offshore platform structure
3. **Co-production Platform**: Facilities for producing both HVDC and H_2 on a platform structure
4. **Full H_2 Island**: H_2 production infrastructure located on an offshore energy island
5. **Full HVDC Island**: HVDC infrastructure located on an offshore energy island
6. **Co-production Island**: Facilities for producing both HVDC and H_2 on an offshore energy island
7. **Full H_2 Onshore**: H_2 production facility located onshore, brought to shore by HVDC transmission
8. **Co-production Onshore**: Facilities for producing both electricity and H_2 located onshore, brought to shore by HVDC transmission and split ashore for hydrogen production and for DC to AC conversion, preparing it to be supplied to the national grid

Figure 4.3 presents a schematic overview of the required components for an island-based full H_2 production configuration. The seven other configurations are presented in Appendix B.

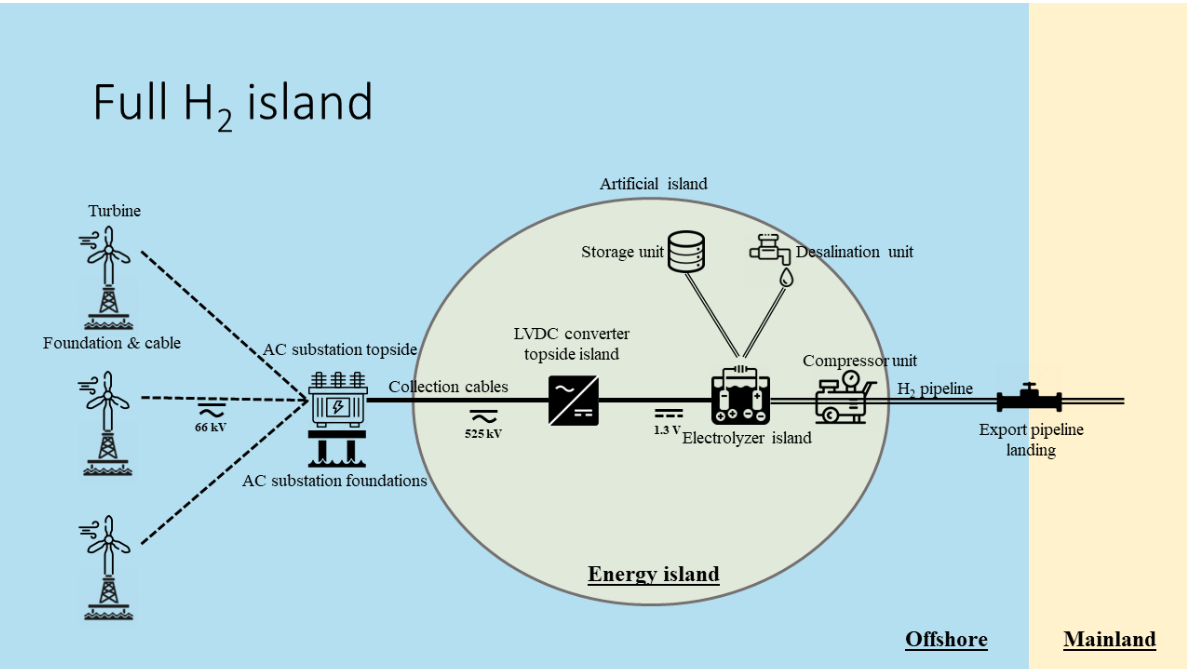

Figure 4.3: Schematic overview of offshore wind-to-hydrogen supply chain configuration - Full H_2 Island

Components	Platform H_2	Platform E	Platform Co.	Island H_2	Island E	Island Co.	Onshore H_2	Onshore Co.
Foundation & cable	×	×	×	×	×	×	×	×
Turbine	×	×	×	×	×	×	×	×
AC collection cable	×	×	×	×	×	×	×	×
AC substation foundations	×	×	×	×	×	×	×	×
HVDC converter foundations		×	×				×	×
LVDC converter foundations	×		×					
Electrolyzer foundations	×		×					
AC substation topside	×	×	×	×	×	×	×	×
Artificial energy island				×	×	×		
HVDC converter topside offshore	×	×					×	×
HVDC converter topside island					×	×		
HVDC converter topside onshore								
LVDC converter topside offshore	×		×					
LVDC converter topside island				×		×		
LVDC converter topside onshore							×	×
Electrolyser topside offshore	×		×					
Electrolyser topside island				×		×		
Electrolyser topside onshore	×						×	×
Desalination unit	×		×	×		×	×	×
Compressor unit	×		×	×		×	×	×
Storage unit	×		×	×		×	×	×
Compressor after storage	×		×	×		×	×	×
DCAC converter		×	×		×	×		×
HVDC export cable		×	×		×	×	×	×
H_2 pipeline	×		×	×		×		
Export cable landing		×	×		×	×	×	×
Export pipeline landing	×		×	×		×		

Table 4.3: Overview of components corresponding with each supply chain configuration

4.4. Definitions and equations

Chapter 2 indicated that the majority of studies evaluate the financial viability of offshore energy supply chain elements through techno-economic analyses employing metrics such as LCOH and Net Present Value (NPV). Feasibility cost models analyze supply chains' CAPEX and OPEX to ascertain their economic attractiveness. In addition to the LCOH and NPV, other financial metrics utilized for assessing financial viability include LCOE, LCOTE, LCOHP and LCOHT.

4.4.1. Discount rate

The discount rate serves as a financial instrument utilized to evaluate the worth of future cash flows in present terms, a crucial element in the NPV formula. It denotes an interest rate employed to discount the value of anticipated future cash flows to their present value. The discount rate reflects the return rate that compensates investors for the time value of money and investment risk (DePamphilis, 2022). In techno-economic analyses for financial feasibility studies, it is common practice to apply a constant discount rate throughout the project's duration. However, this approach assumes a steady state for project risks and financing structure over its lifespan, which diverges from the dynamic nature of real-world scenarios (DePamphilis, 2022).

In financial modeling, the Weighted Average Cost of Capital (WACC) frequently serves as the discount rate for determining the present value of future cash flows. The WACC embodies the average cost of capital for a company, computed by weighing the cost of equity and debt according to the company's capital structure. This structure is defined by the relative proportions of debt and equity within the company's capital mix (DePamphilis, 2022). The preference of using the WACC as discount rate stems from the WACC's ability to accurately capture a company's cost of capital while encompassing associated investment risks. Utilizing the WACC as the discount rate ensures an appropriate adjustment of future cash flows' present value to reflect both the cost of capital and project-related investment risks (DePamphilis, 2022). Since future cash flows are already discounted by WACC, which incorporates interest rates, there is no need to incorporate additional financing expenses (FINEX).

4.4.2. Net Present Value (NPV)

The Net Present Value (NPV) serves as a fundamental metric in financial analysis, representing the actual value of capital. As future cash flows are analyzed within the techno-economic assessment, their present value changes over time due to the applied discounting. Employed as a financial indicator, NPV aids in assessing the feasibility of a project by comparing the actual (present) value of profits to the investments made. This comparison yields the net present value of the project, signifying the difference between profits and investments (Kaldellis, 2022). The NPV calculation is expressed in Eq. 4.1 (McDonagh et al., 2020). Additionally, NPV accounts for the time value of money, reflecting the concept that a dollar today is worth more than a dollar in the future due to its potential earning capacity or inflationary effects. This makes NPV an essential tool for decision-making in investment appraisal and project evaluation.

$$NPV = \sum_{t=1}^{n} \frac{\text{net cash flow}_t}{(1+r)^t} \tag{4.1}$$

where,

- n is the final project year,
- net cash flow is the sum of all costs and revenues.

Calculating the NPV of future cash flows is called the Discounted Cash Flow (DCF) method. The final year cumulative NPV is the sum of all discounted cash flows that have been generated by a project up until the final year. Part of all cash flows is the revenues. A positive final-year cumulative NPV means that the present value of the cash inflows generated by the project exceeds the present value of the cash outflows (total costs) over the project's lifetime. This indicates that the project has created value for its stakeholders (Kaldellis, 2022).

4.4.3. Additional levelized costs

Next to the levelized cost of hydrogen and electricity, this study's methodology employs three other levelized costs, namely: the Levelized Cost of Total Energy, Hydrogen Production and Hydrogen Transport (LCOTE, LCOHP and LCOHT). The LCOTE is introduced as a techno-economic metric to allow for comparison between full hydrogen production, full electricity production and co-production supply chains. It is calculated by Eq. 4.2

$$LCOTE = \frac{\sum_{t=1}^{n} \frac{\text{CAPEX}_{t,H_2} + \text{OPEX}_{t,H_2} + \text{CAPEX}_{t,E} + \text{OPEX}_{t,E}}{(1+r)^t}}{\sum_{t=1}^{n} \frac{(\text{H}_2 \text{ at shore}_t \times 120 \text{ MJ/kg}) + (\text{E at shore}_t \times 3.6 \text{ MJ/kWh})}{(1+r)^t}} = \left[\frac{€}{\text{MJ}}\right] \tag{4.2}$$

Additionally, the LCOH is divided into two elements: the production and the transport. This study assesses the feasibility of offshore wind energy supply chains, with a detailed focus on the transmission methdos. Hence, the subdivision of the hydrogen supply chain was ought to provide more depth to the comparison analysis by assessing the LCOHP and LCOHT. Eq. 4.3 present the LCOHP,

$$LCOHP = \frac{\sum_{t=1}^{n} \frac{\text{CAPEX}_{t,H_2P} + \text{OPEX}_{t,H_2P}}{(1+r)^t}}{\sum_{t=1}^{n} \frac{\text{H}_2 \text{ at shore}_t}{(1+r)^t}} = \left[\frac{€}{\text{kg}}\right] \tag{4.3}$$

and Eq. 4.4 present the LCOHT,

$$LCOHT = \frac{\sum_{t=1}^{n} \frac{\text{CAPEX}_{t,H_2T} + \text{OPEX}_{t,H_2T}}{(1+r)^t}}{\sum_{t=1}^{n} \frac{\text{H}_2 \text{ at shore}_t}{(1+r)^t}} = \left[\frac{€}{\text{kg}}\right] \tag{4.4}$$

where,

- CAPEX_{t,H_2P} is the total capital expenditures for hydrogen **production** supply chain in year t,
- CAPEX_{t,H_2T} is the total capital expenditures for hydrogen **transport** supply chain in year t,

4.4.4. Divestment and depreciation

Depreciation of assets is commonly calculated using the straight-line method, where an asset's value decreases by the same amount each year throughout its useful life. This depreciation amount is determined by dividing the asset's initial value (CAPEX) by its economic lifetime. For instance, if an offshore wind turbine has a total initial CAPEX of €1,000,000 and an economic lifetime (also known as the 'write-off time') of 25 years, the annual depreciation value would result from dividing the CAPEX by the economic lifetime, equalling €40,000 (Blum & Katz, 1965).

When the project duration is shorter than the economic lifetime of an asset, there remains some residual value in the asset. For example, if the project duration is 20 years, in case of the offshore wind turbine, there are 5 more years of asset value remaining. This would amount to 5 times €40,000, equating to €200,000. This residual value serves as an approximation for the divestment value in the cash flow analysis, although in real life the actual divestment value is determined by the asset's market value at the time of sale (Blum & Katz, 1965).

4.4.5. Supply chain efficiency

In addition to the economic aspects previously discussed, the technical elements of the analysis must also be addressed. A key component is the calculation of supply chain efficiency. The model calculates three different efficiency values: hydrogen supply chain efficiency, electricity supply chain efficiency, and total supply chain efficiency. These formulas are defined by the author and presented below. The calculation of the efficiency of the hydrogen supply chain is presented in Eq. 4.5.

$$\eta_{H_2} = \frac{\text{H}_2 \text{ at shore}}{\text{wind production} \times \text{share}_{H_2} \times \text{LHV}^{-1}} \tag{4.5}$$

where,

- η_{H_2} is the total hydrogen supply chain efficiency in [%],
- H_2 at shore is the total hydrogen available onshore in [kg],
- wind production is the total average wind production in [kWh],
- LHV is the lower heating value of hydrogen of 33.33 in [kWh/kg].

The calculation of the efficiency of the electricity supply chain is presented in Eq. 4.6,

$$\eta_E = \frac{\text{E at shore}}{\text{wind production} \times \text{share}_E} \tag{4.6}$$

where,

- η_E is the total hydrogen supply chain efficiency in [%],
- E at shore is the total electricity available onshore in [kWh].

The calculation of the average efficiency of the total supply chain is presented in Eq. 4.7.

$$\eta_{total} = \frac{(\text{H}_2 \text{ at shore} \times \text{LHV}) + (\text{E at shore} \times 3.6 \text{ [MJ kWh}^{-1}])}{\text{wind production} \times 3.6 \text{ [MJ kWh}^{-1}]} \tag{4.7}$$

where,

- η_{total} is the total hydrogen supply chain efficiency in [%],
- LHV is the lower heating value of hydrogen of 120.0 in [MJ/kg].

4.5. Technical assumptions

This section addresses the technical assumptions and model design choices implemented in the techno-economic model.

4.5.1. Difference in onshore, island and offshore platform-based components

A classification has been established for electrolyzers, HVDC, and LVDC converters, distinguishing between offshore (platform), island, or onshore components. Offshore platform-based components are typically associated with higher CAPEX and OPEX when compared to their onshore counterparts. This higher cost is often attributed to the logistical challenges and technical complexities inherent in offshore installations. Conversely, onshore components generally entail lower costs due to easier accessibility and simpler infrastructure requirements. Island-based components fall within a cost spectrum lying between offshore and onshore, reflecting a blend of challenges and advantages associated with both environments. This classification framework aids in understanding the financial implications and strategic considerations for deploying various components in different settings, leading to the required detailing and trade-offs for informed decision-making in energy infrastructure development.

In line with the classification of differentiating in costs, a classification has been implemented for electrolyzer efficiencies. The electrolyzer EDR varies depending on whether they are situated offshore (platform), on an island, or onshore. Processes such as operating temperature and intermittent power supply have strong influence on electrolyzer performance (Buttler & Spliethoff, 2018; Lange et al., 2023). Consequently, it is reasonable to assume that onshore electrolyzers benefit from ample space and redundant balance of plant support, likely resulting in a lower yearly EDR compared to offshore installations. Conversely, offshore electrolyzers positioned on platforms face spatial constraints, necessitating optimization that may compromise the full provision of balance of plant support. Consequently, these constraints often lead to larger efficiency degradation rates per year for offshore electrolyzers. Additionally, island configurations exhibit a lower EDR owing to the possibility of creating a stable base load by connecting multiple wind farms. In contrast, offshore platforms typically operate in a more decentralized manner, making it challenging to establish a stable base load, hence contributing to larger EDRs. This nuanced understanding of efficiency dynamics across different deployment scenarios underscores the importance of tailored strategies and infrastructure planning to mitigate performance degradation and ensure long-term operational viability.

4.5.2. Restriction of commissioned energy island for energy production

In the techno-economic model set-up, the absence of the energy island serves as a critical restriction for energy production, impeding the conversion and transportation of energy to the shore. This limitation is factored into the model, highlighting its significance in determining the overall feasibility and efficiency of the energy system. Once the energy island is constructed, energy production can commence, enabling conversion and transportation of energy resources to the mainland within the model's framework.

4.5.3. Commissioning timing of supply chain components

The model allows for different wind farms having different starting years for construction. Therefore, a phased approach is employed for when construction is commenced for the individual supply chain components. Components are categorized into one-time construction or multi-phased construction. In short, the offshore energy island would be constructed in one go, already accommodating the area required for the future infrastructure on it. In contrast, the electrolyzers on the actual energy island are constructed in time aligned with the corresponding wind farm. If one wind farm is constructed later in time, the accompanying electrolyzer and/or HVDC installations are simultaneously constructed in time to ensure synchronization. This assumption is deemed realistic due to its impact on NPV calculations, preventing an increase in costs for earlier construction phases where components are not yet utilized. By aligning costs with utilization, the NPV calculations accurately reflect the project's economic viability and provide a more realistic assessment of investment returns over time.

The following supply chain components are built simultaneously with the construction of the corresponding wind farm: AC substation (topside and foundation), collection cable, LVDC converter, electrolyzer, desalination unit, compressor unit, storage unit, compressor after storage unit, HVDC converter and

DCAC converter. In contrast, the energy island, HVDC export cable, hydrogen export pipeline, onshore cable landing and onshore pipeline landing are constructed in one go.

4.5.4. Determination energy capacity of components

The sizing of HVDC and electrolyzer components is determined by the original wind farm capacity and the energy split, without accounting for efficiency losses resulting from cable transmission and/or energy conversions. For example, in a scenario with a 4 GW offshore wind capacity and a 100% hydrogen energy split, the electrolyzers are sized to accommodate the full 4 GW of wind energy capacity, despite potential lower capacity reaching the electrolyzer due to minor conversion and transmission losses. In this situation, there would be 4 GW of generated wind power, of which around 1% would be lost due to the inter array cables, 1% due to the AC substation, 1% due to the collection cable, and 1.5% due to the LVDC converter before the wind energy reaches the electrolyzer. Nevertheless, the electrolyzer would be sized to accomodate 4 GW of wind power (in the case of 100% energy split towards hydrogen production). This conservative approach ensures that components downstream in the supply chain are slightly oversized relative to their actual requirements, automatically incorporating contingency costs for instance.

4.5.5. Offshore AC substation

For efficient AC transmission from the wind farm to subsequent components, transformers at AC substations increase the voltage. These substations are strategically situated near or within the wind farm to optimize energy transmission by elevating voltage levels, thus mitigating resistive losses during long-distance transportation. However, the actual positioning of AC substations within the wind farm is not individually determined within the scope of the model, potentially impacting factors such as inter-array cable length, AC substation foundation depth and collection cable length. Instead, a constant value is assigned for inter-array cable costs, while the foundation depth depends on the average water depth of the wind farm. Additionally, the collection cable length is measured from a designated point within the wind farm to subsequent infrastructure.

4.5.6. Cost allocation for LCOH and LCOE calculation

In order to allow calculation of the LCOH and LCOE, an allocation of costs should be made. As shown in Eq. 2.2 and Eq. 2.2, the LCOH and LCOE are calculated by considering the costs specifically related to the production and transport of hydrogen and electricity, respectively. When a supply chain produces both hydrogen and electricity, the costs should be allocated accordingly. For the costs of an electrolyzer, which produces hydrogen, it is straightforward, it will be allocated to hydrogen production and only influences the LCOH. Contrary, a HVDC converter is used in a full HVDC supply chain configuration and therefore only influences the LCOE. Unless, onshore hydrogen production is implemented, in this case it is also part of the hydrogen supply and would be allocated accordingly. For allocation of the costs of an offshore wind turbine, the share of energy for hydrogen production and electricity is utilized, i.e., in a configuration where 30% of the initial wind energy is utilized for hydrogen production, 30% of the costs of the offshore wind turbine would be allocated to the hydrogen production supply chain (LCOH) and the remaining 70% to the electrical supply chain (LCOE).

Due to the constant cost rate specified in €/MW and the absence of a learning rate and scale rate, large-scale electrolyzers have the same cost per MW as small-scale electrolyzers. This results in costs scaling linearly with capacity, a common practice in techno-economic studies. However, it has the implication that for different shares of H_2 and E there is no change in LCOH and LCOE.

4.6. Verification of the developed techno-economic model

In this section, the method for verifying the developed techno-economic model is discussed. Verification is a crucial element in model development. As the model grows in complexity, detecting semantic errors becomes increasingly challenging, even though the syntax may execute without issues. This verification process ensures that the model's implementation accurately follows the intended design and logic, thereby guaranteeing its reliability and correctness before proceeding to further stages.

The verification methodology consists of two elements. First, the techno-economic model incorporates numerous functions to check the correctness of various steps and outcomes within the model. Secondly, the functionality and robustness of the model are tested through unit tests and by running the model with trivial and simple input values, for which the validity of the outcomes can be easily assessed.

4.6.1. Built-in verification functions

The techno-economic model incorporates built-in verification functions. These functions verify the correctness of intermediate steps and final results based on predefined definitions, expected values, and rules established by the author. These verification functions are crucial for ensuring the model's accuracy and reliability.

An example of such a verification function is as follows: the model calculates the actual energy production by multiplying the rated power in kW of the wind farm by the capacity factor and the number of hours in a year. This yields the actual average production in kW of the (individual) wind farm(s) per year. By repeating this calculation for all project years and considering different starting years of the wind farms, a comprehensive data sheet can be generated. Table B.3 presents an example. Next, the relevant transmission and conversion efficiency factors are applied to all actual energy production values. Summing these adjusted values results in the total actual output in kWh (for electricity) and/or kg (for hydrogen). The "real" supply chain efficiency is then determined by dividing the actual output by the total actual average production at the wind farm.

Alternatively, the "theoretical" supply chain efficiency can be calculated using only the efficiency factors. For constant efficiency factors, their values can be simply multiplied together. For changing efficiency factors, such as the collection cable efficiency which varies with cable length, actual capacity, and operational years, a more sophisticated calculation is required. By calculating the "weighted" average efficiency factor for various components, such as the collection cable and electrolyzer, and then multiplying these with other relevant efficiency factors, the "theoretical" supply chain efficiency is obtained. The built-in function then compares the "real" and "theoretical" supply chain efficiencies. If the values do not match, the model generates an error and stops, thereby incorporating an automatic verification mechanism.

- **Built-in check if all scenarios are unique:** the function *check_for_duplicates()* automatically ensures that no duplicate scenarios exist, maintaining the integrity of the scenario analysis
- **Built-in check if the sum of probabilities of occurrence sums to 1.0:** this function verifies that the probabilities for all possible outcomes in a specific configuration add up to 1.0, ensuring that the calculation of probability of occurrence for each unique scenario is correctly done
- **Built-in function for system configuration settings:** the function *check_config_settings()* automatically ensures that the input variables such as energy split and island unit align with the specified supply chain configuration, preventing configuration errors
- **Function to check the number of instances created for each supply chain component:** with this function *print_overview_components()* it can be checked whether the correct number of instances are generated as per the supply chain configuration requirements. For instance, it can be checked if for an island-based full H_2 configuration with 5 wind farms, there is 1 instance of the *Artificial island* supply chain component but 5 instances of the *Turbine*
- **Built-in function to check whether the allocation of costs to H_2 and E happens correctly:** it automatically verifies that the sum equals the total project costs and ensures the correct split between hydrogen production and transmission, and/or electricity production and transmission. This guarantees accurate calculation of LCOH and LCOE, each euro gets allocated to either hydrogen production or electricity production
- **Built-in function to check the sum of capex and opex per component instance:** this function automatically confirms that the sum of the CAPEX and OPEX for each component instance matches the total costs for the specific component instance
- **Built-in function to check if expected components are parsed in the model:** the function *check_component_inclusion()* automatically ensures that all necessary components for the specific supply chain configuration are included and correctly processed in the model

- **Check for total project's net present value:** with this function it can be manually checked if the project's NPV equals 0 € when the hydrogen and electricity prices are set to the LCOH and LCOE, respectively, validating the financial model
- **Built-in check for efficiency values based on 'actual' and 'theoretical' efficiencies:** the function *efficiency_check()* automatically compares the actual efficiencies with the theoretical ones to ensure that the model operates within expected efficiency parameters

4.6.2. Unit testing

In addition to the built-in verification functions, the correctness of the developed techno-economic model is ensured through unit testing. Unit testing is a fundamental practice in software development, including in the domain of techno-economic model development. It involves validating individual components or units of a software application to ensure they function as expected. The unit testing methodology employed in this study consists of evaluating the entire system using simple input values that produce straightforward outputs, making it easy to assess if the results are as expected. One can obtain the same results by enabling the *'testing'* variable in the techno-economic model and using the presented input.

The methodology for testing and verifying the entire system with simplified input involves defining several test setups, each with slight variations in the input variables. For example, for a setup with co-production on an island from two offshore wind farms, the capacity of the wind farms can be doubled, or one wind farm can be removed. By keeping the other values unchanged, assessing the results becomes relatively straightforward. See Table 4.4 for an example of these three setups. Elements such as DECEX and residual value are set to zero, and transmission and conversion efficiency factors are all set to 1.0. The discount rate and escalation rate are also set to zero. The construction duration is set to 1 year, and the economic lifetimes of the supply chain components are set to 29 years. This configuration ensures that there would be no residual value in the components for a project with a lifetime of 30 years, simplifying the model verification process.

These three system setups are used as input, and the output is generated accordingly. Table 4.5 presents the output metrics. Based on these results, it can be assessed whether the developed techno-economic model functions as intended, focusing on the model's semantics – whether it performs the expected tasks rather than merely running without errors.

First, the output values for the supply chain efficiencies can be assessed. These efficiencies are all 100%, which corresponds to the system's input values where all conversion and transmission efficiency factors are set to 1.0, implying that there are no energy losses.

Secondly, by comparing setup 1 and setup 2, where the rated output of the wind farms is doubled while other input parameters remain unchanged, several observations can be made. The total costs double, which aligns with the doubling of the wind farms' capacity. The downstream infrastructure of the supply chain must also be doubled in size, leading to doubled costs due to the constant cost rate for components (in €/MW). Additionally, all levelized costs should remain constant because the model is designed with a constant cost rate per component and no scale benefits. Lastly, the total H_2 and E production should double as well.

Thirdly, intuitively, for the same total capacity, all output values should be similar for setup 2 and setup 3. In setup 3, one wind farm is removed while the other wind farm is doubled in size, maintaining the same overall capacity.

Parameter	Setup 1	Setup 2	Setup 3	Unit
Rated output WF_1	**1000**	**2000**	**4000**	MW
Rated output WF_2	**1000**	**2000**	**-**	MW
Capacity factor	0.5	0.5	0.5	[-]
Share of H_2/E	50/50	50/50	50/50	%
Escalation base year	2030	2030	2030	[yr]
Startyear project	2030	2030	2030	[yr]
Discount rate	0	0	0	%
Escalation rate	0	0	0	%
Island's CAPEX	1m	2m	2m	€
Component's CAPEX	1000	1000	1000	€/MW
Component's CAPEX	1.0	1.0	1.0	€/mMW
Component's OPEX	2	2	2	[% CAPEX]
Component's DECEX	0.0	0.0	0.0	[% CAPEX]
Residual value	0.0	0.0	0.0	[% CAPEX]
Economic lifetime	29	29	29	yrs
Construction duration	1	1	1	yrs
Share of investments	100	100	100	% in year 1
Efficiency factors	1.0	1.0	1.0	%/
EDR	0.0	0.0	0.0	%/yr

Table 4.4: Input values for the supply chain configuration ”Co-production Island” for three test setups for model verification purposes

Assessment of Table 4.5 confirms that these conditions are met, demonstrating that the developed techno-economic model functions as expected for this part. Other system setups should be tested using this approach as well, varying specific input variables while keeping others unchanged. This methodology allows for determining whether the developed techno-economic model operates correctly concerning the system's semantics. In appendix B, the verification process is shown for other system setups as well, further testing all the model's features.

Metric	Set-up 1	Set-up 2	Set-up 3	Unit
Total cost of the project in NPV	35.959m	71.917m	71.917m	€
Levelized Cost of H_2 (LCOH)	0.005709	0.005709	0.005709	€/kg
Levelized Cost of Electricity (LCOE)	0.000122	0.000122	0.000122	€/kWh
Levelized Cost of Total Energy (LCOTE)	0.04072	0.04072	0.04072	€/kJ
Levelized Cost of H_2 Production (LCOHP)	0.001718	0.001718	0.001718	€/kg
Levelized Cost of H_2 Transport (LCOT)	0.003991	0.003991	0.003991	€/kg
Total amount of H_2 produced (discounted)	3.679b	7.358b	7.358b	kg
Total amount of E produced (discounted)	122.635b	245.271b	245.271b	kWh
Total amount of H_2 produced (nominal)	3.679b	7.358b	7.358b	kg
Total amount of E produced (nominal)	122.635b	245.271b	245.271b	kWh
H_2 supply chain efficiency	100.00	100.00	100.00	%
E supply chain efficiency	100.00	100.00	100.00	%
Total supply chain efficiency	100.00	100.00	100.00	%

Table 4.5: Output values for the supply chain configuration ”Co-production Island” for three test set-ups for model verification purposes

4.7. Validation of the developed techno-economic model

In addition to the verification of the developed techno-economic model, validation is also required. Validation refers to the process of ensuring that the model accurately represents real-world scenarios and produces results that are consistent with observed data and established theories.

While verification focuses on confirming that the model is implemented correctly and operates without errors, validation assesses the model's accuracy and reliability in its intended application. This involves comparing the model's outputs with publicly available data, conducting sensitivity analyses, and reviewing the assumptions and methodologies used in the model's development. By validating the model, it is ensured that it provides meaningful and trustworthy insights for decision-making and analysis in techno-economic studies.

The study by McDonagh et al. (2020) analyzed the techno-economic aspects of renewable hydrogen production using a discounted cash flow model for the years 2020, 2030, and 2040. It examines the cost composition, sensitivity to various factors, and the impact of incentives and supplementary incomes. Table 4.6 presents an overview of the project specifications of this study, used for verification of the developed techno-economic model.

Table 4.6: Project specifications of verification study 1, conducted by McDonagh et al. (2020)

Item	Value	Unit
Turbines CAPEX	1,500,000	€/MW
Turbines OPEX	3.0% CAPEX	€/MW
Turbines DECEX	10.0% CAPEX	€/MW
Electrolysis system CAPEX	850,000	€/MW
Electrolysis system OPEX	3.2% CAPEX	€/MW
Balance of Plant CAPEX	127,500	€/MW
Wind park capacity	504	MW
Wind park distance from shore	14.5	km
Discount rate	6	%
Project duration	25	years
Construction duration	3	years
Total supply chain efficiency	0.74	%

In the study, an additional 15% of the CAPEX of the electrolysis system is allocated for the balance of plant. Catalyst replacement and system overhaul were scheduled approximately every eight years, costing 32% of the CAPEX of the electrolysis system each time. The cost of water in the study is 1.2 €/m^3, which can be estimated at 2,100 €/MW, based on the assumptions that 20 L of water is required for 1 kg of hydrogen and that the power output is on average 50 % of the rated power of the wind farm. The electrolysis system is located onshore, at a distance of 14.5 km from the offshore wind farm. The costs for the electric cable infrastructure, however, are not defined. They are assumed at 2,000 €/km/MW, in accordance with the value defined in this author's study.

The analysis assumed no inflation, a project duration (T) of 25 years, and a discount rate of 6%. In the study it was stated that respective systems are assumed to commence operation in 2030, therefore beginning construction ca. 2027. From this, a construction period of 3 years is assumed for all components. Additionally, it was stated that commissioning and decommissioning periods are not included, associated costs are incurred wholly in year one and the final year respectively. Therefore, the CAPEX of elements are fully incurred in the first year, rather than spread out over the construction years. The study did not consider alternative incomes or the effects of the debt-to-equity ratio, implying a discount rate rather than WACC.

The study used the higher heating value (HHV) of hydrogen, which is 141.7 MJ/kg or 39.4 kWh/kg, corresponding to 3.54 kWh/m^3. The total system efficiency was 74%. Finally, the electrolyzer EDR was not specified and is therefore assumed to be zero.

Incorporating the key values of the study of McDonagh et al. (2020) into the author's own model as a full hydrogen production based configuration, a LCOH of 3.87 €/kg was calculated, which differs around 2% from the calculated LCOH in the original study at 3.78 €/kg. This difference might be explained at how McDonagh et al. (2020) defines the share of capital investments over the construction duration, on which no details are provided.

5 Application of standardized model on case study hub North in the North Sea

Chapter 4 details the development of a standardized, harmonized, open-source comparison model with transparent technical, economic, and financial assumptions. After comprehensive verification and validation with a publicly available research paper, the model's applicability is demonstrated using the Hub North case study within the NSE programme.

5.1. North Sea Energy programme - hub North

The North Sea has the potential to become Europe's green energy hub, aiding in the transition to low-carbon energy (North Sea Energy, 2024c). Europe aims to cut emissions by 55% by 2030 and achieve climate neutrality by 2050, necessitating a large-scale rollout of offshore wind, floating solar, offshore hydrogen production, transport and storage, and carbon capture & storage (CCS), while phasing out gas production. Achieving these goals will be challenging without a coordinated approach for the North Sea. The NSE research programme seeks to reduce costs, time, emissions, space, and capital through offshore system integration, leveraging synergies between offshore wind, marine energy, CCS, natural gas, and hydrogen. Figure 1.1 shows current and future offshore wind farm plans, shipping routes, Natura2000 areas, and potential offshore energy hubs (Rijksoverheid, 2022). The NSE roadmap aims for a carbon-neutral energy supply by 2050, integrating offshore wind, hydrogen, CCS, and natural gas. It identifies challenges such as spatial constraints, stakeholder alignment, regulatory gaps, and market conditions. The roadmap proposes short, medium, and long-term actions to overcome these challenges, unlocking the North Sea's energy potential and ensuring economic, social, and environmental sustainability.

In the North Sea Energy programme, three hubs are considered, each with unique characteristics. Hubs West and East have established concepts and begun tendering and design processes, while hub North is distinctive as it does not include existing wind farms, allowing for a comprehensive design approach. Plans for hub North include installing 19.5 GW of wind energy between 2030 and 2040 (North Sea Energy, 2024b). The open-ended nature of hub North's plans makes it an ideal case study to apply the developed techno-economic model, aiming to evaluate the feasibility of concepts like energy islands.

Figure 1.1 show wind search are 6 and 7, consisting of 8 and 10 GW of offshore wind energy, respectively. However, new plans indicate a total of 19.5 GW in the hub, which is the value that is considered in this case study. The search areas are subdivided into smaller plots of around 4 GW, indicated in a schematic overview in Figure 5.1 and C.1. Within the NSE programme, hub North involves a common implementation of greenfield gas extraction, platform electrification, offshore wind production and partial conversion towards renewable hydrogen, and is located the furthest from shore compared to the other hubs. However, for the application of the developed techno-economic model, greenfield gas extraction will be excluded in the techno-economic assessment of the energy infrastructure system.

In the NSE programme plans, the hub is projected to consist of 19.5 GW of offshore wind capacity and 8 GW of electrolyser capacity, initially assumed to be located on platforms due to the belief that the water depth is too great for sandy islands (North Sea Energy, 2024a). However, as discussed in Subsection

4.2.2, several factors support the technical feasibility of constructing an energy island at these depths. Therefore, this study assumes its feasibility. Consequently, the method of an offshore artificial energy island is integrated into the options for supply chain configurations for the techno-economic assessment. In short, the most important characteristics of hub North are:

- Total future energy capacity of 19.5 GW
- Water depth of 40 - 50 m
- Located far offshore, with export infrastructure expected at 200 - 350 km

The techno-economic model allows for a harmonized comparison of different supply chain configurations for energy transmission to shore. The configurations that are considered are explained in Chapter 4 in more detail. Figure 5.1 and C.1 indicate the geospatial data for an island-based and platform-based supply chain configuration. For the island-based supply chain configuration, there are 2 possible locations (A and B) for a centralized offshore artificial energy island shown in the map, each with distinct cable lengths and water depths. Similarly, for the platform-based supply chain configuration, the 2 locations (A and B) are considered, featuring a centralized platform configuration where a group of platforms is installed for energy conversion and transmission. Additionally, a decentralized platform configuration is introduced for the platform-based configurations, with each wind farm plot equipped with its own conversion and transmission platforms. While this setup minimizes the length of collection cables, it requires longer export infrastructure to connect to shore.

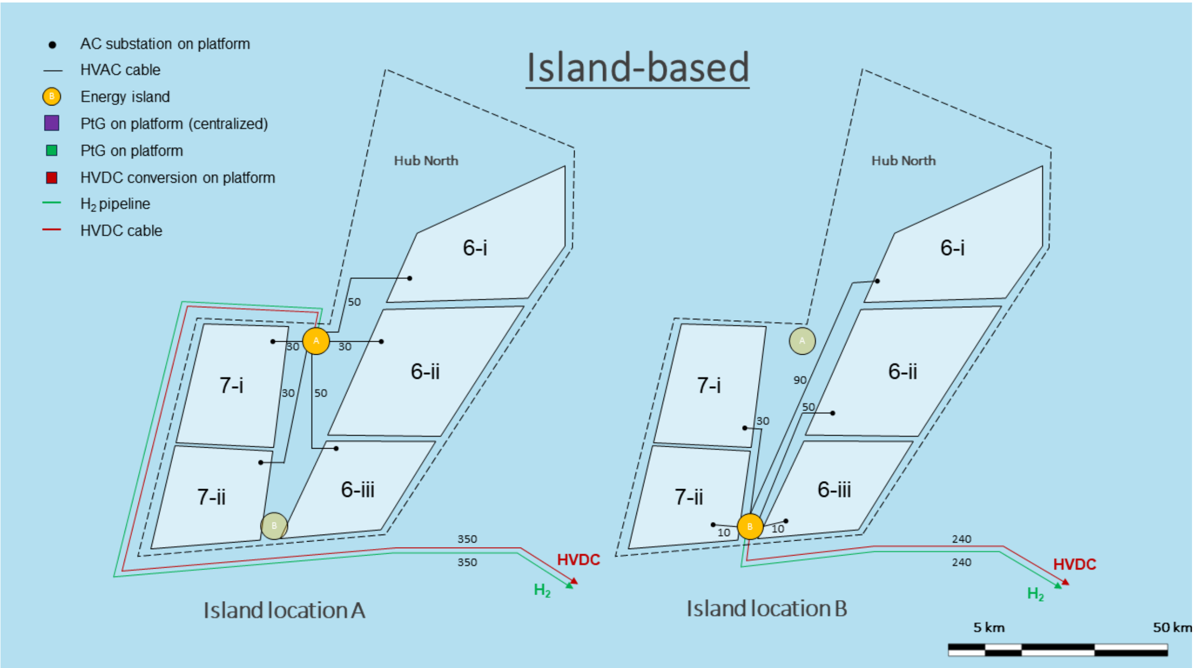

Figure 5.1: Overview of island-based supply chain configuration for hub North in North Sea Energy programme - Location A and location B

To apply the techno-economic model for the specific case study of hub North, the input data must be defined. To run the model, there are several input files required, which are addressed below:

- **Cost component input:** input file where for each component the cost assumptions (CAPEX, OPEX, DECEX), economic lifetime, construction duration and share of investment are defined. Table B.1 presents a schematic overview of the actual cost input data
- **Hub North specifications:** wind energy capacities of each wind farm (plot), possible starting years of the wind farms, possible starting years of the energy island, different island types, different island locations, distance table - see Table C.1 and C.2
- **Conversion and transmission efficiency:** most conversion and transmission component exhibit a constant efficiency factor. For the collection cables (AC), export cables (DC) and hydrogen pipeline, the transmission efficiency depends on the length, see Table C.3

- **Scenario data:** based on the different possible starting years, locations and energy island types, different scenarios can be constructed - see Table C.4 and C.5

From these input values, a multitude of scenarios can be generated, varying based on the wind farm and island start years, locations, and island types (if applicable). This results in a total of 4374 scenarios for the island-based supply chain configuration and 729 scenarios for the platform-based supply chain configuration. See Table C.4 and C.5 for an overview of the scenario input data. The input values that were used for all calculations are project duration $T = 30$ yrs; escalation rate (inflation) = 2%; uniform discount rate for all components (WACC) = 5.65%. The WACC calculation is based on a debt-to-equity ratio of 70/30, a nominal risk-free rate of 2.61%, U.S. equity risk premium of 4.60%, additional country risk premium of the Netherlands of 0%, an unleveraged beta of 0.56, a corporate tax rate of 25.8%, and a SOFR of 5.31%; all accessed on the 8th of March, 2024.

5.2. Results harmonized comparison all configurations

The application of the model provides economic and technical performance metrics such as LCOH, LCOE, LCOTE, NPV of the total project costs, and the system's total energy, hydrogen and electricity energy efficiency. Based on these performance metrics, the different supply chain configurations can be compared with each other. For a specific supply chain configuration, for example an island-based co-production configuration, an input of 4374 scenarios is used, and for each scenario are the technical and economical performance metrics calculated. Based on the input data for offshore, island or onshore based, there are respectively 729, 4374 and 729 scenarios. Table 5.1 presents a part of the scenario results for a specific supply chain configuration, in this case co-production on an offshore energy island.

Table 5.1: Example of results for island-based co-production supply chain configuration

			Startyear							
Scen.	**Loc.**	**Type**	**Island**	**...**	**WF5**	**Isl. costs** [€]	**NPV costs** [€]	**LCOH** [€/kg]	**LCOE** [€/kWh]	**...**
1	A	I	2030	...	2030	2.79b	138.8b	8.64	0.138	...
2	A	I	2030	...	2032	2.79b	136.9b	8.65	0.138	...
3	A	I	2030	...	2034	2.79b	134.9b	8.74	0.140	...
4	A	I	2030	...	2030	2.79b	137.1b	8.66	0.138	...
...	...	...	...	...	...	...	...	...	...	...
4374	B	III	2032	...	2034	16.25b	128.4b	10.1	0.157	...

5.2.1. Levelized cost of total energy (LCOTE)

Plotting the results from Table 5.1 for each specific scenario generates a cloud of data points. For all island-based configurations (full HVDC with H_2/E share of 0/100%, co-production at H_2/E shares of 30/70, 50/50, and 70/30, and full H_2 at 100/0%), this is illustrated in Figure 5.2. This figure provides a partial view of the parameter space, excluding platform and onshore-based configurations for readability. Each dot in Figure 5.2 represents a specific scenario for a specific supply chain configuration with a specific probability of occurrence, see Table 5.1 for an example of a scenario. In this case the island-based configurations for different shares of H_2/E production (colour) are shown. The different locations for the energy island and the type of island are displayed with the same dot, without making a distinction. For instance, the cloud of data points for H_2/E share of 70/30 in light green show simultaneously the different scenarios (starting years) and also the different island locations and island types.

Each scenario has a specific probability of occurrence, summing to 1 for all scenarios within a supply chain configuration and location. This allows calculation of weighted values for economic and technical performance metrics. Figure 5.3 shows this by plotting the weighted LCOTE and NPV of total project costs. Contrary to Figure 5.2, it includes all possible supply chain configurations, including onshore and platform-based setups. Differentiation has been applied for the type of island or platform (marker type), the share of H_2/E (colour) and the island or platform location (subscript "A" or "B") or decentralized platform configuration (subscript "P"). This comprehensive view of all supply chain configurations enables a harmonized comparison of their technical and economic performance.

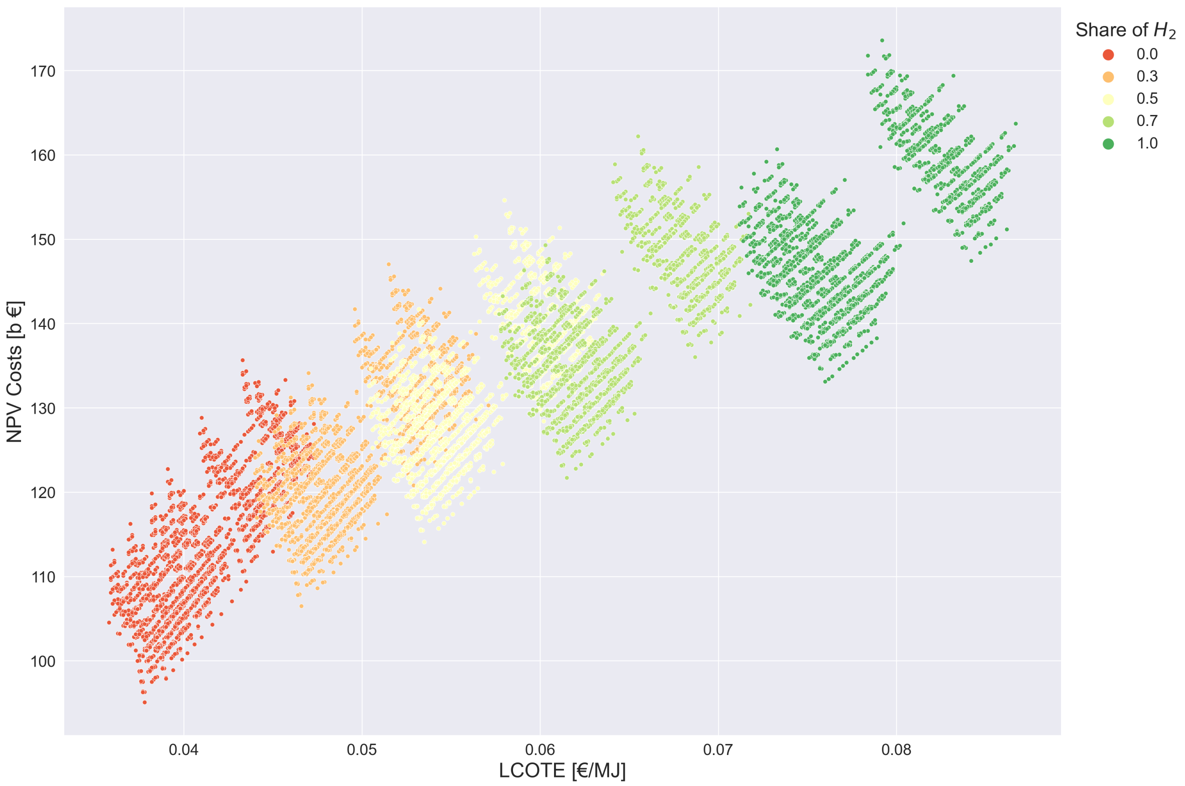

Figure 5.2: The LCOTE and the NPV of the total project costs for the 5 different island-based supply chain configurations, for full HVDC production, full hydrogen production and co-production

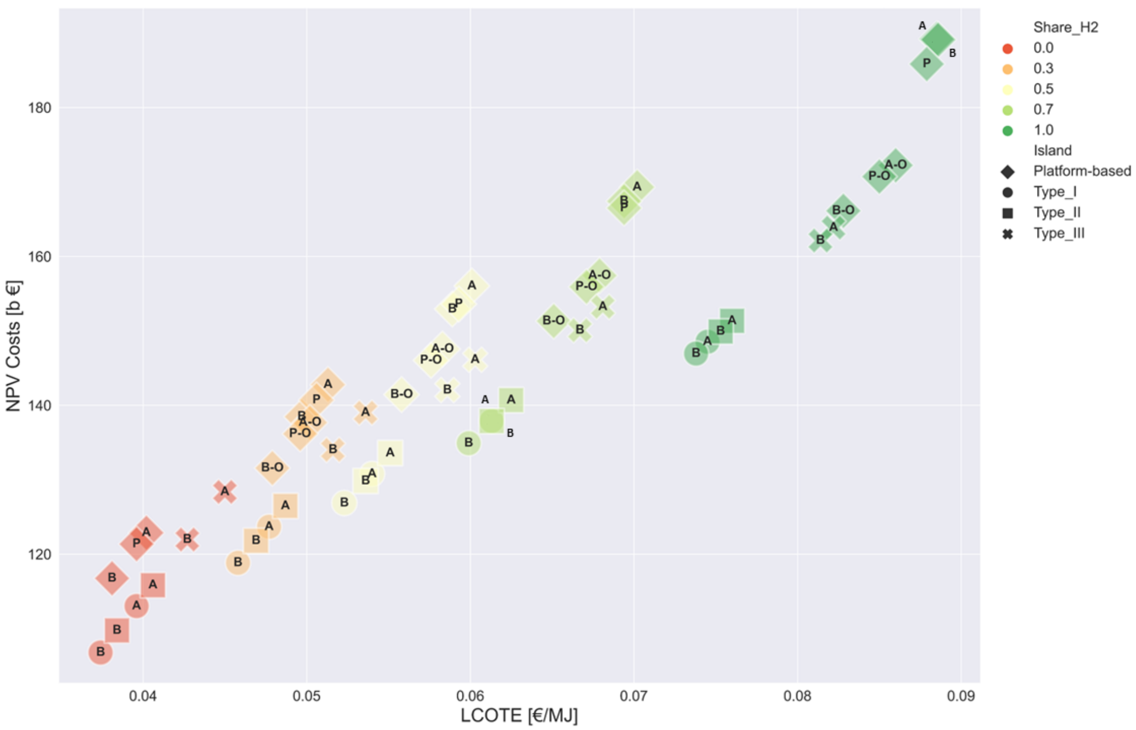

Figure 5.3: The LCOTE and the NPV of the total project costs for all different supply chain configurations, text additions in graph indicate centralized setup at location "A" or "B", decentralized platform setup "P", and the suffix "O" implies Onshore electrolysis

Figure 5.3 leads to the following two preliminary observations:

1. The full HVDC (H_2/E share of 0/100%) supply chain configurations has, for both platform and island based, the lowest LCOTE, which indicates that in any case the full electric transmission method has the best economic performance metrics
   - The average LCOTE for island types I and II at locations "A" and "B" is 55% lower for full HVDC transmission compared to full production of H_2 and subsequent transmission
2. For the hydrogen production supply chain configurations (co-production or full production), the island-based configurations always exhibit better performing economic metrics than their onshore or platform based counterpart. Analysis of the specific supply chain configurations in the figure indicates that both LCOTE and NPV of total project costs are lower for all the island-based configurations compared to their relative platform or onshore counterpart
   - Considering full H_2 production, the average LCOTE for island types I and II at locations "A" and "B" is 15% lower for island-based compared to platform-based configurations
   - Considering full H_2 production, the average LCOTE for island types I and II at locations "A" and "B" is 11% lower for island-based compared to onshore-based configurations

5.2.2. Total system's energy efficiency

Analysis of the technical performance metrics covers the comparison of the supply chain's hydrogen, electricity and total energy efficiency. The system's energy efficiency has direct impact on the economic metrics, as higher efficiency yields higher energy production, hence a lower levelized cost. Moreover, these energy infrastructure systems are designed for the coming decades. Hence, finding an optimization between total system costs and energy efficiency is crucial for the project's feasibility. Figure 5.4 includes the energy efficiency values for all the different supply chain configurations. From this figure it is evident that a full HVDC supply chain configuration holds the highest system energy efficiency. This can be explained by the fact that HVDC transmission is efficient. Although a HVDC converter station is more complex, expensive and has larger efficiency losses than HVAC processes, the actual energy transmission is really efficient. This holds true especially for larger distances which are the case for hub North to the mainland. Moreover, it is clear that hydrogen-based configurations have significantly lower system energy efficiency due to the electrolysis process, currently at an efficiency of 0.60 - 0.70, impacting the final system's energy efficiency significantly.

Lastly, in terms of a system's total energy efficiency, the onshore-based hydrogen production configurations significantly underperform compared to offshore hydrogen production, whether for a island or platform based configuration. This difference results from the presence of a 'double' conversion process. In case of offshore hydrogen production, the electrolysis process is performed offshore and the hydrogen is transported by pipelines to shore, with minimal losses assumed in hydrogen pipelines. However, with onshore hydrogen production, two additional conversion steps are required, and the electrolysis process still needs to occur onshore. In this case, first offshore wind energy is converted to HVDC for efficient transmission to shore. Once onshore, the HVDC power must be stepped down from a voltage of 525 kV to around 1.3 V, resulting in additional energy efficiency losses. In contrast, offshore hydrogen production avoids this additional conversion to HVDC, and subsequently to low-voltage DC. Instead, the wind farm's HVAC power can be easily stepped down using transformers and then converted to low-voltage DC, bypassing the entire additional complex conversion steps required for the onshore electrolysis process altogether.

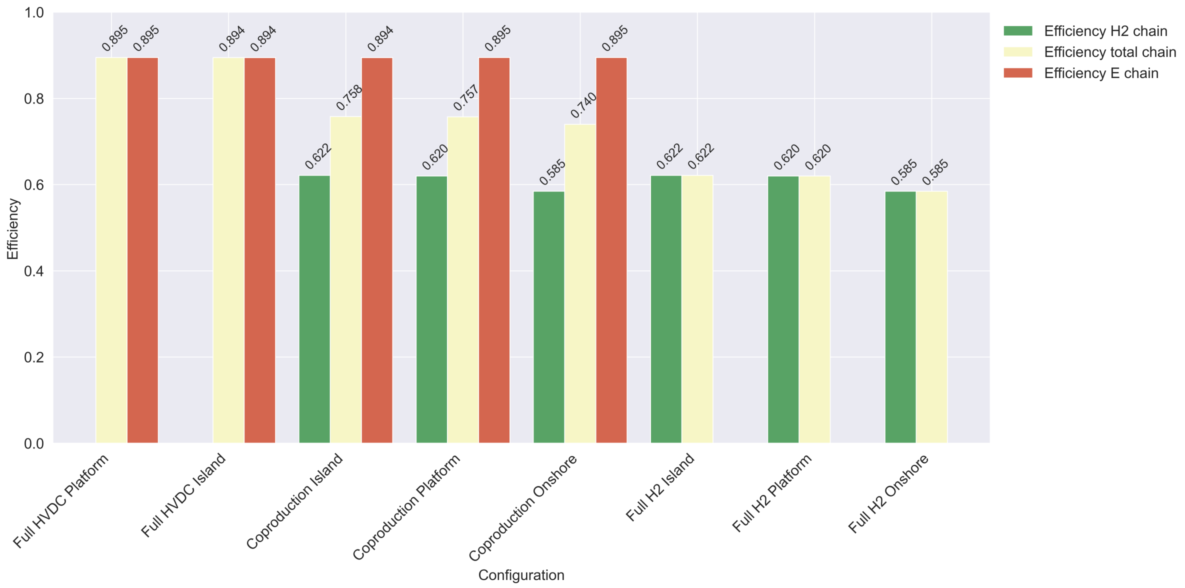

Figure 5.4: Barplot of the total system efficiencies for all 8 different supply chain configurations

Figure 5.4 leads to the following two preliminary observations:

1. The full HVDC supply chain configurations has the highest total supply chain efficiency
2. The onshore-based hydrogen production supply chain configuration (both full H_2 production and co-production) has a lower total system's energy efficiency then offshore hydrogen production

5.2.3. Levelized cost of hydrogen (LCOH)

Another economic performance metric that the model can calculate is the LCOH, which is assessed in a harmonized comparison in this section. Contrary to the assessment of the LCOTE, which covers a broader scope, the LCOH results focus solely on (partly) hydrogen production supply chain configurations. Due to the setup of the model, in which the components costs scale with capacity for a constant €/MW and for which each individual component is allocated to hydrogen or electricity production, there is no difference in LCOH for different shares of hydrogen production (H_2/E of 30/70, 50/50. 70/30 or 100/0). For instance, comparing an island-based configuration with H_2/E of 30/70 with 100/0, there is no difference in LCOH between the two. Although the NPV of total project costs will be lower since the relatively lower costs of HVDC infrastructure compared to H_2 infrastructure are included in this metric as well, it does not affect the LCOH for different shares of H_2/E. This results from the fact that in the calculation of the LCOH only the costs of components relevant for hydrogen production are included. This allocation of costs makes that the share of H_2/E does not affect the LCOH.

Displaying the LCOH values for the hydrogen production configurations results in Figure 5.5, for which can be observed that there is no difference in LCOH for different shares of hydrogen production. From the assessment it is evident that the island-based configurations outperform platform and onshore setups economically. Even for island type III, which is a significantly more expensive energy island at €16.25b (compared to €2.79b for type I), the LCOH is lower than for onshore or platform-based configurations. This advantage for island-based compared to platform-based is due to lower operational and capital expenses for electrical and electrolyzer systems, along with longer electrolyzer stack lifetimes and reduced efficiency degradation rates (EDR), outweighing the higher initial investment of the energy island. Although offshore foundation structures like jackets typically entail lower investment costs, their decentralized nature poses other challenges. It is difficult to maintain a constant direct current base load, leading to increased electrolyzer EDR. Additionally, heavier conditions result in higher investment costs compared to onshore or island facilities.

The LCOH is for the island-based configurations slightly lower for island location B compared to location "A", with 8.86 against 8.95 €/kg for island type I and 9.04 against 9.11 €/kg for island type II. The range of calculated LCOH values for all island-based scenarios is 8.54 - 10.40 €/kg (based on $n = 4374$ scenarios). Platform-based configurations hold a LCOH of 10.62 and 10.63 €/kg for a centralized layout at location "A" and "B", respectively, and 10.55 €/kg for the decentralized layout ("P"). The range of calculated LCOH values for all platform-based scenarios is 10.13 - 11.44 €/kg (based on $n = 729$ scenarios).

Similarly, for the onshore-based hydrogen production configuration, the lowest LCOH is achieved for a centralized platform configuration at location "B" ("B-O") at 9.94 €/kg compared to 10.32 €/kg at location "A" ("A-O"). The decentralized platform configuration for onshore-based H_2 production has a LCOH of 10.20 €/kg. The range of calculated LCOH values for all onshore-based scenarios is 9.52 - 11.06 €/kg (based on $n = 729$). In this onshore-based supply chain configuration, there is offshore conversion of HVAC to HVDC on platforms: centralized at location "A" or "B", or decentralized adjacent to each wind farm plot ("P"). In comparing a centralized platform situated at locations "A" and "B," the key distinction lies in the export cable length and water depth; location "A" has shallower depths, albeit requiring a longer export cable compared to location "B." The costs of HVDC export cables for additional lengths are relatively high compared to the additional costs for platform foundations for larger water depths, resulting in a lower LCOH for location "B" since HVDC export cable lengths are lower.

Figure 5.5 leads to the following 2 preliminary observations:

1. For hydrogen production, every island-based configuration outperforms platform or onshore setups economically
    - The average LCOH for island types I and II at locations "A" and "B" is 15% lower for island-based compared to platform-based configurations
    - The average LCOH for island types I and II at locations "A" and "B" is 11% lower for island-based compared to onshore-based configurations
2. Location B holds for the island and onshore-based supply chain configuration the lowest LCOH, for the platform-based configuration there is no significant difference between location A or B

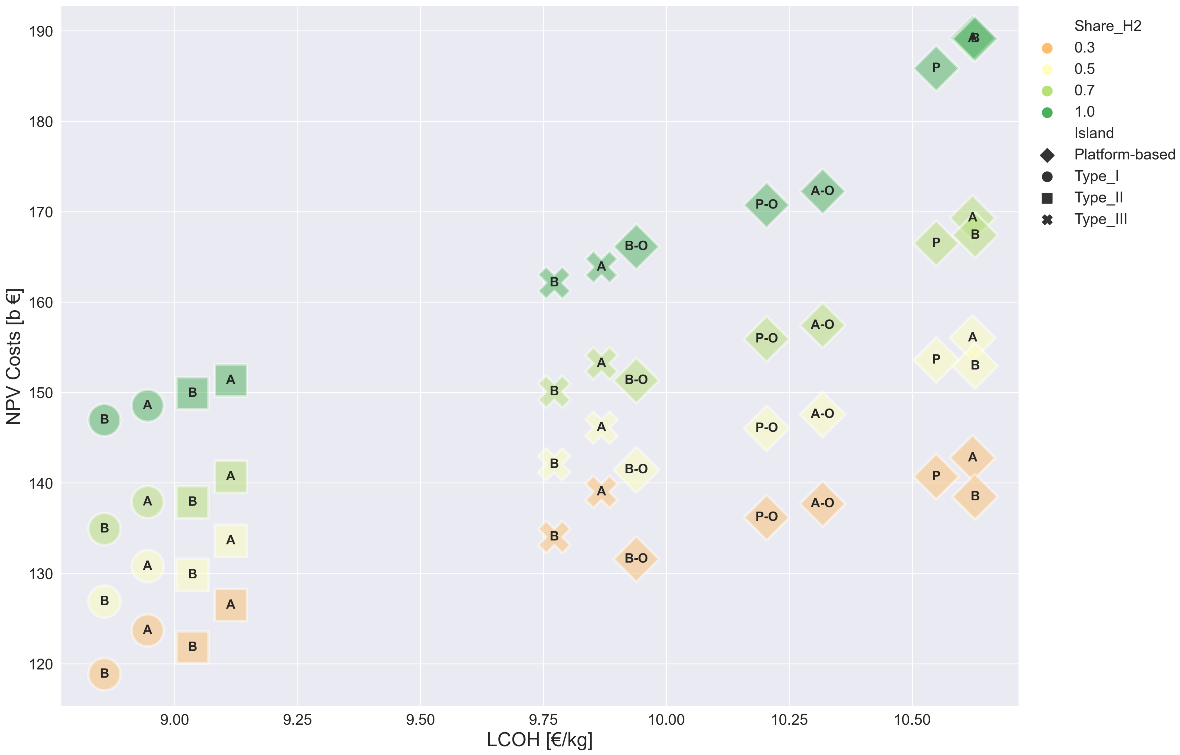

Figure 5.5: The LCOH and the NPV of the total project costs for the H_2 production supply chain configurations, text additions in graph indicate centralized setup at location "A" or "B", decentralized platform setup "P", and the suffix "O" implies Onshore electrolysis

5.2.4. Levelized cost of hydrogen production (LCOHP) and transport (LCOHT)

Further breakdown of the LCOH into production and transmission yields the Levelized Cost of Hydrogen Production (LCOHP) and Transport (LCOHT), respectively, both summing up to the total LCOH. Within the LCOHP, the cost of components related to offshore wind energy production are included, encompassing wind turbine, foundation, wind farm cables, collection cable (AC), AC substation topside and AC substation foundation. The costs associated with the wind energy production are significant, primarily attributed to the high costs of wind turbine and their foundation, constituting to 40 - 50 % of the total project costs in general. This translates to a LCOHP ranging between 3.58 and 3.87 €/kg for the calculated hydrogen producing supply chain configurations in this study. However, it is important to note that this study focuses on offshore energy transmission methods rather than optimizing and detailing the wind farm itself. Consequently, examining the LCOHT in greater detail is important, as comparing LCOHT values offers a more comprehensive view of the techno-economic benefits of the different supply chain configurations.

Examination of Figure 5.6 leads to the following 2 preliminary observations:

1. For hydrogen production, every island-based configuration outperforms platform or onshore setups economically
    - The average LCOHT for island types I and II at locations "A" and "B" is 27% lower for island-based compared to platform-based configurations
    - The average LCOHT for island types I and II at locations "A" and "B" is 19% lower for island-based compared to onshore-based configurations
2. The results for the LCOHT show large similarities with the results of the LCOH, implying that the mutual differences in Figure 5.5 can be attributed to the differences in LCOHT rather than in LCOHP. Meaning that for this study it is indeed more relevant to address LCOHT than LCOHP (see Figure C.2)

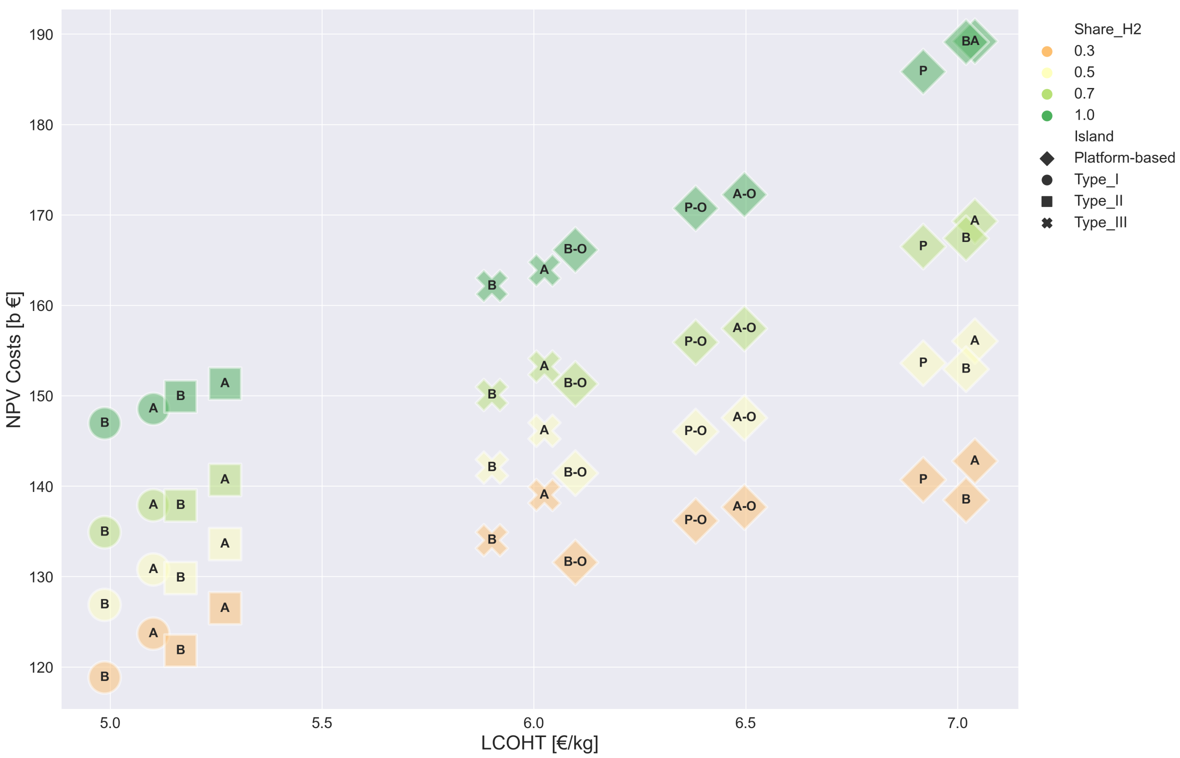

Figure 5.6: The LCOHT and the NPV of the total project costs for the H_2 production supply chain configurations, text additions in graph indicate centralized setup at location "A" or "B", decentralized platform setup "P", and the suffix "O" implies Onshore electrolysis

6

Benchmark import costs of hydrogen

This chapter reviews literature and industry studies that identify high-potential countries for producing and exporting hydrogen and ammonia. The goal is to provide realistic values for the levelized cost of hydrogen and ammonia, including production and transport, to benchmark these options against the levelized cost of domestically produced hydrogen.

To establish an appropriate range of levelized costs for importing hydrogen and its derivatives from high-potential countries to Europe, it is essential to understand the assumptions and elements of the various studies. In this chapter, these assumptions and elements will be addressed, after which an overview will be presented with the estimates for the levelized cost of imported hydrogen in Europe.

6.1. Potential hydrogen (derivatives) import locations and costs

As demand for clean energy sources increases, understanding the feasibility, cost, and logistical implications of importing hydrogen and ammonia is crucial. The most effective production sites are often remote, impacting the levelized cost of production and transport. Since demand is highest in industrialized and densely populated areas, often far from these renewable production locations, this analysis is essential for strategic planning and cost management (Roland Berger, 2021). Getting hydrogen from global production sites to end users at the lowest possible cost will be key to the success of the green economy, as the potential for onsite green hydrogen production in European demand centers is limited due to three primary reasons (Roland Berger, 2021).

First, huge amounts of green electricity will be needed to power the hydrogen-producing electrolyzers. The conversion of the European steel industry to a more emission-friendly process by using hydrogen for the direct reduction of iron alone would require up to 10 million tons of hydrogen per year. Depending on the system efficiency, the production of green hydrogen for the steel industry would require roughly 60 GW of electrolysis capacity and 120-180 GW of renewable energy capacity. To put those numbers in perspective, Germany's total installed capacity of onshore and offshore wind power stands at 63 GW today (Roland Berger, 2021). This highlights the significant scale of renewable energy required to meet hydrogen demands.

Second, the physical space required to achieve such capacities is substantial, especially in regions with less favorable conditions for renewables (Roland Berger, 2021). Such space is rarely available, posing another significant challenge to onsite production.

Third, the expansion of the electricity grid to transport such huge amounts of renewable energy is a difficult undertaking (Roland Berger, 2021). Many ongoing high voltage grid projects face delays, and those delays, in fact, hinder a faster renewable energy build-out in Europe. Extending the grid infrastructure is essential to facilitate the transport of renewable energy from production sites to areas where it is needed for hydrogen production.

Therefore, green hydrogen will largely be produced near the most cost-competitive renewable electricity hubs, such as the wind farms of the North Sea and the solar parks of the Middle East. The difference in global production costs is substantial, with costs varying by up to 250% between regions abundant in renewable resources and those less favorable for renewable energy production. Even within the European Union, cost differences are significant, with a delta of more than 130% between countries like Spain and Germany (Roland Berger, 2021). Figure 6.1 provides an impression of these cost disparities.

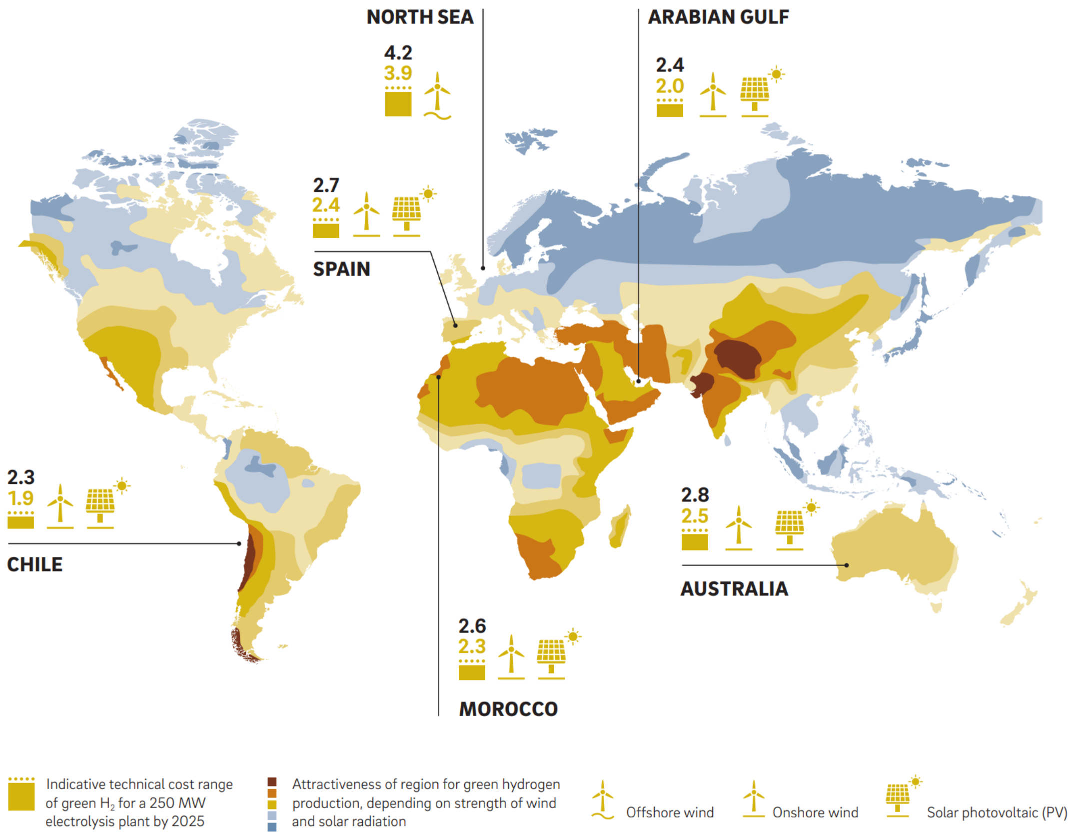

Figure 6.1: Hydrogen production locations - Cost-competitive renewable electricity and green hydrogen production hubs are typically located distant from demand centers [€/kg], adopted from Roland Berger (2021)

In the study by Roland Berger (2021), several archetypes were assessed: (1) Large-scale harbor-to-harbor, (2) Mid-scale multimodal transportation, (3) Small-scale multimodal transportation, and (4) Small-scale truck-only transportation. This analysis focuses on archetype 1 (Large-scale harbor-to-harbor), with a one-way trip of 12,000 km via vessel. Figure E.1 shows that ammonia and LOHC have very similar total costs of ownership — a comprehensive assessment of all direct and indirect costs associated with the purchase, operation, and maintenance of a product over its lifecycle, similar to the principle of levelized cost — for hydrogen transportation, both ranging from 2.2 to 2.3 €/kg of hydrogen, making them the lowest-cost options. For ammonia, reconversion (cracking it back into hydrogen) constitutes more than one-third of the overall cost. This suggests that clean ammonia could be particularly attractive for decarbonizing sectors where it is already used as a bulk chemical derived from natural gas, rather than solely as a hydrogen carrier (Roland Berger, 2021).

With LOHC, the large volumes of carrier required to store and transport hydrogen, combined with the long distances involved, increase its capital expenditures. Transportation via LH_2 is the most expensive technology, with a total cost of ownership for hydrogen transportation at 2.8 €/kg. Lanphen (2019) concluded in her study a similar result, that for such distances the LH_2 transport is the least cost-efficient method. Major contributing factors include boil-off due to prolonged storage, the high energy demand for liquefaction, and the capital-intensive infrastructure needed for large-scale liquefaction plants. The landed cost of hydrogen, encompassing both transportation and production costs, is estimated at 4.2

to 4.8 €/kg by 2025, assuming a production cost of 2.0 €/kg for all carriers. This suggests that large-scale, imported clean hydrogen could be competitively priced depending on the carrier method (Roland Berger, 2021).

One key assumption in the study of Roland Berger (2021) must be addressed in specific: ”In all cases, adequate storage facilities are assumed at the points of departure and destination, and, where relevant, the point of transshipment”. This assumption is significant because it overlooks the required port infrastructure, such as landing equipment, terminal facilities, and storage facilities. In contrast, the methods presented in this study include storage and landing facilities, thus assessing the entire supply chain. These elements are incorporated into the LCOH calculated by this study, providing a more comprehensive analysis. This assumption is frequently observed in hydrogen and/or ammonia import studies, leading to overly optimistic estimates for the LCOH (Kakavand et al., 2023; Klein et al., 2023).

6.2. Cost comparison across studies

Examination of several studies within the literature assessing hydrogen and/or ammonia shipment revealed the following findings, summarized in Table 6.1. Egerer et al. (2023) contributed to understanding the transformation of global energy trade to green energy carriers, focusing on green ammonia. Galimova et al. (2023) assessed the feasibility of e-hydrogen imports to Germany and Finland from two case regions with a high availability of low-cost renewable electricity, Chile and Morocco, in comparison to domestic supply, with special attention to the transport infrastructure. In the study of Correa et al. (2022), the techno-economic feasibility of green hydrogen production in Argentine Patagonia with subsequent ship transport to Italy is investigated. The study includes the entire supply chain, from the production of hydrogen with renewable energy sources to its final use as a fuel for mobility in Italy. Lastly, the study by Sens et al. (2024) assessed the energy efficiency and the cost of a green hydrogen supply from well to tank exemplified for fuel cell heavy-duty vehicles in Germany for the years 2030 and 2050. For this, compressed gaseous hydrogen, liquid hydrogen, liquid organic hydrogen carriers, methanol and ammonia were considered and different hydrogen production regions in North and Central Germany, as well as an import from Tunisia and Argentina (Patagonia) were assumed.

Table 6.1: Overview of landed LCOH from different studies. The abbreviations in the table mean: P for Production, T for Transport, IT for Import Terminal, R for Reconversion to hydrogen (in case of ammonia or LOHC, HC for Hinterland Connection, S for Storage

Author	**Year**	**Scope**	**LCOH in 2030 [€/kg]**	**Carrier form**	**Remarks**
Roland Berger	(2021)	P, S & T	4.2 - 4.8	NH_3 & LOHC	Different carrier methods, locations and transport scales, TRL
Abrahamse	(2021)	P, T, IT & HC	• 4.0 - 4.3 • 3.8 - 3.9	• LH_2 • NH_3	Australia - Rotterdam (in 2020)
Correa et al.	(2022)	P, T, IT, R, HC, S	8.60	LOHC	Argentina - Italy; well-to-tank
Aurora	(2023)	P, T, R	4.68 - 4.72	NH_3 & LOHC	Morocco - Germany
Egerer et al.	(2023)	P, T, S, R	3.66	NH_3	Australia - Germany
Fraunhofer ISE	(2023)	P & T	5.25 - 7.76	GH_2	Dedicated H_2 pipelines from Spain and N-Africa
Galimova et al.	(2023)	P, T & IT	• 2.7 - 4.7 • 2.2 - 3.7	• GH_2 • LH_2	• Chile - Germany • Morocco - Germany
Sens et al.	(2024)	P, T, IT & S	• 5 in (4-8) • 7 in (5-12)	• GH_2 • LH_2	Import from Tunisia by pipeline or vessel; well-to-tank

6.3. Dutch and European demand - end-user

In 2019, hydrogen usage in the Netherlands was 175 PJ, primarily for industrial applications such as refineries and ammonia production. This annual consumption, equivalent to about 1.5 million tonnes per annum of H_2 (mtpa), translates to approximately 20 GW of offshore wind power, depending on the capacity factor, transmission, and conversion efficiencies. This significant figure is based on 2019 data, with future hydrogen usage in the Netherlands expected to increase substantially.

For example, the New Energy Coalition (2019) considers three scenarios for hydrogen uptake in the Netherlands by 2050. Scenario 1 envisions a modest uptake of hydrogen for energy applications. Scenario 2 focuses on creating a green energy system aiming to achieve nearly 95% CO_2 emission reductions for energy applications by 2050. Scenario 3 aims to maintain the Netherlands as an energy hub open to international trade and positions the country as an innovative leader in the hydrogen economy. The expected yearly hydrogen demands for these scenarios by 2050 are 233 PJ, 355 PJ, and 463 PJ, respectively, equivalent to 1.9, 3.0, and 3.9 mtpa. These values correspond to 20-50 GW of dedicated (offshore) wind energy for hydrogen production, depending on the capacity factor, transmission, and conversion efficiencies.

Given the substantial dedicated wind energy required for hydrogen production, it is reasonable to assume that the examined offshore wind system of hub North in the NSE programme (19.5 GW) will have direct end-users. This makes it unnecessary to use fuel cells to convert hydrogen back to electricity for household supply, avoiding additional conversion losses. Another application of the hydrogen could be for long-term storage. Consequently, the conversion step with a fuel cell is not considered in the supply chain configuration, and comparisons with electricity based on energy content in MJ are deemed reasonable.

In the highest hydrogen usage scenario of the New Energy Coalition (2019), the Netherlands would need 40-50 GW of offshore wind capacity dedicated solely to hydrogen production. These figures are substantial and are unlikely to be achieved by purely domestic production. In light of the European ambition, the Dutch hydrogen usage in 2019 of 175 PJ (equivalent to about 1.5 H_2 mtpa), represents 15% of the planned annual hydrogen import by 2030 for the entire European Union (European Commission, 2022). This underscores the European Commission's awareness and planning for large-scale hydrogen imports (European Commission, 2022), necessitating long-term strategic design, development, and policy implementation to ensure a stable and sufficient hydrogen supply.

7
Discussion

In this chapter, the most important results obtained in this research are discussed. New insights that can be gained with this model and research are briefly explained and uncertainties within the offshore wind and electrolyzer industry are addressed. In addition, the limitations of this research are highlighted, addressing the quality and reliability of this research. Lastly, recommendations are presented for potential continuation of the methods presented in this study.

7.1. Interpretation of results

This section delves into the interpretation of the results obtained from the research conducted in this thesis. The findings presented here result from the data analysis and study undertaken to address the research questions and objectives outlined in the earlier chapters. Through careful examination and analysis, meaningful insights are extracted, conclusions drawn, and implications provided. This section serves as a clarifying component in understanding the significance and contributions of the research findings to the broader academic field and the offshore wind industry.

7.1.1. Integration of full HVDC into energy system

Currently, the world is undergoing the largest energy transition in history, moving away from fossil fuels towards electrification. This shift necessitates diverse energy storage solutions across various time scales, from hourly to seasonal storage. While batteries are excellent for short-term storage, hydrogen storage, comprising electrolysis and fuel cells, proves especially effective for meeting longer-term energy demands, such as powering the Netherlands for two weeks in winter. Its technical characteristics make it particularly suitable for these needs (Chatenet et al., 2022). At present, hydrogen is the lowest-cost technology with more than one month (7000 h) of discharge time; and in regions of the world which cannot use pumped hydro or underground compressed air storage, hydrogen is the lowest-cost solution for discharge durations beyond one day (Chatenet et al., 2022).

To achieve long-term flexibility, a mix of various sources of flexibility is required. Under certain scenarios based on a number of assumptions, it is estimated that 15 to 17 GW of controllable capacity (such as long-term demand-side response from hybrid systems, interconnection, large-scale storage, and controllable production) will be needed in an average weather year (Ministerie van Economische Zaken en Klimaat, 2019). If we take the example of meeting the electricity demand of the Netherlands in winter for 2 weeks, it learns that it would require a significant area for batteries and involve serious cost of battery storage. The electricity demand in winter for 2 weeks is presumed at 5 TWh (EBN, 2024). To store a capacity of 1 MWh, it is approximated that 5 m^2 are required (IRENA, 2019a). In terms of utility scale battery storage, this would require already half of the industrial area of the Port of Rotterdam (Port of Rotterdam, 2024) to address electric energy stability for 2 weeks. Furthermore, costs are estimated at €1 billion to €2 billion (IRENA, 2019a). In contrast, hydrogen storage would cost approximately €0.1 billion to €0.2 billion (Yousefi et al., 2023), with the added benefit of extending the period of storage and scalability of the storage capacity.

Despite that the results from this study clearly indicate that a full HVDC supply chain configuration would provide the most energy and cost-efficient method for energy transmission from offshore wind farms, it is not realistic to supply full HVDC power transmission from a 19.5 GW offshore wind farm to the national electrical grid due to the aforementioned arguments regarding required space and costs for utility scale battery storage. There is another complicating factor: the grid already experiences significant capacity constraints (TenneT, 2024c). Based on the annual electricity usage in 2022 (EBN, 2024), and considering that each connection in the grid uses around 50% of its capacity for stability considerations (TenneT, 2024c), it is estimated that during peak hours, the grid should allow around 40 GW of capacity. With this in perspective, the addition of a potential 19.5 GW from hub North is enormous, posing substantial integration challenges.

Concluding, achieving full electrification poses notable challenges, especially considering current grid capacity limitations. Technical constraints arise, with battery storage not being viable due to space constraints, and direct supply to the grid faces challenges due to capacity constraints and the intermittent nature of the offshore wind power. Consequently, alternative storage methods like hydrogen or ammonia become essential for weekly, monthly and seasonal storage time scales, for maintaining grid stability and to alleviate the national electricity grid. Since HVDC power transmission remains the most energy efficient method, the objective should be to maximize HVDC transmission and direct utilization while ensuring grid stability and implementing seasonal storage solutions through optimizing hydrogen production.

7.1.2. Island-based supply chain configurations

For hydrogen producing supply chain configurations, island-based configurations outperform platform or onshore setups economically. Considering production of hydrogen, island-based configurations have a lower LCOH at 8.86 €/kg, versus 10.55 €/kg for platform-based and 9.94 €/kg for onshore-based configurations. This advantage for island-based compared to platform-based is due to lower operational and capital expenses for electrical and electrolyzer systems and reduced efficiency degradation rates (EDR), outweighing the higher initial investment of the energy island. Although offshore foundation structures like jackets typically entail lower investment costs, their decentralized nature poses challenges. It is difficult to maintain a constant direct current base load, leading to increased electrolyzer EDR. Additionally, heavier conditions result in higher investment costs compared to onshore or island facilities.

Offshore foundation structures, such as jackets, are often favored for their lower initial investment costs compared to an offshore artificial energy island. However, the additional adjustments needed for the topside, such as installation methods, operational costs and exposure to harsh outdoor conditions, can drive up costs. This heightened exposure to extreme conditions in offshore environments may shorten economic lifetimes or require higher upfront investments. Specifically, for electrolyzer topsides, the decentralized nature of multiple platforms with electrolyzer units presents challenges in maintaining a consistent direct current base load, especially given the variability of wind energy supply from a single adjacent wind farm. This variability impacts electrolyzer efficiency, particularly for alkaline electrolyzers, which have better operational performance for constant DC power supply.

These factors collectively underscore the complex considerations involved in offshore infrastructure development and highlight the importance of addressing these challenges for the sustainable advancement of offshore energy production. Moreover, the causes are presented of why the energy island-based hydrogen producing supply chain configurations are outperforming onshore and platform-based configurations.

7.1.3. The levelized cost of hydrogen

The absence of a learning rate in the calculations of this study mean that the LCOH does not decrease over time due to learning and innovation. Moreover, the absence of a scaling factor fails to account for cost reductions in larger projects, where fixed costs can be spread across greater capacity, resulting in a decreased LCOH. Additionally, all costs are assumed for the year 2030 or earlier, without considering potential cost reductions for units constructed in subsequent years, such as 2035 or 2040. The hydrogen production sector has significant potential for learning curves and optimization over time, which could result in lower costs for future units. The assumption of not considering a learning rate provides a conservative estimate for the LCOH, Therefore, the current model may not accurately reflect the potential cost reductions achievable through technological advancements and efficiency improvements in the sector, resulting in a conservative estimation for the LCOH.

In comparison to electrolyzer cost estimates typically found in academic studies, the electrolyzer cost estimates in this study are notably higher, ranging from 900,000 to 1,420,000 €/MW, applicable to onshore and offshore platform-based electrolyzers, respectively. This cost estimate is derived from preliminary input data obtained during the NSE programme phase 5 sprint 1. As part of the NSE programme, input on electrolyzer cost estimates were requested from diverse stakeholders within the electrolyzer industry. This input was derived from real projects and internal key values, providing valuable insights into the cost dynamics of electrolyzer technology. Nevertheless, no GW-scale electrolyzer has been commissioned to this date and costs incorporate large uncertainties. The elevated electrolyzer cost applied in this study, as opposed to figures from academic literature, consequently results in a higher LCOH. In this specific case study for hub North, it leads to an approximate 20% increase compared to the electrolyzer cost estimates typically utilized in academic studies (Giampieri et al., 2024).

Finally, it is important to note that the LCOH remains constant for varying shares of hydrogen production. This is due to the model's structure, where component costs scale linearly with capacity at a constant cost per MW. Costs for each component are allocated to hydrogen or electricity production, or both, based on the co-production share. Consequently, there are no cost benefits gained from increasing hydrogen production capacity, or cost disadvantages from low capacity hydrogen production, resulting in similar LCOH values regardless of the co-production ratio. This does not completely correspond with reality, assessment of a hydrogen pipeline in more detail learns that: at 100% capacity, the maximum theoretical throughput of a pipeline comprises 16.9 GW for a 48-inch 80 bar pipeline, 4.7 GW for a 36-inch 50 bar pipeline and 1.2 GW for a 20-inch 50 bar pipeline (Wang et al., 2021). This highlights the potential advantages and disadvantages associated with hydrogen pipeline sizing, emphasizing that the assumption of a constant cost component rate may not be entirely accurate. Specifically for hydrogen pipelines, capacity increases significantly with diameter while the investment cost remain proportional (Wingerden et al., 2023). In other elements of the infrastructure, costs increase proportionally with capacity. This discrepancy underscores the need for a more nuanced approach to cost modeling for hydrogen pipelines to ensure accurate economic assessments.

7.1.4. Benchmarking with hydrogen import

Drawing from the findings presented in Chapter 5, where the LCOH was calculated for various supply chain configurations under harmonized technical, economic, and financial assumptions, a comparative analysis can be conducted with the estimated LCOH for imported hydrogen or its derivatives.

As solar photovoltaic energy experiences a surge in popularity and becomes increasingly accessible at competitive prices, nations with substantial solar potential are directing significant investments towards solar farms, often coupled with electrolyzer installations. Countries such as those in the Middle East, Morocco, and Australia have abundant land for onshore photovoltaic installations and electrolyzers, quickly yielding economically viable business propositions. This contrasts with the Netherlands, where onshore initiatives face complexity due to land scarcity and where offshore initiatives require significantly higher investments.

Consequently, it is foreseeable that these solar-rich nations will generate substantial amounts of solar energy and potentially hydrogen. Many agreements and contracts are already in place to facilitate this transition and global market. The potential for hydrogen or ammonia export from these regions is significant, aligning with the Netherlands' aspirations to emerge as a hydrogen hub. As such, the import of hydrogen is set to become a substantial component of the Dutch energy landscape. To address this, the costs of domestically produced hydrogen from North Sea offshore wind energy must be benchmarked with that of potentially imported hydrogen. In this way, it can be assessed whether the Netherlands should focus on domestic production, import or a combination of both. There could be several geopolitical reasons for this, but first a quantitative assessment will be made.

With a calculated range of LCOH between 8.86 and 10.63 €/kg for offshore island-based and centralized platform-based electrolysis, respectively, it can compete with imported hydrogen, priced between 4.50 and 8.00 €/kg. This is especially true given the current optimistic estimation of LCOH for hydrogen import, often excluding the cost of required onshore infrastructure.

Additionally to the quantitative assessment, there are qualitative arguments for domestic hydrogen production. First of all, based on multiple other study outcomes, domestic hydrogen production would enhance energy system efficiency by reducing curtailment, alleviating grid constraints and allowing for energy storage. Also, investing in domestic production fosters technological innovation and leadership in the hydrogen sector, positioning the region as a global leader in sustainable energy. Domestic production provides greater control over the entire supply chain, reducing vulnerability to disruptions and geopolitical tensions associated with importing hydrogen, ultimately reducing reliance on foreign sources and enhancing energy security. Lastly, it enhances long-term cost stability. While initial investment costs may be higher for domestic production, it offers long-term cost stability and price predictability compared to relying on imported hydrogen, which may be subject to fluctuating international prices and geopolitical factors.

7.2. Uncertainties within offshore electrolysis

Uncertainties remain in the offshore wind supply chain system. The primary uncertainty revolves around the deployment of electrolyzers at the required GW-scale. While alkaline electrolysis (AEL) and proton exchange membrane electrolysis (PEMEL) are the most advanced methods, with technology readiness levels of 9 and 6-8 respectively, neither has a plant operational at a scale of multiple GWs. This lack of precedent raises questions about the scalability and practicality of these technologies when applied at such large capacities. However, with worldwide optimization and scaling efforts and the first GW-scale projects under construction, it is realistic to assume that GW-scale electrolyser plants are possible.

Furthermore, while AEL demonstrates promise due to its lower cost and maturity compared to other electrolysis methods, it encounters challenges related to input and start-up time flexibility. The process demands stable and consistent DC power input, which does not align well with the intermittent nature of renewable energy sources such as offshore wind. This intermittency of offshore wind resources poses a significant challenge for alkaline electrolyzer operation, as it may lead to periods of low or zero electricity generation, affecting the overall efficiency and economic viability of hydrogen production. Contrary, PEMEL has the ability to rapidly respond to changes in electricity input. It can quickly ramp up or down its production rate to match fluctuations in renewable energy generation. However, PEMEL has a strong reliance on iridium oxide catalysts, presenting a significant concern. These catalysts are rare and costly, potentially limiting the scalability and widespread adoption of PEMEL technology. Consequently, both AEL and PEMEL face challenges related to efficiency and cost-effectiveness when operating at the scale required for large offshore wind projects and its intermittency.

These issues underscore the importance of exploring alternative electrolysis technologies and developing strategies to mitigate the limitations of existing methods, next to studying methods to leverage the benefits of both electrolysis methods. A study by Yu et al. (2024) showed improvements of 6.6% in annual return, 13.4% in device lifespan, and 30.1% in optimization time by combination of AEL and PEMEL techniques. Considering the potential synergy of both electrolyzer techniques, it can be argued that for the size of the project under consideration (19.5 GW), it is a realistic assumption that the intermittent nature of wind energy can be accommodated by the electrolyzers for a large-scale centralized hub. This further advocates for a large-scale energy hub with a centralized hydrogen production facility. Additionally, during research on the technical feasibility of flexible electrolyser operation, it has been demonstrated that electrolyzers are technically capable of quickly adjusting their power consumption in response to fluctuations in renewable power supply (Qi et al., 2021; Zheng et al., 2022a, 2022b).

7.3. Limitation of the study

Despite significant improvements compared to the former method of the standardized, techno-economic model of Van den Haak (2023), the model remains having limitations. These inherent constraints and limitations primarily come from the necessary assumptions and choices made in constructing the model setup. To ensure the feasibility of this relatively concise study, certain decisions were made, paving the way for a streamlined approach. This section delves into the primary limitations, assessing their potential impact on the simulation results.

7.3.1. Level of detail of hydrogen storage

Given the study's aim to evaluate the techno-economic feasibility of offshore electrolysis within the context of energy island concepts in the North Sea in a larger system perspective, the scope extended beyond merely assessing the offshore supply chain, and aspects such as energy storage and grid capacity constraint were considered as well. Qualitative arguments were addressed regarding seasonal storage and grid capacity constraints. Based on such arguments, (offshore) hydrogen production was favoured over full electric power supply to the national electrical grid. While the costs of hydrogen storage were incorporated into the techno-economic model, a precise estimation of required storage in the Netherlands, specific costs for different storage methods, and considerations regarding storage losses were not detailed to the desired extent.

Incorporating such aspects of energy storage is vital for conducting a comprehensive feasibility assessment from a broader system perspective, necessitating their inclusion in subsequent model development efforts. Both offshore wind energy and potentially offshore hydrogen production require careful consideration of energy storage solutions. Energy storage plays a pivotal role in balancing the fluctuations between energy supply and demand, thereby ensuring grid stability and reliability. Furthermore, efficient energy storage mechanisms are essential for maximizing the utilization of renewable energy sources such as offshore wind, which inherently exhibit intermittent generation patterns. As a clean and efficient energy source with flexible production, hydrogen energy can effectively promote the "interconnection" of various energy networks, such as power grids, transportation networks and heat networks, and improve the overall energy utilization (Ge et al., 2024). Embracing these storage solutions is pivotal in advancing the transition towards a sustainable energy landscape.

The current feasibility assessment regarding energy storage within the techno-economic method relies on initial calculations and insights drawn from previous studies (Yousefi et al., 2023; Elberry et al., 2021; Abdin, Khalilpour, & Catchpole, 2022). These studies suggest that hydrogen storage is viable in the Netherlands, potentially utilizing salt caverns or repurposed gas fields. These findings are incorporated into the analysis by introducing a storage cost component expressed in €/MW, which automatically scales with increasing hydrogen production capacity. Considering the current 1,500 kton of hydrogen usage in the Netherlands (Elzenga & Strengers, 2024), indicates that this demand could be fulfilled with approximately 20 GW of offshore wind energy dedicated to hydrogen production. This leads to the reasonable assumption that all the domestically produced hydrogen from a 20 GW offshore wind farm could be directly utilized by industry. A part of the produced hydrogen could be allocated for energy storage, for which the storage costs are already covered by the implemented storage cost component. In this way, despite limitations in the depth of analysis regarding hydrogen storage, this study assumes that the issue has been adequately addressed.

7.3.2. No discrete values employed, component costs scale linearly

The model adopts a cost-scaling mechanism based on capacity, denoted in €/MW. This method ensures that component costs adjust automatically in proportion to energy capacity, a common practice in literature (Giampieri et al., 2024; Rogeau et al., 2023; Hill et al., 2024; BVG Associates, 2019), offering accurate cost estimations for larger capacity projects. However, for smaller projects (up to a few MW), this approach omits a lower threshold cost for installation and vessel deployment, for example, resulting in cost underestimations. In reality, there are constant costs for executing an installation operation, resulting in a constant base costs, significantly increasing the LCOH for small capacities. Furthermore, the method fails to capture the advantages inherent in large-scale projects, further discussed in subsection 7.3.3. The current model setup does not provide different results for the LCOH for varying proportions of H_2/E. In reality, a higher share of hydrogen production would optimize resource utilization, consequently lowering the LCOH.

The cost estimation for the hydrogen pipeline poses particular challenges, particularly with the linear scaling of component costs. Mobilizing cable-laying vessels, conducting survey works, clearing routes, and executing the cable-laying process entail significant expenses that must be incurred regardless of the scale of the cable or pipeline being installed. While larger pipelines or cables do result in fewer lengths being shipped per vessel and necessitate more vessel movements, thereby slightly increasing costs, the essential costs associated with the process remain unchanged. Additionally, the scalability of pipelines presents a significant advantage: doubling the diameter translates to quadrupling the volumes that can be transported, making large-scale deployment highly beneficial (Wingerden et al., 2023; van Rossum et al., 2022).

Consequently, for offshore hydrogen pipelines, fixed costs such as mobilizing cable-laying vessels, conducting survey works, clearing routes, and executing the cable-laying process can be spread out over a larger capacity when installing a substantial pipeline capable of handling multiple gigawatts equivalent of hydrogen. In practice, this means that for large-scale hydrogen pipeline installations, the component cost in €/MW would decrease rather than remaining constant, as it does presently in the model setup. This discrepancy could lead to overly conservative estimations for the component cost of hydrogen pipelines. For cable production and installation this shortcoming in the model does not really provide conservative values as for cables the large scale electricity transport is limited by the cable capacty. AC-transport cables have a maximum capacity of around 350 MW_{el} and DC-cables of around 2 GW_{el} (Wingerden et al., 2023). Cable investments will not significantly decrease with larger capacities.

7.3.3. No cost benefit from learning and scale rate employment

In the current techno-economic model, the absence of learning and scale rates presents a significant limitation, as it overlooks the potential benefits of future improvements driven by research and development (R&D) and economies of scale achieved in larger-scale plants. This omission can lead to an overly conservative estimation of costs and performance metrics, especially for the GW-scale characteristic for hub North, ultimately affecting the feasibility assessments of hydrogen pipeline infrastructure and other components within the system.

Learning rates represent the cost reductions associated with cumulative experience and technological advancements over time. As industries mature and production scales up, costs typically decrease due to improved efficiencies, innovation, and optimization processes (Nemet, 2006; McDonald & Schrattenholzer, 2001). By excluding learning rates, the model fails to account for the potential decrease in costs that could be realized through continuous R&D efforts and the subsequent adoption of more efficient technologies. Similarly, the model's exclusion of scale rates neglects the cost benefits associated with scaling up production and deployment. Larger-scale plants generally benefit from economies of scale, where the per-unit cost of production decreases as the volume of production increases (Grubler, 2012). For hydrogen production, a larger-scale plant could significantly reduce the cost per unit of produced hydrogen compared to smaller installations. The current model's failure to incorporate these learning and scale effects may result in overestimating costs and underestimating the potential economic advantages of large-scale hydrogen infrastructure projects.

7.3.4. Wind energy yield - efficiency and capacity factor

In the model, wind energy production estimation relies on a constant capacity factor assumed throughout the project's lifespan (Jang et al., 2022; National Renewable Energy Laboratory, 2022). Given the model's objectives and scope, this approach, unlike using actual wind speed data as seen in previous studies (Yan et al., 2021; Groenemans et al., 2022; Egeland-Eriksen et al., 2023), is presumed realistic. The capacity factor in offshore wind refers to the ratio of actual electrical output to the maximum potential output over a given time. It indicates how efficiently wind turbines are generating electricity, affected by factors like wind speed and maintenance downtime. For wind turbine manufacturers, the capacity factor serves as a key design parameter. Presently, offshore wind turbines commonly exhibit a capacity factor of 0.5, with forthcoming models expected to reach 0.61 (GE Vernova, 2024). Yet, as this factor directly impacts turbine costs, it is appropriate to maintain the current wind turbine costs and the current capacity factor of 0.5.

While it would be more realistic to adopt an efficiency degradation rate for the wind turbine, reflecting its gradual decline in performance over time (Staffell & Green, 2014), the focus of the study precluded such an inclusion. Instead, the model's focus is on harmoniously comparing different supply chain configurations for cost and energy efficient transmission infrastructure rather than calculating the best approximation for wind energy production. It was a deliberate model design choice to tailor the parameters to the specific objectives at hand, prioritizing simplicity and feasibility regarding wind energy production. By streamlining the variables to those directly pertinent to the study's scope, unnecessary complexities were avoided, allowing for a more focused analysis of the primary factors influencing the project's outcomes.

In the model, energy losses due to energy conversion or transmission are calculated based on results from other academic studies. For more accurate results, these losses should be determined based on physical relationships, including the actual current, voltage and resistance. For example, the inter-array cables provide 66 kV AC to the AC substation, which steps up the voltage to 380 kV AC with a transformer. Energy losses could be calculated here based on physical relationships rather than commonly employed constant values for energy losses in AC substation in literature (Rogeau et al., 2023; Apostolaki-Iosifidou et al., 2019; Wingerden et al., 2023). Additionally, for HVDC and HVAC cables, estimations are made within the model depending on the cable length, resulting from studies of Apostolaki-Iosifidou et al. (2019) and Giampieri et al. (2024). By applying physical relationships, based on the actual current, voltage and resistance of a cable, better estimations could be made. However, given that the voltages and currents in the techno-economic model are comparable in magnitude to those in the referenced studies, it is presumed that there would be minimal deviation between the estimated values derived from other studies and the actual results obtained from physical functions.

7.3.5. No financial risks included in the model setup

In the study by Van den Haak (2023), the impact of wind farm commissioning timing on the project's financial feasibility was evaluated using a simplified system of two wind farms. This approach offers a valuable perspective given the dynamics of the current offshore wind market. However, to conduct a realistic financial feasibility study for an offshore wind system potentially including an energy island, it is essential to include financial risks. The methods used by Van den Haak (2023) and the current methodologies employed in this study do not account for financial risks such as regulatory uncertainty, market price volatility, construction and supply chain risks, operational risks, financing risks, and market demand and offtake risks. These factors significantly impact the financial feasibility of offshore wind projects. Therefore, a realistic financial feasibility assessment cannot be performed without consideration of such financial risks. It was therefore a deliberate model setup design choice to incorporate wind farm commissioning timing as an additional uncertainty factor rather than using it as a design parameter for an offshore wind project's financial feasibility, which is not realistic if financial risks are excluded from the assessment.

In assessing the financial feasibility of a project involving wind farms and an energy island, considerations of both commissioning timing and financial risks become pivotal. For example, when analyzing various commissioning years for wind farm projects alongside the construction of an energy island, with a focus on synchronizing energy production commencement, a critical finding emerges: optimal commissioning timing without consideration of financial risks suggests that planning the construction of the energy island to be commissioned as close to the wind farms' commissioning dates as feasible is the most beneficial strategy. This outcome results from the NPV calculation, which discounts cash flows, indicating that investments made later yield lower values for the NPV of the project costs. In this situation, it is beneficial to postpone investments and construction of an energy island in such a way that they perfectly align with the commissioning of the wind farms. In a theoretical world this would prove to be possible. However, in practice, it is likely that project construction and supply chain risks delay the energy island's commissioning, leading to postponed energy production as a commissioned island is required for energy conversion and transmission. Often strict contracts are in place within the industry, leading to financial penalties for parties constructing the actual energy island due to delayed commissioning. Without consideration of such financial risks, a financial feasibility study would provide trivial results, rendering their outcomes superficial and of diminished significance.

7.3.6. Uniform inflation & discount rate

In the cash flow analyses, a constant escalation rate (inflation) was applied to reflect real economic conditions and account for the time value of money, significantly impacting a project's feasibility. Currently, soaring costs are causing wind power developers to delay or halt projects worth over $30 billion (The Wall Street Journal, 2023). However, as highlighted in Chapter 2, techno-economic studies often lack transparency and explicit discussion on this matter. Including or excluding a 2% inflation rate notably affects a project's OPEX and revenue. For instance, a 2% inflation rate over a 30-year project results in a 35% difference in yearly revenue.

The assumed rate in the techno-economic model is 2%, mirroring the European Central Bank's (ECB) target (European Central Bank, 2024b). This constant rate assumes a stable inflation environment, simplifying the model and providing consistency in the valuation process. However, it does not capture potential fluctuations in inflation over time, which can affect the accuracy of long-term financial forecasts. Future studies should consider variable inflation rates to better reflect economic volatility and enhance the robustness of financial projections. However, the improvement in model accuracy by incorporating dynamic inflation rates remains uncertain due to the inherent unpredictability of inflation trends. Instead, it may be more practical to assess the impact of specific, short-term changes, such as a sudden 30% increase in steel prices, on the project's financial feasibility through a sensitivity analysis. This approach introduces fewer uncertainties and offers greater accuracy, as it requires forecasting only over a 2 to 3-year period, making it more manageable and reliable.

In the NPV calculation within the model, a well-considered discount rate was utilized, a common method in techno-economic studies. This discount rate is typically established based on economic metrics such as inflation. On the other hand, the WACC, which is a company-specific discount rate employed by financial managers, provides a more precise method for companies to assess the financial feasibility of a project or asset. By adopting the WACC, the model would accurately reflect their financing conditions, as the WACC includes the mix of debt and equity within a company, reflecting their actual weighted average cost of capital. Consequently, using the WACC in NPV calculations offers a more accurate estimation of a project's or asset's financial feasibility.

However, given the scope of the current study, which encompasses the entire supply chain including multiple specific industries such as offshore wind, electrolyzers, and electricity, and a diverse array of companies, it is impractical and unrealistic to apply a single WACC value to the entire system. This approach would assume a homogeneous financial environment, which does not accurately reflect the diverse nature of the industries involved. Such an assumption could lead to misinterpretation, falsely suggesting that the debt-to-equity ratio for the entire industry is known, which is evidently not true. This could result in inaccurate conclusions and undermine the credibility of the study. Therefore, it is crucial to recognize the heterogeneity of financial conditions across different sectors and companies within the supply chain to ensure accurate and credible analysis.

These two elements pose a significant challenge. It is a nuanced consideration to choose between using the WACC or a general discount rate. For a broad and correct implementation, it is more appropriate to use a 'general' discount rate, which can be consistently applied across various industries and scenarios. However, using the WACC would enable more precise NPV calculations, tailored to the specific financial conditions of individual companies. This precision makes the model more attractive and relevant for companies, encouraging them to engage with and apply the model. By incorporating the WACC, companies can accurately reflect their cost of capital based on their financial considerations regarding debt-to-equity ratios, leading to more reliable and applicable results. Nonetheless, for accurate application to an entire offshore wind supply chain system, it is considered more appropriate to use the general discount rate rather than the company-specific WACC. Balancing the general applicability of the model with the need for precise, company-specific financial metrics is crucial for the model's credibility and usefulness in real-world applications.

One method to address this complexity is to apply industry-specific differentiation for the WACC values used for different components in the supply chain. For instance, the electrolyzer industry, characterized by higher uncertainties and risks, would warrant a higher WACC value. Conversely, the cable-laying industry, being more mature and stable, would justify a lower WACC. This approach would lead to a more accurate and effective use of WACC in the context of the entire supply chain system, ensuring that the financial conditions and risk profiles of each industry segment are appropriately accounted for.

7.4. Recommendations for further research

Building upon the limitations outlined in Section 7.3, several concrete recommendations appear, each offering substantial potential for improvement in future studies:

- **Assess required hydrogen storage for grid stability and seasonal storage in more detail**

  Further assess the required hydrogen storage capacity, considering factors such as managing grid stability and seasonal variations in hydrogen demand and supply. Additionally, explore realistic methodologies for incorporating hydrogen storage costs and operational considerations into the techno-economic assessment method to provide a more comprehensive economic analysis

- **Explicit integration of a PBS, ABS and COR within the standardized model**

  This study provides a qualitative assessment regarding the integration of the concepts of Physical Breakdown Structure (PBS), Activity Breakdown Structure (ABS), and Code of Resource (COR), with a specific focus on the PBS. The recommendation for future studies is to explicitly integrate a PBS, ABS and COR within the standardized model, incorporating detailed frameworks for categorizing project components, activities, and resource allocations.

- **Include full HVAC export power transmission supply chain configuration**

  As an additional supply chain configuration, incorporate full HVAC power transmission from the offshore wind farm to shore, omitting the need for offshore HVDC conversion and subsequent onshore HVDC to HVAC conversion, despite higher energy losses for HVAC power transmission for longer distances

- **Examine possibilities for grid connection for electrolysis**

  Currently, the techno-economic model only assesses hydrogen production from offshore wind energy. Integration with the national electricity grid opens up new potential for efficiency and flexibility. By integrating with the grid, the system gains the ability to utilize surplus electricity during periods of low demand or high renewable energy generation. This not only enhances the overall utilization of renewable energy resources but also offers opportunities for demand response and grid balancing.

- **Include curtailment rates in the techno-economic model**

  Further study the implications of curtailment on the HVDC configurations to assess its impact on overall system efficiency and economic viability. In the current methods curtailment is not included, resulting in overly optimistic estimates for the LCOTE and LCOE. It is unrealistic that all HVDC power could be integrated in the national grid, necessitating curtailment and decreasing power production, resulting in a higher LCOTE and LCOE

- **Improve values for energy losses due to transmission and conversion**

  Further improve the energy losses by integration of the physical relations for energy losses due to energy transmission and conversion. For example, calculate the energy loss in a 525 kV HVDC export cable with a specific length, based on its resistance and power characteristics rather than using estimating curves from other studies

- **Allow for industry-specific WACC cash flow analyses and a dynamic short-term inflation rate**

  Allowing for industry-specific WACC cash flow analyses and a dynamic short-term inflation rate enhances the accuracy of financial projections by tailoring the discount rate to the specific industry's risk profile and adjusting for inflation fluctuations, providing a more realistic assessment of project feasibility

8
Conclusion

The conclusions from this study are presented in section 8.1. Furthermore, section 8.2 provides an outlook in which is elaborated on concrete advises for the NSE program, directing bodies such as the Ministry of Infrastructure and Water Management, and the offshore wind industry as a whole.

8.1. Conclusions study

The offshore W2H market is rapidly evolving, driven by diverse stakeholders and numerous in-house models. However, there is still no industry-wide, standardized, open-source model ready for utilization by the industry available yet. This study evaluates various supply chain configurations for offshore wind to hydrogen and electricity in the North Sea, considering their integration within a broader energy system that includes transmission and storage. The objective of this study was two-fold: (i) to improve and develop an industry-wide, standardized, open-source techno-economic model with automated supply chain generation and an energy island cost estimation tool, and (ii) to apply the developed model to evaluate the feasibility of offshore island-based hydrogen production for the Hub North case study within the NSE programme, benchmarking it against hydrogen import options.

1. How are feasibility assessment studies for offshore wind production supply chains and global hydrogen import typically conducted in literature, how can the current knowledge be extended?

A literature review provided the status quo of offshore wind supply chain feasibility assessment methods. It revealed that the common method for feasibility studies is to conduct a techno-economic assessment, with elements such as a constant component cost rate, discounted cash flow analyses and levelized costs. Moreover, the literature review indicated that efforts into "softer" aspects such as implementation of standardization, making the model suitable for industry-wide application, and enhancing its attractiveness for industry stakeholders, are often overlooked in these techno-economic studies, as well as transparency in presenting assumptions, input, and methodologies. This lack of transparency and the diversity in assumptions across studies makes meaningful comparisons challenging, diminishing the significance of study outcomes.

2. How can explicit implementation of standardization, syntax and semantics into the standardized techno-economic model enhance effective study comparison, allowing for industry-wide adoption?

Assessment of international and industry standards indicated that no single standard comprehensively applies to the entire offshore W2P and W2H system concerning a physical breakdown schedule. Consequently, this study's model development cannot rely on a single standard for efficient study comparison. Therefore, another method is assessed: the LCOH, which offers simplicity and clarity within one metric. However, it also has its implications and considerations, primarily centered around the discount rate. The discount rate significantly impacts the LCOH, additionally observed by Galimova et al. (2023), and there is no single standard practice for defining this rate, further increasing its complexity.

In this study, two methods for definition of the rate are considered: the general discount rate and the WACC. While a general discount rate uniformly applied to the entire supply chain ensures correct implementation, using the WACC would enable more precise NPV calculations, tailored to the specific financial conditions of individual companies. Balancing the general applicability of the model with the need for precise, company-specific financial metrics is crucial for the model's credibility and usefulness in real-world applications. In this study, the decision has been made to incorporate the WACC to improve the accuracy and relevance of the model for individual stakeholders, despite its implicit limitations.

Although no single standard is fully applicable in this study's model development, ISO standard 19008:2016 exhibits high similarities with the intended definition of supply chain components. It has the potential to become the industry standard for the offshore (North Sea) energy transition by including two additional component definitions: the electrolyzer (offshore and onshore-based) and an energy island as a type of offshore substructure in PBS level 3. Given the high degree of similarity and the potential for future full coverage between this study's component definition and the standard's PBS, alignment with this standard has been maximized for the PBS. The SAB and COR, fundamental parts of the standard, hold significant potential for future model development, further enhancing the ability for efficient model comparison. However, due to time and scope limitations, they are not explicitly incorporated in this study's model development, and their relevance is addressed in qualitative terms.

In this context, international standardization might hold the solution for this challenge of a correct, yet realistic and engaging, utilization of the discount rate. If an international standard included all the necessary component definitions for a physical breakdown, the WACC could be specified for each component. This approach allows for realistic discounting of each component's cash flows by defining an industry-specific WACC for each component. This method captures significant differences between industries, such as those for electrolyzers and platform substructures. Consequently, the resulting LCOH becomes more comparable and insightful than if a uniform discount rate were applied.

Lastly, examination of modeling concepts such as domain semantics, metamodels, and ontologies, indicated that explicit implementation enables the primary benefits of model-based systems engineering, including design collaboration among all stakeholders, model sharing, terminology consistency, and reduction of ambiguity. Consequently, this study qualitatively addressed the importance of including such MBSE concepts in future techno-economic model development. Explicitly implementing taxonomy allows for the inclusion of specific products with accurate properties as defined by the manufacturer, enhancing the model's accuracy, relevance, and clarity. Additionally, explicit implementation of ontologies would greatly enhance efficient model utilization. By requiring each component to have a specific set of properties, the model becomes more structured, prevents inconsistent component definitions, and ensures that all components have complete and accurate properties

Explicitly addressing these challenges will enhance the model's accuracy and equip it with unique capabilities that surpass current industry standards. This advancement positions the model at the forefront of standardized techno-economic assessment methods for offshore hydrogen production on energy islands, enabling more reliable and comprehensive analyses. Bridging these gaps provides a valuable foundation for both academics and the offshore industry to develop more efficient and cost-effective solutions, driving innovation and facilitating the transition to sustainable energy systems.

3. How can automating the supply chain generation and development of an offshore artificial energy island cost estimating tool better facilitate efficient supply chain comparison?

To facilitate efficient concept comparison and offshore infrastructure design planning, it is crucial to be able to quickly quantify different supply chain configurations in terms of levelized costs and supply chain efficiencies. In the methods of Van den Haak (2023), these configurations were manually generated and did not allow for quick quantification. Enabling automated generation of multiple supply chain configuration types represents a significant improvement, making supply chain comparison achievable in practice. Additionally, including a comprehensive offshore artificial energy island cost estimation tool enables more accurate calculation of island-based supply chain configurations, thereby enhancing the quality of comparisons between different offshore infrastructure concepts. By taking this approach, it ensures that high-potential concepts such as energy islands are not overlooked, thereby preventing decision-making in offshore energy infrastructure systems based on sub-optimal information sources.

4. What are the estimated costs of hydrogen import for the Netherlands and Europe in literature and who would be the end-user?

Studies on hydrogen import into (Northwestern) Europe offer a basis for determination of a future cost benchmark, which are compared with this study's calculated LCOH of domestically produced hydrogen. These studies assess potential imports of green hydrogen from various global locations and as different energy carriers. Often, gaseous hydrogen is economically viable for short distances, such as from Morocco, but alternatives like ammonia, liquid hydrogen, and LOHC are more cost-effective for longer distances due to their higher energy density and associated benefits.

In Dutch practices hydrogen is primarily used in refineries and ammonia production for agriculture, with potential future use in grid balancing. Due to the advantages of shipping ammonia, most imported hydrogen will likely be in this form. As current ammonia demand is already considerable, and future demand is expected to increase, it is unlikely that the imported ammonia would be utilized in fuel cells to generate electricity for grid stability, excluding the necessity for ammonia cracking. Potential exporters for hydrogen are Morocco, the Middle East, Australia, Chile, and the USA, with an estimated LCOH for 2030 in the range of 4 to 9 €/kg. However, these estimates often exclude additional costs such as an import terminal, reconversion, and (short-term) storage, leading to overly optimistic scenarios.

5. How are the techno-economical performance metrics of different energy transmission methods for offshore wind-to-hydrogen and wind-to-power systems evaluated in a harmonized way using this study's developed model, focusing on the hub North case study in the North Sea Energy programme?

Application of the developed techno-economic model for the proposed 19.5 GW offshore wind plans of hub North within the NSE program indicates three important conclusions. First, with a LCOTE of 0.037 €/MJ for an island-based full HVDC configuration, it is evident that this configuration provides an optimal design in terms of energy and cost efficiency. In contrast, co-production and full hydrogen configurations range from 0.046 to 0.089 €/MJ, showing inferior performance. This results from HVDC systems having lower energy losses and costs compared to electrolyzer systems. However, seamlessly integrating 19.5 GW of HVDC offshore wind energy into the national grid is unrealistic due to curtailment and grid congestion issues. Moreover, the absence of potential seasonal energy storage in case of merely electricity production, critical for energy security, underscores the necessity for local hydrogen production and excludes adoption of a full HVDC production method.
Secondly, when hydrogen production is considered, island-based configurations outperform platform or onshore setups economically. Considering co-production of hydrogen and electricity, at both 50%, island-based configurations have a lower LCOH at 8.86 €/kg, versus 10.55 €/kg for platform-based and 9.94 €/kg for onshore-based configurations. This advantage for island-based compared to platform-based is due to lower CAPEX and OPEX for electrical and electrolyzer systems, along with longer electrolyzer stack lifetimes and reduced electrolyzer EDR, outweighing the higher CAPEX of the energy island. Although offshore foundation structures like jackets typically entail lower CAPEX, their decentralized nature poses other challenges. It is difficult to maintain a constant direct current base load, leading to increased electrolyzer EDRs. Additionally, saline marine conditions and extreme metocean conditions result in a higher CAPEX, compared to onshore and island facilities.
Lastly, with a calculated range of LCOH between 8.54 and 10.40 €/kg for offshore island-based configurations, it can compete with imported hydrogen, priced between 4 and 9 €/kg. This is especially true given the optimistic estimation of LCOH for hydrogen import and the potential for subsidizing North Sea-produced hydrogen to improve our energy security, thereby increasing the feasibility of the business case for domestic hydrogen production from offshore wind.

Conclusion main research question

By obtaining answers to these five sub-questions, the main research question can be answered. This approach enables the study to achieve its objective of developing a standardized comparison method, create an offshore artificial energy island cost estimation tool and apply those to the Hub North case study within the NSE programme to evaluate the feasibility of an energy island concept in detail.

How can the evaluation of offshore wind supply chain configurations be standardized to enhance industry-wide collaboration? And how can this standardized approach be applied to evaluate the feasibility of energy island concepts for the hub North case study in the North Sea Energy programme compared to hydrogen import?

To enhance industry-wide collaboration, a standardized techno-economic model must prioritize transparency, ease of use through automated supply chain configuration generation, and alignment with industry or international standards. These elements are crucial for facilitating efficient discussions and are implemented in a standardized techno-economic model developed in programming language Python. The presented method is open-source, further enhancing its transparency. Moreover, in order to be able to evaluate the feasibility of an energy island concept - an aspect often overlooked in literature - for Hub North within the NSE programme in further detail, an energy island cost estimation tool is developed.

Integration of an international standard would significantly enhance the comparability of results. However, after examination of standards it is concluded that no single international standard encompasses the entire system. Therefore, the author defined a PBS based on common practices in studies and the methods of ISO standard 19008:2016, resulting in a PBS being aligned as closely as possible. Based on components in the PBS, supply chain configurations are automatically generated and their feasibility evaluated in a harmonized assessment based on identical financial and technical assumptions.

Within this study's setup, the results indicate that domestic offshore hydrogen production is most feasible on centralized offshore artificial energy islands rather than onshore or on offshore platforms. For the centralized offshore energy island supply chain configuration, at location ′B′ for the rock revetment island (′Type I′) for Hub North in the NSE programme, the weighted LCOH is 8.86 €/kg. Subsidies or government initiatives as initiating construction of an energy island or European Hydrogen Backbone could potentially decrease the LCOH with around 5 - 10 %, based on the model's output. Hydrogen import is generally estimated at 4 to 9 €/kg, however, often not considering required onshore infrastructure, leading to overly optimistic results. Taking this into account, based on the feasibility study, it is considered that offshore W2H energy island concepts in the North Sea are at competitive price levels.

Study's value for the industry

Global temperatures are on a relentless upward trajectory, reaching new records with alarming frequency. Figures from EU's Copernicus Climate Change Service show it was 11^{th} time in a row monthly record has been broken (The Guardian, 2024). The imperative to phase out fossil fuels and transition to renewable energy has never been more urgent. This shift demands the most extensive energy transformation in human history, and we find ourselves at its epicenter.

The expansion of Dutch offshore wind capacity is expected to grow tremendously, necessitating long-term strategic development to fulfill the North Sea's energy ambitions. This includes the adoption of innovative solutions like offshore artificial energy islands, designed to maximize energy efficiency, facilitate hydrogen storage, and ensure grid stability. Unfortunately, existing pre-feasibility studies often overlook these cutting-edge methods, and the industry landscape lacks the collaborative spirit necessary for idea exchange and alignment of efforts.

This study bridges these gaps and offers a pathway to propel the transition toward a sustainable future. The significance of this research cannot be overstated, as it directly addresses the challenges that currently impede collaboration among stakeholders in the energy transition sector. Failure to enhance cooperation among players in the industry could lead to the inefficient allocation of financial resources towards infrastructure projects in unsuitable locations with sub-optimal setups. Moreover, as time passes, our most valuable asset is wasted, while rising temperatures escalate the urgency for action. Through subjecting the techno-economic model to industry validation and incorporating stakeholder feedback, the aim is to solidify its reputation as an independent, publicly available, transparent and universally recognized method for enhancing decision-making processes within the offshore wind-to-hydrogen industry.

The time has come for all industry players to unite and take decisive steps toward a sustainable future. Rather than leveraging their significant resources for developing advanced in-house models in a rapidly evolving market, industry players should shift their focus towards industry-wide collaboration effort into developing a standardized, transparent open-source techno-economic model. This study has demonstrated the potential of such an approach, presenting a method that serves as a crucial initial stride in this direction.

8.2. Outlook

This section provides an outlook in which is elaborated on concrete advises for the NSE program, directing bodies such as the Ministry of Infrastructure and Water Management, and the offshore wind industry as a whole. These advises could potentially be incorporated in future research programs, directing innovation efforts into high-potential fields and allocation of financial resources. These advises are independent of the recommendations on further improving the techno-economic model, which are presented in Section 7.4.

- **This study has demonstrated the energy island's techno-economic feasibility, with significant potential for further optimization in areas such as location, construction methods, and logistics**

  This study demonstrates the technical advantages and economic feasibility of an offshore energy island for (partial) hydrogen production. It presents promising results compared to platform-based configurations, and further optimization of an offshore energy island could enhance its feasibility even further. Therefore, it is recommended that within the NSE program, the offshore energy island concept is continued to be explored and focus is allocated to optimizing its location. Additionally, development of component standardization by other parties might be leveraged for improved economic and technical performance.

- **Identification of additional benefits - not yet reflected in the LCOH - would further strengthen the concept of offshore energy islands**

  The LCOH considers many factors, but regarding the feasibility assessment of energy islands significant benefits are overlooked. For instance, as growing offshore wind infrastructure will further narrow and intensify maritime routes, there is need for better maritime monitoring and assistance, for which an energy island could greatly improve operational efficiency, cut costs, and enhance safety for these activities, highlighting its broader value beyond economic assessments.

- **By this study's proof of concept, the Ministry is suggested to stimulate standardized, open-source, industry-wide model development to overcome the industry's challenging isolated dynamics**

  Specifically, recommendations include fostering standardized model development practices to streamline project assessment and decision-making processes. Moreover, advocating for industry-wide collaboration initiatives can accelerate innovation by facilitating knowledge sharing and resource sharing. Additionally, promoting the adoption of innovative installation methods and optimizing electrolyzer technology and installation and replacement methods can enhance operational efficiency and reduce costs across the sector. Furthermore, investing in infrastructure development and advancing efficiency in energy storage solutions are crucial steps toward promoting domestic hydrogen production and fostering a sustainable energy landscape

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A

Offshore wind capacity

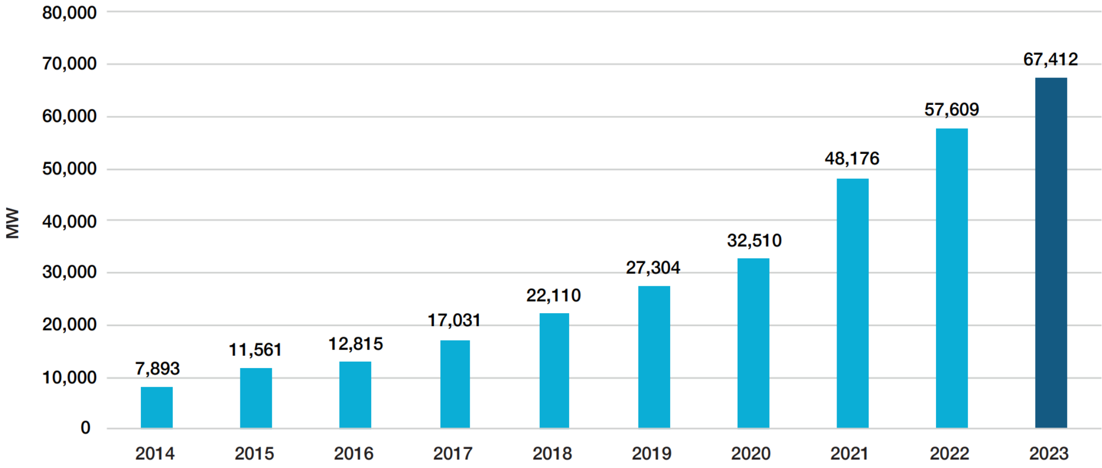

Figure A.1: Global offshore wind capacity in operation - Cumulative, adopted from Herzig (2023)

B

Methodology model development

This appendix supports Chapter 4 ”Methodology - standardized techno-economic model”, by providing detailed supplementary materials that enhance the understanding of the methodological framework used in this study. It includes tables, structural diagrams, overviews, and verification tests. These elements are important for illustrating the data, processes, and validation techniques employed. By presenting these materials, the appendix aims to offer a thorough and transparent view of the methodology, ensuring the reproducibility and robustness of the research findings.

B.1. Component overview per supply chain configuration

B.1.1. Platform-based configurations

Figure B.1 presents a schematic overview of the required components for an offshore platform-based full H_2 production configuration. Figure B.2 presents a schematic overview of the required components for an offshore platform-based full HVDC production configuration. Figure B.3 presents a schematic overview of the required components for an offshore platform-based co-production configuration.

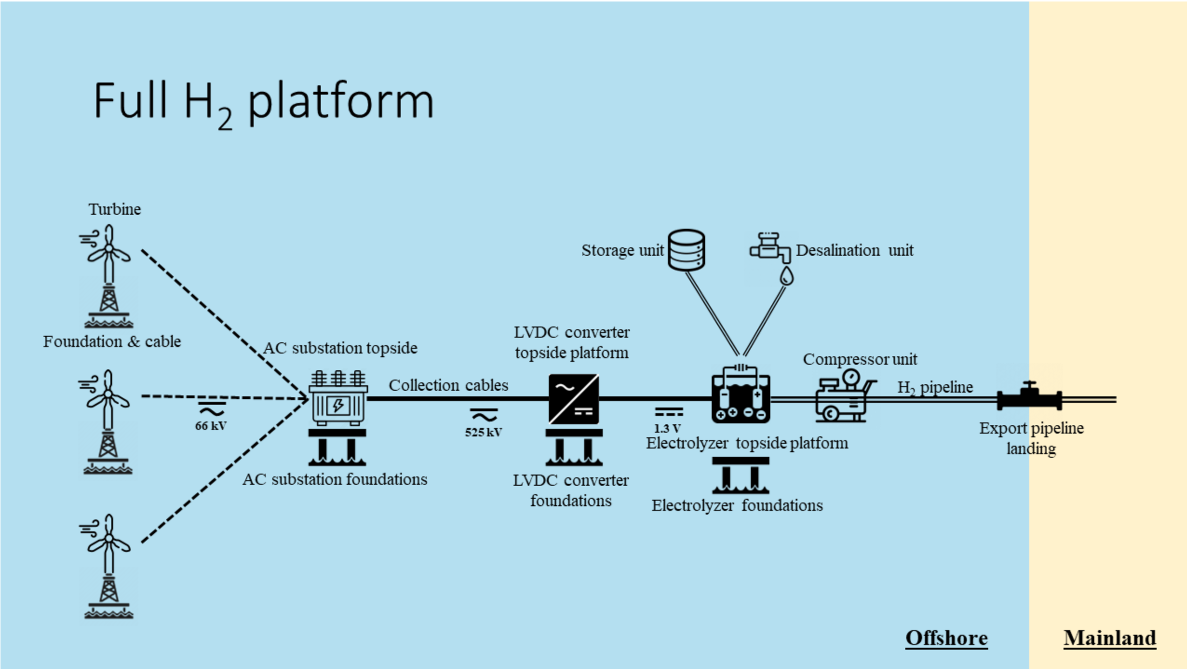

Figure B.1: Schematic overview of offshore wind-to-hydrogen supply chain configuration - Full H_2 platform

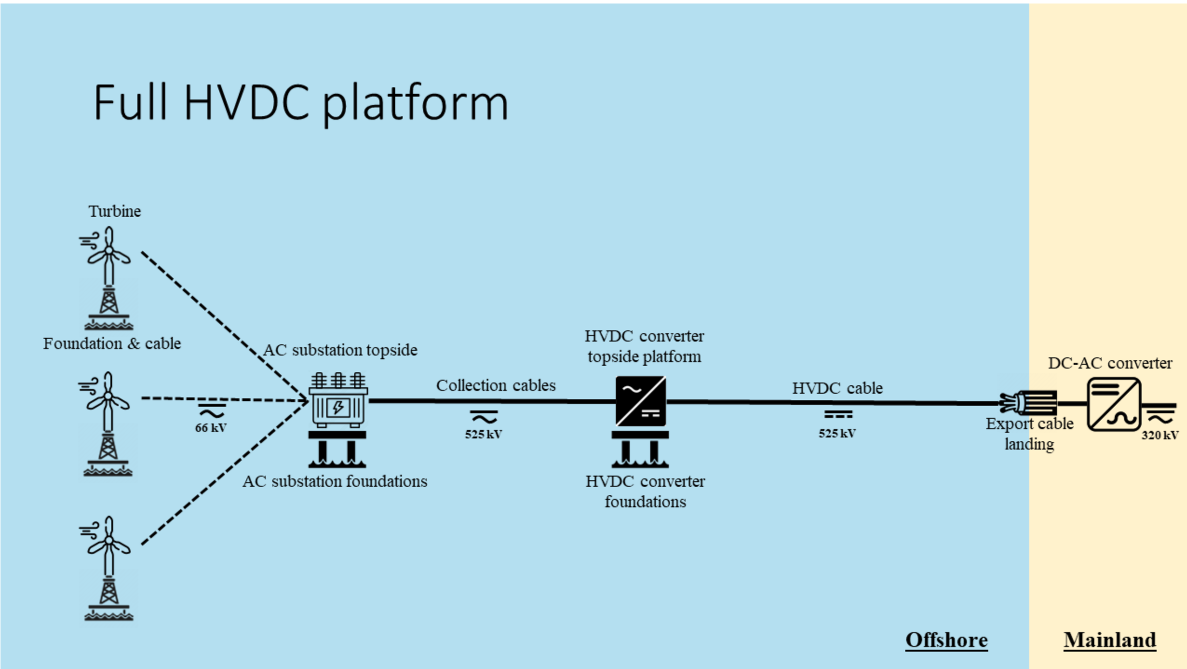

Figure B.2: Schematic overview of offshore wind-to-hydrogen supply chain configuration - Full HVDC platform

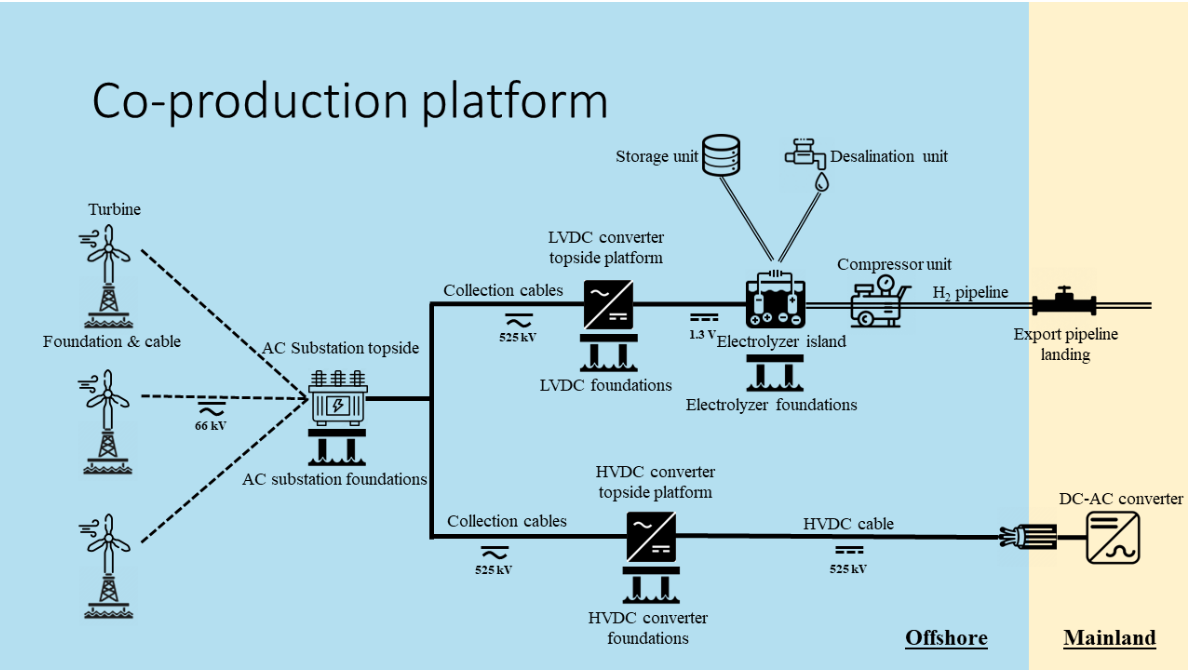

Figure B.3: Schematic overview of offshore wind-to-hydrogen supply chain configuration - Co-production platform

B.1.2. Island-based configurations

Figure B.4 presents a schematic overview of the required components for an island-based full H_2 production configuration. Figure B.5 presents a schematic overview of the required components for an island-based full HVDC production configuration. Figure B.6 presents a schematic overview of the required components for an island-based co-production configuration.

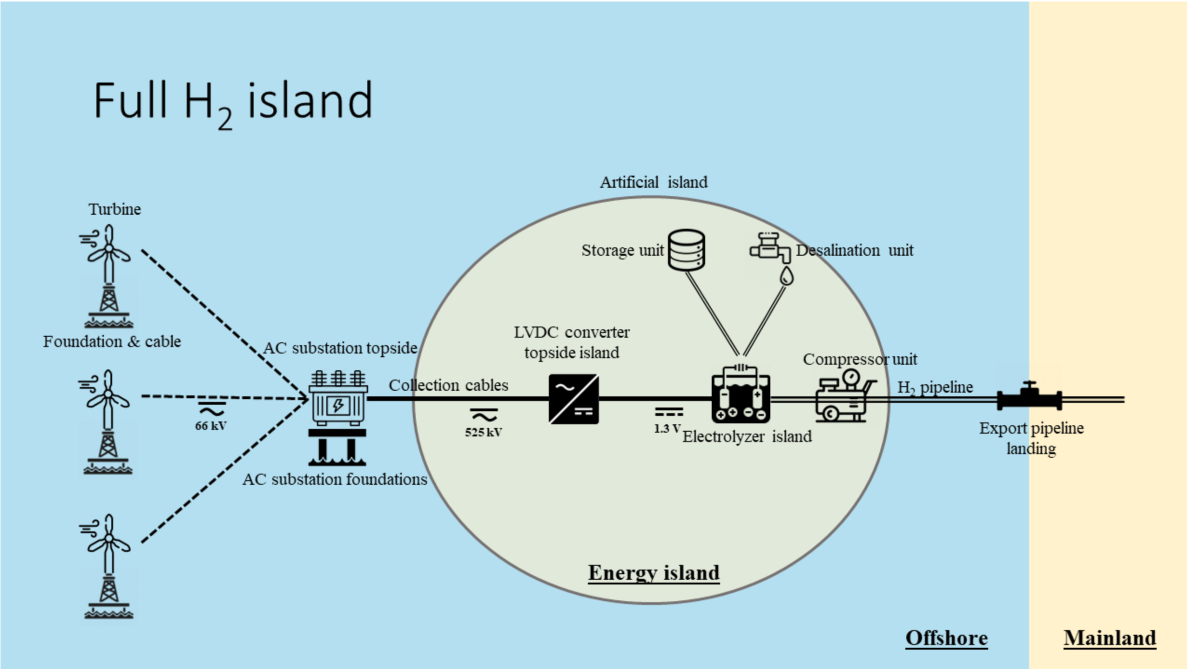

Figure B.4: Schematic overview of offshore wind-to-hydrogen supply chain configuration - Full H_2 island

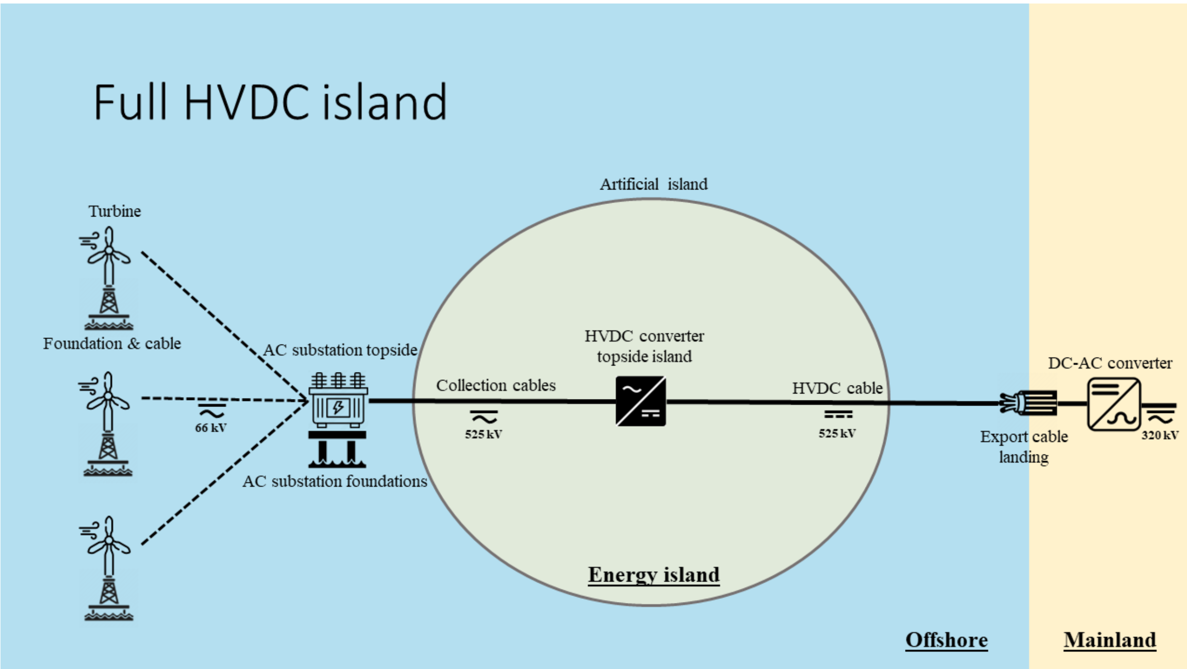

Figure B.5: Schematic overview of offshore wind-to-hydrogen supply chain configuration - Full HVDC island

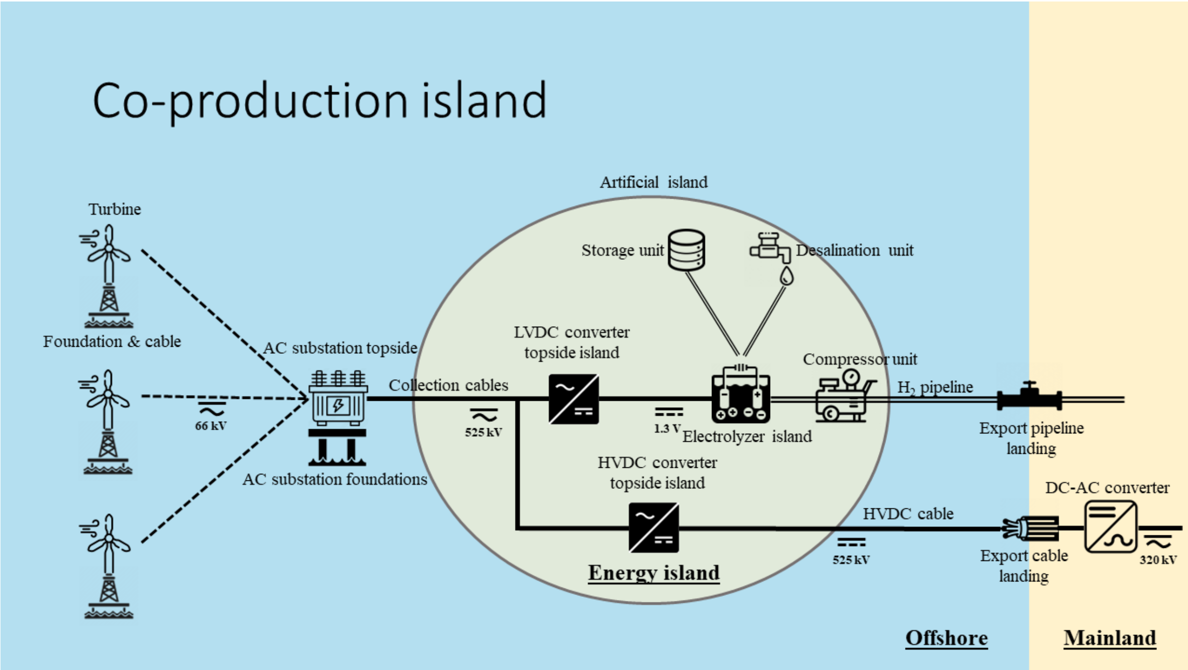

Figure B.6: Schematic overview of offshore wind-to-hydrogen supply chain configuration - Co-production island

B.1.3. Onshore-based configurations

Figure B.7 presents a schematic overview of the required components for an onshore-based full H_2 production configuration. Figure B.8 presents a schematic overview of the required components for an onshore-based co-production configuration.

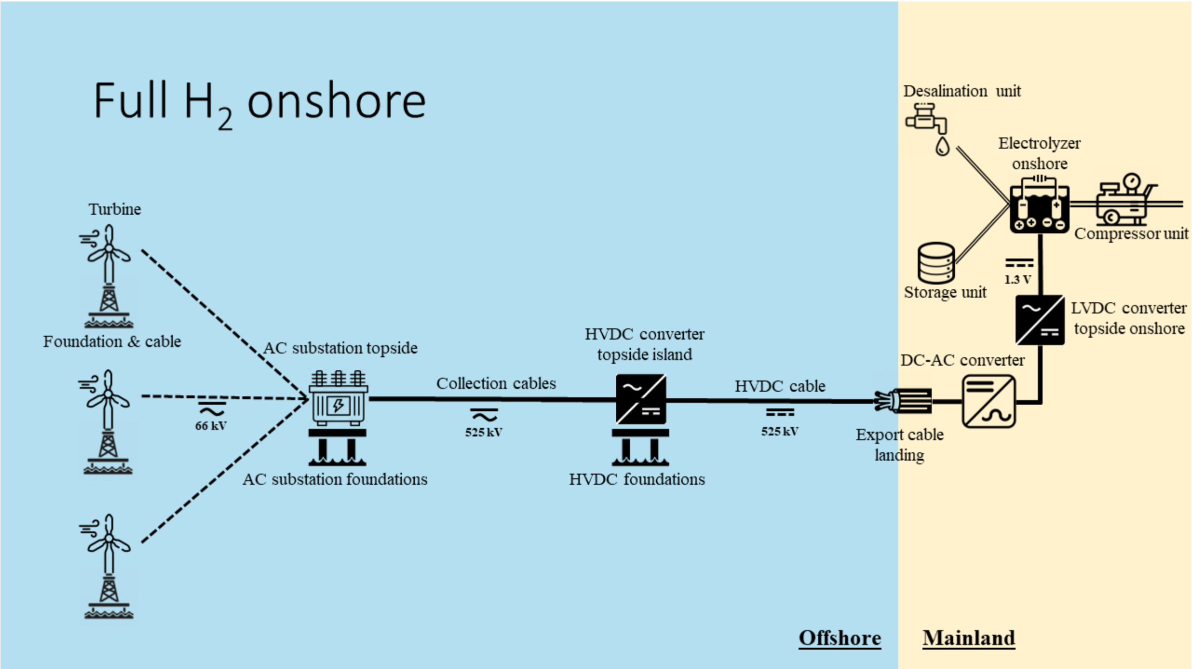

Figure B.7: Schematic overview of offshore wind-to-hydrogen supply chain configuration - Full H_2 onshore

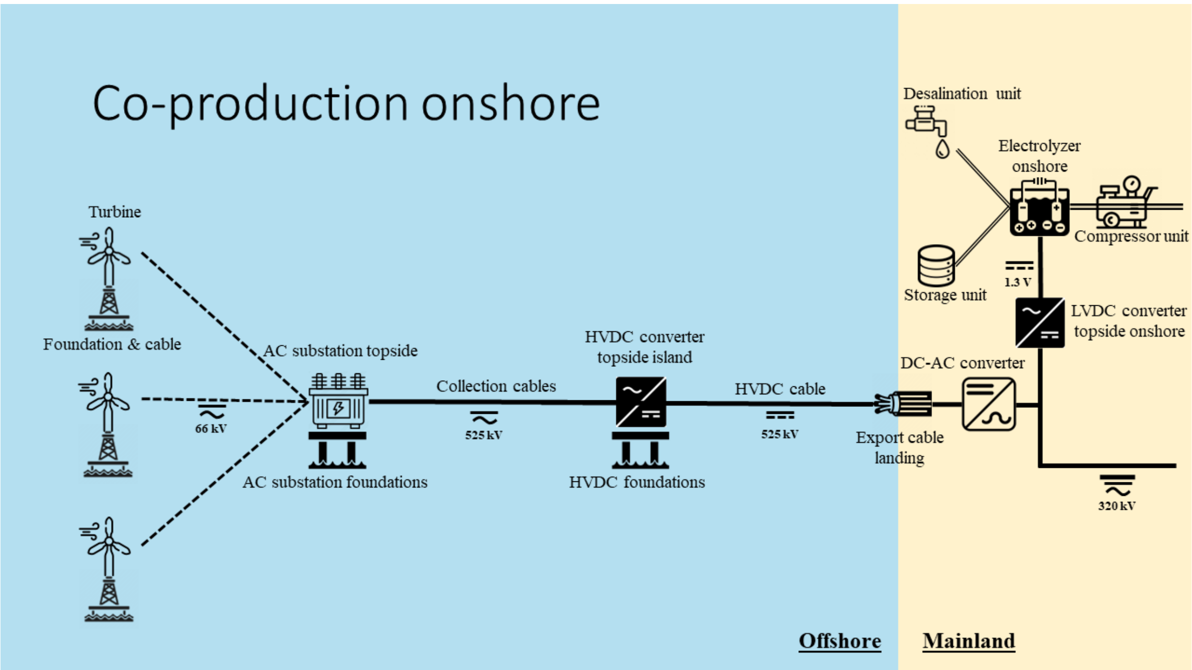

Figure B.8: Schematic overview of offshore wind-to-hydrogen supply chain configuration - Co-production onshore

B.2. Supply chain component cost overview

Table B.1 presents an overview of all possible supply chain configuration components and their corresponding CAPEX, OPEX and DECEX in the relevant unit, together with the economic lifetime of each component. Which supply chain components are required in which specific supply chain configuration are depicted in Table 4.3.

Table B.1: Overview of previous research in the field of techno-economic analyses on utilization of wind energy for electrolysis

Component	**CAPEX**	**CAPEX Unit**	**OPEX**	**OPEX Unit**	**DECEX**	**DECEX Unit**	**Lifetime [yrs]**	**Cost Reference**
Foundation & cable	1,000,000	EUR/MW	1.5	CAPEX	35	CAPEX	30	Prel. data NSE5; (BVG Associates, 2019)
Turbine	1,200,000	EUR/MW	3.0	%CAPEX	20	%CAPEX	30	Prel. data NSE5; (BVG Associates, 2019)
AC collection cable	7,000	EUR/km/MW	1.0	%CAPEX	30	%CAPEX	25	Prel. data NSE5; (Wingerden et al., 2023)
AC substation foundations	160,000	EUR/MW	0.5	%CAPEX	90	%CAPEX	40	Prel. data NSE5; (Wingerden et al., 2023; Rogeau et al., 2023)
LVDC converter foundations	220,000	EUR/MW	0.5	%CAPEX	90	%CAPEX	40	Prel. data NSE5; (Wingerden et al., 2023; Rogeau et al., 2023)
HVDC converter foundations	260,000	EUR/MW	0.5	%CAPEX	90	%CAPEX	40	Prel. data NSE5; (Wingerden et al., 2023; Rogeau et al., 2023)
Electrolyser foundations	460,000	EUR/MW	0.5	%CAPEX	90	%CAPEX	40	Prel. data NSE5; (Wingerden et al., 2023; Rogeau et al., 2023)
AC substation topside	31,000	EUR/MW	1.5	%CAPEX	20	%CAPEX	40	Prel. data NSE5; (Wingerden et al., 2023)
HVDC converter topside offshore	550,000	EUR/MW	3.0	%CAPEX	20	%CAPEX	30	Prel. data NSE5 (Wingerden et al., 2023)
HVDC converter topside island	400,000	EUR/MW	2.25	%CAPEX	20	%CAPEX	30	Prel. data NSE5 (Wingerden et al., 2023)
HVDC converter topside onshore	260,000	EUR/MW	1.5	%CAPEX	20	%CAPEX	30	Prel. data NSE5 (Wingerden et al., 2023)
LVDC converter topside offshore	275,000	EUR/MW	2.0	%CAPEX	20	%CAPEX	30	Author's interpolation based on HVDC & HVAC
LVDC converter topside island	200,000	EUR/MW	1.5	%CAPEX	20	%CAPEX	30	Author's interpolation based on HVDC & HVAC
LVDC converter topside onshore	130,000	EUR/MW	1.0	%CAPEX	20	%CAPEX	30	Author's interpolation based on HVDC & HVAC
Electrolyser topside offshore	1,420,000	EUR/MW	4.0	%CAPEX	20	%CAPEX	8	Prel. data NSE5; (Wingerden et al., 2023; Superchi et al., 2023)
Electrolyser topside island	1,200,000	EUR/MW	3.0	%CAPEX	20	%CAPEX	8	Prel. data NSE5; (Wingerden et al., 2023; Superchi et al., 2023)
Electrolyser topside onshore	900,000	EUR/MW	2.0	%CAPEX	20	%CAPEX	8	Prel. data NSE5; (Wingerden et al., 2023; Superchi et al., 2023)
Desalination unit	10,000	EUR/MW	10	%CAPEX	20	%CAPEX	15	(Giampieri et al., 2024)
Compressor unit	150,000	EUR/MW	4.0	%CAPEX	20	%CAPEX	15	(Giampieri et al., 2024; BVG Associates, 2019)
Storage unit	300,000	EUR/MW	2.0	%CAPEX	20	%CAPEX	30	(Yousefi et al., 2023)

Compressor after storage	10,000	EUR/MW	4.0	%CAPEX	20	%CAPEX	15	(Van den Haak, 2023)
DCAC converter	260,000	EUR/MW	3.0	%CAPEX	20	%CAPEX	30	Prel. data NSE5
HVDC export cable	2,000	EUR/km/MW	1.5	%CAPEX	30	%CAPEX	25	(Wang et al., 2021)
H2 pipeline	500	EUR/km/MW	5.0	%CAPEX	30	%CAPEX	40	(Wang et al., 2021; Galimova et al., 2023)
Export cable landing	20,000	EUR/MW	2.0	%CAPEX	20	%CAPEX	30	(North Sea Energy, 2022)
Export pipeline landing	4,000	EUR/MW	2.0	%CAPEX	20	%CAPEX	30	(North Sea Energy, 2022)

Table B.3 presents an example of an overview of the rated power output of individual wind farms. In the techno-economic model this overview is referred to as *df_capacity* and is used to calculate the actual energy production values, after application of transmission and conversion efficiency factors.

Table B.3: Rated power output of the wind parks in MW and the average output based on the capacity factor in kWh over the years

	Rated output [MW]						Avg. output [kWh]
Year	**Park 1**	**Park 2**	**Park 3**	**Park 4**	**Park 5**	**Total parks**	**Total parks**
2030	0	0	0	0	0	0	0
2031	0	0	0	0	0	0	0
2032	0	0	0	0	0	0	0
2033	0	0	0	0	0	0	0
2034	4000	0	0	0	0	4000	17520000000
2035	4000	4000	3500	4000	4000	19500	85410000000
2036	4000	4000	3500	4000	4000	19500	85410000000
2037	4000	4000	3500	4000	4000	19500	85410000000
2038	4000	4000	3500	4000	4000	19500	85410000000
2039	4000	4000	3500	4000	4000	19500	85410000000
2040	4000	4000	3500	4000	4000	19500	85410000000
2041	4000	4000	3500	4000	4000	19500	85410000000
2042	4000	4000	3500	4000	4000	19500	85410000000
2043	4000	4000	3500	4000	4000	19500	85410000000
2044	4000	4000	3500	4000	4000	19500	85410000000
2045	4000	4000	3500	4000	4000	19500	85410000000
2046	4000	4000	3500	4000	4000	19500	85410000000
2047	4000	4000	3500	4000	4000	19500	85410000000
2048	4000	4000	3500	4000	4000	19500	85410000000
2049	4000	4000	3500	4000	4000	19500	85410000000
2050	4000	4000	3500	4000	4000	19500	85410000000
2051	4000	4000	3500	4000	4000	19500	85410000000
2052	4000	4000	3500	4000	4000	19500	85410000000
2053	4000	4000	3500	4000	4000	19500	85410000000
2054	4000	4000	3500	4000	4000	19500	85410000000
2055	4000	4000	3500	4000	4000	19500	85410000000
2056	4000	4000	3500	4000	4000	19500	85410000000
2057	4000	4000	3500	4000	4000	19500	85410000000
2058	4000	4000	3500	4000	4000	19500	85410000000
2059	4000	4000	3500	4000	4000	19500	85410000000

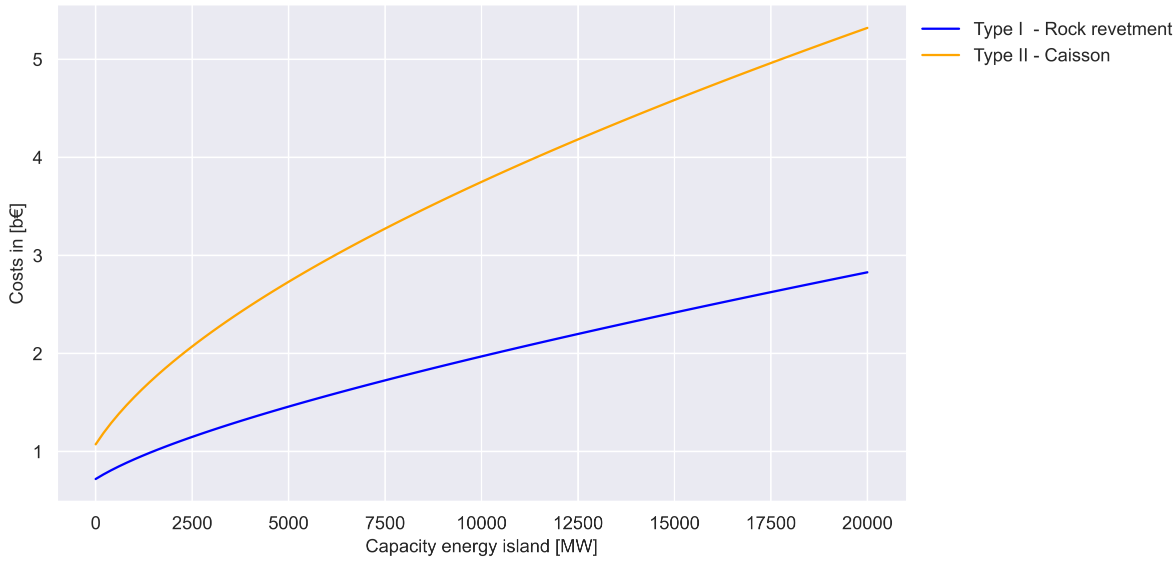

Figure B.9: Cost development for energy island type I & II in a water depth of 40 [m] and a footprint of 80 [m^2/MW]

B.3. Verification tests

In this section, the methodology for testing and verifying the entire system with simplified input of subsection 4.6.2 is continued. The verification process is shown for other system setups as well, further testing all the model's features, involving defining several test setups, each with slight variations in the input variables. If the *'testing'* variable in the techno-economic model is enabled, and the presented input is used, the same results should be obtained.

B.3.1. Verification test 2

Table B.4 presents the input for verification test 2. For this verification test the EDR is varied, with values of 0%/yr, 1%/yr and 2%/yr, the other input values remain constant.

Table B.4: Input values for the supply chain configuration "Co-production Island" for three test setups for model verification purposes

Parameter	Setup 1	Setup 2	Setup 3	Unit
EDR	**0.0**	**1.0**	**2.0**	%/yr
Rated output WF_1	1000	1000	1000	MW
Rated output WF_2	1000	1000	1000	MW
Capacity factor	0.5	0.5	0.5	[-]
Share of H_2/E	50/50	50/50	50/50	%
Escalation base year	2030	2030	2030	[yr]
Startyear project	2030	2030	2030	[yr]
Discount rate	0	0	0	%
Escalation rate	0	0	0	%
Island's CAPEX	1m	1m	1m	€
Component's CAPEX	1000	1000	1000	€/MW
Component's CAPEX	1.0	1.0	1.0	€/mMW
Component's OPEX	2	2	2	[% CAPEX]
Component's DECEX	0.0	0.0	0.0	[% CAPEX]
Residual value	0.0	0.0	0.0	[% CAPEX]
Economic lifetime	29	29	29	yrs
Construction duration	1	1	1	yrs
Share of investments	100	100	100	% in year 1
Efficiency factors	1.0	1.0	1.0	%/

Executing the three setups provides the results presented in Table B.5. Analysis of these results provides the following insights regarding varying the electrolyzer efficiency degradation rate (EDR):

- Total cost of the project remain constant, which is correct as the EDR has no influence on the supply chain component costs
- The LCOH increases for increasing EDR. The LCOH increases proportional with the decrease in H_2 production (discounted), as the total projects costs remain constant. This is what is expected based on the nature of the LCOH calculation
- The LCOE remains constant, which is correct as there is no change to electricity production or costs for a varying electrolyzer EDR
- The LCOTE increases for increasing EDR. The LCOTE increases proportional with the decrease in H_2 production (discounted), taking into account the split of energy for H_2/E production at 50/50%. This is what is expected based on the nature of the LCOTE calculation
- Similar principle holds for LCOHP and LCOHT as for the LCOH
- Discounted and nominal value for H_2 production decrease for increasing EDR. A higher yearly efficiency degradation for the electrolyzer holds a lower production yield. The decrease in H_2 supply chain efficiency corresponds with the decrease in produced H_2 (nominal), which indicates a correct utilization of these variables in the model

Table B.5: Output values for the supply chain configuration "Co-production Island" for three test setups for model verification purposes

Metric	Setup 1	Setup 2	Setup 3	Unit
Total cost of the project in NPV	35.959m	35.959m	35.959m	€
Levelized Cost of H_2 (LCOH)	0.005709	0.006600	0.007820	€/kg
Levelized Cost of Electricity (LCOE)	0.000122	0.000122	0.000122	€/kWh
Levelized Cost of Total Energy (LCOTE)	0.04072	0.04367	0.04708	€/kJ
Levelized Cost of H_2 Production (LCOHP)	0.001718	0.001986	0.002353	€/kg
Levelized Cost of H_2 Transport (LCOHT)	0.003991	0.004614	0.005467	€/kg
Total amount of H_2 produced (discounted)	3.679b	3.182b	2.686b	kg
Total amount of E produced (discounted)	122.635b	122.635b	122.635b	kWh
Total amount of H_2 produced (nominal)	3.679b	3.182b	2.686b	kg
Total amount of E produced (nominal)	122.635b	122.635b	122.635b	kWh
H_2 supply chain efficiency	100.00	86.50	73.00	%
E supply chain efficiency	100.00	100.00	100.00	%
Total supply chain efficiency	100.00	93.25	86.50	%

In addition to assessing the final results, one of the intermediate steps is examined in further detail here. Using the function *create_df_efficiency_electrolyser()*, the yearly efficiency values of each individual electrolyzer are calculated and presented in a dataframe. For the results in this table B.6, scenario 2 (row 1) was used instead of scenario 1. Scenario 2 involves a start year of 2030 for the island, start year of 2030 for wind farm 1, and start year of 2032 for wind farm 2. The electrolyzer EDR is 2% per year.

Since the construction duration of all components is set to 1 year, and the electrolyzer infrastructure cannot be built on the island before it is commissioned, the construction (and production) of electrolyzer unit 1 is restricted by the island's commissioning. Thus, production can only start in 2032 (startyear construction island (2030) + 1 year for island construction + 1 year for electrolyzer construction), while the accompanying wind farm will be commissioned in 2031 (start year 2030 + 1 year construction duration). For wind farm 2 and electrolyzer unit 2, the start is in 2032 when the island is already commissioned, so there is no restriction by the island's commissioning. Electrolyzer unit 2 becomes operational in 2033 (2032 + 1 year construction duration). This reasoning is reflected in Table B.6, indicating that the model correctly handles restrictions by the island's commissioning, the start year of the electrolyzer unit, and the electrolyzer EDR.

Furthermore, the economic lifetime of all components was set to 29 years, including the electrolyzer, as shown by the continuous degradation of the efficiency factor with no replacement. Changing the economic lifetime of the *Electrolyzer island* to 15 years in *'Cost_input_UNIT_TEST.xlsx'* would show that after 15 years, the electrolyzer will be replaced, and the efficiency factor would reset to the initial value of 1.0.

Table B.6: Yearly efficiency factors of the individual electrolyzers units

	Efficiency electrolyzer [-]		
Year	**Unit 1**	**Unit 2**	**Avg units**
2030	0.00	0.00	0.00
2031	0.00	0.00	0.00
2032	1.00	0.00	1.00
2033	0.98	1.00	0.99
2034	0.96	0.98	0.97
2035	0.94	0.96	0.95
2036	0.92	0.94	0.93
2037	0.90	0.92	0.91
2038	0.88	0.90	0.89
2039	0.86	0.88	0.87
2040	0.84	0.86	0.85
2041	0.82	0.84	0.83
2042	0.80	0.82	0.81
2043	0.78	0.80	0.79
2044	0.76	0.78	0.77
2045	0.74	0.76	0.75
2046	0.72	0.74	0.73
2047	0.70	0.72	0.71
2048	0.68	0.70	0.69
2049	0.66	0.68	0.67
2050	0.64	0.66	0.65
2051	0.62	0.64	0.63
2052	0.60	0.62	0.61
2053	0.58	0.60	0.59
2054	0.56	0.58	0.57
2055	0.54	0.56	0.55
2056	0.52	0.54	0.53
2057	0.50	0.52	0.51
2058	0.48	0.50	0.49
2059	0.46	0.48	0.47

Based on the results of this verification test, it is concluded that the developed techno-economic model functions correctly in terms of the system's semantics.

B.3.2. Verification test 3

Table B.7 presents the input for verification test 3. For this verification test the supply chain configuration is varied, the other input values remain constant.

Table B.7: Input values for the "Full H_2 Island" and "Co-production Island" at 100% H_2 supply chain configurations, two test setups for model verification purposes

Parameter	Setup 1	Setup 2	Unit
Supply chain configuration	**Full H_2**	**Co-prod.**	[-]
Share of H_2/E	**100/0**	**100/0**	%
Rated output WF_1	1000	1000	MW
Rated output WF_2	1000	1000	MW
Capacity factor	0.5	0.5	[-]
Escalation base year	2030	2030	[yr]
Startyear project	2030	2030	[yr]
Discount rate	0	0	%
Escalation rate	0	0	%
Island's CAPEX	1m	1m	€
Component's CAPEX	1000	1000	€/MW
Component's CAPEX	1.0	1.0	€/mMW
Component's OPEX	2	2	[% CAPEX]
Component's DECEX	0.0	0.0	[% CAPEX]
Residual value	0.0	0.0	[% CAPEX]
Economic lifetime	29	29	yrs
Construction duration	1	1	yrs
Share of investments	100	100	% in year 1
Efficiency factors	1.0	1.0	%/
EDR	0.0	0.0	%/yr

Executing the two setups provides the results presented in Table B.8. Analysis of these results provides the following insights regarding varying the supply chain configuration and the share of hydrogen production:

- Results are exactly similar, which corresponds with the expected outcome. A "Full H_2 Island" configuration contains the same components as a "Co-production Island" at 100% H_2 production. The required component capacities are equal, hence the associated costs
- The calculated values for electricity production are 0.0 kWh, correctly represented as a number rather than NaN
- The calculated LCOE is NaN, which is correct because the costs are divided by 0 kWh, resulting in NaN

Table B.8: Output values for the "Full H_2 Island" and "Co-production Island" at 100% H_2 supply chain configurations, two test setups for model verification purposes

Metric	Setup 1	Setup 2	Unit
Total cost of the project in NPV	42.006m	42.006m	€
Levelized Cost of H_2 (LCOH)	0.005709	0.005709	€/kg
Levelized Cost of Electricity (LCOE)	NaN	NaN	€/kWh
Levelized Cost of Total Energy (LCOTE)	0.04757	0.04757	€/kJ
Levelized Cost of H_2 Production (LCOHP)	0.001718	0.001718	€/kg
Levelized Cost of H_2 Transport (LCOHT)	0.003991	0.003991	€/kg
Total amount of H_2 produced (discounted)	7.358b	7.358b	kg
Total amount of E produced (discounted)	0.000b	0.000b	kWh
Total amount of H_2 produced (nominal)	7.358b	7.358b	kg
Total amount of E produced (nominal)	0.000b	0.000b	kWh
H_2 supply chain efficiency	100.00	100.00	%
E supply chain efficiency	NaN	NaN	%
Total supply chain efficiency	100.00	100.00	%

Based on the results of this verification test, it is concluded that the developed techno-economic model functions correctly in terms of the system's semantics.

B.3.3. Verification test 4

Table B.9 presents the input for verification test 4. Few academic papers in the literature assess different starting years for the construction of components within the supply chain. Consequently, the starting year mechanism in the model is difficult to validate using public data and studies. Therefore, this section aims to verify the mechanism to ensure its accuracy and reliability. For this verification test the start year of the energy island and wind farm 1 is varied, the other input values remain constant.

Table B.9: Input values for the supply chain configuration "Co-production Island" for four test setups for model verification purposes

Parameter	**Setup 1**	**Setup 2**	**Setup 3**	**Setup 4**	**Unit**
Startyear island	**2030**	**2031**	**2030**	**2031**	[-]
Startyear windfarm 1	**2030**	**2030**	**2032**	**2032**	[-]
Rated output WF_1	1000	1000	1000	1000	MW
Rated output WF_2	1000	1000	1000	1000	MW
Capacity factor	0.5	0.5	0.5	0.5	[-]
Share of H_2/E	100/00	100/0	100/00	100/0	%
Escalation base year	2030	2030	2030	2030	[yr]
Startyear project	2030	2030	2030	2030	[yr]
Discount rate	0	0	0	0	%
Escalation rate	0	0	0	0	%
Island's CAPEX	1m	1m	1m	1m	€
Component's CAPEX	1000	1000	1000	1000	€/MW
Component's CAPEX	1.0	1.0	1.0	1.0	€/mMW
Component's OPEX	2	2	2	2	[% CAPEX]
Component's DECEX	0.0	0.0	0.0	0.0	[% CAPEX]
Residual value	0.0	0.0	0.0	0.0	[% CAPEX]
Economic lifetime	29	29	29	29	yrs
Construction duration	1	1	1	1	yrs
Share of investments	100	100	100	100	% in year 1
Efficiency factors	1.0	1.0	1.0	1.0	%/
EDR	0.0	0.0	0.0	0.0	%/yr

First, setup 1 is addressed in further detail. In this assessment, the focus is not on the economic output metrics, such as LCOH and LCOE, but rather on the distribution of *npv* of total costs of all components. For this, a pie chart of is presented in which all components processed in the model are included, based on the supply chain configuration. See Figure B.10 for the pie chart.

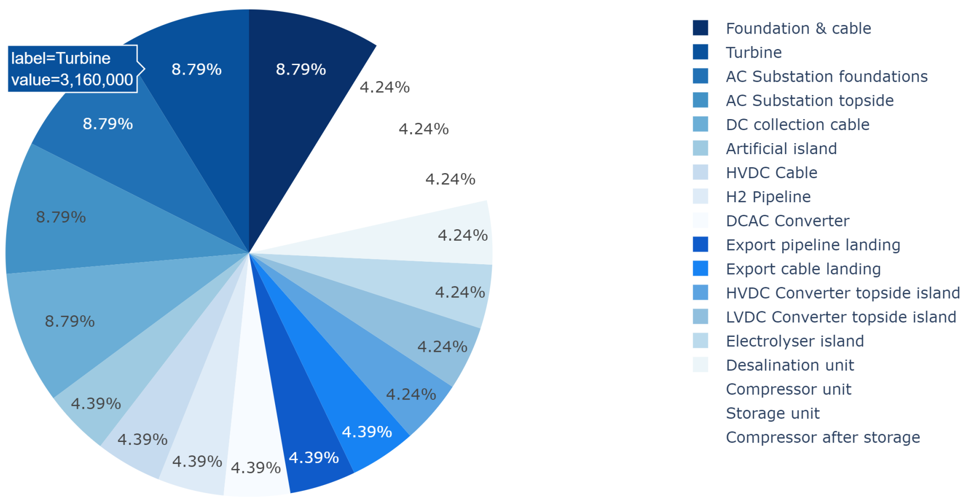

Figure B.10: Pie chart for a "Co-production Island" supply chain configuration with 50/50% of the available wind power dedicated to H_2/E, startyear island = 2030; startyear windfarm 1 = 2030; startyear windfarm 2 = 2030

Given that the energy share for H_2/E is 50/50%, that all components have an economic lifetime of 29 years, and that all components have a construction duration of 1 year, the pie chart can be analyzed in further detail:

- The supply chain components 'Foundation & cable', 'Turbine', 'AC substation foundations', 'AC substation topside' and 'Collection cable' all have a NPV of total costs of €3,160,000. Table B.10 present the cash flow analysis of the *'Turbine'* component of wind farm 1. Since there are two wind farms with the same characteristics, the values can be doubled and indeed equal €3,160,000 as seen in the figure. For the components 'Foundation & cable', 'AC substation foundations', 'AC substation topside' and 'Collection cable', the same time frame of construction and commissioning applies, resulting in exactly similar NPV of total costs, as shown in Figure B.10, where all components have the same percentage.
- The model is set up so that the construction of export transport infrastructure, namely the H_2 pipeline and HVDC cable, begins simultaneously with the construction of the energy island. Additionally, there is only a single instance of the component constructed (if present), rather than starting construction of individual components aligned with the corresponding wind farm. The H_2 pipeline and HVDC cable are already installed at the future final capacity. Figure B.10 shows that the NPV of total costs are exactly equal for the 'Artificial Island,' 'HVDC Cable,' and 'H2 Pipeline,' indicating that construction starts in the same year, which represents the intended model setup. Furthermore, the 'Export pipeline landing' and 'Export cable landing' are installed simultaneously with the cable and pipeline, as well as the onshore 'DCAC converter' facility. Lastly, the NPV of total costs for these components are exactly 50% of those for the 'Foundation & cable,' 'Turbine,' etc., which is correct as all components are indicated at 1,000 €/MW, with energy supplied at a share of 50/50% rate for H_2/E.
- Lastly, the remaining components, namely the 'HVDC Converter topside island,' 'LVDC Converter topside island,' 'Electrolyser island,' 'Desalination unit,' 'Compressor unit,' 'Storage unit,' and 'Compressor after storage,' have a different NPV of total costs compared to the other components. This is expected due to their different start year. Because their construction is restricted by the island's commissioning, these components cannot be constructed simultaneously with the others starting in 2030. Instead, they are constructed in 2031, resulting in different cash flows and NPV calculations. Given their economic lifetime of 29 years and the project duration of only 28 years for them, there is some remaining value due to the depreciation mechanism and the proxy for the divestment value. The divestment value is a positive cash flow, reducing the NPV of total costs of the concerned components. The proxy for the divestment value is calculated

by $CAPEX/T_{asset} \times T_{asset,left}$ = €500,000/29yr × 1yr = €17,241. This corresponds with the divestment value provided by the model, depicted in Table B.11.

Table B.10: Cash flows for the component 'Turbine' of wind farm 1

Year	CAPEX [€]	OPEX [€]	Cashflow [€]	Cashflow Sum [€]
2030	-1,000,000.0	0.0	-1,000,000.0	-1,000,000.0
2031	0.0	-20,000.0	-20,000.0	-1,020,000.0
2032	0.0	-20,000.0	-20,000.0	-1,040,000.0
2033	0.0	-20,000.0	-20,000.0	-1,060,000.0
2034	0.0	-20,000.0	-20,000.0	-1,080,000.0
2035	0.0	-20,000.0	-20,000.0	-1,100,000.0
2036	0.0	-20,000.0	-20,000.0	-1,120,000.0
2037	0.0	-20,000.0	-20,000.0	-1,140,000.0
2038	0.0	-20,000.0	-20,000.0	-1,160,000.0
2039	0.0	-20,000.0	-20,000.0	-1,180,000.0
2040	0.0	-20,000.0	-20,000.0	-1,200,000.0
2041	0.0	-20,000.0	-20,000.0	-1,220,000.0
2042	0.0	-20,000.0	-20,000.0	-1,240,000.0
2043	0.0	-20,000.0	-20,000.0	-1,260,000.0
2044	0.0	-20,000.0	-20,000.0	-1,280,000.0
2045	0.0	-20,000.0	-20,000.0	-1,300,000.0
2046	0.0	-20,000.0	-20,000.0	-1,320,000.0
2047	0.0	-20,000.0	-20,000.0	-1,340,000.0
2048	0.0	-20,000.0	-20,000.0	-1,360,000.0
2049	0.0	-20,000.0	-20,000.0	-1,380,000.0
2050	0.0	-20,000.0	-20,000.0	-1,400,000.0
2051	0.0	-20,000.0	-20,000.0	-1,420,000.0
2052	0.0	-20,000.0	-20,000.0	-1,440,000.0
2053	0.0	-20,000.0	-20,000.0	-1,460,000.0
2054	0.0	-20,000.0	-20,000.0	-1,480,000.0
2055	0.0	-20,000.0	-20,000.0	-1,500,000.0
2056	0.0	-20,000.0	-20,000.0	-1,520,000.0
2057	0.0	-20,000.0	-20,000.0	-1,540,000.0
2058	0.0	-20,000.0	-20,000.0	-1,560,000.0
2059	0.0	-20,000.0	-20,000.0	-1,580,000.0

Table B.11: Cash flows for the component 'HVDC converter topside island' of wind farm 1

Year	CAPEX [€]	OPEX [€]	Cashflow [€]	Cashflow Sum [€]
2030	0.00000	0.0	0.00000	0.00000
2031	-500000.00000	0.0	-500000.00000	-500000.00000
2032	0.00000	-10000.0	-10000.00000	-510000.00000
2033	0.00000	-10000.0	-10000.00000	-520000.00000
2034	0.00000	-10000.0	-10000.00000	-530000.00000
2035	0.00000	-10000.0	-10000.00000	-540000.00000
2036	0.00000	-10000.0	-10000.00000	-550000.00000
2037	0.00000	-10000.0	-10000.00000	-560000.00000
2038	0.00000	-10000.0	-10000.00000	-570000.00000
2039	0.00000	-10000.0	-10000.00000	-580000.00000
2040	0.00000	-10000.0	-10000.00000	-590000.00000
2041	0.00000	-10000.0	-10000.00000	-600000.00000
2042	0.00000	-10000.0	-10000.00000	-610000.00000
2043	0.00000	-10000.0	-10000.00000	-620000.00000
2044	0.00000	-10000.0	-10000.00000	-630000.00000
2045	0.00000	-10000.0	-10000.00000	-640000.00000
2046	0.00000	-10000.0	-10000.00000	-650000.00000
2047	0.00000	-10000.0	-10000.00000	-660000.00000
2048	0.00000	-10000.0	-10000.00000	-670000.00000
2049	0.00000	-10000.0	-10000.00000	-680000.00000
2050	0.00000	-10000.0	-10000.00000	-690000.00000
2051	0.00000	-10000.0	-10000.00000	-700000.00000
2052	0.00000	-10000.0	-10000.00000	-710000.00000
2053	0.00000	-10000.0	-10000.00000	-720000.00000
2054	0.00000	-10000.0	-10000.00000	-730000.00000
2055	0.00000	-10000.0	-10000.00000	-740000.00000
2056	0.00000	-10000.0	-10000.00000	-750000.00000
2057	0.00000	-10000.0	-10000.00000	-760000.00000
2058	0.00000	-10000.0	-10000.00000	-770000.00000
2059	17241.4	-10000.0	7241.37931	-762758.62069

This assessment was also executed for setup 2, 3 and 4 of Table B.9, on which the conclusion is drawn that the developed techno-economic model functions correctly in terms of the system's semantics.

B.3.4. Other verification tests

Similar to the other verification test setups in Chapter 4 and Appendix A, other setups were assessed, on which the conclusion is drawn that the developed techno-economic model functions correctly in terms of the intended system's semantics.

C
Case study hub North

This appendix supports Chapter 5 ”Application of standardized model on case study North Sea”, by providing detailed supplementary materials that further clarify and support the results, conclusion and discussion of the case study of hub North in the NSE program.

C.1. Input case study hub North

Figure C.1 presents the geospatial layout for the platform-based configuration of hub North. The centralized platform option with location "A" and "B" is indicated, as well as the decentralized platform option. Distances are provided in kilometers, the export cables and pipeline are connected to the Dutch mainland.

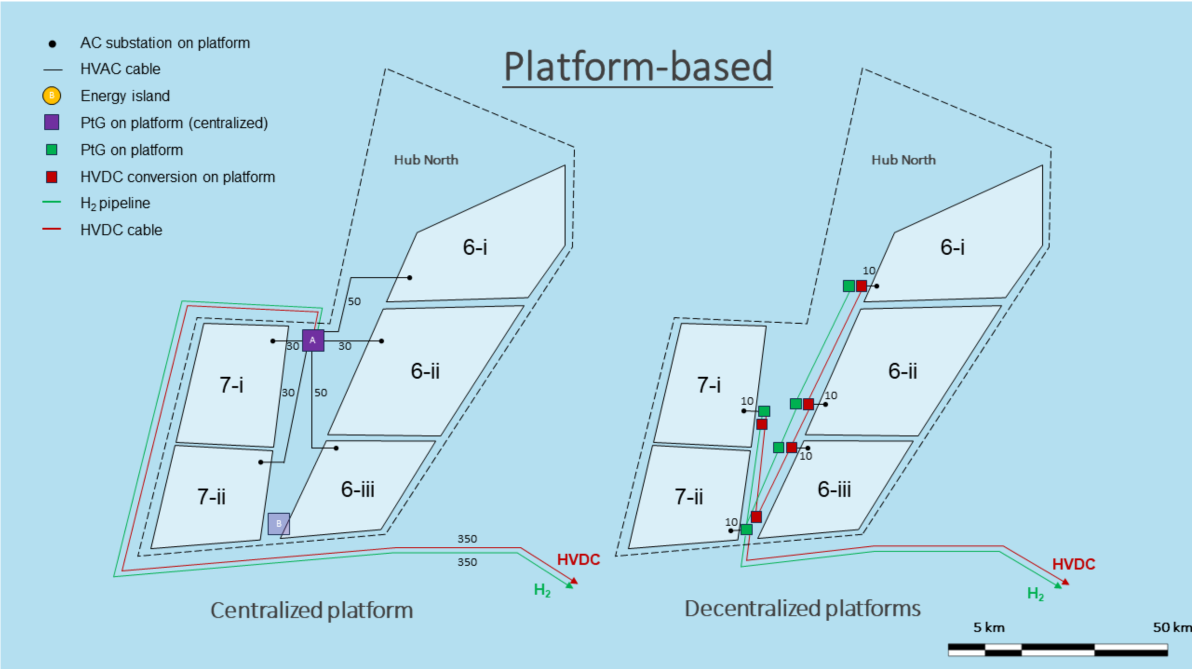

Figure C.1: Overview of platform-based supply chain configuration for hub North in North Sea Energy Program - Centralized platform and decentralized platform

Tables C.1, C.2 and C.3 present the input to generate the dataset of scenarios. The result of this scenarios generation is shown in Table C.4 for the island-based configurations and in Table C.5 for the platform-based configurations.

Wind Park	WF number	Cap. (GW)	Start year	Prob. of occurrence
Zoekgebied 7-i	WF1	4.0	2030, 2032, 2034	0.5, 0.3, 0.2
Zoekgebied 7-ii	WF2	4.0	2030, 2032, 2034	0.5, 0.3, 0.2
Zoekgebied 6-i	WF3	3.5	2030, 2032, 2034	0.5, 0.3, 0.2
Zoekgebied 6-ii	WF4	4.0	2030, 2032, 2034	0.5, 0.3, 0.2
Zoekgebied 6-iii	WF5	4.0	2030, 2032, 2034	0.5, 0.3, 0.2

Table C.1: Input Table Hub North

Component	Location	Type	Start year	Prob. of occurrence
Energy island	A, B	I, II, III	2031, 2032, 2033, 2034	0.3, 0.4, 0.2, 0.1
Platform	A, B, P	N/A	N/A	1

Table C.2: Input Table Energy Island

Component	Distance	Efficiency
Efficiency inter array cable	N/A	0.99
Efficiency AC substation	N/A	0.99
Efficiency HVDC converter	N/A	0.96
Efficiency LVDC converter	N/A	0.98
Efficiency compressor H2	N/A	0.985
Efficiency DCAC converter	N/A	0.96
Efficiency electrolyser	N/A	0.7

Table C.3: Component Efficiency

Table C.4 shows the actual input for the techno-economic model for the island-based configurations. Table C.5 shows the actual input for the techno-economic model for the platform-based configurations.

			Startyear						
Scenario	**Loc.**	**Type**	**Island**	**WF1**	**WF2**	**WF3**	**WF4**	**WF5**	**Isl. costs**
1	A	I	2030	2030	2030	2030	2030	**2030**	€2.79b
2	A	I	2030	2030	2030	2030	2030	**2032**	€2.79b
3	A	I	2030	2030	2030	2030	2030	**2034**	€2.79b
4	A	I	2030	2030	2030	2030	**2032**	**2030**	€2.79b
5	A	I	2030	2030	2030	2030	**2032**	**2032**	€2.79b
...	...	...	...	...	...	...	...	...	...
4374	B	III	2032	2034	2034	2034	2034	2034	€16.25b

Table C.4: Scenario details for the island-based supply chain configuration

			Startyear						
Scenario	**Loc.**	**Type**	**Island**	**WF1**	**WF2**	**WF3**	**WF4**	**WF5**	**Isl. costs**
1	A	N/A	N/A	2030	2030	2030	2030	**2030**	N/A
2	A	N/A	N/A	2030	2030	2030	2030	**2032**	N/A
3	A	N/A	N/A	2030	2030	2030	2030	**2034**	N/A
4	A	N/A	N/A	2030	2030	2030	**2032**	**2030**	N/A
5	A	N/A	N/A	2030	2030	2030	**2032**	**2032**	N/A
...	...	...	...	...	...	...	...	...	...
729	P	N/A	N/A	2034	2034	2034	2034	2034	N/A

Table C.5: Scenario details for the platform-based supply chain configuration

C.2. Processed output case study hub North

A large dataset for individual scenarios was generated, depicted in Figure 5.2 for the LCOTE and NPV of total costs. All results, including LCOTE, LCOH, NPV of total costs, and efficiencies, were aggregated into weighted values based on the probability of each unique scenario. The aggregated weighted values are shown in Table C.6. The weighted results for LCOTE and NPV of total costs are plotted in Figure 5.3.

Table C.6: Overview of the final aggregated weighted values for the techno-economic metrics for all supply chain configurations within the NSE program hub North case study

Location	**Island**	LCOH	LCOE	LCOTE	LCOHT	LCOHP	Costs_{NPV}	Eff_{H_2}	Eff_E	Eff_{Total}	**Configuration**	H_2
A	Platform		0.145	0.040			122.9		89.4	0.894	Full HVDC Platform	0
B	Platform		0.137	0.038			116.8		89.5	0.895	Full HVDC Platform	0
P	Platform		0.143	0.040			121.4		89.6	0.896	Full HVDC Platform	0
A	Type_I		0.143	0.040			113.0		89.4	0.894	Full HVDC Island	0
A	Type_II		0.146	0.041			115.8		89.4	0.894	Full HVDC Island	0
A	Type_III		0.162	0.045			128.4		89.4	0.894	Full HVDC Island	0
B	Type_I		0.135	0.037			106.8		89.5	0.895	Full HVDC Island	0
B	Type_II		0.138	0.038			109.8		89.5	0.895	Full HVDC Island	0
B	Type_III		0.154	0.043			122.0		89.5	0.895	Full HVDC Island	0
A	Platform	10.62	0.145	0.051	7.04	3.58	142.8	62.3	89.4	81.2	Co-prod. Platform	0.3
B	Platform	10.63	0.137	0.050	7.02	3.61	138.5	62.2	89.5	81.3	Co-prod. Platform	0.3
P	Platform	10.55	0.143	0.051	6.92	3.63	140.7	61.5	89.6	81.2	Co-prod. Platform	0.3
A-O	Platform	10.32	0.145	0.050	6.50	3.82	137.7	58.4	89.4	80.1	Co-prod. Onshore	0.3
B-O	Platform	9.94	0.137	0.048	6.10	3.84	131.6	58.5	89.5	80.2	Co-prod. Onshore	0.3
P-O	Platform	10.20	0.143	0.050	6.38	3.82	136.2	58.5	89.6	80.3	Co-prod. Onshore	0.3
A	Type_I	8.95	0.143	0.048	5.10	3.84	123.7	62.2	89.4	81.2	Co-prod. Island	0.3
A	Type_II	9.11	0.146	0.049	5.27	3.84	126.5	62.2	89.4	81.2	Co-prod. Island	0.3
A	Type_III	9.87	0.162	0.054	6.03	3.84	139.0	62.2	89.4	81.2	Co-prod. Island	0.3
B	Type_I	8.86	0.135	0.046	4.99	3.87	118.8	62.1	89.5	81.3	Co-prod. Island	0.3
B	Type_II	9.04	0.138	0.047	5.17	3.87	121.8	62.1	89.5	81.3	Co-prod. Island	0.3
B	Type_III	9.77	0.154	0.052	5.90	3.87	134.0	62.1	89.5	81.3	Co-prod. Island	0.3
A	Platform	10.62	0.145	0.060	7.04	3.58	156.0	62.3	89.4	75.8	Co-prod. Platform	0.5
B	Platform	10.63	0.137	0.059	7.02	3.61	152.9	62.2	89.5	75.8	Co-prod. Platform	0.5
P	Platform	10.55	0.143	0.059	6.92	3.63	153.6	61.5	89.6	75.6	Co-prod. Platform	0.5
A-O	Platform	10.32	0.145	0.058	6.50	3.82	147.6	58.4	89.4	73.9	Co-prod. Onshore	0.5
B-O	Platform	9.94	0.137	0.056	6.10	3.84	141.4	58.5	89.5	74	Co-prod. Onshore	0.5
P-O	Platform	10.20	0.143	0.058	6.38	3.82	146.0	58.5	89.6	74.1	Co-prod. Onshore	0.5
A	Type_I	8.95	0.143	0.054	5.10	3.84	130.8	62.2	89.4	75.8	Co-prod. Island	0.5
A	Type_II	9.11	0.146	0.055	5.27	3.84	133.6	62.2	89.4	75.8	Co-prod. Island	0.5
A	Type_III	9.87	0.162	0.060	6.03	3.84	146.1	62.2	89.4	75.8	Co-prod. Island	0.5
B	Type_I	8.86	0.135	0.052	4.99	3.87	126.9	62.1	89.5	75.8	Co-prod. Island	0.5
B	Type_II	9.04	0.138	0.054	5.17	3.87	129.8	62.1	89.5	75.8	Co-prod. Island	0.5
B	Type_III	9.77	0.154	0.059	5.90	3.87	142.0	62.1	89.5	75.8	Co-prod. Island	0.5
A	Platform	10.62	0.145	0.070	7.04	3.58	169.3	62.3	89.4	70.4	Co-prod. Platform	0.7
B	Platform	10.63	0.137	0.069	7.02	3.61	167.4	62.2	89.5	70.4	Co-prod. Platform	0.7
P	Platform	10.55	0.143	0.069	6.92	3.63	166.5	61.5	89.6	69.9	Co-prod. Platform	0.7
A-O	Platform	10.32	0.145	0.068	6.50	3.82	157.4	58.4	89.4	67.7	Co-prod. Onshore	0.7
B-O	Platform	9.94	0.137	0.065	6.10	3.84	151.3	58.5	89.5	67.8	Co-prod. Onshore	0.7
P-O	Platform	10.20	0.143	0.067	6.38	3.82	155.9	58.5	89.6	67.8	Co-prod. Onshore	0.7

A	Type_I	8.95	0.143	0.061	5.10	3.84	137.9	62.2	89.4	70.3	Co-prod. Island	0.7
A	Type_II	9.11	0.146	0.063	5.27	3.84	140.7	62.2	89.4	70.3	Co-prod. Island	0.7
A	Type_III	9.87	0.162	0.068	6.03	3.84	153.2	62.2	89.4	70.3	Co-prod. Island	0.7
B	Type_I	8.86	0.135	0.060	4.99	3.87	134.9	62.1	89.5	70.3	Co-prod. Island	0.7
B	Type_II	9.04	0.138	0.061	5.17	3.87	137.9	62.1	89.5	70.3	Co-prod. Island	0.7
B	Type_III	9.77	0.154	0.067	5.90	3.87	150.1	62.1	89.5	70.3	Co-prod. Island	0.7
A	Platform	10.62		0.089	7.04	3.58	189.2	62.3	0	62.3	Full H2 Platform	1
B	Platform	10.63		0.089	7.02	3.61	189.1	62.2	0	62.2	Full H2 Platform	1
P	Platform	10.55		0.088	6.92	3.63	185.8	61.5	0	61.5	Full H2 Platform	1
A-O	Platform	10.32		0.086	6.50	3.82	172.2	58.4	0	58.4	Full H2 Onshore	1
B-O	Platform	9.94		0.083	6.10	3.84	166.1	58.5	0	58.5	Full H2 Onshore	1
P-O	Platform	10.20		0.085	6.38	3.82	170.7	58.5	0	58.5	Full H2 Onshore	1
A	Type_I	8.95		0.075	5.10	3.84	148.5	62.2	0	62.2	Full H2 Island	1
A	Type_II	9.11		0.076	5.27	3.84	151.3	62.2	0	62.2	Full H2 Island	1
A	Type_III	9.87		0.082	6.03	3.84	163.9	62.2	0	62.2	Full H2 Island	1
B	Type_I	8.86		0.074	4.99	3.87	146.9	62.1	0	62.1	Full H2 Island	1
B	Type_II	9.04		0.075	5.17	3.87	149.9	62.1	0	62.1	Full H2 Island	1
B	Type_III	9.77		0.081	5.90	3.87	162.1	62.1	0	62.1	Full H2 Island	1

The plot of the LCOHP and NPV of the total project costs is presented in Figure C.2.

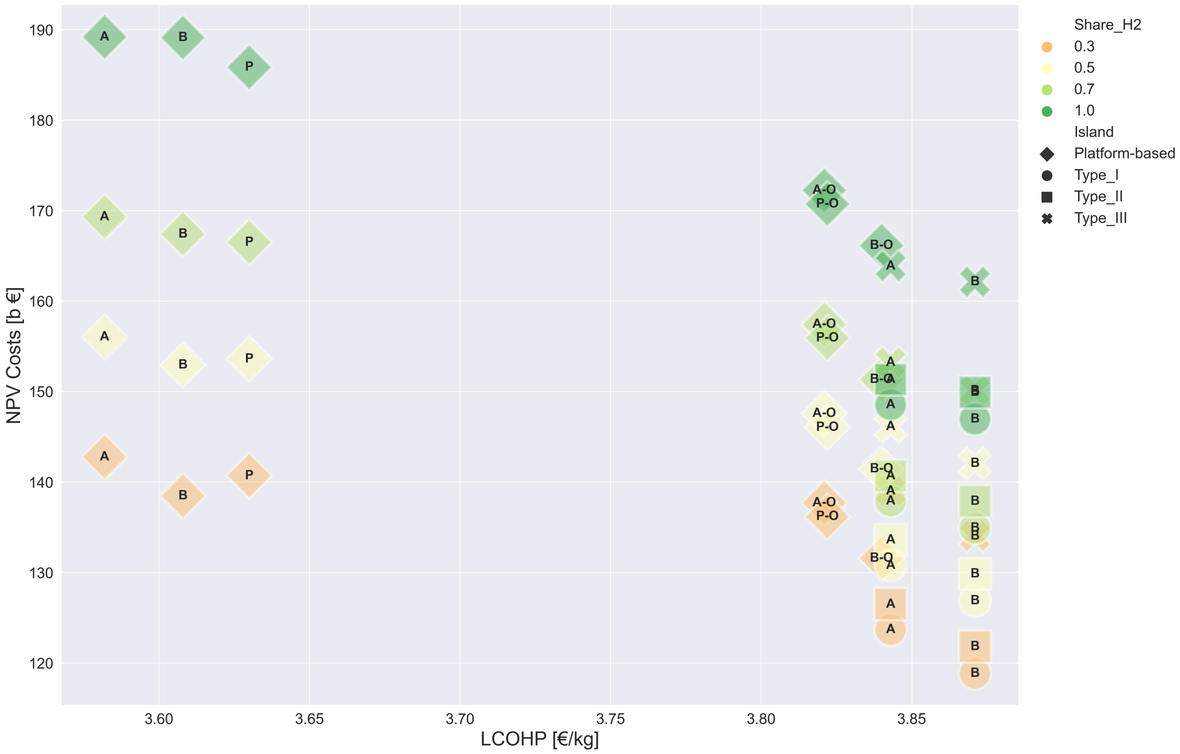

Figure C.2: The LCOHP and the NPV of the total project costs for the H_2 production supply chain configurations, text additions in graph indicate centralized setup at location "A" or "B", decentralized platform setup "P", and the suffix "O" implies Onshore electrolysis

D
Open-source techno-economic model

Figure D.1: QR code redirecting to the github repository of the open-source, standardized, techno-economic model

E

Costs of hydrogen import

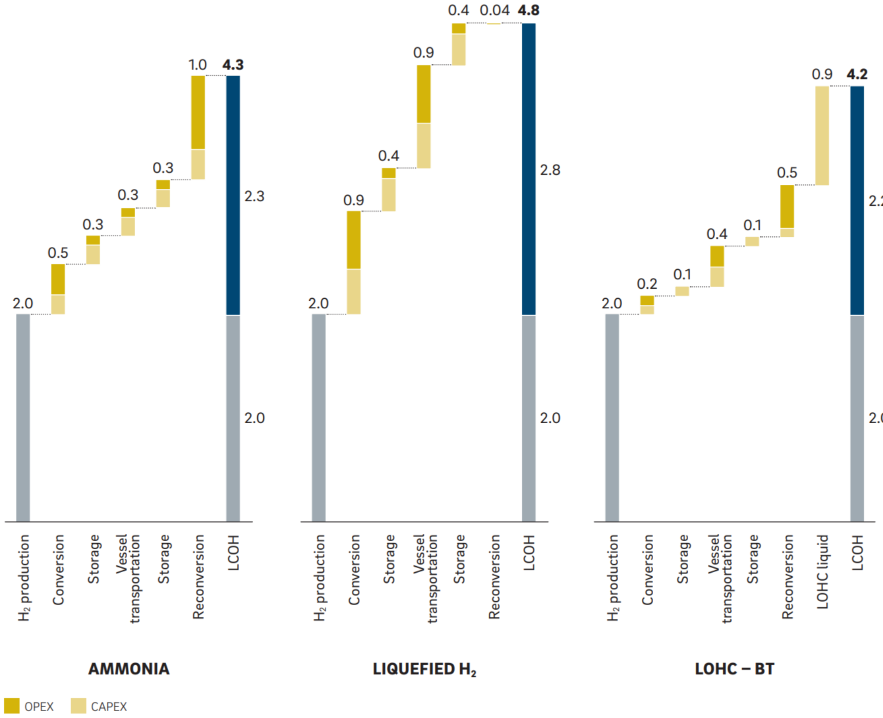

Figure E.1: The landed cost of hydrogen, incl. production, storage and transportation for archetype 1 in 2025 [€/kg H2] for large-scale harbor-to-harbor transport, adopted from Roland Berger (2021)

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