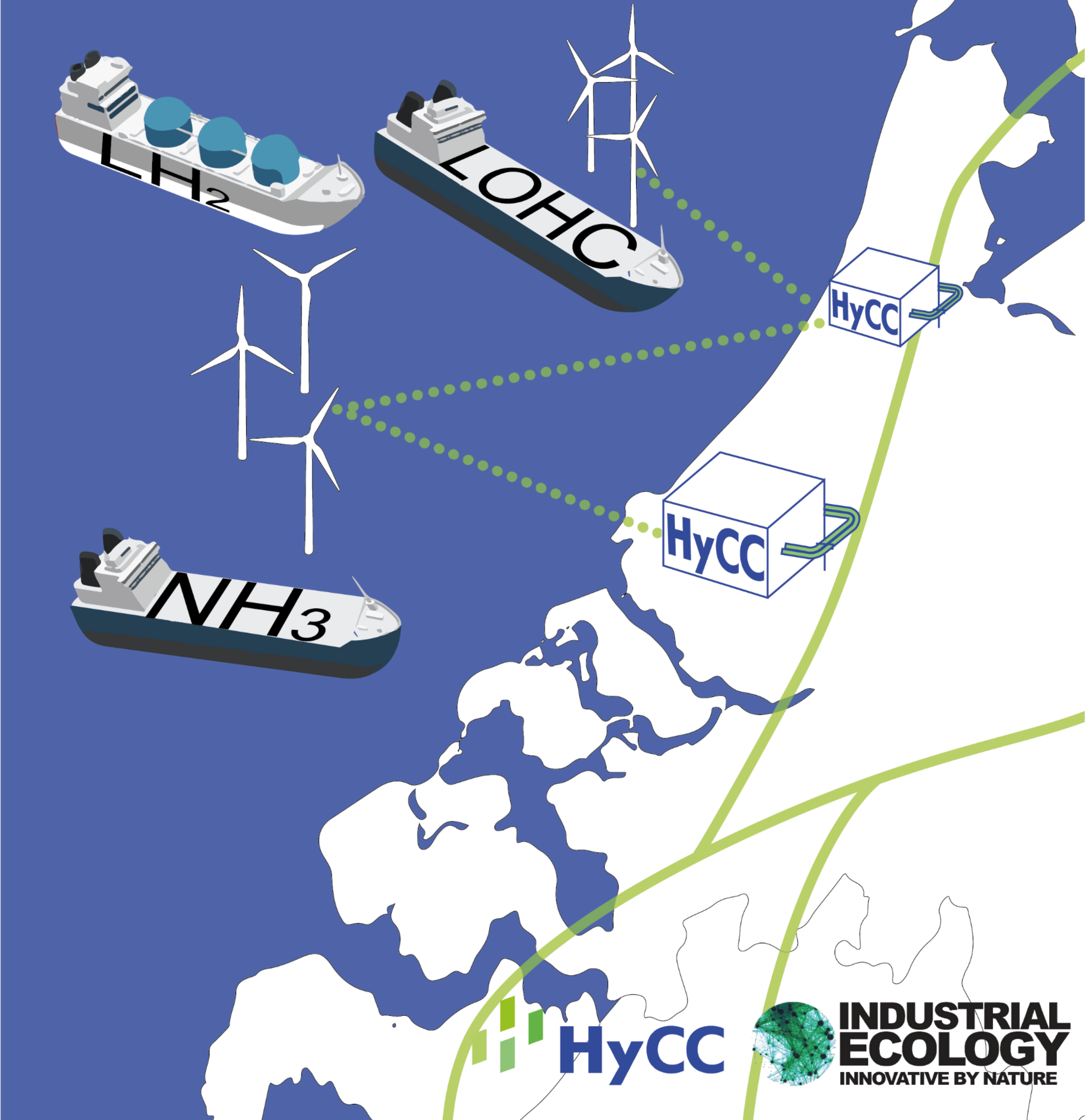
The Weighty Challenge of Importing the Lightest Element

A techno-economic assessment of the dynamics between the first developing green hydrogen importing supply chains and domestic production by 2030.

Sieb Rodenburg



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Sieb Rodenburg - September 2023

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Supporting documents

This thesis is supported by three Excel documents:
MCA_hydrogen_import
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To all readers, I hope you find this work engaging. I'm always open for a discussion and can be easily reached via LinkedIn.

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Abstract

Green hydrogen is anticipated to be pivotal in the decarbonisation of global energy systems. For the Netherlands, both domestic production and imports of green hydrogen are believed to be needed for effective decarbonisation. Yet, significant uncertainty surrounds the cost discrepancy between domestic productions and initial imports, largely attributed to insufficient comparability of different reports. This study conducted a techno-economic assessment (TEA) to better understand these cost dynamics.

To ensure that viable exporting countries are assessed a multicriteria analysis (MCA) was employed. Within this MCA, contributing factors underwent expert weighting. It was found that the earliest developing value chains might not necessarily be the most economical. Among potential initial exporters to the Netherlands, Chile, Spain, and the United States emerged as frontrunners, which led to their assessment in the TEA.

The study highlighted the importance of wind availability for cost-effective hydrogen production. Even with favourable wind conditions in the Dutch North Sea, the Netherlands faces higher hydrogen costs due to the added expenses of connecting the wind with an onshore electrolyser through the grid.

The costs of hydrogen transport were evaluated based on four possible hydrogen import development scenarios for transport as ammonia, liquified hydrogen and the liquid organic hydrogen carrier (LOHC) DBT. Results indicated that the costs of delivered hydrogen will likely range from similar to thrice that of domestic production across the different countries and carriers for the two scenarios where gigawatt supply chains are realised. Consequently, the study suggests that overseas imported green hydrogen will be more costly than domestically produced hydrogen in 2030.

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1. Introduction

Green hydrogen, an energy carrier derived from the electrolysis of water using renewable electricity, is poised to play a pivotal role in decarbonising sectors like heavy industry and long-haul transport. In a fully decarbonised energy system, it's projected to account for 12-15% of global energy demand (DNV, 2022a; European Commission, 2020; IRENA, 2022a). The European Union (EU) (2022) anticipates that only domestic production is not enough, targeting both the production and import of 10 million tons of green hydrogen annually by 2030. Although pipeline transport of hydrogen to Europe is expected to be dominant in the long run, there are no pipeline imports to the Netherlands possible yet in 2030. Instead, an import corridor largely based on overseas transport is foreseen (EHB & Guidehouse, 2022). Consequently, Dutch ports are gearing up to handle imports in various forms that enhance energy density and facilitating shipping, such as liquid hydrogen, ammonia, and liquid organic hydrogen carriers (TKI, 2022).

However, there is no academic consensus on the most cost-effective overseas import mode, and there are varying cost estimates that often do not compare imported and domestically-produced hydrogen. The cost discrepancies between these emerging markets might hinder each other's forming. Consequently, if it is desired that both different types of overseas import and domestic production develop it is important to get a comprehensive understanding of the cost dynamics between these markets by 2030. This leads to the central research question: "*How can the economic value proposition of the initial green hydrogen import value streams entering the Netherlands be compared with domestic green hydrogen production?"*

While economic factors are significant, they aren't the sole determinants in shaping supply chains. To comprehensively understand the forming of these initial value chains, it's essential to address what the drivers are behind their establishment and how they define the forming of these value chains. This will enable the identification of the countries that will emerge as probable initial exporters to the Netherlands, ensuring that the economic analysis is not corrupted by the inclusion of countries that are unlikely to export to the Netherlands in the initial phases. This inquiry leads to the sub-question: "*What are potential green hydrogen import value chains to the Netherlands and what criteria shape this?"*

After identifying the potential initial value chains, it is possible to compare their economic value proposition with that of domestic production. However, to understand the economics it is important that the technological system design of these supply chains is well understood. This gives rise to the second sub-question:
"How does the techno-economic performance of different green hydrogen import streams compare with domestic production in the Netherlands in 2030?"

By approaching the main research question through these two sub-questions a systems perspective is adopted. This approach ensures that both technological aspects, as well as non-technological and non-economic factors driving the formation of these supply chains are integrated into the final evaluation of the economic value propositions.

The research unfolds with a research plan, followed by a literature review and methods chapter. Subsequently, results are presented which are used in a discussion to answer the research questions. Finally a conclusion is presented and recommendations are given.

2. Research plan

This research commences with a literature review aiming to do three things. Initially, the literature review gives an overview on the current knowledge on hydrogen imports, highlighting known areas and acknowledging gaps. It thereby gives context to this thesis and justifies its relevance.

Subsequently, the literature review discusses possible methods, before selecting the appropriate methods and their corresponding frameworks.

To address the first sub-question, a method is seeked that finds the various factors influencing the formation of these supply chains and that enables us to compare these to find valuable pilot supply chains to compare with domestic production. Recognizing that some factors may be non-monetizable, it is essential to adopt a method facilitating comparison between such factors, thereby enabling a comparative analysis of potential exporting countries.

To compare the techno-economic proposition of these pilot initiatives with domestic production, it's important to have a thorough understanding of their technical components, ensuring an accurate assessment of the system design. Consequently, the literature review aims to identify a method focused on this technical system design, encompassing all costs from raw resources (cradle) to delivery (gate) for both domestic production and imports from the pilot locations. Furthermore, a method must be chosen that ensures that this is done in a systematic way, to ensure proper comparison.

With these methodological insights, the stage is set for the methodology chapter, which translates theoretical frameworks into actionable methods. This chapter offers a clear overview of what has been undertaken to reach the results, enabling replication or allowing other researchers to assess the reliability.

The results chapter, anticipated to be the most extensive, delineates the findings derived from the applied methods. Data will be predominantly showcased through figures and tables, accompanied by explanatory text. This chapter aims to provide all inputs necessary to discuss the research questions, but also hopes to by itself stand as a valuable resource for stakeholders in green hydrogen development.

The subsequent discussion chapter is again threefold: an interpretation of the results, a discussion on the limitations, and the implications of the research.

The result interpretations discuss both sub-questions and the primary research question. When discussing the first sub-question, the value of the results is put in the context of hydrogen development, but it also gives us the main exporting countries to focus the second part of the analysis on. After discussing both of the sub research questions, the discussion pivots to the primary research question. This holistic assessment examines the interplay between economic considerations and other factors, determining their collective influence on the economic viability of initial value chains and their potential impact on the Netherlands' hydrogen import landscape.

The limitations section evaluates the research's reliability, acknowledging potential constraints, which might stem from the adopted methodology or data sources. In exploring the research's implications, the broader consequences of the findings are discussed on aspects such as company and government policy. It thereby aims to demonstrate the significance for different stakeholders in the area of green hydrogen.

The discussion chapter will enable the reader to better understand the results and the implications that the results could have on their work, thereby giving more value to the overall analysis.

The concluding chapter encapsulates the research findings and their implications. Recommendations offer guidance on utilising the study's outcomes, catering to both hydrogen industry stakeholders and academics.

3. Literature review

3.1 Context

In this first section of the literature review the context of this research is given. Beginning with an introduction to hydrogen and hydrogen imports, the review progresses to explore the reasons for importing hydrogen, the methods of import, the associated costs, and potential source regions. Within this context the research gap becomes clear and the relevance of this research is clarified.

3.1.1 Introduction to hydrogen

The transition from fossil fuels to renewable energy sources like solar and wind power marks a monumental shift in the global energy system as this shift extends beyond simply replacing traditional energy sources with renewable power from solar and wind. In the Netherlands, for example, electricity accounts for only 17% of total energy consumption (EBN, 2022). Thus, there is a need to electrify various sectors of our energy system, including residential heating, transportation, and certain industrial processes, which could lead to about 50-60% of our energy system being electrified (IEA, 2021b). However, total electrification is not feasible for all sectors due to their high energy density requirements, high-temperature processes, or molecular feedstock or reductant usage (IEA, 2022b; PBL, 2022). These hard-to-abate sectors necessitate the use of alternative energy carriers such as hydrogen (IEA, 2022b).

Hydrogen is today not yet a sustainable energy carrier though, because it is predominantly produced through fossil fuels. It is mainly produced for refineries and the fertiliser industry and thereby contributes to about 2,5% of global carbon emissions (IEA, 2022b).

Hydrogen can be generated sustainably via electrolysis, a process that splits water with electricity (IEA, 2022b). When this electricity is renewable a sustainable energy carrier is created (IEA, 2022b). This 'green' hydrogen could help decarbonize existing hydrogen demands and serve the hard-to-abate sectors (IEA, 2022b). Owing to its substantially lower transport and storage costs, hydrogen also serves as a crucial medium for the storage and transportation of energy, particularly during extended periods of low renewable availability (Abdin et al., 2020; IEA, 2022). Nevertheless, the transition towards a hydrogen economy might initially require carbon capture on fossil hydrogen, known as 'blue hydrogen', due to constraints in renewable power availability for hydrogen production (IEA, 2022b). Capturing installations can either be amended to existing fossil hydrogen production installations, or new installations can be build that enable the capturing of up to 99% of the carbon emissions (IEA, 2022b).

Looking ahead, hydrogen is expected to comprise 12-15% of the global energy demand by 2050 (DNV, 2022a; European Commission, 2020; IRENA, 2022a). Part of this hydrogen will be produced domestically, but there is also consensus on the need for hydrogen imports (European Commission, 2022; TKI, 2022). Therefore, the European Commission's REPowerEU plan aims to annually produce and import 10 million tonnes (Mt) of renewable hydrogen each by 2030

(European Commission, 2022). This 20 Mt equates to roughly 3,7% of Europe's 2020 energy demand (IEA, 2020; IRENA, 2022d). To further put this in context, one of the Netherlands' largest green hydrogen projects, a 250 MW project by the green hydrogen project developer HyCC would contribute merely 0,125% to this 20 Mt target (HyCC, 2023). These imports will be stimulated through different European support mechanisms (European Commission, 2023b).

3.1.2 Why should we import hydrogen

There are four reasons for hydrogen imports to the Netherlands identified in literature. Initially, there's the fundamental challenge of domestic production constraints: the Netherlands, as research suggests, seems unlikely to fulfil its anticipated hydrogen demand through domestic production alone (EHB & Guidehouse, 2021; TKI, 2022). This anticipated shortfall propels the country towards an inescapable decision - ramp up imports or recalibrate demand expectations.

The second reason for imported hydrogen's appeal as a tradeable clean energy form lies in its ease of transportation. Despite a lower energy density compared to fossil fuels, hydrogen's molecular structure facilitates simpler transport, making it about eight times cheaper than transporting power (DeSantis et al., 2021). Hydrogen trade is therefore believed to enable us to harvest the renewable energy from places with cheap and abundant renewable power (IEA, 2022b; van Wijk & Wouters, 2021).

Another dimension is geopolitics, which emerges from the REPowerEU plans. Unlike fossil energy sources, which have geographic limitations, hydrogen can be produced across a vast spectrum of nations (European Commission, 2022; IRENA, 2022a). The REPowerEU plans therefore not only aim at accelerating the European energy transition, but also at enhancing Europe's energy independence following the energy crisis that resulted from the war in Ukraine (European Commission, 2022).

Lastly, hydrogen imports can solidify long term relevance for Dutch ports. The Port of Rotterdam is currently the leading energy cluster in Northwest Europe, therefore Notermans et al. (2020) emphasise the importance for the Port of Rotterdam to lead in hydrogen if it wants to retain this position in the long run. The same can be concluded for the Port of Amsterdam, as it is the world's largest petrol port (Port of Amsterdam, 2023).

3.1.3 How can we import hydrogen

The energy density of hydrogen is lower than that of fossil fuels, posing challenges for transport. For transport through pipes the energy density can be increased by pressurising the hydrogen (DeSantis et al., 2021). However, for shipping purposes, the energy density of pressurised hydrogen is inadequate, necessitating liquefaction or conversion into carriers like Ammonia (NH3), Methanol (MeOH), and Liquid Organic Hydrogen Carriers (LOHC), with dibenzyltoluene (DBT) and methylcyclohexane (MCH) being the most promising LOHCs (IEA, 2022b; Patonia & Poudineh, 2022; JRC, 2022; Roland Berger, 2021).

Literature reveals partial consensus on the optimal hydrogen transport methods, influenced by transport distance, supply chain size and end use. For shorter distances, pipeline transport is widely agreed upon to be the most economical solution (ENTEC, 2022; IEA, 2019; JRC, 2022; Wijayanta et al., 2019). Therefore import through pipeline from the Mediterranean and northern Africa is expected to be the most prominent mode of hydrogen imports to Europe (Hydrogen Council & McKinsey and Company, 2022; IRENA, 2022b). However, the viability of pipeline projects hinges on large-scale shared infrastructure, which may pose a challenge due to an initial lack of sufficient hydrogen production (EHB & Guidehouse, 2022; IRENA, 2022d).

The European Hydrogen Backbone initiative, an alliance of all European transmission system operators (TSOs), is developing a pan-European hydrogen pipeline infrastructure (EHB & Guidehouse, 2022). The project aims to establish five import corridors by 2030 and achieve full connectivity by 2040 (EHB & Guidehouse, 2022). To the Netherlands a corridor will form based on shipped imports and local production based on offshore wind and solar. By 2040 also long distance piped imports to the Netherlands will be possible (EHB & Guidehouse, 2022).

When shipping hydrogen, the hydrogen must either be liquefied or a hydrogen carrier should be created, such as methanol, ammonia, or liquid organic hydrogen carriers (LOHCs).

Methanol, though often discussed, is typically deemed non-competitive as a standalone carrier due to difficulties in sustainably sourcing the carbon feedstock necessary for its production and is therefore not included in this analysis (ISPT, 2019; JRC, 2022). A quick overview of ammonia (NH3), liquid hydrogen (LH2) and LOHCs is given below and is visualised in Figure 3.1. Prior to conversion, temporary hydrogen storage may be necessary, and either the hydrogen or the carrier must be transported to the port.

Hydrogen liquefaction requires cooling to -253℃. This is an energy-intensive process that costs between approximately 5-10 kWh/kg of hydrogen (IRENA, 2022d). The low temperatures also necessitates costly specialised ships and storage facilities (ISPT, 2019; Patonia & Poudineh, 2022; Roland Berger, 2021). Advantageous about this process is that the high energy demand is in the form of power and that it takes place in the exporting country where energy is cheaper. Conversely, the energy-intensive processes of reconverting ammonia and LOHCs occurs in the importing country. Liquefied hydrogen furthermore does not require purification for high-purity applications, unlike other carriers (Patonia & Poudineh, 2022).

Ammonia (NH3), a combination of hydrogen and nitrogen, is easier to transport as a liquid than hydrogen due to its lower boiling point of -33℃ (JRC, 2022). By cracking the ammonia the hydrogen can again be retrieved (JRC, 2022). Its wide use in the fertiliser industry lends an advantage, as legislation is available, infrastructure can partly be repurposed and fossil-based ammonia can be directly replaced (Patonia & Poudineh, 2022). This means that the conversion back to hydrogen could initially be bypassed. If ammonia is the end product, it is considered the most competitive hydrogen carrier and could serve as a springboard for establishing supply chains (Zhang et al., 2020). The applications of ammonia are furthermore expected to expand through its use as a shipping fuel, but also a potential direct use in power plants (Valera-Medina et al., 2021; Xu et al., 2022). However, its toxicity may pose safety concerns and potentially limit public acceptance for broader use (Roland Berger, 2021; Valera-Medina et al., 2021).

LOHCs are liquid substances that can bind and unbind hydrogen for transportation purposes (JRC, 2022). They are considered safer and simpler to produce than ammonia and can be transported and stored using existing fossil fuel assets (IEA, 2022b; Patonia & Poudineh, 2022). Despite these advantages, LOHCs' primary drawback is their low hydrogen mass content (for example, only 6,2% for DBT), which results in high shipping costs (ISPT, 2019). Additionally, the endothermic process of retrieving the hydrogen requires significant heat, between 150-400℃ (JRC, 2022).

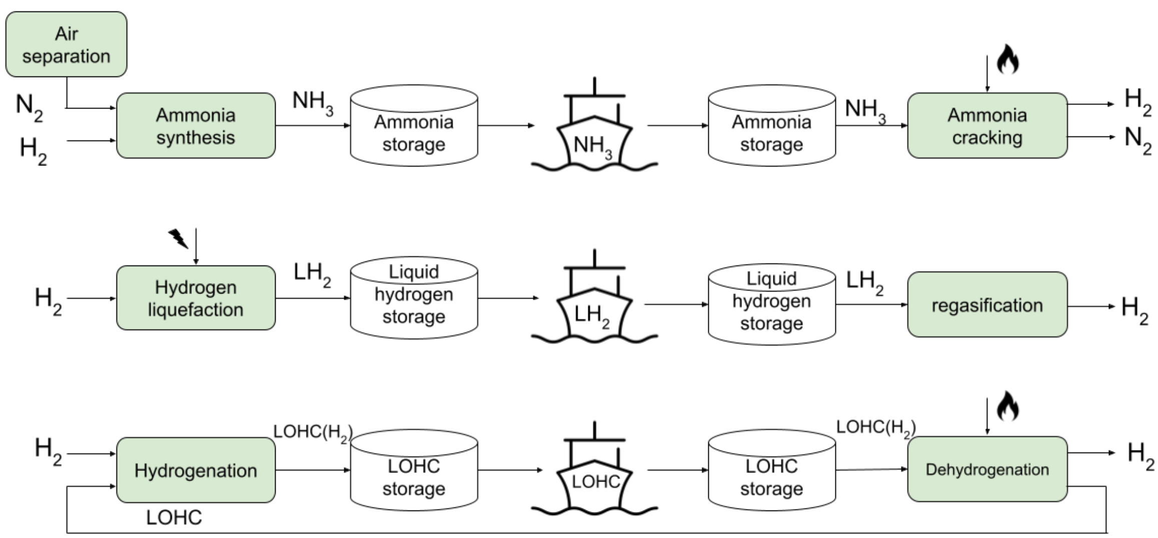


Figure 3.1: A schematic overview of three possible solutions for hydrogen transport, adapted from Roland Berger (2021).

The combined promise of piped and shipped hydrogen trade is large. For instance, the Hydrogen Council & McKinsey and Company (2022) project that by 2030, long-distance transportation will account for 60 million tonnes (Mt) of hydrogen, with overseas transport eventually satisfying approximately two-thirds of global demand. Moreover, the IEA (2022) reports an anticipated 12 Mt of hydrogen exports before 2030, primarily via shipping. This figure comprises predominantly ammonia projects, supplemented by a smaller proportion of liquefied hydrogen and LOHCs. Notable is that most of these projects do not yet have an offset market.

Dutch ports are leading in this area and aim to achieve a combined import of 5 Mt by 2030 (IEA, 2022b). The Port of Amsterdam plans to import 1 Mt of LOHC, while the Port of Rotterdam believes it could import 4,6 Mt by 2030, primarily focusing on ammonia. (Port of Amsterdam, 2022; Port of Rotterdam, 2022b). The latter will replace fossil ammonia, but there are also plans to develop an ammonia cracker to extract 1 Mt of hydrogen annually (Port of Rotterdam, 2022a, 2022c; Vopak, 2022).

Despite this progress, some scholars and experts, including Liebreich (2022) and Patonia & Poudineh (2022), express scepticism about the emergence of a global hydrogen market. One of the primary challenges identified is that even after undergoing complex liquefaction or conversion processes, hydrogen's energy density remains substantially lower than that of traditional fossil fuels (Arbelaez, 2023; Liebreich, 2022). This is by some seen to undermine the economic viability of shipping hydrogen imports in comparison to domestic production (Arbelaez, 2023; Liebreich, 2022). Additionally, the economic benefits of pipeline transport from regions like North Africa and the Mediterranean raise questions about the necessity of overseas hydrogen shipping (ENTEC, 2022; IRENA, 2022b; Liebreich, 2022). Section 3.1.4 of this literature review delves deeper into this critical economic value proposition.

3.1.4 Costs of the hydrogen importing supply chain

To understand the cost of imported hydrogen, it is first of all important to address the production costs of the hydrogen itself. A review of different cost assessments by Hajonides van der Meulen et al. (2022) provide a foundation for this. They find a cost range of €1100-4600 per tonne of hydrogen for 2030, averaging around €2700.

Diving deeper, an analysis of seven 2030-targeted export reports listed in Appendix 1.1 demonstrates a cost spectrum between €1000-3600 per tonne, with a lower average cost of €2100.

Although these figures shed light on the uncertainty of overall hydrogen production costs, determining how the production costs in potential exporting countries compares to those in the Netherlands remains a challenge. This is largely because most export reports don't juxtapose the costs of importing with domestic production. However, select reports do provide a perspective on global production cost differences. Drawing from four such reports, as delineated in Appendix 1.2, the cost variance for producing hydrogen in the Netherlands versus the most economical location is between €500 to €1.900 more costly per tonnes. The fact that these figures stem from different reports than those detailing import costs introduces complexities in direct comparison of import with domestic production, especially given that assumptions made about production costs can have cascading effects on transportation costs due to potentially pricier supply chain losses.

The costs of transport

When examining the costs associated with different methods of hydrogen transport, several studies highlight a correlation between shipping distance and the most cost-effective carrier (IEA, 2019; IRENA, 2022d; JRC, 2022). In Appendix 1.1, eleven reports were scrutinised to identify the optimal carrier for hydrogen transport over roughly 10,000 km. There wasn't a unanimous consensus; ammonia was deemed most cost-effective in eight reports, LOHCs in three, and liquid hydrogen in two.

An analysis from Hajonides van der Meulen et al. (2022), depicted in Figure 3.2, indicates that there is also a lack of clarity regarding the costs of delivering hydrogen to the Netherlands, particularly by 2030. Although there's a higher certainty on current and future costs, the cost range in 2030 is between €1,70-7,90 per kilogram. The study fails to delineate the specific elements contributing to these cost uncertainties.

A subsequent examination of 2030-focused reports from Appendix 1.1 highlighted a cost range between €2,11 and €5,65 per kilogram for the most economically viable route. Pinpointing the sources of cost uncertainties is challenging though.

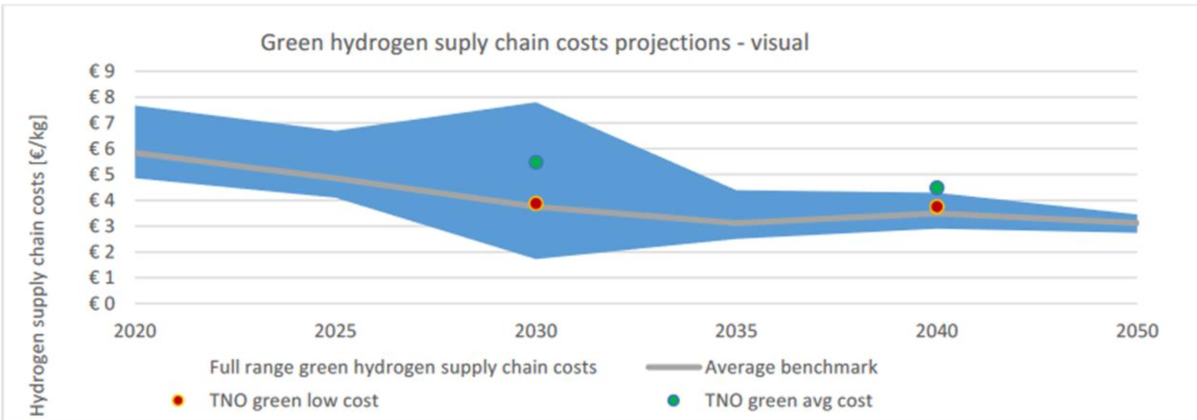


Figure 3.2: A study by Hajonides van der Meulen et al. (2022) that shows the cost projections of hydrogen delivery to the Netherlands of different benchmark studies over time including production. The blue area represents the cost range presented by the studies assessed.

Appendix 1.1 gives insight into some of these complicating factors. Some reports present their system design, but do not fully disclose their data, while others present CAPEX and OPEX values without presenting system design. Crucially, many other reports neglect or simplify the hydrogen production, or exclude specific supply chain elements such as intermediate transport, storage, or regasification units.

Furthermore, IEA (2021c) highlights the pronounced influence of capital costs on renewable energy, which can differ significantly due to project and country specific risk. Often, these locational differences are either oversimplified, disregarded, or derived from outdated references. Also the depreciation periods for supply chain components, as suggested by some studies, might not align with what is realistically expected from commercial companies (PBL, 2023).

Lastly, there are many inconsistencies in system design parameters, such as different assessed countries, supply chain sizes, storage buffer needs, or shipping fuels. Differences in power mixes and pricing, combined with data presented in varying units, further hinder straightforward comparisons.

To truly grasp the economic value proposition of imports, it must be clarified what the impacts of simplifications and variations in system design are across different reports on these cost discrepancies. Additionally, pinpointing the primary drivers to this cost uncertainty is crucial. As was seen, comparing these reports to domestic production metrics proves even more intricate as sparse import studies use their assumptions to also provide domestic production cost estimates for the Netherlands. A good understanding of the expected economic dynamics between imports and domestic production by 2030 is therefore missing.

Additional cost uncertainty

It must be noted that even when consensus emerges on costs, rigorous scrutiny of these estimates remains paramount. Flyvbjerg (2014) articulates the multiple pitfalls that frequently cause multibillion-dollar projects to exceed budgets and timelines. A staggering nine out of ten projects overshoot their budgets, often experiencing a surge of up to 50% in costs (Flyvbjerg, 2014. Such overruns stem from factors such as underestimating expenses, long planning horizons, and the involvement of multiple stakeholders. As there are multiple system elements to import projects, these projects also include many stakeholders (IRENA, 2022d). These multiple system elements also lead to the phenomenon called project-on-project risk, where the success of the different elements depends on each other (Law Insider, 2023). In simpler terms, the pace of the supply chain is determined by its slowest component.

Lastly, it is crucial to recognize that production costs don't dictate the selling price of hydrogen. Factors like transaction costs and market dynamics, such as spot sales versus long-term contracts, significantly influence the final price (Hajonides van der Meulen et al., 2022).

3.1.5 Potential hydrogen exporters

It is essential to understand where the hydrogen could come from to assess its costs. Several countries have expressed an interest in becoming hydrogen exporters, of which the most important potential exporters are marked blue in Figure 3.3 from the Hydrogen Council & McKinsey and Company (2022). This assessment aligns with those of IRENA (2022a) and PWC (2023a). Their potential lies in their abundant renewable energy resources, available space for renewable energy development and possible cheap labour (IEA, 2022b). Also location specific capital costs affect the costs of the hydrogen (IEA, 2021c).

Also economic policy significantly shapes these supply chains' evolution, as exemplified by the Inflation Reduction Act. Its provision of hydrogen production tax credits of 3 dollars per kilogram are believed to potentially half the costs of hydrogen delivered to Europe (The White House, 2022; Janzow et al., 2022).

Beyond economic considerations, various non-economic elements aid certain countries in establishing export value chains. Examples include pre-existing trade relations, hydrogen expertise, and ongoing project initiatives (IRENA, 2022b). IRENA (2022b) therefore posits that the initial value chains likely won't be the most economical.

Patonia & Poudineh (2022) highlight the need for a robust legal framework available locally to foster the growth of these supply chains. Complementing this, IEA (2022b) underscores the role of governance in propelling their evolution. An example of this governance are the visits of the Dutch government to specific nations to promote hydrogen supply chains (Biogradlija, 2023b).

Nuñez-Jimenez & De Blasio (2022) discuss another crucial non-economic determinant: a country's ability—based on human resources, corporate entities, and institutional structures—to undertake export projects. They assess this ability based on the current infrastructure quality of a country. Their stance goes beyond IRENA's (2022b) by suggesting that such capacity will even restrict countries from establishing export projects.

Furthermore, the determination of whether hydrogen produced will indeed reach the Netherlands can be influenced by both local demand and the presence of competing importers (IRENA, 2022b; Strategy&, 2020).

Among the potential exporters in Figure 3.3, both current players and newcomers seeking to enter the energy market are seen. While IRENA (2022a) predicts that the rise of these new energy exporters will significantly alter global geopolitical dynamics, Pflugmann & De Blasio (2020) believe that the status quo in global energy trade will likely remain.

Figure 3.3: Projected hydrogen trade by 2030, as depicted by the Hydrogen Council & McKinsey and Company (2022). Countries highlighted in blue are anticipated hydrogen exporters, while those in orange are prospective hydrogen importers.

3.1.6 Knowledge gap & Contribution

To summarise, it was seen that numerous studies have investigated hydrogen import value chains. However, there's significant variance in their cost estimates. This disparity arises from many differing assumptions and system design considerations. Consequently, it is unclear through what elements these uncertainties are caused. They furthermore seldom compare imports with domestic production. This lack of comparison results in diverging assumptions on aspects such as the capital expenditure (CAPEX) of green hydrogen factories, complicating any attempts at proper cost comparison.

If it is desired that significant quantities of hydrogen are to be imported into Dutch ports by 2030, a better understanding of the cost dynamics between the initial import and domestic production is essential to reveal potential policy gaps that need to be overcome.

However, it was seen that the most economic value chains might not be the first to form. Therefore, it must be explored what these first value chains might be before assessing their economic proposition. This way it is ensured that the economic analysis is not corrupted by the inclusion of countries that are unlikely to export to the Netherlands in the initial phases. To do this there should be a much better understanding of how these different factors that shape the forming of these supply chains will influence their forming.

This thesis takes a systems perspective on the topic of hydrogen imports by combining both these techno-economic as well as non-economic elements that form this knowledge gap. It aims to bridge this knowledge gap through answering the research questions proposed in the introduction.

3.2 Review of suitable methods

As discussed in the research plan, methods need to be found to address both sub research questions.

3.2.1 Sub-question 1

First a method will be found for the first sub-question: “*What are potential green hydrogen import value chains to the Netherlands and what criteria shape this?”*

Literature analysis revealed that multiple factors play a role in the development of hydrogen supply chains and that the most economical supply chain might not be the first supply chain to form (IRENA, 2022d). Ideally all other factors are therefore monetised in such a way that a cost benefit analysis can be applied (Mouter et al., 2020). This approach of monetisation translates all values to the same unit which allows for easy comparison (Mouter et al., 2020). However, there is a high degree of uncertainty around hydrogen imports, especially on the value of the different aspects that influence whether a supply chain will form (IRENA, 2022d). It is for example not possible to monetise how a trade relation between two countries will affect the forming a supply chain. It will on the other hand play a role in derisking the project for investors and thereby in enlarging the likelihood of the supply chain to form. Therefore, an approach is needed that considers different aspects and their interplay without monetisation. The most suitable approach to do this is a multicriteria analysis (MCA) (Dean, 2022; Mouter et al., 2020).

A multicriteria analysis, or multi-criteria decision analysis, is an umbrella term for any decision process that involves normalising various criteria in relation to each other and assigning weights to their importance (Dean, 2022). In this thesis the MCA framework of Dean (2022) is chosen as it is well elaborated and highly similar to other frameworks, such as the one presented by the Department for Communities and Local Government (2009).

Figure 3.4 presents the analytical framework along with its primary components. Initially, the "Problem Analysis" elaborates the research question. Following this, "Criteria" defines the factors that influence whether supply chains will form. The "Options" refer to the countries under scrutiny, while the "Performance Profile" illustrates their respective performances against the set criteria. To enable a direct comparison across variables, all the criteria undergo a "Normalisation" process. Subsequent to this, the "Weighting" phase assigns significance or weight to each criterion, highlighting its relative importance. By combining the assigned weights with the individual scores, the preliminary "Results" are derived. To ensure the validity of these findings, they are subjected to a "Sensitivity Analysis" before their final presentation and interpretation. The precise methodology used within this study is further elaborated upon in the methodology chapter.

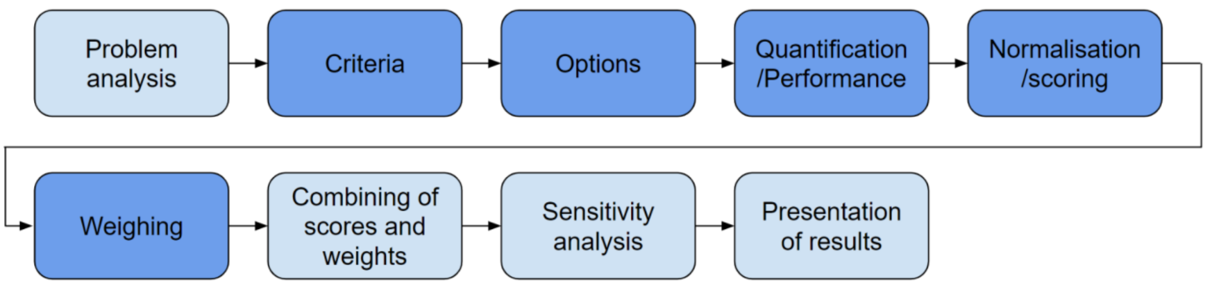


Figure 3.4: The chosen order of the MCA steps. Based on Dean (2022). The order of the dark blue sections can be changed.

3.2.2 Sub-question 2

Secondly a suitable method is found to address the second sub-question: *"How does the techno-economic performance of different green hydrogen import streams compare with domestic production in the Netherlands in 2030?"*

Evaluating the economic viability of different hydrogen import pathways, as compared to local production, necessitates an examination of the complete supply chain costs. Multiple approaches exist for assessing the financial feasibility of such alternatives, for which financial analysis is often used (Tuovila et al., 2023). This form of analysis aims to determine a project's financial viability and profitability from an investor or a company's perspective, allowing comparison between the profitability of different alternatives (Tuovila et al., 2023). However, financial analysis predominantly employs historical financial statements, which are not yet available for green hydrogen supply chains (Tuovila et al., 2023). Moreover, it lacks a structured approach, leading to potential inconsistencies between analysts working with the same data (Rajak, 2023). This method's inability to include technology-related aspects further limits its usefulness for exploring optimal supply chain design.

An analysis that overcomes all these problems is the techno-economic analysis (Zimmermann et al., 2020). A techno-economic analysis (TEA) is a comprehensive method used to evaluate the economic feasibility and performance of a technology, system, or project (Zimmermann et al., 2020). It combines the technical aspects such as system design and efficiency with the economic aspects (Zimmermann et al., 2020).

TEA aims to provide a systematic, unbiased evaluation that allows for the comparison of different technologies or projects (Zimmermann et al., 2020). It estimates the full lifecycle costs and benefits of each alternative and compares these to determine which provides the best economic performance (Zimmermann et al., 2020). Lifetime benefits refer to the revenues generated by the hydrogen, while lifetime costs incorporate all expenses, from initial capital expenditures (CAPEX) to operational costs (OPEX) (Zimmermann et al., 2020). Future benefits and costs are discounted to their present values (Zimmermann et al., 2020).

By covering each step of the supply chain, from raw materials sourcing to product delivery, TEA provides a comprehensive cost overview (Zimmermann et al., 2020). This assists in identifying cost drivers, potential bottlenecks, and areas for optimization (Zimmermann et al., 2020). The analysis does not have to start from raw materials, as it can also be built up from other TEAs for the elements of the supply chain.

Adopting a TEA framework ensures a systematic approach, enabling a fair comparison of different hydrogen supply chains. As there is no established TEA framework specific to hydrogen supply chains, a framework adapted from Zimmermann et al. (2020) is proposed. This framework is chosen as it follows the lifecycle assessment (LCA) methodology outlined by the European Commission & JRC (2010). Both methodologies share similarities in their comparative and lifecycle approaches, but diverge in focus: TEA centres on economics while LCA focuses on environmental impact (Zimmermann et al., 2020). Figure 3.5 illustrates the five main stages of a TEA. The translation of this framework into the methodology used within this thesis is made in the methods chapter.

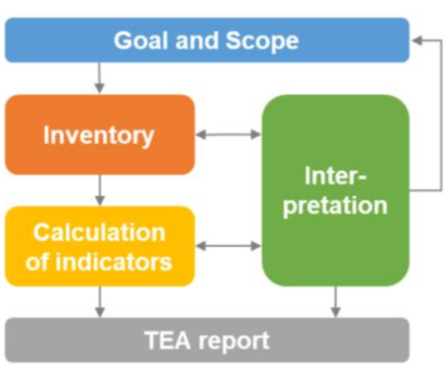


Figure 3.5: The different stages of a TEA.

3.2.3 Main research question

In conventional approaches, an MCA is typically executed following a TEA to aid the final decision-making process (Zimmerman et al., 2020). This thesis, however, isn't designed to arbitrate between importation or domestic production but rather to furnish the requisite economic insights for informed policymaking. It's imperative to validate that the countries that will be assessed as possible exporters are genuinely viable candidates for exporting to the Netherlands, which is done through the MCA. Thus, the MCA is part of an earlier section of the TEA, namely the selection of the reference flows which are determined within the study's goal and scope. This integrated framework is represented in Figure 3.6.

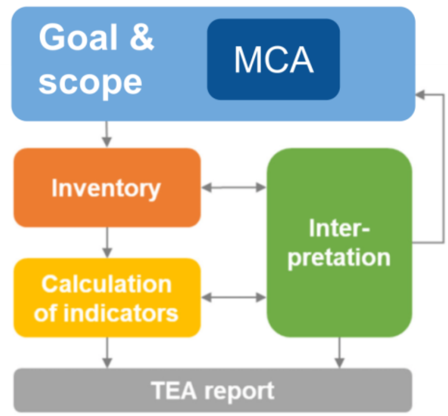


Figure 3.6: A graphical visualisation of the methodological framework when using an MCA for the selection of the reference flows of the TEA.

3.3 Valuable data sources

As green hydrogen will play such an important role within the future energy system it has already grown into a multi-billion dollar industry (IEA, 2022b). Therefore research within the field of hydrogen is done by all kinds of different organisations, such as academic institutions, companies, consultancies, but also many independent research organisations. These independent research organisations often collaborate with companies at the forefront of technology development, yet they maintain research independence. Prominent examples include the International Energy Agency (IEA), the International Renewable Energy Agency (IRENA), and the Dutch Association for Applied Scientific Research (TNO), among others. Another valuable organisation in these developments is the Netherlands Environmental Assessment Agency (PBL), which advises the government on subsidy schemes. Therefore, it is imperative for PBL to have a thorough understanding of the actual costs associated with specific energy transition solutions.

For the assessment of these hydrogen supply chains it is therefore assumed that independent institutions are the most valuable source of data, followed by academic literature. While consultancy and corporate reports also provide valuable insights due to their comprehensive research and expertise, it's important to approach their perspectives with a discerning eye, assessing potential biases or vested interests.

4. Methods

In this chapter the frameworks on the methods found in the literature review are translated into the practical methodologies used in this research.

4.1 Data gathering

Given the dynamic nature of this topic and its importance, substantial research is being done in the Netherlands and globally. It is therefore important that the most up-to-date information is gathered. Also expert interviews are therefore important, serving a dual purpose: to gather the most recent information and to optimally leverage existing research foundations. The interviews, sourced through my own network and those of HyCC, the organisation that was collaborated with for this research, are thoroughly planned and conducted either in person or via web-call. A blend of structured and semi-structured interview techniques are employed. This approach facilitates the collection of quantifiable data, while also providing room for open-ended, qualitative information that could yield valuable insights (De Jonckheere & Vaughn, 2019). This ensures that the interviews fully harness the expertise of the individuals involved.

4.2 Multicriteria Analysis

In this section, the framework form Dean (2022) is translated into a specific method to be used in this research. This is done by elaborating on the different steps of the analysis. Various forms of MCA's differ in for example their complexity, the order of steps, and the level of participation of experts within the MCA framework.

The results chapter will commence with the researcher-led portion of the study, which is predominantly based on literature and is performed quantitatively. It involves the selection of the options and criteria and the quantification and normalisation of most of these criteria. Subsequently, in the participatory part of the study, weighting is applied by experts. Finally, sensitivity analysis is conducted, and the results are presented.

4.2.1 Problem analysis

The problem analysis should be the section where the problem is clearly elaborated and where the approach is structured (Dean, 2022). The elaboration of the problem is logically already partly done in the other chapters of this report but is for ease of reading further done in the introductions to the criteria. Also the methods section is part of the problem analysis in an MCA. The topics within the problem analysis that affect the method are: the scope, the type of MCA, the order of the different steps and the level of participation (Dean, 2022). The identification of relevant stakeholders is further discussed in the weighing section.

The scope of the MCA

According to Roy (1996), MCA can address choice, sorting, ranking, or description problems. The scope of this MCA is to rank different options based on their competence to become an exporter of green hydrogen to the Netherlands by 2030.

Type of MCA

The type of MCA affects process complexity. Two main categories exist: formal and simplified methods. Formal MCA methods handle MCAs with infinite options or non-linear utility equations (Dean, 2022). An example is that a criterion might only be important if an option scores below a certain threshold. While there are also formal methods available that are suitable, a simplified MCA approach is chosen. Complex MCA methods are time-consuming for both analysts and participants, which is not feasible due to limited participant availability (Dean, 2022). Moreover, complex methods often involve intricate equation systems, making them challenging to comprehend for participants and the research audience (Dean, 2022). This study employs the simple additive weighting method, the most popular approach in MCA. It multiplies and sums criterion scores and weights to form an overall numerical score used for ranking the options assessed.

Level of participation

Participation in the MCA process can involve decision-making on options, criteria, scoring, and weighting (Dean, 2022). All four steps can be carried out with expert input, resulting in a fully participatory MCA, but they can also be handled solely by the analyst. However, most MCAs fall somewhere in between (Dean, 2022). While more participatory MCAs offer greater democratic involvement, they require higher levels of expertise from the participating group and can be more challenging to manage (Dean, 2022). In this study, an analyst-led MCA approach was chosen. The selection of options and criteria was informed by literature, and scoring mostly relied on literature as well. One criterion was determined through an export workshop, as it could not be quantified based on available literature. Throughout the analyst-led process, a smaller expert group was also consulted to help iterate and improve the analysis. The weighting was exclusively determined in the expert workshop.

Order of different steps

A second decision was made regarding the sequence of the MCA steps. There are nine steps in total of which four are fixed, as seen in Figure 4.1. The analysis always begins with the problem analysis, while the MCA concludes with the combination of scores and weights, sensitivity analysis, and presentation of results (Dean, 2022). In between, the steps include option selection, criterion selection, weighting, quantification, and normalisation (Dean, 2022). The order of these steps can vary and can even involve iterations (Dean, 2022).In this study, the decision was made to initially explore the different criteria and select options based on their performance. This approach was chosen to prevent the loss of overview, given the multitude of potential exporting countries that should have otherwise been assessed. The subsequent sections will provide further elaboration on the different steps of the method.

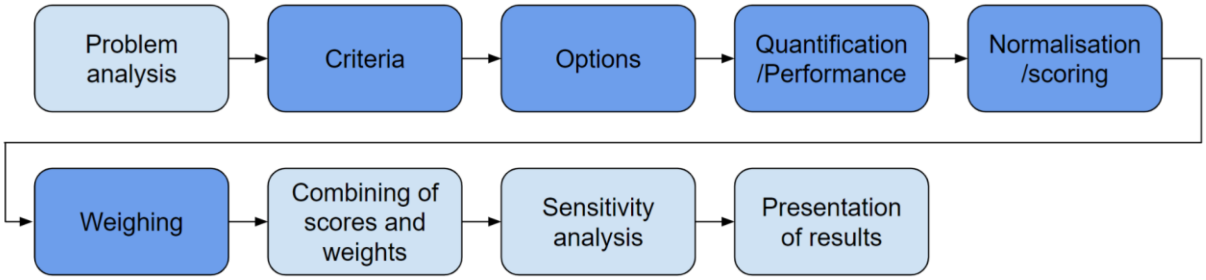


Figure 4.1: The chosen order of the MCA steps. Based on Dean (2022). The order of the dark blue sections can be changed.

4.2.2 Criteria

An overview of all the influential factors is created through system mapping, which is based on literature. This system diagram is further refined through expert interviews. It helps identify country-specific aspects and determine which aspects should be considered as criteria for the MCA.

4.2.3 Options

The shortlist of options is formed based on their performance across the different criteria. To ensure the inclusion of diverse options, countries are selected from various exporting regions. Additionally, following the example of Hajonides van der Meulen et al. (2022), some neighbouring countries are assessed to explore whether these will significantly differ.

4.2.4 Quantification/ Performance profile

In this step, the criteria are quantified by measuring a quantifiable indicator for each criterion. The quantification results in a performance profile, which provides an overview of the quantification of different options (Dean, 2022). This process is iterated through various expert interviews.

4.2.5 Normalisation/ Scoring

Normalisation is a crucial step in MCA as it addresses the issue of criteria performances being expressed in different units, making direct comparisons difficult. In this research, normalisation is carried out by transforming all criteria into a numeric scale ranging from 0 to 1. This allows for proper weighting and ranking of alternative countries. In this scale, a score of 1 always represents the maximum benefit, while 0 represents the maximum cost. (Dean, 2022)

Various normalisation techniques are available. Their suitability depends on the ease of quantifying the criterion and the desired goal of the normalisation process. Many popular normalisation methods require numeric results that make it possible to apply a formula (Palczewski & Sałabun, 2019). In this case it is desired that the criteria are normalised relative to each other to ensure significant differences and thereby impactful weighing.

Maximum-minimum normalisation is therefore chosen, which normalises performance in comparison to the best performing value (Palczewski & Sałabun, 2019). This method yields more precise values using a simple formula, as shown in formulas 4.1 and 4.2. Formula 4.1 is used for criteria representing benefits, while formula 4.2 is used for costs.

$$r_{ij\ benefit} = \frac{x_{ij} - min_j(x_{ij})}{max_j(x_{ij}) - min_j(x_{ij})} \qquad (4.1)$$

$$r_{ij\ cost} = \frac{max_j(x_{ij}) - x_{ij}}{max_j(x_{ij}) - min_j(x_{ij})} \qquad (4.2)$$

$r_{ij\ benefit}$	The normalised score of a country when the criteria represents a benefit.
$r_{ij\ cost}$	The normalised score of a country when the criteria represents a cost.
x_{ij}	The performance of the country assessed.
$min_j(x_{ij})$	The performance of the worst performing country assessed.
$max_j(x_{ij})$	The performance of the best performing country assessed.

However, for criteria that are answered with a "yes" or "no," such methods are not applicable. In such cases, the direct rating approach is employed, where answers are linked directly to ratings (e.g., "yes" as 1 and "no" as 0) (Dean, 2022).

As one criterion is normalised based on expert input this is done through asking the participants to rate the different countries on a Likert scale of five, from likely to unlikely.

4.2.6 Weights

There are various approaches to participatory weighing in MCA. Participants can either individually assign weights to the criteria or collectively determine weights in a workshop setting, as depicted in Figure 4.2 (Dean, 2022). Due to the inability to organise a workshop attended by all participants, this MCA employs individual weighting.

In these individual weighting workshops, the meaning of each criterion is thoroughly explained to the participants without providing country-specific examples that could potentially bias the outcomes. Participants are encouraged to vocalise their thought processes during the weighting process, as their reasoning behind the weights can be insightful.

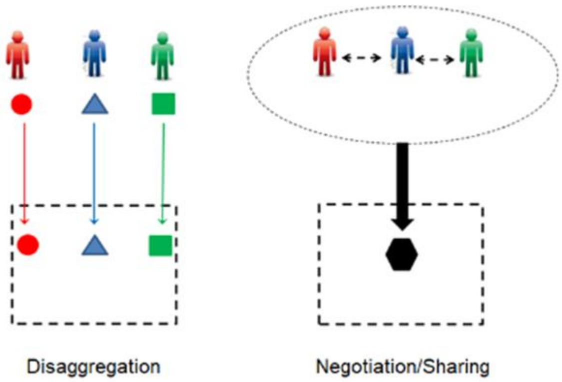


Figure 4.2: Separate weighing and weighing through a discussion from Dean (2022).

4.2.7 Final chapters

The final results will be obtained by multiplying the scores and weights of all criteria and summing them up. Sensitivity analyses will be conducted by changing the scores and weights of certain criteria.

To address potential uncertainties and inherent subjectivity, and to validate the robustness of the findings, sensitivity analysis is conducted (dean, 2022). Sensitivity analysis illuminates how modifications in input data could influence the outcomes. This might encompass alterations in data values or adjustments in assigned weights (Dean, 2022). An exhaustive sensitivity analysis ideally involves adjusting one variable at a time, which can make the process highly time consuming (Dean, 2022). To manage time effectively, sensitivity analysis is conducted primarily for criteria with uncertain scores and for the weights of the three most influential criteria. The latter is done by increasing the weight with 20%, which is deducted from the competing criteria while maintaining their proportional difference. This is done through Formula 4.3 and 4.4.

$$CrA = CrA + 20\% \qquad (4.3)$$
$$Crn = Crn - (20\% * Crn/(100\% - CrA)) \qquad (4.4)$$

CrA	The performance of the criterium under assessment
Crn	The performance of the other criteria

The findings are illustrated through graphs and figures, complemented by objective commentary. In the discussion section, these results are further interpreted, and the associated limitations and implications are detailed.

4.3 Techno-economic analysis

In this section, the framework proposed by Zimmermann et al. (2022) and presented in Figure 4.3 is adapted to align with the objectives of this research. This is done by elaborating on the different steps of the analysis. Given the large number of possible exporters and the substantial variation among individual cases, the analysis is focussed on four or five specific pilot import scenarios. These pilot projects are selected in the multicriteria analysis.

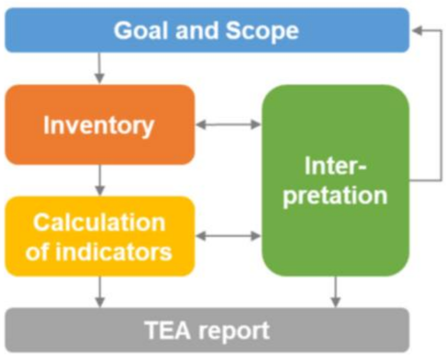


Figure 4.3: The different stages of a TEA

4.3.1 The Goal and Scope definition

The initial phase of the assessment involved defining the goal and scope of the analysis, which could be seen as an extension to the methods chapter. The MCA is part of the goal and scope.

The goal not only encompasses the research question but the broader context - the what, where, when, why, and for whom (Zimmermann et al., 2020). It furthermore sets out the commissioners, constraints, and scenarios being investigated (Zimmermann et al., 2020).

The scope section outlines the system boundaries, which are established via the functional unit and reference flows. The functional unit provides a description of the common function that all alternatives are compared against, which, in combination with the alternatives, form the reference flows. These clarify whether the analysis includes full lifetime (cradle-to-cradle) costs or cradle-to-gate costs. A clear representation of the system boundaries is given in a figure.

Finally, the scope phase sets out the assessment indicators, which are key metrics such as capital expenditure (CAPEX) or energy efficiency to be evaluated for each process step. Another commonly used indicator in TEA is the Technology Readiness Level (TRL), which assesses the technologies maturity. This indicator can be crucial because different maturity levels require unique approaches for forecasting process costs (Buchner et al., 2018). However, since this analysis bases cost data on existing TEAs, TRL is excluded.

4.3.2 The Inventory Analysis

In the inventory analysis, data is collected relating to both the technical system design and the assessment indicators. This process is split into three primary sections: The discount rate & investment duration, hydrogen production and transport.

4.3.2.1 The discount rate & investment duration

In the initial segment, all components of the inventory necessary are compiled to translate the benefits and costs into a projected cost of hydrogen. These are the discount rate and the desired return period for the investment. Often, levelized cost analyses employ the Weighted Average Cost of Capital (WACC) as a proxy for the discount rate (Hargrave et al., 2022). WACC can be ascertained using Formula 4.5, which is a combination of a factor for the equity and the debt. The inflation-adjusted 'real WACC' is what represents the discount rate. In typical WACC calculations, a tax shield is incorporated to account for income tax savings (Hargrave et al., 2022). However, as this analysis is focused on assessing the LCOH before tax, the tax shield has been deliberately excluded from the evaluation. A more detailed methodology, outlining the derivation of various WACC components, can be found in Appendix 5.

$$WACC = E\% * Re + D\% * Rd \quad (4.5)$$

E%	Share of equity
Re	The return on equity
D%	The share of debt, or gearing
Rd	The return on debt
Tc	Corporate tax rate

4.3.2.2 Hydrogen production

Hydrogen production data is gathered from an examination of literature, placing emphasis on the areas where system design or costs differ among the evaluated countries. This literature review is supplemented by expert interviews to optimally understand the supply chain for hydrogen production by 2030, facilitating accurate system modelling.

4.3.2.3 Hydrogen transport

The inventory analysis for hydrogen transport begins with a review of existing techno-economic assessments from academic literature and institutional reports. Ten particular reports that give insight into their input values were selected as benchmark TEAs. Each of these TEAs individually assesses the full supply chain costs, and is supported again by other TEAs on the specific supply chain elements. Consequently, some assumptions in these reports are grounded in the same literature, with some also referencing each other. Figure 4.4 provides a visual example of how these reports are built up and potentially interconnected. All assessed reports are assumed to have adhered properly to TEA methodology, thereby presenting trustworthy values.

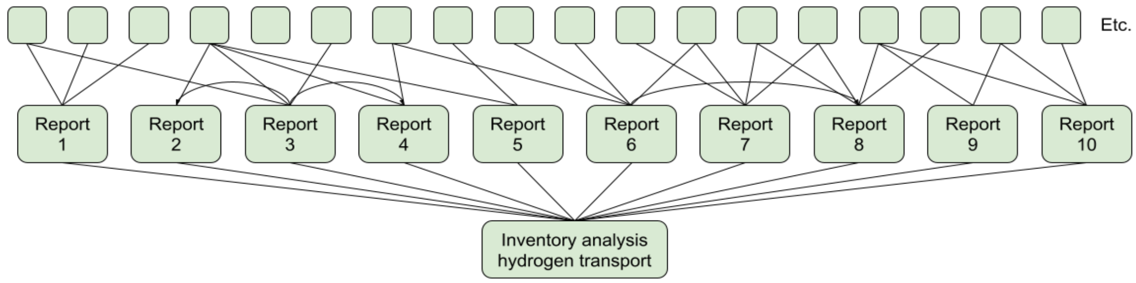


Figure 4.4: An example of how the different TEAs assessed are built up and possibly interlinked.

This review involved the collection and documentation of all reported assessment indicators from each report. As these indicators are reported in varying units, they were normalised to enable comparisons. When plant availability was required for normalisation, a value of 8,000 hours or approximately 91.3% was used, in accordance with ISPT (2019) and JRC (2022). The formulas and constants applied for normalisation are provided in Table 4.1.

Table 4.1: Formulas and constants used for normalisation (IRENA, 2022d; ISPT, 2019; Xe Currency Converter, 2023).

Base calculations	
Kilo (k), Mega (M), million (M), Giga (G)	k ='000, M = '000.000, G = '000.000.000
Joules (J)	J/3600 sec = Wh
Watt (W)	W * 8000 hours = Wh/year
Tonnes per day (TPD)	TPD/24*8000 = tonnes/year
Energy density	
Hydrogen	39,396 kWh/kg at HHV
Ammonia	6,25 kWh/kg at HHV
DBT	1,878 kWh/kg at HHV
Mass density	
Liquid hydrogen	0,0710 tonnes/m^3
Ammonia	0,769 tonnes/m^3
DBT	0,871 tonnes/m^3
Hydrogen mass density	
Ammonia	17,77% H2

DBT	6,2% H_2
Currency	
US dollar (USD)	1 USD = €0,92
Australian dollar (AUS$)	1 AUS$ = €0,63

The normalisation process yields a wide spectrum of values for the assessment indicators, representing the full range of potential scenarios for the development of hydrogen imports for each carrier. This range is furthermore valuable in indicating the relative certainty or uncertainty of the costs associated with different elements. However, due to its extensive width, this range is not useful for evaluating the development of imports or identifying potential policy gaps. Consequently, a narrower, most-likely range within this cost range is sought.

Some cost differences are explained by the sizing of the elements. For instance, if the literature suggests a projected cost decrease correlates with an increase in the size of an element, it is worthwhile to investigate the relationship between size and cost.

The distances for the transport to the port is found through Google Maps (2023) and the shipping distance through Sea-Distances.org (2023). The technical and system design part of the inventory analysis is further enriched and adjusted through expert interviews to optimise supply chain design.

Table 4.2: An overview of the assessed reports.

Report	Reference year	Organisation	Type of study
ISPT (2019)	2050	Dutch research organisation with strong collaboration with industry	HyChain 2, part of a series of studies on hydrogen. 13,6 Mt to NL through many different carriers. High over analysis
Daiyan et al. (2021)	2030	HySupply project. Large consortium on hydrogen transport from Australia to Germany	Different carriers to Port of Rotterdam from different Australian locations
JRC (2022)	2030-2035	EU Joint Research Centre	1 Mt supply chain from Portugal to Wilhelmshaven
TNO (2022)	2030	Dutch research and applied science organisation with strong collaboration with industry	Dutch research organisation. Different supply chains to the Netherlands.
IEA (2021)	2030	International Energy Agency	Raw input assumptions on the supply chain elements.

IRENA (2022d)	2030	International Renewable Energy Agency	Optimistic and pessimistic scenario. Small, 10.000 t/year supply chain.
EHB & Guidehouse (2021)	2030	European hydrogen backbone initiative	Plans for European pipeline network, including import overseas to Port of Rotterdam.
DNV GL (2020)	n.d.	Large independent assurance and risk management expert	Paper review on existing assessments to support a likely cost scenario
ENTEC (2022)	2030	EU Energy Transition Expertise Centre	Broad report on role of storage and import for EU
Sekkesæter (2019)	2025	Graduation thesis that is widely quoted in other reports	Two supply chains, from Iceland to Norway and from Norway to Japan.

Most-likely scenario - size and cost correlation

In industry a scaling factor is often applied to address the correlation between size and costs (My Engineering Tools, 2023). This factor is used when costs for a known plant size are available, and predictions for smaller or larger plants are needed (My Engineering Tools, 2023). The formula for the scaling factor is shown in Formula 4.6. If a scaling factor is identified, the curve follows a power function, or a function with a fixed exponent (Gladwin, 2012).

$$C_B = C_A*(PS_B/PS_A)^s \qquad (4.6)$$

C_B CAPEX of plant B
C_A CAPEX of plant A
PS_B Plant size B
PS_A Plant size A
s Scaling factor

The appropriateness of a power function can be evaluated in Excel, which provides an R-squared value indicating the accuracy of the identified function. In this study, a scaling factor is assumed when Excel demonstrates >90% certainty, and no greater certainty is found for a linear scaling factor. A higher certainty for a linear increase challenges the theory of economies of scale.

If certainty is insufficient to determine a scaling factor but a likely correlation with size exists, a most-likely scenario is established differently. Specifically, those data points are included whose element size lies within 75-125% of the assessed size. Furthermore, any realistic values associated with larger elements and correspondingly larger costs are included. Similarly, smaller elements associated with lower costs are also included. An example is seen in Figure 4.5.

If the assessed size is 50,000 tonnes, the extreme high and low values between 40,000 and 60,000 form the most likely scenario. However, if any values fall within the blue boxes, these represent exceptions to the principle of economies of scale and, therefore, are also included in the most likely range. This approach ensures all relevant data is incorporated into the analysis, providing a more comprehensive and realistic scenario.

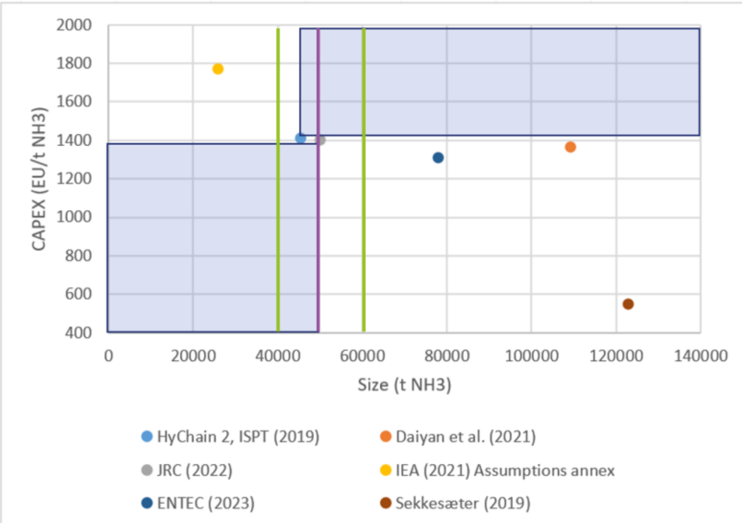


Figure 4.5: The applied method to select the most-likely scenario when there is a cost-size correlation, but no scaling factor.

Most likely scenario - other

For other indicators, the most-likely scenario is determined by excluding the unlikely high and low values. The realism of data points is firstly verified where possible, then the likelihood of certain ranges is assessed. The chosen method to do so should respond to dataset uncertainty, expanding or contracting the most-likely range accordingly.

One method that responds to uncertainty is using the Z-score, which is calculated with the standard deviation. The standard deviation is a statistical measurement that shows the spread of a set of data points. A low standard deviation suggests data points are close to the mean, while a high standard deviation indicates a broader range.

Z-score measures the number of standard deviations a data point deviates from the mean. As seen in Figure 4.6, a data point with a Z-value above 2 is seen as moderately unusual, and could therefore be excluded.

A limitation of using the Z-score is that a dataset must show a normal distribution. This signifies the dataset's mean is also the median, and outliers are found on both extremes. As the data can exhibit asymmetric, also referred to as skewness, this method is not applicable.

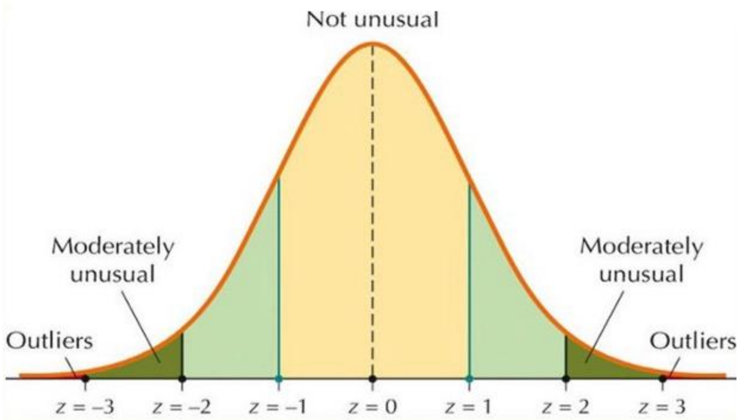


Figure 4.6: A visualisation of normal data distribution and how Z-scores can be used (Bhat, 2023).

An alternative method that overcomes this challenge is the Interquartile Range (IQR), which leverages the median instead of the mean, making it more robust to skewness (Bhat, 2023). The IQR encompasses the middle 50% of data points, determined by calculating the median of the dataset, and subsequently finding the medians of the lower and upper halves. These represent the 25th (Q1) and 75th (Q3) percentiles, respectively. The IQR, as illustrated in Formula 4.7, is the difference between Q3 and Q1. Outliers are identified by applying a factor to the IQR: subtracted from Q1 or added to Q3. While a factor of 1,5 is commonly used to identify outliers, this study aims to define a most-likely range, and therefore applies a factor of 1 to the IQR. The most-likely range is defined by Formula 4.8 and 4.9.

Figure 4.7 demonstrates the application of IQR to identify outliers (Bhat, 2023). Excel is used to determine Q1 and Q3.

$$IQR = Q3-Q1 \qquad (4.7)$$
$$MLl = Q1-1*IQR \qquad (4.8)$$
$$MLh = Q3 + 1*IQR \qquad (4.9)$$

IQR	Interquartile range
Q3	The 75th percentile
Q1	The 25th percentile
MLl	Most-likely low value
MLh	Most-likely high value

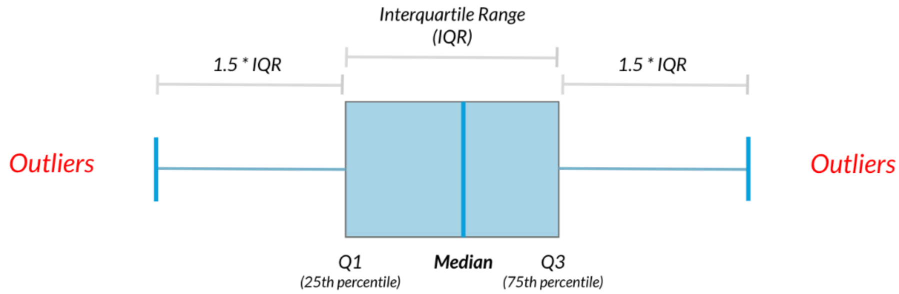


Figure 4.7: The application of IQR to identify outliers (Bhat, 2023).

4.3.3 Calculation of indicators

Following data collection, findings are processed into results using Excel. The model sequentially guides the user through all the process steps defined in the analysis goal and scope for each supply chain. In every process step the model uses the assessment indicators to determine the energy output of the process, as well as the yearly costs or capital costs that are involved in the process step. The model computes the hourly energy yield from the process steps through starting with raw wind and solar data and amends these to find the annual yield.

The annual costs are found by amending the cost associated with each process step discovered during the inventory analysis. To compute the cost of hydrogen, the Levelized Cost of Energy (LCOE) method, or in this instance, the Levelized Cost of Hydrogen (LCOH) method, as explained by Short et al. (1995) is used. This method determines the cost by dividing the present-day value of all lifetime costs by the total lifetime benefits, wherein future benefits and costs are discounted to their Net Present Value (NPV). The LCOH is calculated using formulas 4.10, 4.11, and 4.12

$$LCOH = \frac{NPV\ of\ lifetime\ costs}{NPV\ of\ lifetime\ hydrogen\ produced} \tag{4.10}$$

$$NPV\ of\ lifetime\ costs = \sum_{t=1}^{n} \frac{I_t + M_t}{(1+r)^t} \tag{4.11}$$

$$NPV\ of\ lifetime\ hydrogen\ produced = \sum_{t=1}^{n} \frac{H_t}{(1+r)^t} \tag{4.12}$$

I_t	The capital expenditures in year t
M_t	The fixed and variable operational costs in year t
H_t	The amount of hydrogen produced in year t
n	The lifetime of the investment
r	The discount rate

The real WACC values identified in the inventory represent the discount rates for the costs of a certain element within that country. For ships the Dutch discount rate is assumed. The hydrogen's cost is discounted using a combination of the exporting country's WACC and the Dutch WACC, aligned with the proportion of costs originating from each respective country.

The optimal installed quantities of wind and solar power, which will minimise the hydrogen production cost in each country can be found with the model. This optimization is conducted using Excel's Solver add-in. The results provide the optimal installed capacities, representing the power that will feed into the electrolyser under each scenario. If additional power is needed for other processes this is added in the same wind to PV ratio.

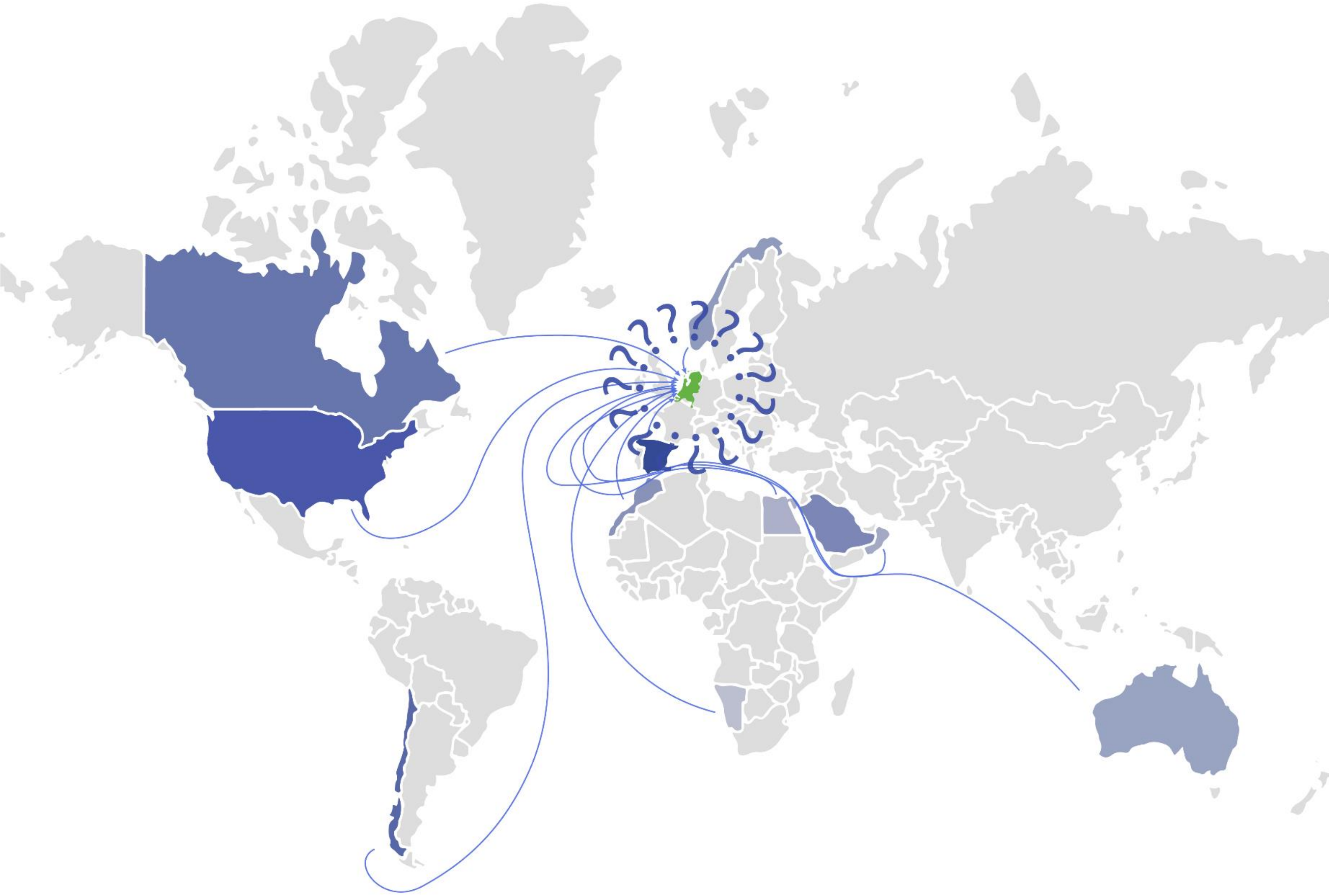
The efficiency of transportation is quantified by taking the ratio of the hydrogen energy output to the total energy required to deliver the hydrogen, starting from the point of its production. This encompasses energy losses from processes such as hydrogen cracking or shipping. It also accounts for the energy drawn from the Dutch grid or consumed in the exporting country.

When considering the costs associated with each system element, proper allocation is crucial. A simplistic approach would involve dividing the individual element costs by the net present value (NPV) of the produced hydrogen. However, this method does not account for the energy losses within the system. To accurately address these losses, the lost energy share of the costs related to the processes that precede an energy loss are allocated to the element where the loss occurs. Additionally, renewable energies employed for intermediate transportation, storage, or carrier formation are correspondingly attributed to those specific processes.

4.3.4 Interpretation & implications

Throughout the project, a continual process of interpretation ensures that data and intermediate results align with the research goal and scope (Zimmermann et al., 2020). Furthermore, final conclusions are drawn and results are translated into practical recommendations for stakeholders.

5. Results MCA - The first developing value chains



To assess what the most valuable pilots are to address it should be explored what the first value chains could be that are forming to the Netherlands. To do this both different modes of hydrogen transport and different exporting countries should be explored. In this chapter it is assessed how countries differ in their potential to become an early hydrogen exporter to the Netherlands and what is shaping this potential. First the criteria are explored, after which the options, or countries under assessment, are selected. The criteria are then quantified and normalised. For ease of reading this report, the options are first presented, to directly explain, quantify and normalise each of the criteria. Subsequently, in the participatory part of the study, weighting is applied by experts. Finally, sensitivity analysis is conducted, and the results are presented.

5.1 Options - Countries assessed

The options are selected based on their performance in the criteria. To create a diverse set of options they are selected from all areas of the world that are potential exporters. Following the example of Hajonides van der Meulen et al. (2022) also some neighbouring countries are specifically assessed to explore whether there is a significant difference. These areas are North America, South America, North Afrika, South Africa, the Middle East and Oceania (Hydrogen Council & McKinsey and Company, 2022; IRENA, 2022b). This can also be seen in figure 5.1. Notably, despite its inclusion in IRENA's (2022b) assessment, Russia is excluded due to Europe's specific demand for independence from its imports (European Commission, 2022). Within Europe itself also Northern Europe and the Mediterranean region are seen as potential exporters (European Commission, 2022).

Within these regions all countries recognised as potential exporters by Hydrogen Council & McKinsey and Company (2022), IRENA (2022b), IEA (2022b) or REPowerEU considered (European Commission, 2022). They are broadly evaluated based on the quantifiable criteria: distance to the Netherlands (Sea-Distances.org, 2023), hydrogen production cost potential (PWC, 2023a), trade relations (European Commission, 2022; IRENA, 2022a), local subsidies (IRENA, 2022b), national hydrogen strategy presence (IEA, 2022b), projects in the pipeline (IEA, 2022c) and country risk (Atradius, 2023). Additional compelling factors are noted when relevant. Each region's brief evaluation follows, with the criteria further elaborated in section 5.2.

Figure 5.1: Expected global hydrogen trade in 2030 according to Hydrogen Council & McKinsey and Company (2022).

North America

Both the United States and Canada could potentially be exporters by 2030, with strengths in project volume, local subsidies, and country risk. The United States demonstrates higher affordable hydrogen production potential, while Canada has a hydrogen trade relation with the Netherlands. Consequently, both countries are included to explore whether they will differ significantly in ranking.

South America

Among South American countries, Chile, Argentina, and Brazil emerge as possible key exporters. Brazil is geographically closer to the Netherlands than Chile and Argentina. However, Chile exhibits a more substantial potential for low-cost hydrogen, local subsidies, lower country risk, a greater number of projects in the pipeline, and a hydrogen trade relation with the Netherlands. Therefore, only Chile is included.

Sub-Saharan Africa

Namibia and South Africa present viable options in Sub-Saharan Africa. Though comparable on most criteria, Namibia has a slightly higher country risk and fewer projects in the pipeline. Despite this, the substantial investments from the Dutch and German governments favour Namibia (Invest International, 2023; Sasscal, 2022). Only Namibia is therefore included.

North Africa

Many North African Countries are promising, but mainly Mauritania, Algeria, Morocco and Egypt are often mentioned. Despite certain similarities, Egypt and Morocco distinguish themselves. Morocco has the lowest country risk and has an MOU with the Netherlands, while Egypt has most projects in the pipeline and is specifically mentioned in REPowerEU. These are therefore both included.

Middle East

Oman, Saudi Arabia, and the United Arab Emirates are potential exporters from the Middle East. Oman has a higher country risk, but has a substantial project pipeline and has an MOU with the Netherlands. Saudi Arabia also has an MOU and could be one of the first mover through the NEOM project (ACWA Power, 2023). Therefore these two are assessed and The United Arab Emirates is excluded from the analysis.

Oceania

In Oceania Australia is the main country of interest. It is large in size, has a great renewable energy potential, the largest project pipeline and an MOU with the Netherlands.

Northern Europe

Norway, Sweden, Denmark, and Iceland are frequently cited among Northern European countries. Despite Iceland's significant geothermal and hydropower potential, it lacks major hydrogen projects. (Hoes et al., 2017; Richter, 2020). Limited space and consequently sparse public support seem to restrict the development of hydrogen projects in Iceland (X. Japin, expert interview, May 3, 2023). As a result, Iceland is excluded from consideration. Among the remaining Scandinavian countries, Norway draws attention due to its specific mention in the Hydrogen Council report, as well as the plans for a European Hydrogen Backbone (EHB & Guidehouse, 2022). Norway is therefore included in the analysis.

Northern Mediterranean & Ukraine

Spain, Portugal, and Ukraine emerge as potential exporters. Nonetheless, the escalated country risk in Ukraine, a consequence of the 2022 war, precludes it from consideration. While Spain and Portugal exhibit comparable characteristics, Spain's superior subsidies and more extensive project pipeline secure its selection.

5.2 Criteria, quantification and normalisation

This section draws from a full system diagram of potential factors affecting the development of green hydrogen supply chains to the Netherlands. Three primary categories emerged from this scrutiny: factors affecting hydrogen costs, those determining if alternative hydrogen uses are more appealing, and those providing countries an early advantage in development. This section delves into these primary categories and their respective influencing criteria. A thorough exposition of all influential factors, accompanied by the system diagram, is available in Appendix 2.

5.2.1 Levelized cost of hydrogen delivered to the Netherlands

The cost of the hydrogen is very important in the adoption of the energy carrier and thereby in the forming of supply chains (IEA, 2019). The Levelized Cost of Hydrogen (LCOH) delivered is shaped by three primary factors: the potential for low cost hydrogen production, transportation costs, and the country specific costs of capital. While the costs of producing and transporting the hydrogen are intuitive, also the cost of capital is highly important. Capital costs for example constitute 20-50% of the levelized cost of solar electricity, as recognized by the IEA (2021a).

Given significant uncertainties surrounding these cost elements, their contributions to the LCOH are explained, quantified, and normalised below, with the weightings determined during the expert workshop.

5.2.1.1 Potential to produce low cost hydrogen

A country's potential to export hydrogen logically correlates with its ability to produce low-cost hydrogen. To do this the most important country specific variable is the cost of renewable electricity (Hajonides van der Meulen et al., 2022). Globally, solar and wind potential, illustrated in Figures 5.2 and 5.3, are pivotal for hydrogen production. Regions like Australia, large parts of Africa, the Middle East, U.S., Mexico, and Chile possess strong solar potential, with Australia, the Saharan region, and the Middle East also displaying substantial wind potential. This dual potential enhances electrolyser operation, reducing the cost proportion of hydrogen factory CAPEX through increased production (IRENA, 2022c).

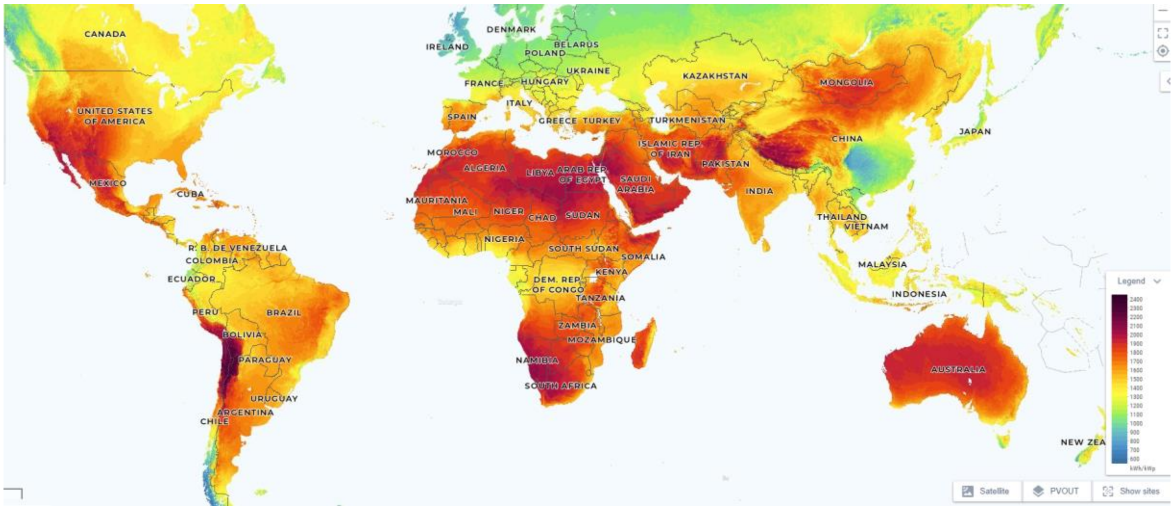


Figure 5.2: global average solar irradiation. (Global Solar Atlas, 2023)

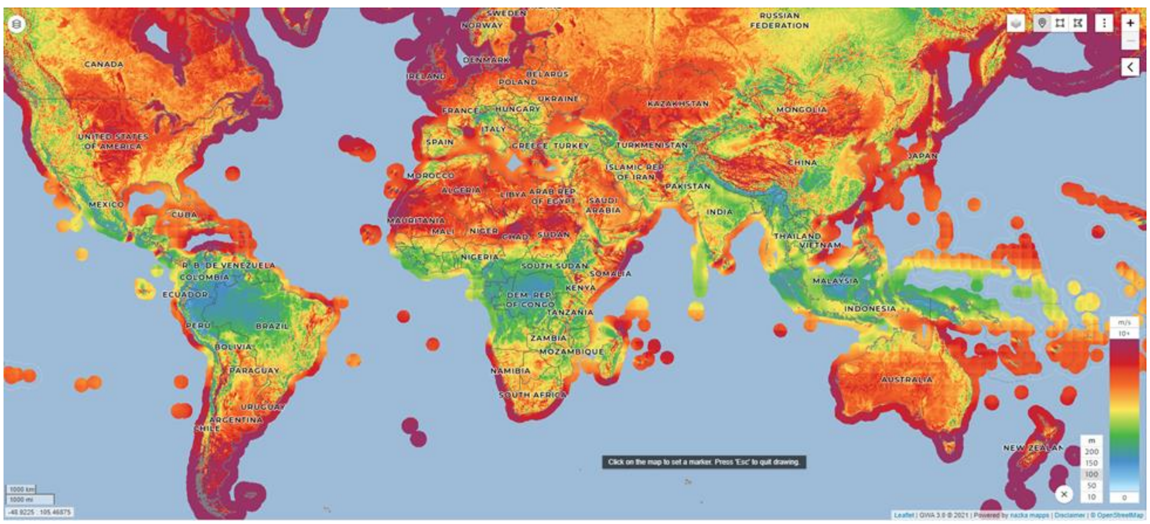


Figure 5.3: Global average wind speeds. (Global Wind Atlas, 2023)

Also other renewables such as geothermal energy, biomass or hydropower can be used for hydrogen production if they are abundantly available and can sustainably be harvested. Large parts of South America, Canada, Scandinavia or Indonesia are examples of areas that possess high hydropower potential (Hoes et al., 2017). Iceland, parts of North America and Oceania show a strong geothermal energy potential (Richter, 2020). Although these sources offer controllable electricity production and less intermittency, expansion constraints exist due to ecosystem effects (hydropower) and cost competitiveness (geothermal) (Enel, 2023; Energy.gov, 2023; Fendt & Parsons, 2021; IRENA, 2022b).

Several techniques are available for hydrogen production from biomass, including gasification, pyrolysis, and reforming (Binder et al., 2018). Gasification primarily yields hydrogen and carbon monoxide (syngas), with additional hydrogen producible through a water-gas-shift reaction, where carbon monoxide and water form carbon dioxide and hydrogen. Pyrolysis results in a diverse set of outputs, such as syngas, bio-char, gas, and oil; these can be further gasified or reformed to produce hydrogen (Binder et al., 2018). However, the feasibility of using biomass for hydrogen export is constrained by factors such as the limited availability of sustainable biomass and its competing applications in green chemistry for producing various sustainable hydrocarbons (Binder et al., 2018; IEA, 2021d). This is also confirmed by the lack of large scale biobased hydrogen production projects in the hydrogen projects database of the IEA (2022c). The main focus for renewable hydrogen production is therefore on wind and solar (Hajonides van der Meulen et al., 2022; IEA, 2019; Roland Berger, 2021).

As seen in Figure 5.4, Chile emerges as one of the most cost-efficient hydrogen producers, along with northern and southern Africa, the Middle East, parts of Asia, Australia, and the U.S. (IEA, 2019).

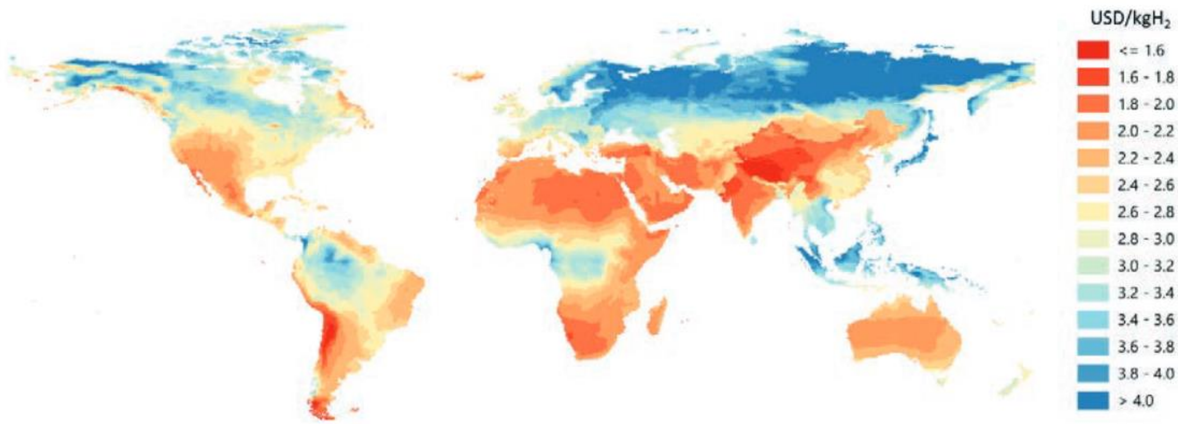


Figure 5.4: the forecasted future production cost of hydrogen based and combined solar and wind from IEA (2019).

Quantification & Normalisation

For the quantification of the hydrogen cost price the average trend in normalisation scores of four different reports is taken. Due to the many assumptions made every single report can only approach a difference in cost price. By combining these normalisations the relative difference in cost prices between the different countries can be approached. An example is that the IEA (2019) and Roland Berger (2021) only account for wind and solar potential while the others include all renewable energy types. Other differences result from for example the level of detail, technology cost uncertainties and the differing reference years.

Table 5.1: The cost price of hydrogen based on the pessimistic scenarios of four reports. Quantified and normalised as compared to each other.

country	IEA (2019) - Long term		PWC (2023a) - 2030		IRENA (2022b) - 2050		Roland Berger (2021) (Eu/kg - 2025)		Overall normalised score
	($/kg)	Norm.	(EU/kg)	Norm.	($/kg)	Norm.	(EU/kg)	Norm.	
Spain	**2,4**	0,40	**2,75**	0,00	**1,70**	0,57	**2,70**	0,56	0,38
Norway	**2,8**	0,00	**2,5**	0,50	**2,30**	0,00	**3,20**	0,00	0,13
Australia	**2,4**	0,40	**2,75**	0,00	**1,25**	1,00	**2,80**	0,44	0,46
United States	**2,2**	0,60	**2,75**	0,00	**1,50**	0,76	**2,70**	0,56	0,48
Canada	**2,8**	0,00	**2,75**	0,00	**1,25**	1,00	**3,20**	0,00	0,25
Morocco	**2,0**	0,80	**2,75**	0,00	**1,90**	0,38	**2,60**	0,67	0,46
Egypt	**2,0**	0,80	**2,50**	0,50	**1,90**	0,38	**2,60**	0,67	0,59
Namibia	**2,0**	0,80	**2,75**	0,00	**1,50**	0,76	**2,60**	0,67	0,56
Chile	**1,8**	1,00	**2,25**	1,00	**1,25**	1,00	**2,30**	1,00	1,00
Saudi Arabia	**2,0**	0,80	**2,50**	0,50	**1,90**	0,38	**2,60**	0,67	0,59
Oman	**2,0**	0,80	**2,50**	0,50	**1,90**	0,38	**2,60**	0,67	0,59

5.2.1.2 Cost of hydrogen transport to the Netherlands - Shipping distance

The costs associated with transporting hydrogen to the Netherlands are largely dependent on the chosen mode of transport. However, different routes of conversion, transport, and reconversion vary significantly in terms of CAPEX, OPEX, and energy use assumptions (IEA, 2021a). Due to discrepancies in the literature regarding the preferred mode of transport for a given distance, quantifying the costs of hydrogen transport from different countries becomes impossible. Consequently, the only quantifiable country-specific factor influencing costs is the distance to the Netherlands. Reports generally agree that certain break-even points exist, indicating when the preferred mode of transport changes. Longer distances result in increased energy use and necessitate a larger shipping fleet.

Quantification & Normalisation

Quantification and normalisation of transport costs are challenging due to the aforementioned uncertainties. Therefore, the shipping distance to the Netherlands is selected for quantification

and normalisation, and the expert workshop will assess the perceived influence of this factor on the hydrogen cost price.
The distance to the Netherlands is determined by identifying the shortest shipping distance to the Port of Rotterdam, while the reference port in the exporting country is chosen based on proximity to the largest project in that country from the IEA (2022) project database.

Table 5.2: Quantification of the shipping distance to the Netherlands.

Country	Project	Nearest port	Distance to Port of Rotterdam (Nautical miles) (Sea-Distances.org, 2023)	Normalisation
Spain	HyDeal	Santander	748	1,00
Norway	Hy2gen Sauda	Husnes	789	1,00
Australia	Asian Renewable Energy Hub	Port Hedland	9461	0,00
United States	HIF USA	Houston	5052	0,51
Canada	COURANT	Quebec	3151	0,72
Morocco	Amun	Agadir	1576	0,90
Egypt	Masdar Hassan Allam	Suez	3361	0,70
Namibia	Hyphen Hydrogen Energy	Walvis Bay	5545	0,45
Chile	H2 Magallanes	Punta Arenas	7416	0,23
Saudi Arabia	NEOM	Yanbu	3821	0,65
Oman	Oman-Al Wusta green H2 project	Sultan Qaboos	5866	0,41

5.2.1.3 Weighted average cost of capital

The weighted average cost of capital (WACC) gauges the average capital cost for a project, symbolising the minimum return essential to satisfy both equity and debt stakeholders. Capital comes with a cost as there are inherent risks to investments, as well as alternative financial opportunities. The IEA (2021a) asserts that the WACC contributes to 20-50% of the levelized cost for solar electricity, underscoring its significance in renewable energy project costs.

Risk profiles, and consequently WACC values, can vary across projects and countries (IEA, 2021b; Steffen, 2020). For instance, Steffen (2020) finds that non-OECD countries' solar PV projects can have WACC values 40% lower than those in OECD nations. Ondraczek et al. (2015) further highlight these disparities, citing a 4,3% WACC for the Netherlands compared to a 14,1% average for solar PV projects. To account for country-specific risk, WACC calculations incorporate a country risk factor, which remains consistent across projects within a given country. Various institutions, such as the OECD, trade firms, and insurance companies present what they believe should be this factor (Allianz Trade, 2023; Atradius, 2023; OECD, 2023). The built up of this risk factor and its interplay with project-specific components within the WACC are detailed further in Appendix 2.1.

Quantification and normalisation

For this research, the country risk map from Atradius (2023) is chosen. Atradius employs a six-point scale, where the lowest-scoring countries assessed are classified as moderate-high risk. To facilitate normalisation relative to the other countries, a four-point scale with increments of 0,333 is therefore utilised, as shown in Table 5.3.

Comparison with Allianz Trade’s (2023) country risk map for sensitivity reveals similar results. Allianz employs a four-point scale though, resulting in slight variations for certain countries.

Table 5.3: Quantification and normalisation of country risk.

Country	Country Risk (Atradius, 2023)	
Spain	Moderate-Low Risk	0,66
Norway	Low Risk	1
Australia	Low Risk	1
United States	Low Risk	1
Canada	Low Risk	1
Morocco	Moderate Risk	0,33
Egypt	Moderate-High Risk	0

Namibia	Moderate-High Risk	0
Chile	Moderate-Low Risk	0,66
Saudi Arabia	Moderate-Low Risk	0,66
Oman	Moderate Risk	0,33

5.2.2 A better business case for other use of the green hydrogen

Apart from exporting green hydrogen to the Netherlands, the sustainable energy carrier has various potential uses that could prevent the hydrogen from coming to the Netherlands. Below three possible alternative uses are elaborated that could lead to a country producing green hydrogen without exporting it to the Netherlands. These are that the country: (1) Uses the green hydrogen in its own industry (2) Sets up its own green industry (3) Sells it to alternative exporting offtakers.

Because it is impossible to quantify this criterion is qualitatively assessed by the participants of the MCA. They are asked to evaluate the likelihood of any of these factors preventing a country from developing exporting value chains to the Netherlands. Figure 5.5 shows the section of the system diagram that affects whether there is a better business case for other use of the green hydrogen.

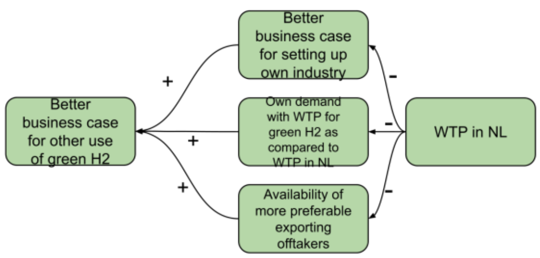


Figure 5.5: The aspects that affect whether there is a better business case for other use of the green hydrogen.

5.2.2.1 Own demand as compared to the willingness to pay in the Netherlands

The potential to produce low-cost hydrogen does not guarantee export, as a country may prioritise domestic consumption, particularly if it has a large energy-intensive industry. Strategy& (2020) for example identifies the United States, China, India, and Brazil as countries that are likely self-sufficient, while Australia, Canada, Chile, Argentina, Norway, and Gulf countries will likely be exporters. The Hydrogen Council & McKinsey and Company (2022) believe that both China and India will import hydrogen though. In similar studies the Carbon Tracker Initiative (2021) and IRENA (2022b) conclude that mainly the southern hemisphere will have a renewable energy potential that exceeds their own demand.

When looking at the first developing value chains the role of climate policies could overrule the above mentioned. Through different global climate policies the willingness to pay (WTP) for green hydrogen is not equal globally. European examples are the plans of the European hydrogen bank or H2Global (European Commission, 2023b; H2Global Stiftung, 2023). These initiatives will subsidise hydrogen import to the EU and will thereby increase the European willingness to pay. Wealthier consumers are additionally more willing to pay a premium for a green product (Horani, 2020). This will thus cause a larger WTP in developed countries like the Netherlands. Exporting countries may also exhibit a domestic Willingness to Pay (WTP) for hydrogen, particularly if they either produce a substantial volume of grey hydrogen or are importers of related products such as ammonia. For this particular criterion, the condition under which hydrogen will be exported can be defined as follows: hydrogen will be exported if the sum of the WTP in the exporting country and the associated transportation costs is still lower than the WTP in the Netherlands. This relationship is formally expressed in Formula 5.1. To illustrate, consider the case of Morocco, where ammonia is currently imported (Atchison, 2022). This could indicate a sufficient domestic WTP to utilize their locally produced green ammonia. However, if exporting to the Netherlands yields higher profitability, it is more probable that they would opt for export.

WTP for green H_2 in country X + H_2 transport costs < WTP for green H_2 in NL (5.1)

5.2.2.2 Setting up a domestic green industry

In the absence of green hydrogen demand in current domestic sectors, establishing industries for green products, such as green steel or sustainable fuels, can enhance local value and promote local green hydrogen consumption (Ministry of Mines and Energy Namibia, 2022). It also eliminates the need for conversion and reconversion of the hydrogen, bettering the exporting business case (Ministry of Mines and Energy Namibia, 2022).

Also the emergence of new markets can create opportunities for certain countries to develop a green industry domestically. For instance, Egypt's proximity to the Suez Canal positions it as a potential hub for green methanol bunkering (R. van Riel, expert interview, May 30, 2023).

Some argue that the establishment of these industries is crucial, viewing hydrogen importation as reflecting neo-colonial patterns, where European countries exploit the rich solar and wind potential of developing countries (Corporate Europe Observatory, 2023; Williams, 2021). The development of these local industries is proposed as a solution to address these concerns (Ministry of Mines and Energy Namibia, 2022).

However, predicting the dynamics between hydrogen exports and exports of its derivatives in the early stages is challenging.

5.2.2.3 Availability of more preferable exporting off-takers

Lastly, it is possible that a country becomes a hydrogen exporter, but that the Netherlands may not be the most economically viable destination. For example, if an Asian market for green hydrogen develops, it may be more attractive for Australia to export to that offset market rather than the European market. Both IRENA (2022d) and Hydrogen Council & McKinsey and Company (2022) believe that Australia will primarily export to Asia in the long run. IRENA (2022e) furthermore predicts the middle east will export to both the Asian as well as the European market. These are future scenarios though that may not align with the first developing value chains. These other directions will only compete if their willingness to pay for the green hydrogen is comparable with the Dutch willingness to pay. Currently, PWC (2023a) recognizes Japan and South Korea as the only non-European countries interested in importing green hydrogen. Hydrogen is rapidly developing in these countries and Korea has proposed large subsidies to stimulate imports (M. Mannien, expert interview, May 23, 2023). Furthermore, Korean companies are believed to be less risk-averse, making them more willing to take on the investment risks associated with hydrogen imports (M. Mannien, expert interview, May 23, 2023).

Competition for hydrogen supply could also apply within Europe. Hydrogen from the Mediterranean region, for example, may first supply other countries such as France, Belgium, or Germany before reaching the Netherlands (EHB & Guidehouse, 2022; Nuñez-Jimenez & De Blasio, 2022). In contrast, hydrogen from northern countries may initially reach the Netherlands and northern Germany. PWC (2023b) therefore even indicates that southern Germany could face supply problems by 2030.

Simplified these countries may be more favourable off-takers if the difference in their willingness to pay is larger than the difference in transporting costs, thus if Formula (5.2) holds true:

ΔWTP for green $H_2 < \Delta$ transporting costs (5.2)

The mode of transport will also influence whether more nearby off-takers are more attractive. For ammonia the shipping costs are for example low as compared to the fixed costs of conversion (JRC, 2022).

Quantification & Normalisation

The scoring of this criterion is done by the participants of MCA. They are asked to assess the likelihood of any of the above factors preventing a country from developing exporting value chains to the Netherlands. They will do this based on a five point Likert scale ranging from unlikely to likely. Figure 5.6 shows the results based on the inputs of ten experts. It is seen that mainly Australia is perceived to be prevented from export to the Netherlands, while the countries closer to the Netherlands are perceived to export to the Netherlands. Also the United States, possibly due to their significant own industry and climate policies is perceived less likely to export to the Netherlands.

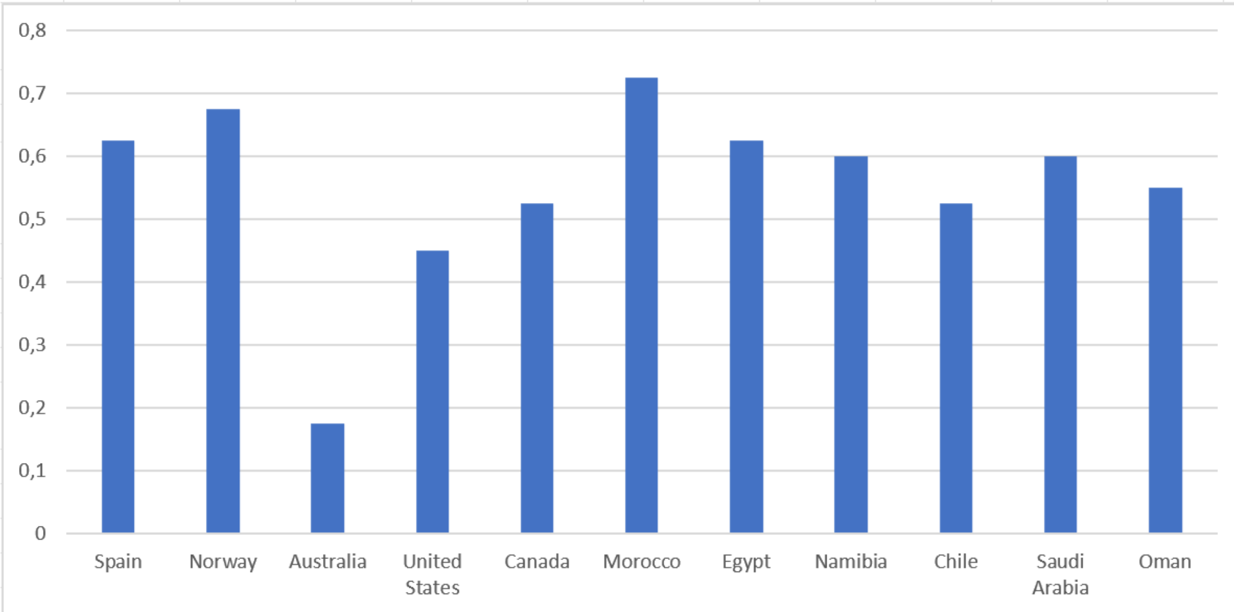


Figure 5.6: Normalised results from a participatory rating assessing the likelihood that certain countries might prioritise alternative uses for hydrogen over exporting to the Netherlands.

5.2.3 A head start

IRENA (2022e) suggests that the most economical value chains may not be the first ones to form due to various factors that give countries a head start. Four key aspects contributing to this head start are discussed below. Another factor causing a head start, as recognised by the IEA (2022b) and IRENA (2022d) is having a hydrogen strategy. A hydrogen strategy clearly outlines the goals for hydrogen development in countries and thereby derisks the project on for example the field of legislation (IRENA, 2022d). It is noted though that all countries assessed in the study have presented a hydrogen strategy (IEA, 2022b; Ministry of Mines and Energy Namibia, 2022; Nakano, 2022; State Information Service Egypt, 2022).

The four aspects included are bilateral agreements and trade relations, local subsidies, projects in the pipeline and soft resources.

5.2.3.1 Bilateral agreements & trade relations

Another possible head start is that of good trade relations. Notable among these relations are Memorandums of Understanding (MoUs), which are agreements entered into by governments and entities such as port organisations. Their intent is to streamline trade processes between countries and potentially mitigate project risks (R. Peeters, expert interview, June 21, 2023). Notably, governmental MoUs have been established with eight of the countries under assessment (Biogradlija, 2023b; IRENA, 2022a; Reuters, 2023b).

Historical trade relations can also ease contemporary trade. The United States are for example one of the top 6 trading partners of the Netherlands both on imports and exports (OEC, 2021). Through this many large companies are situated in both countries, exemplifying a distinct trade advantage for the United States (R. van Riel, expert interview, May 30, 2023). A more detailed exploration of this topic is available in Appendix 2.2.1.

Quantification and normalisation
Countries that have specific trade relations with the Netherlands in the form of an MOU were added as well as the United States for which an outstanding strong historical trade relation was identified. These are normalised with a rating of '1'. Countries without such trade relations are normalised with a rating of '0'.

Table 5.4: An overview of countries that have a trade relation with the Dutch government or a Dutch port.

Bilateral agreements or MOU's for collaboration					
Spain	yes	1	Egypt	no	0
Norway	no	0	Namibia	yes	1
Australia	yes	1	Chile	yes	1
United States	yes	1	Saudi Arabia	yes	1
Canada	yes	1	Oman	yes	1
Morocco	yes	1			

5.2.3.2 Local subsidies

Support in exporting countries can also significantly influence the development of hydrogen supply chains. For instance, the Inflation Reduction Act includes hydrogen production tax credits of $3 per kilogram (The White House, 2022). Some experts believe that these credits could potentially reduce the costs of hydrogen delivered to Europe by more than 50%, making it competitive with domestic production (Janzow et al., 2022). IRENA (2022a) visualises known subsidy programmes, as seen in Figure 5.7. It is noted that support in the form of subsidies is primarily available in more developed potential exporters such as Australia, the United States, Norway, Canada, and Spain. However, this data is somewhat dated and can be supplemented with information from the hydrogen review and policy database of the IEA (2022a, 2022b) and other sources (Australian Government, 2023; Fowler et al., 2023; Hydrogen Central, 2023; Reuters, 2023a). A more detailed exploration of this topic is available in Appendix 2.2.2.

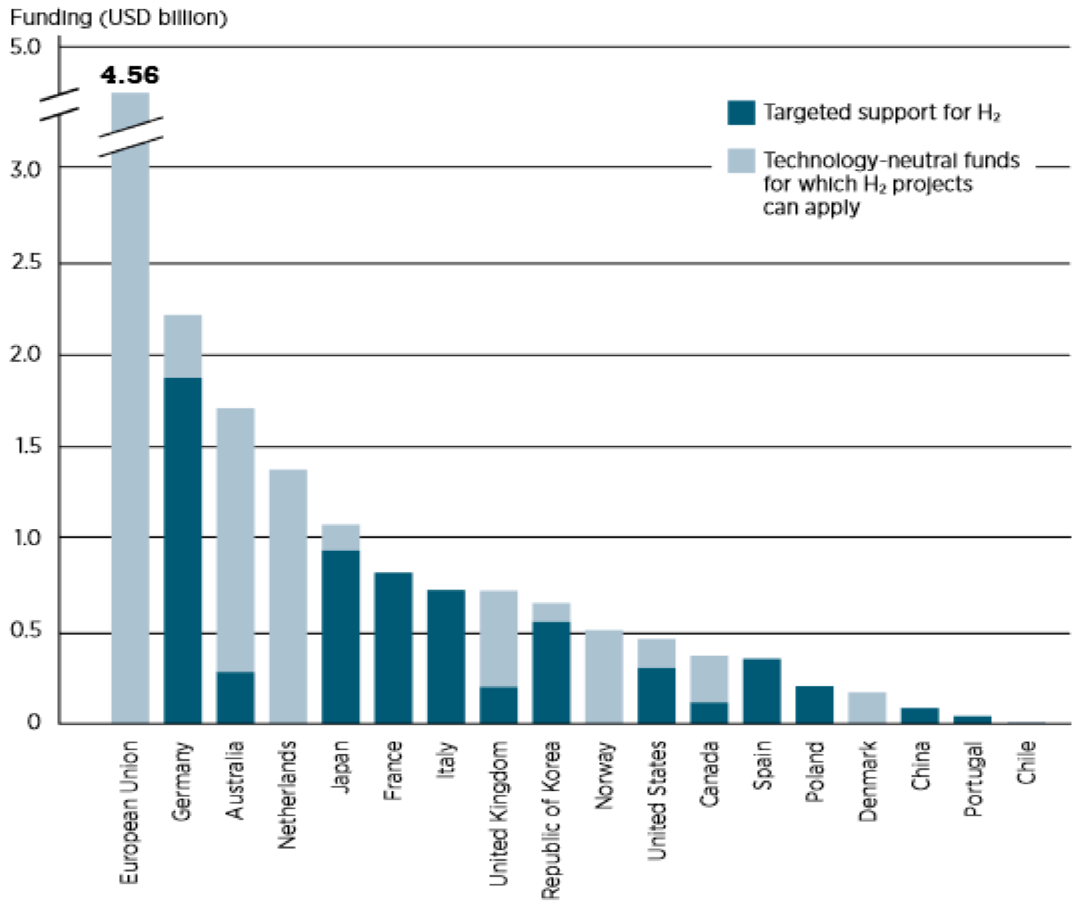


Figure 5.7 Annual funding available for hydrogen projects until 2030 from IRENA (2022a).

Quantification and normalisation

Quantifying subsidies is a challenging task due to the variations in CAPEX and OPEX-based subsidies, uncertainties regarding their impact on hydrogen exports, and difficulties in translating subsidies into per annum values. As a result, this criterion has to be quantified very high over. Countries without any form of subsidy will receive a rating of '0'. Countries with hydrogen subsidies below €500 million will receive a rating of '0.5', while countries with subsidies exceeding €500 million will receive a rating of '1'. The results of this normalisation process are presented in Table 5.5.

Table 5.5: Quantification and normalisation of the criteria for local subsidies.

Country	Local financial support	
	(IEA, 2022a, 2022b; IRENA, 2022a)	Normalised
Spain	~1555 MEU	1
Norway	9 MEU H2 infra + ~111 MEU H2 + NH3 production (Reuters, 2021)	0,5
Australia	1,33 b USD + ~349 M USD H2 hubs + ~206 M USD Advancing H2 fund + ~100M USD hydrogen trade program	1
United States	3 USD/kg tax credit (IRA has no cap, but Clifford (2023) expects ~100 b USD)	1
Canada	40% production tax discount + ~12,6 b USD announced between 2023-2035 (Fowler et al., 2023)	1
Morocco	0	0
Egypt	0	0
Namibia	0	0
Chile	50 M$	0,5
Saudi Arabia	0	0
Oman	0	0

5.2.3.3 Existing projects in the pipeline

The development of hydrogen import has reached a critical stage where it has become essential that actual projects are in the pipeline (M. Stoelinga, expert interview, April 4, 2023). The IEA (2022c) has compiled a comprehensive database of known projects as of October 2022. To ensure the reliability of the information, the database was cross-checked for completeness and consistency with known projects in the countries of interest. As a result, corrections were made to the capacity of the Namibian project, Hyphen, and the Moroccan project, Amun, was added (Ammonia Energy Association, 2022; Hyphen, 2023). Additionally, three new Canadian projects were added (Hy2Gen, 2023; Parkes, 2022; Penrod, 2023).

Next, the database was filtered to remove projects without presented capacities, those based on fossil fuels, and smaller projects below 100 MW. An important complication is that some projects only present the electrolyser capacity, while others only present the amount of hydrogen produced. When this is the case the database assumes 8000 operating hours (IEA, 2022c). The results of the cumulative proposed yearly production until 2030 is visualised in Figure 5.8. As the database does not include a proposed online data for all projects the total proposed capacity and the amount of projects were used, irrespective of a proposed online date. A discussion on these results as well as the proposed capacity and amount of projects for a broader group of potential exporting countries is found in Appendix 2.2.3.

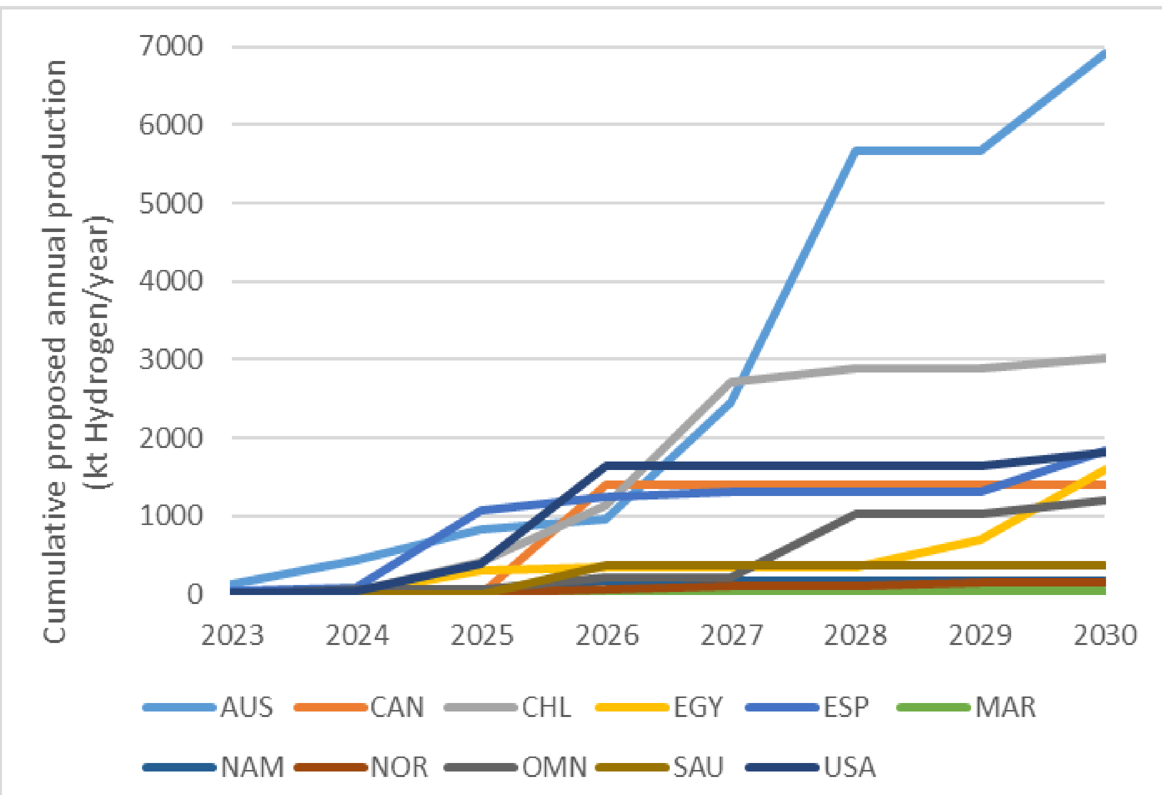


Figure 5.8: All projects with proposed date in operation before 2030, expressed in hydrogen produced.

Quantification and normalisation

Both the proposed total electrolyser volume and the number of proposed projects undergo maximum normalisation, irrespective of a proposed online date. The results are displayed in Table 5.6.

Table 5.6: Total proposed projects of 100 MW or more.

Country	Total proposed electrolyser power		Amount of proposed projects	
	MW (IEA, 2022)	Normalised	(IEA, 2022)	Normalised
Spain	13351	0,15	23	0,55
Norway	3679	0,03	8	0,18
Australia	84221	1,00	41	1,00
United States	28935	0,34	16	0,38
Canada	12503	0,13	7	0,08
Morocco	2307	0,02	3	0,05
Egypt	9912	0,11	14	0,33
Namibia	4000	0,04	2	0,03
Chile	19774	0,23	13	0,30
Saudi Arabia	2200	0,02	1	0,00
Oman	18502	0,21	9	0,20

5.2.3.4 (Soft) resources

Soft resources are non-economic, non-physical factors that can be important in developing value chains. Examples are human resources and available companies, but also institutions and other aspects that ease the local development of these projects. They can go hand-in-hand with physical resources. Therefore soft is put between brackets in this impact factor.

5.2.3.4.1 Competitiveness

Pflugmann & De Blasio (2020) and Nuñez-Jimenez & De Blasio (2022) see a country's ability to realise the infrastructure as a limiting factor for the development of a hydrogen supply chain. They assess this ability using the World Economic Forum's (2019) World Competitiveness Index that rates the quality of existing infrastructure. Their conclusion is that a substantial share of countries is currently not equipped to become successful exporters. A country's infrastructure is one of the twelve pillars of the Global Competitiveness Index (GCI) which tends to measure "the attributes and qualities of an economy that allow for a more efficient use of factors of production" (World Economic Forum, 2019, p. 2). Essentially, these are thus factors influencing a country's potential for economic growth.

Although it is debatable how much their current infrastructure quality will impact their capacity to build new infrastructure, certain aspects of their existing infrastructure could prove valuable in the development of the supply chains. Examples include power infrastructure, good roads, port facilities, or potentially repurposable gas infrastructure (ENTEC, 2022).

IRENA (2022b) calls a comparable group of factors assessed in the GCI soft resources. They believe these factors are likely to cause a premium paid for hydrogen through certain value chains that have these soft resources. Intriguingly, some of these resources also align with the GCI pillars (World Economic Forum, 2019). IRENA (2022b) for instance, emphasises the significance of human capital, mirrored in the GCI's skills and labour market pillars (World Economic Forum, 2019). Additionally, IRENA (2022b) recognises the importance of diverse economic factors, similar to the GCI pillars of financial system, macroeconomic stability, and business dynamism. They also highlight the critical role of policy aspects, such as government transparency and a sound legal framework, which is included under the GCI's institutions pillar (IRENA, 2022b; World Economic Forum, 2019). It is therefore concluded that the GCI can be applicable as an indicator of a country's soft resources, which again results in possible hard resources through their assessed infrastructure potential. More information on soft resources is found in Appendix 2.2.4.

Quantification and Normalisation
Countries are quantified based on their GCI scores from the World Economic Forum, as seen in Table 5.7.

Table 5.7: The global competitiveness index.

Country	Global Competitiveness Index (World Economic Forum, 2019)	Maximum normalisation
Spain	75,3	0,71
Norway	78,1	0,81
Australia	78,7	0,83
United States	83,7	1,00
Canada	79,6	0,86
Morocco	60,0	0,19
Egypt	54,5	0,00
Namibia	54,5	0,00
Chile	70,5	0,55
Saudi Arabia	70,0	0,53
Oman	63,6	0,31

5.2.3.4.2 Experience with hydrogen or its derivatives

Experience with hydrogen is a soft resource mentioned by IRENA (2022b) that is not included in the GCI. Countries with such experience are more likely to have the required workforce, corporate entities, and knowledge for handling hydrogen, thereby enjoying an advantage over others. Similarly, countries with experience in managing hydrogen carriers, such as ammonia, will share this advantage. This soft resource will consequently also possibly result in having usable or repurposable infrastructure for supply chain development.

Quantification and normalisation

Assessing a country's experience in handling hydrogen or hydrogen carriers is challenging. Canada, Egypt, the U.S., and Saudi Arabia are addressed by IRENA (2022a) as countries with a large current hydrogen demand. For the other countries, the two primary hydrogen-consuming industries are considered: refineries and fertiliser production (IEA, 2022b). For the latter a country is viewed as having significant experience with hydrogen or ammonia if it imports or exports >1 Mt of ammonia or urea annually. Besides the aforementioned countries, this criterion only applies to Oman and Morocco (ICIS, 2018). A country is considered to have significant experience with hydrogen in refineries if it houses an above-average number of refineries. The average number of refineries per country stands at 3.8; hence, only Spain and Australia score above average among the remaining countries (Aizarani, 2023; Auch, 2017; Worldometer, 2023). Notable hydrogen experience is scored as ‘1’, and a lack thereof is scored as ‘0’, as indicated in Table 5.8.

Table 5.8: Quantification and normalisation of a country's experience with handling hydrogen.

Country	Experience with hydrogen			
	Part of top hydrogen consuming countries according to IRENA (2022a)	Importer of ammonia or exporter of ammonia or urea (ICIS, 2018)	Above average refineries (Aizarani, 2023; Auch, 2017; Worldometer, 2023)	Normalisation
Spain	no	no	yes	1
Norway	no	no	no	0
Australia	no	no	yes	1
United States	yes			1
Canada	yes			1
Morocco	no	yes		1
Egypt	yes			1
Namibia	no	no	no	0
Chile	no	no	no	0
Saudi Arabia	yes			1
Oman	no	yes		1

5.2.4 Summary of criteria selection

Figure 5.9 provides an overview of the aforementioned criteria. This overview also served as a guide for explaining the criteria to participants of the weighing workshop. These were distilled from a more extensive exploration of potential influential criteria, as depicted in Figure 5.10. A detailed discussion on this can be found in Appendix 2.

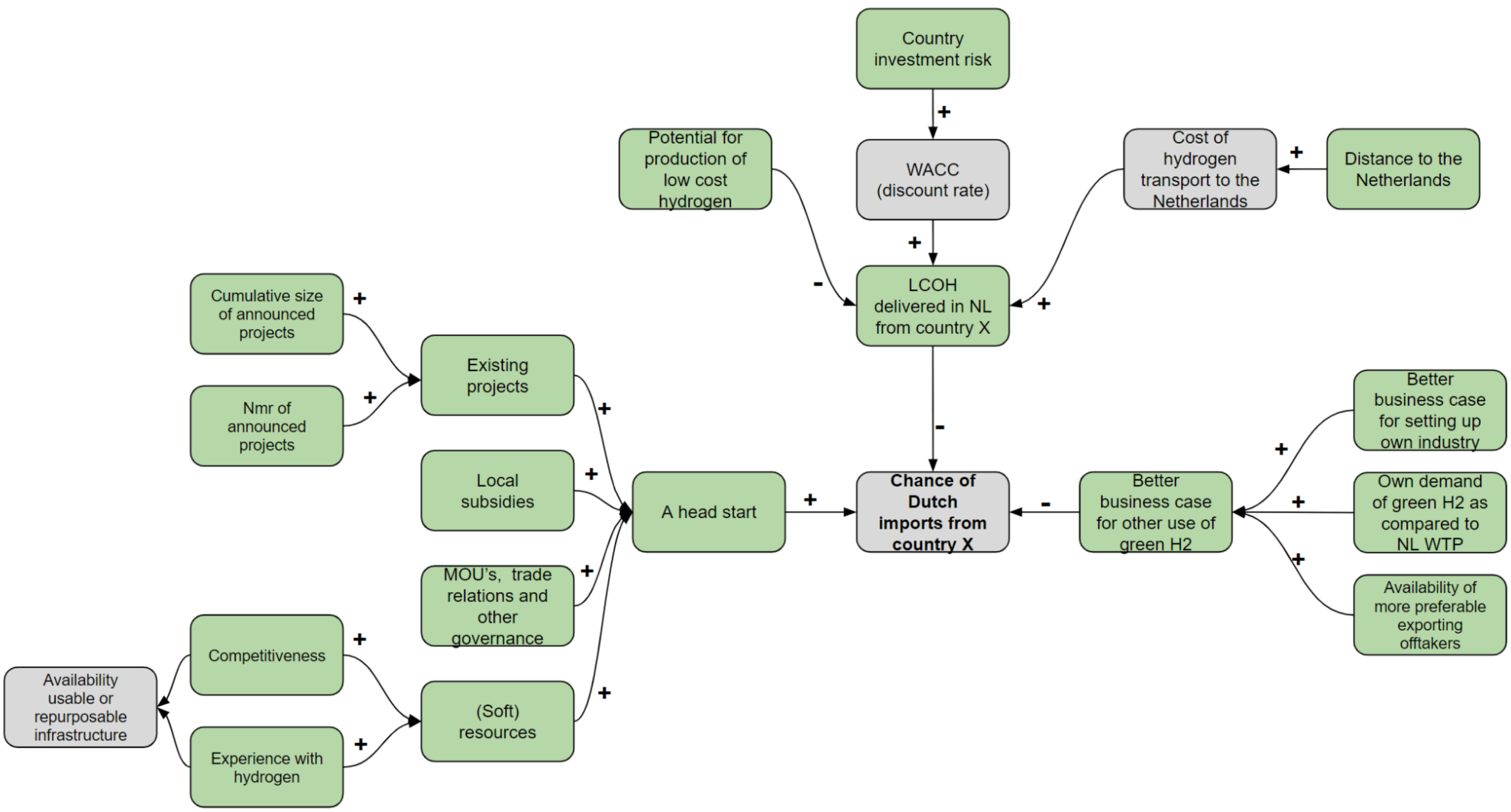


Figure 5.9: A summary of the criteria included in the MCA. The green boxes present the criteria that were weighted.

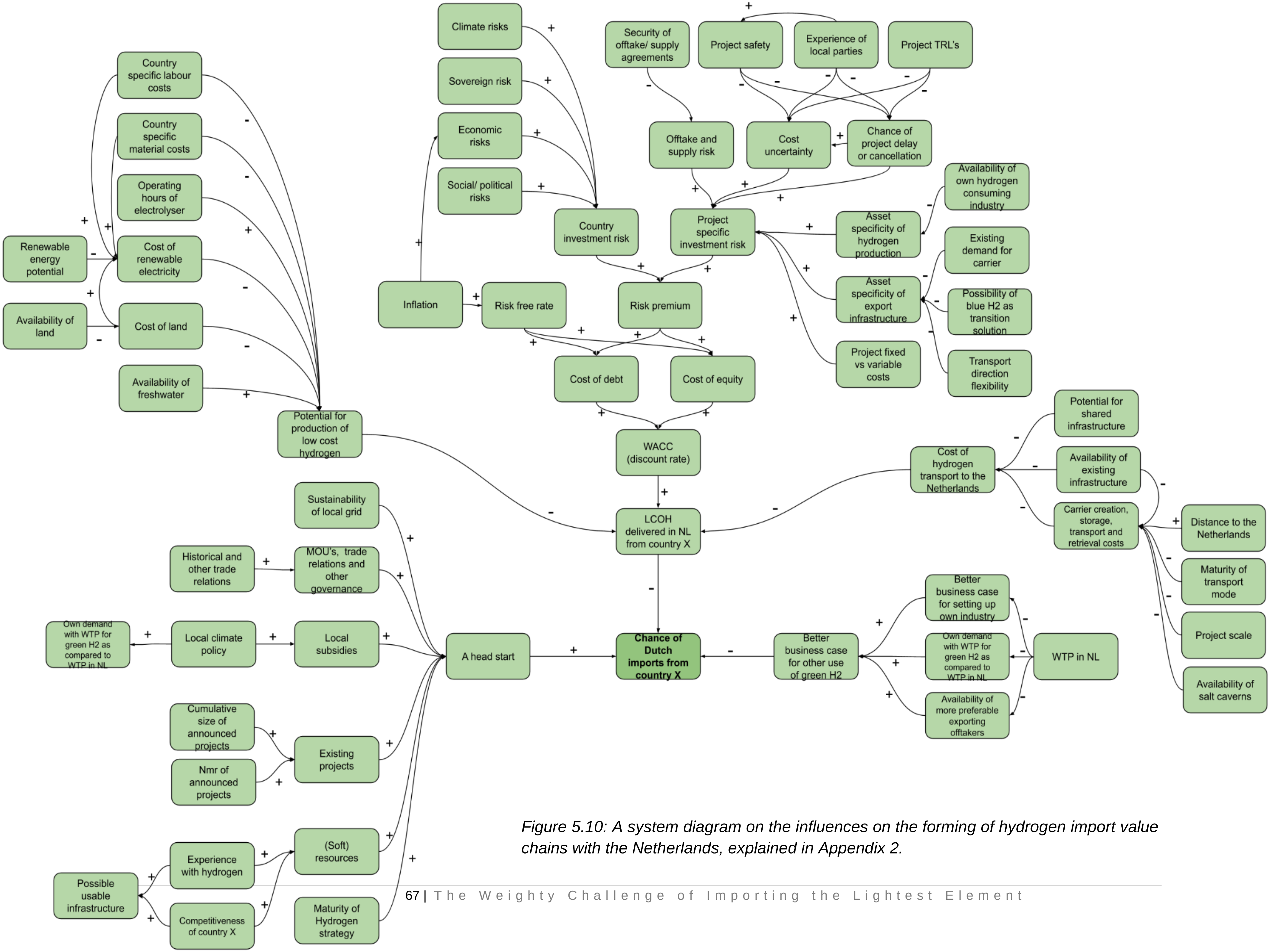


Figure 5.10: A system diagram on the influences on the forming of hydrogen import value chains with the Netherlands, explained in Appendix 2.

5.3 Weighing

To obtain reliable results from the weighting process, it is crucial to follow the prescribed method correctly. Key aspects include clearly defined scoring and criteria, and avoiding an excessive number of criteria to be weighed simultaneously. The latter was the motivation to group the different criteria and perform the weighing in different steps. Moreover, having a participant group with the proper expertise to conduct the weighting is essential. The identification of relevant stakeholders is done below, following which the results of the weighting process are presented.

5.3.1 Identification of relevant stakeholders

The main focus group is anyone that is involved in hydrogen imports, but that does not have a bias for a specific country. Specific country representatives or people developing an import project could for example respond differently to specific criteria to promote their country. Ideal participants for the weighing process for example include people working for the government, for port authorities, companies that try to acquire imported hydrogen, research organisations, or for companies that consider launching projects abroad, but that are not yet specifically invested in a single country. A list of the 10 experts that participated in the weighing is found in Appendix 3.

5.3.2 Results of the weighing

Figure 5.11 shows the weighting form presented to the participants of the MCA, including the average weights that were given and Figure 5.12 visualises these. The consensus appears to be that cost factors are of the largest importance, followed by the potential for alternative uses of green hydrogen. One participant interestingly suggested that the alternative use of hydrogen could possibly even be more effective when used not as a weighted element but a prerequisite for countries to be considered in the analysis (M. Fruytier, expert interview, June 27, 2023).

Among cost factors, differences in hydrogen production are believed to have the most significant impact. A country's head start was deemed the least influential factor in determining its likelihood of exporting to the Netherlands by 2030, despite encompassing the most factors. Within this category, trade relations were seen as having the least impact. One reason given was the volume of MOUs, which simply made them lose their credibility (W. Frens, expert interview, 2023).

A better business case for other use of the green hydrogen	33%				
Head start	24%	MOU's and trade relations	17%		
		Local subsidies	26%		
		Existing projects	26%	Number of projects	47%
				Proposed capacity	53%
				Total	**100%**
		Soft resources	32%	Competitiveness	62%
				Experience with hydrogen	38%
		Total	**100%**	**Total**	**100%**
Costs	43%	Relative difference in cost of hydrogen production	53%		
		Shipping distance to NL	18%		
		WACC - Country Risk	28%		
		Total	**100%**		
Total	**100%**				

Figure 5.11: The weighing form with the average given weights.

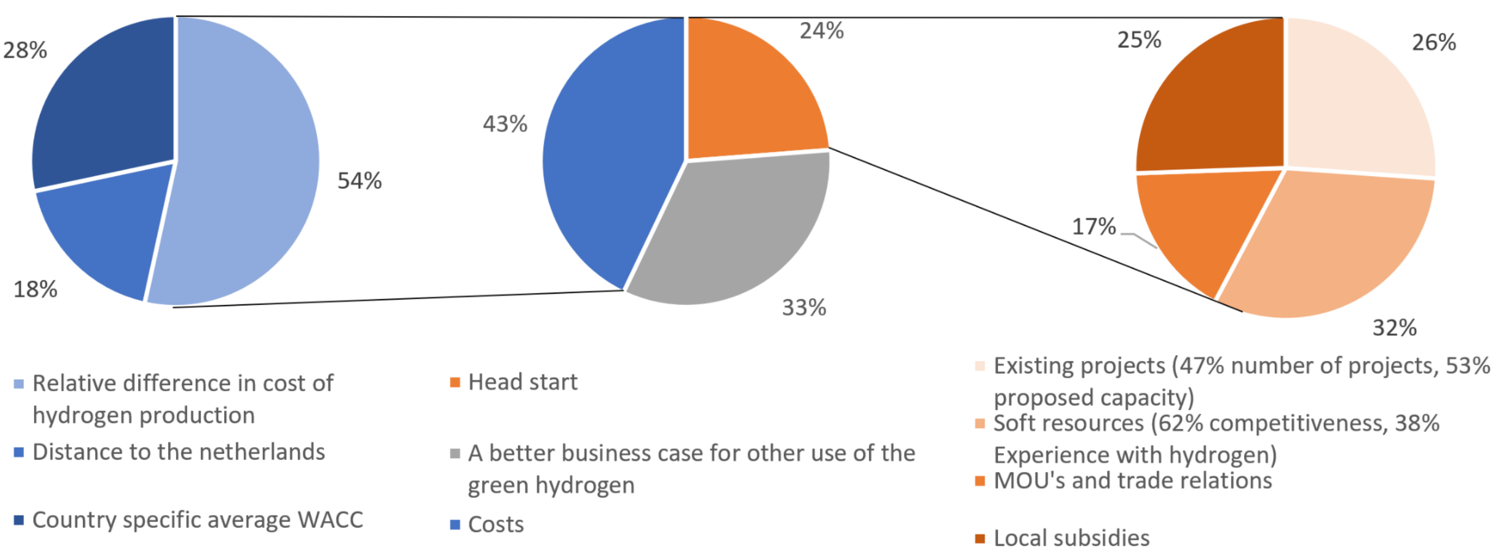


Figure 5.12: The weighing of different factors influencing hydrogen imports to the Netherlands.

5.4 Combining scores and weights

Figure 5.13 presents the combination of scores and weights, showing a relatively narrow score range between 0,4 and 0,62. Spain emerges as the leading scorer, followed closely by the United States and Chile. Figure 5.14 shows the contribution of the different criteria to the overall scores.

While the United States didn't perform as well in terms of alternative business cases for the hydrogen, local subsidies compensated for this deficiency, earning it a spot in the top three. The country's favourable Weighted Average Cost of Capital (WACC) was also a significant factor in this regard.

Chile, similar to the United States, showed comparable performance concerning alternative use cases, but scored highly on its potential for affordable hydrogen production. However, it underperformed in comparison to the United States on WACC, distance to the Netherlands, and soft resources.

Spain outperformed both Chile and the United States with a less attractive hydrogen cost price and WACC, owing to its superior performance on the alternative use of hydrogen and its proximity to the Netherlands.

It is seen that it is a close call between the best performing countries, as no single country outperforms in all criteria. It's furthermore not a single criterion where the top performers excel in that determine their ranking, but rather a well-rounded performance across an array of criteria, as exemplified by Spain and the United States.

Furthermore, significant score discrepancies exist among neighbouring countries such as Saudi Arabia and Oman or the U.S. and Canada. This shows that a country's potential does not reflect an entire region. These differences are seen in WACC and proposed projects, but also local differences in their potential for low cost hydrogen and distance to the Netherlands.

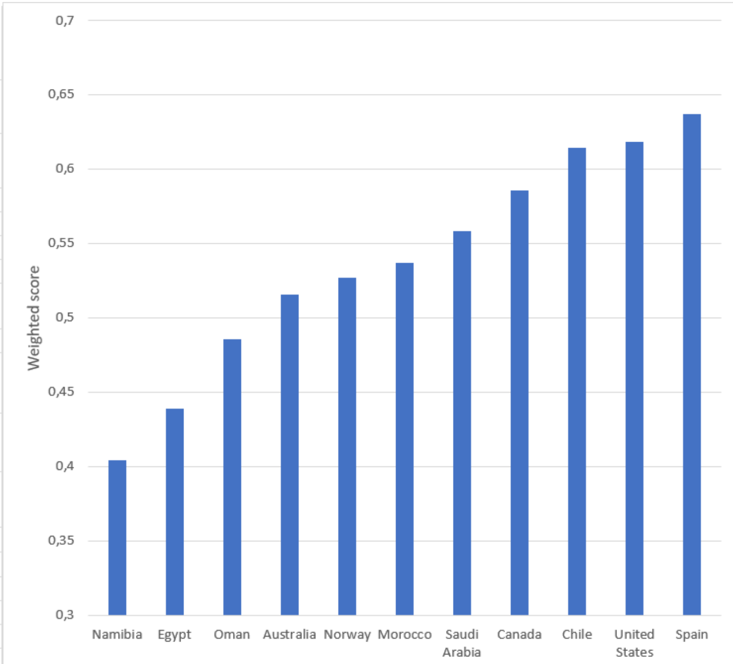


Figure 5.13: The combination of the scores and weights and resulting country ranking.

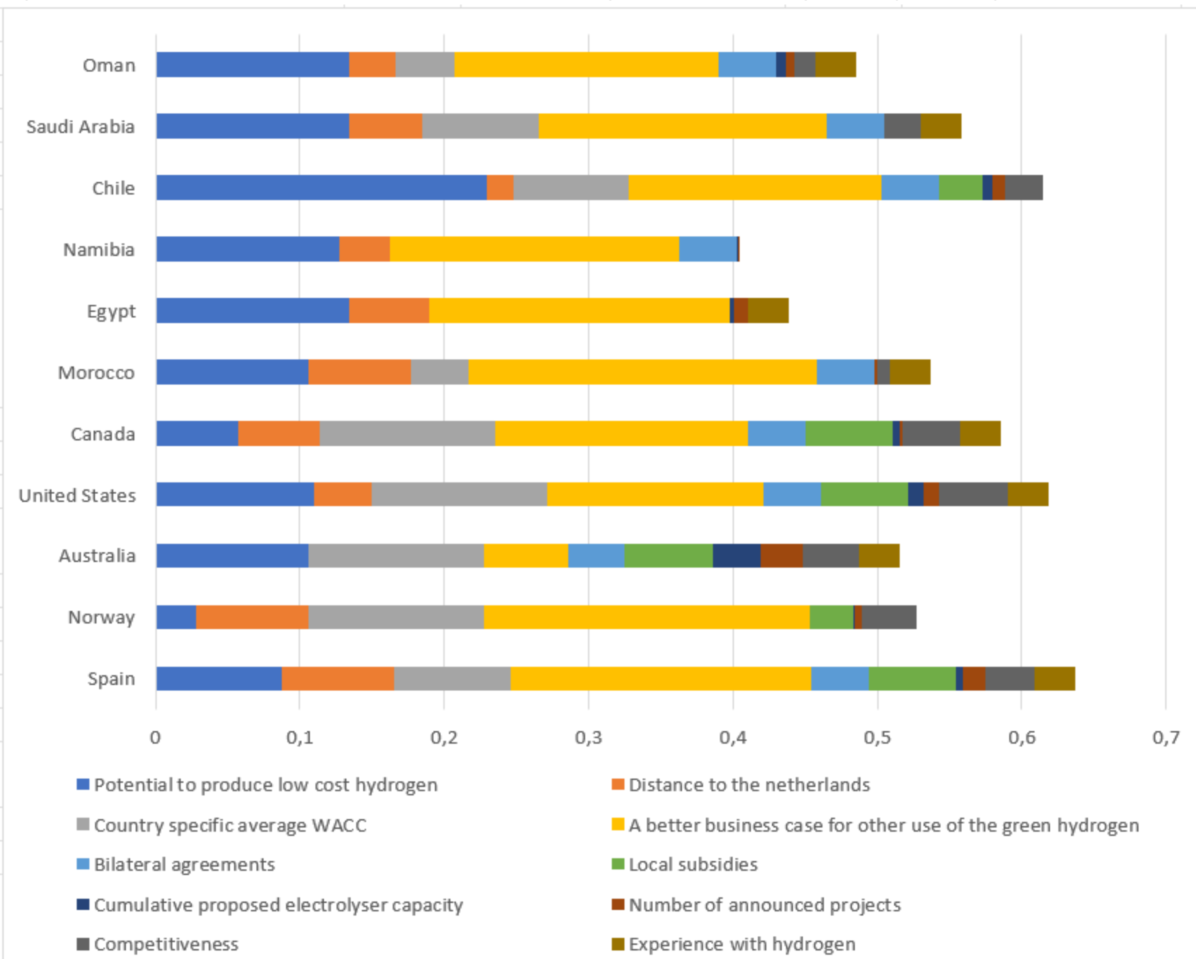


Figure 5.14: Contribution of the different criteria to a country's score.

5.5 Sensitivity analysis

5.5.1 Sensitivity analysis on the weighing

In the sensitivity analysis, it's valuable to explore how varying weights for top-ranked criteria might affect the performance of different countries. Specifically, the most influential criteria were given a 20% larger weight than its initial weight. This increase was offset by proportionally reducing the weights of other competing criteria. The three main criteria and 'the potential to produce low cost hydrogen' underwent sensitivity analysis.

The analysis reveals that rankings are sensitive to adjustments in criteria weights. The most pronounced shift in country order arose when altering the alternative uses for the hydrogen. Notably, a greater difference was observed when adjusting solely for the potential for low-cost hydrogen compared to modifying the entire cost contribution, even though the sub-criterion has significantly less weight on the overall scoring. This shows that different cost criteria compensate each other.

Table 5.9: Sensitivity analysis displays the revised rankings after increasing the weights of select criteria by 20%.

Base case (low to high)	Better business case for other use of the hydrogen	Costs	Head start	Potential for low cost hydrogen production
Namibia	+1	0	0	0
Egypt	+1	0	0	+1
Oman	+1	0	0	+2
Australia	-3	0	+5	0
Norway	+3	-1	-1	-3
Morocco	+4	+1	-1	0
Saudi Arabia	0	+1	-1	+1
Canada	-2	-1	0	-1
Chile	0	+2	-2	+2
United States	-5	0	+1	-1
Spain	0	-2	-1	-1
Total places shifted	**10**	**4**	**6**	**6**

5.5.2 Sensitivity analysis to quantification and normalisation

Local subsidies

It is noted that the normalisation of the local subsidies does not account for the size of the economy, making it challenging to determine whether the subsidy is significant enough to enable hydrogen exports. To address this, sensitivity analysis attempts to quantify the subsidies in relation to the country's GDP. To do this only the 12,6 billion USD Canadian package is included and 100 billion USD is assumed for the Inflation Reduction Act as estimated by Clifford (2023). The scoring results show the same trend. Among the countries subsidising hydrogen, Norway and Chile have allocated significantly fewer funds per GDP. A table of the sensitivity results is found in Appendix 4.

Another intriguing aspect to consider is how Saudi Arabia's score would be affected if the pronounced government involvement were viewed as local subsidies. By aligning Saudi Arabia's score with the top-performing countries, it would rise to the position of the second-best performing nation.

Projects in the pipeline

For sensitivity analysis it is instructive to examine how countries fare when only advanced projects are considered. This entails evaluating which projects have progressed beyond the conceptual stage and are anticipated to be operational by 2030. Figure 5.14 indicates that Canada, Egypt, Morocco, and Norway have a below-average number of advanced projects, diminishing their performance in this scenario. Conversely, Saudi Arabia, Spain, and Chile, with a greater proportion of projects past the concept phase, will perform better.

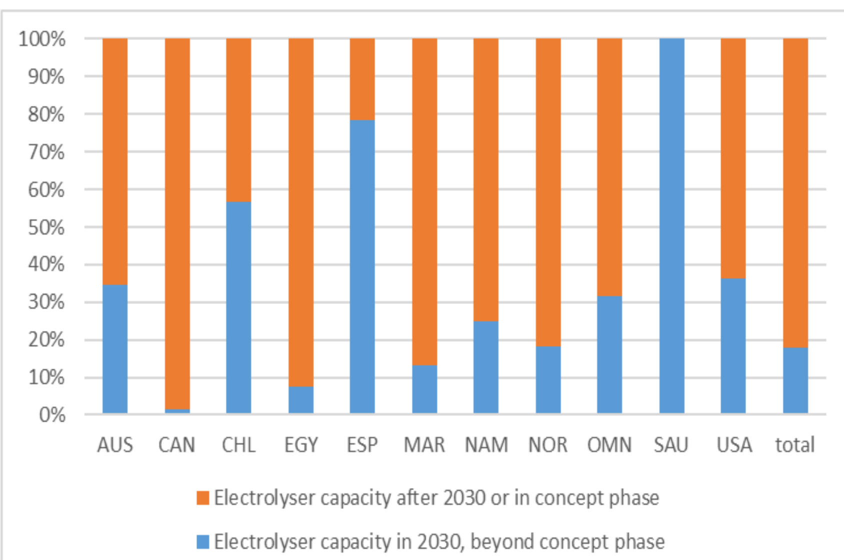


Figure 5.15: The proportion of projects that propose to be operational before 2030 and that are out of the concept phase.

Experience with hydrogen

A key metric used to assess a country's hydrogen experience was its number of oil refineries. For sensitivity analysis, the contribution to the GDP can also be evaluated. This is done by dividing the number of refineries in a country by its GDP, yielding a global average of 7,32 refineries per trillion USD (Aizarani, 2023; O'Neill, 2023). According to this measurement, only Chile has an above-average number of refineries (Auch, 2017; World Bank, 2021).

5.6 Discussion on MCA

5.6.1 Interpretation

The analysis revealed that the competition among potential exporting countries was tight, with Spain, the United States, and Chile emerging as front-runners to become initial hydrogen exporters to the Netherlands. Notably, these are three countries from diverging regions. It was seen that a good score on a range of factors contributed to their top rankings, underscoring the broad nature of these value chains. Furthermore, countries like Chile or Spain are not among the large global energy exporters meaning there could indeed be a potential transformation in the global energy landscape.

While costs were weighted as the most important factor, more than half of the weights were assigned to non-economic factors. While existing literature largely adopts a techno-economic lens, these findings prove that this does not give a complete picture of the development of these value chains.

While other reports did discuss non-economic factors, such as those of IRENA (2022a) and Pflugmann & De Blasio (2020) on geopolitics or IRENA's (2022b) assessment of soft resources, no report attempted to assign weights to these elements. The approach has its limitations, but it was seen that the MCA is an effective method to incorporate the role of these non-economic factors into the assessment of possible value chains.

Also the approach of Nuñez-Jimenez & De Blasio (2022) of excluding specific countries based on non-economic elements is faulty when viewed against the findings of this report which underscored that countries can counterbalance weaknesses in certain areas by excelling in others.

However, the complexity of hydrogen imports became evident, making it crucial to account for the study's limitations when interpreting the results.

5.6.2 Limitations

The process of assessing the potential for green hydrogen exportation in different countries is inherently complex. Although the multi-criteria analysis (MCA) approach is optimal for addressing non-monetizable aspects, its limitations need to be acknowledged.

5.6.2.1 Limitations to the method

A primary limitation of the MCA pertains to its normalisation method. Criteria were normalised against the best and worst performing options to enhance the weighting's effectiveness. However, this approach is sensitive to the performance range of the included options. If all options excel in a particular criterion, the relative difference diminishes in value. Conversely, adding a poorly performing option can notably elevate the normalisation scores for other options.

Furthermore, the MCA relies heavily on subjective weights assigned by participants, which can pose a challenge to its credibility. As the green hydrogen import market is still in development, there is no concrete understanding of the relative importance of various criteria. Participants, will moreover often possess expertise in only a subset of these criteria, which can bring bias to their overall weights. As participants' rationales for specific weight assignments are not always clear, it also remains uncertain what specific aspects of the weights are biassed, despite prompts to vocalise their thought processes.

Additionally, experts in the field can inherently lean towards particular criteria or countries based on their personal or professional affiliations. This further adds to the subjectivity of the MCA process. While having a larger pool of expert participants might increase the credibility of the results, it can also be challenging to remain quality due to the need for specialised knowledge. The weighting is moreover a time-consuming endeavour.

The use of sub-criteria in this study warrants discussion. While sub-criteria were essential for participants to maintain an overview during the weighing process, they had considerably less influence than the main criteria. For instance, hydrogen experience was deemed over 15 times less influential than the business case for alternative hydrogen uses. Had these criteria been weighed directly against each other, the disparity might have been less pronounced.

5.6.2.2 General limitations to the study

A primary limitation of this study lies in the relatively small differences between the countries under examination, rendering the analysis highly sensitive to weight adjustments. Furthermore, given the numerous uncertainties surrounding the study, it remains unclear what score differential would be required to confidently assert that one country has a higher hydrogen exporting potential than another. The sensitivity analysis revealed that any shift in weight considerably alters the country rankings. This complicates the comparison between countries with similar scores. However, a consistent trend was observed, with certain countries consistently ranking low and others consistently high, even in sensitivity analyses.

Another key limitation of the study is the overlap between the weighting of the MCA and the factors monetized in the Techno-Economic Analysis. Since the TEA quantifies the cost of production, transport and capital, its results are more reliable than subjective weighting. Using the results of the TEA as input to the MCA will generate significantly different results.

Another limitation is the complex interdependencies among criteria, which can lead to circular influences. For example, a country with low-cost hydrogen production or substantial local subsidies might have more projects in the pipeline, which in turn could influence trade relationships. Similarly, the potential for large-scale green hydrogen production could improve the business case, lowering project risk and the weighted average cost of capital (WACC). It is challenging where to accept some interaction between criteria while avoiding double counting.

Quantifying criteria also presents significant challenges. On multiple criteria large assumptions had to be made. An example is local subsidies, due to uncertainty about their impact on exports. Defining the level of experience with hydrogen was also problematic, as the boundary between 'significant' and 'insufficient' experience is ambiguous.

Also the selection of countries could be a point of discussion. Although the study incorporated countries from various regions, it does not guarantee that these are the best performers. It's plausible that there are other nations with comparable or superior scores, especially given the rapidly evolving nature of hydrogen technology. Conversely, one might question the fairness of evaluating a country in its entirety, especially for large nations that will have significant regional disparities.

Finally, will the data quality limit the trustworthiness of the research. The rapidly evolving landscape of hydrogen development and trade can outdate the analysis quickly. The dynamic nature of the field, with new projects, trade relations, and subsidies emerging frequently, means that the analysis is already somewhat outdated upon release, especially for the sources that come from the previous year.

5.6.2.3 Limitations considering specific criteria

Many uncertainties exist in the process of quantification and normalisation that affect specific criteria. The explorative sensitivity analyses have indicated that the scoring can be highly sensitive to variations in the quantification approach. Some of these uncertainties are detailed below. Additionally, debates can arise regarding the inclusion or exclusion of particular criteria.

The study could have benefited from considering certain criteria that were ultimately excluded. For instance, the TEA indicated that the availability of salt caverns likely causes cost savings given their role in intermediate hydrogen storage. This could have therefore been included in the cost criterion.

Furthermore, there was ambiguity about whether the sustainability of the local power grid should be factored in. The key question was if the sustainable use of hydropower could be effectively integrated with intermittent wind and solar power without disrupting electrification or increasing the local grid's carbon footprint. If this were extensively researched, it could result in including it in the head start or incorporating it into the cost of hydrogen production.

Local subsidies

Regarding local subsidies, it was unclear whether these would directly affect costs by reducing production cost of export expenses or primarily facilitate the initiation of hydrogen production in the country, thereby indirectly aiding exporting supply chains to arise. It can therefore be discussed under what criterion local subsidies should be weighted. Furthermore, can the exclusion of Saudi Arabia be disputed. The role of governmental ownership was instrumental in achieving financial closure for the NEOM hydrogen project (Darasha, 2023). While not classified as a subsidy, it is essential economic involvement of the government.

Projects in the pipeline

There are limitations inherent to this evaluation method. Specifically, the analysis doesn't differentiate between the various development stages of these projects, potentially affecting the results. Many projects remain conceptual, while others, such as Saudi Arabia's NEOM project, are nearing completion (ACWA Power, 2023). Given that NEOM is Saudi Arabia's sole project under development, it results in a low score for the country on this criterion. In sensitivity the strong difference in the ratio between developed and undeveloped projects was seen. However, significant uncertainty also surrounds the assessment of the project development phase.

Finally, there are two more noteworthy points of critique. Firstly, the certainty around the proper amendment of the database remains ambiguous. Secondly, the analysis does not adjust for the size of the economy, making it uncertain whether these projects will export.

Competitiveness

The last published GCI index dates back to 2019, so the data's recency is somewhat compromised. The use of comparable, more up-to-date indexes, such as the IMD World Competitiveness Center (2022) offers a comparable competitiveness index, albeit not covering all countries. It's also crucial to note that some GCI aspects, such as economic stability, might overlap with the country risk score, leading to potential double counting. Nevertheless, given the majority of aspects do not overlap, double counting is unlikely to pose a significant issue. In a sensitivity analysis it is assessed how this affects the results.

Experience with hydrogen

In sensitivity analysis it was found that, when assessing the amount of oil refineries as compared to a country's GDP that only Chile would be included, which proves the possible limitation of the approach used.

5.6.3 Implications

The results of the Multi-Criteria Analysis (MCA), despite its limitations, carry substantial implications particularly for policymakers, hydrogen project developers, and future hydrogen customers. This research gives insight into many of the factors that influence the likelihood of green hydrogen supply chains to form, including aspects that go beyond economic feasibility. These insights may prove valuable for prioritising areas of focus when evaluating potential exporters, as well as providing a tentative outlook on promising countries for hydrogen importation before 2030.

For policymakers in potential exporting countries, the MCA can provide a comparative framework for understanding their country's standing relative to other prospective exporters. This comparison can aid them in evaluating their potential as early exporters. Additionally, it may guide policy adjustments to enhance their competitive position in the hydrogen market.

As for Dutch policymakers, this research could inform strategies to support specific countries in developing hydrogen export projects. Furthermore, it could assist in identifying countries to prioritise for future focus and collaboration.

For hydrogen project developers and businesses seeking to acquire hydrogen, the top-ranking countries in the MCA could be interesting candidates for further investigation, which is also done through the TEA presented in this thesis. Moreover, the evaluated criteria could highlight potential non-economic barriers that are valuable to assess in the early stages of project development.

For the field of research the findings from this Multi-Criteria Analysis (MCA) highlight the substantial role of non-economic factors in the development of hydrogen export markets. It proves that while difficult, it is possible to weigh these criteria. The research therefore implicates many areas of possible research to properly quantify the criteria in their role for the development of international hydrogen supply chains.

From a geopolitical perspective, the MCA implies that there could indeed be a potential transformation in the global energy landscape, as countries such as Chile, exhibited higher scores than established energy exporters like Saudi Arabia.

5.7 Conclusion and recommendations

5.7.1 Conclusion

The formation of hydrogen import supply chains from various countries to the Netherlands is influenced by a range of different factors, many of which are non-economic and cannot be monetized. Despite challenges in quantifying and normalising these criteria, it is evident that Multi-Criteria Analysis (MCA) is a suitable method for incorporating such aspects into the evaluation of potential hydrogen exporters.

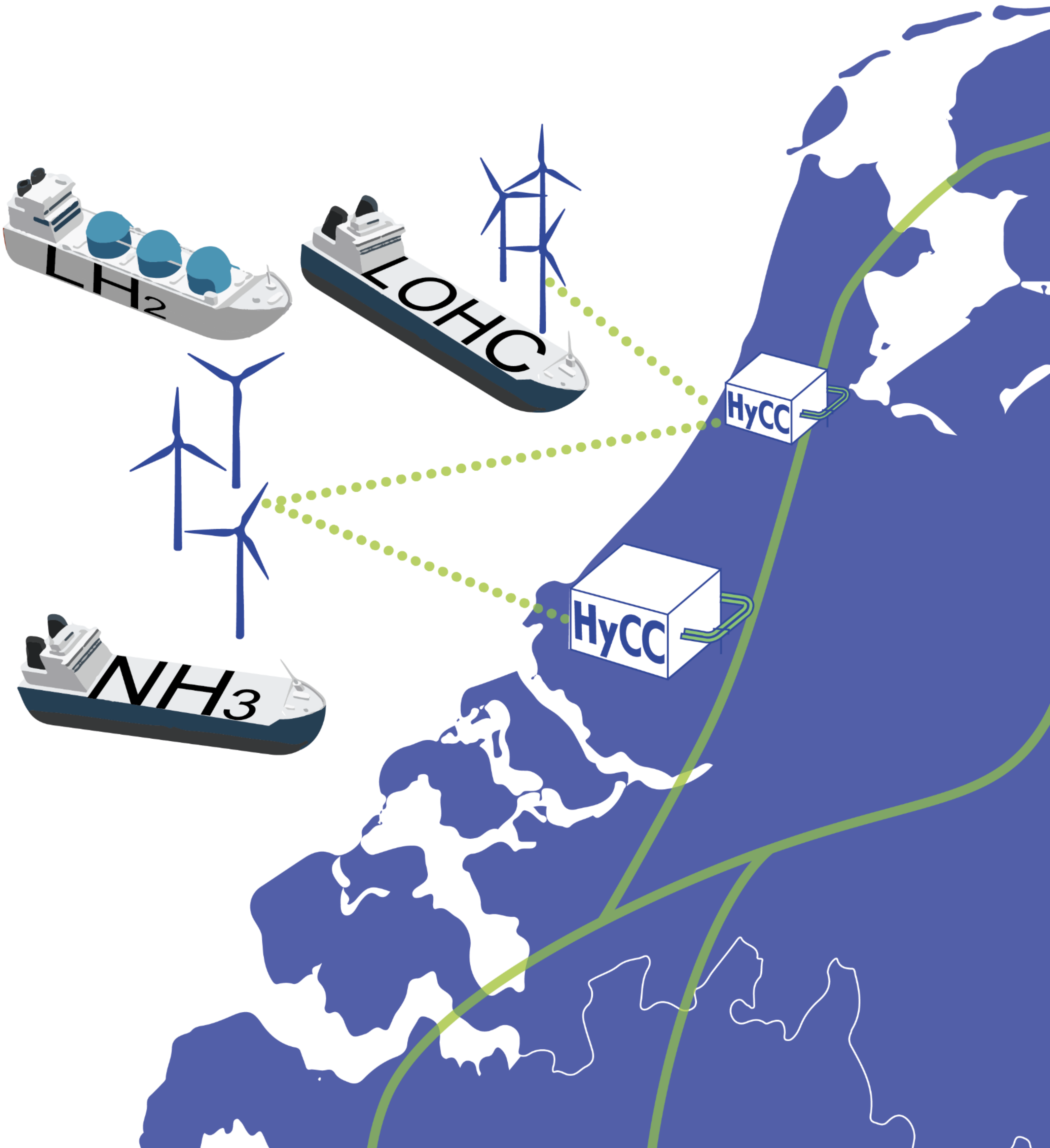
A significant 57% of the evaluation weight was attributed to non-economic factors, underscoring their crucial role in the forming of importing supply chains. It can therefore be concluded that a solely techno-economic viewpoint is insufficient in assessing the forming of these supply chains, but that a systems perspective is essential.

It was lastly concluded that Chile, the United States and Spain are the countries that have the largest potential for developing initial importing value chains to the Netherlands. While this high-level country ranking provides valuable insights, the precision of the specific rankings is debatable due to the numerous limitations encountered in implementing this methodology.

5.7.2 Recommendations

As the MCA led to the selection of pilot countries for the TEA also the monetizable inputs were weighted by the participants of the MCA. However, the credibility of the MCA outcomes would have been enhanced If the TEA results would serve as the inputs of the cost criterion. Hence, expanding the TEA for all potential countries of interest is recommended, followed by a reassessment of the MCA using these findings. Additionally, it is recommended for future research to try to address some of the MCA's limitations. This could involve a detailed examination of each criterion and its quantification, and enlisting a larger panel of experts for weighting. Furthermore, it is valuable to conduct more sensitivity analyses, such as through exploring different weighting methodologies or alternative normalisation techniques.

6. Results TEA - The costs of the first hydrogen imports



6.1 Goal and scope

6.1.1 Goal

The goal of the TEA is to address the following sub-question: "How does the techno-economic performance of different green hydrogen import streams compare with domestic production in the Netherlands in 2030?" This section gives the rationale behind this research question.

6.1.1.2 Research perspective

The research goal can be guided by varying perspectives such as Research and Development (R&D), corporate, or market perspective (Zimmermann et al., 2020). The first two perspectives typically concentrate on specific projects, while this study adopts a market perspective. The rationale behind adopting a market perspective is to analyse how new concepts could influence existing market structures (Zimmermann et al., 2020). Here, the aim is to explore how two emerging markets will influence each other, namely the import and domestic production of green hydrogen.

6.1.1.2 Context

The temporal focus is on value chains that will be developed by 2030, comparing hydrogen transportation from various exporting countries to the Netherlands in comparison with domestic production.

Project realisation requires considerable time, implying that cost estimates for 2030 may not align with the actual costs for supply chains operational by then. For instance, PBL (2023) projects the costs for projects financed in 2023 but constructed in subsequent years. Looking at hydrogen supply chains, the NEOM hydrogen project is projected to take three years to complete from the final investment decision (FID) (NEOM, 2023). Similarly, ISPT (2022) cites a minimum of two years to build a hydrogen plant. Given this research's focus on complete supply chains, including elements like ships and (re)conversion plants with substantial construction times, it's reasonable to assume that projects operational by 2030 would have made their final investment decisions between 2023 and 2027. As costs are expected to decrease within this period, this study takes the year 2027 as the reference year for cost assumptions on project finance rather than construction.

The countries that are assessed are those identified as most promising from the MCA: Chile, Spain, and the United States. Furthermore, two additional countries are added in the model. Australia is included to assess long-distance transport effects, and Morocco is incorporated for a comparative study on shipping and pipeline imports. These are assessed on their local hydrogen production costs in the report, but are excluded from the analysis of transport to the Netherlands. In all countries the specific location of the largest project according to IEA (2022c) is assessed.

The evaluation includes the transport methods ammonia, liquid hydrogen, and liquid organic hydrogen carriers, for a supply chain with a one-gigawatt (GW) electrolyser capacity. Given that large-scale projects range between 0,1-14GW, with over 80% between 0,1-1GW, this size ensures realism as well as an export-oriented focus (IEA, 2022c). The 1 GW scale furthermore ensures that there is proper data availability (ISPT, 2022). It is also assessed what a smaller or larger scale would do with the hydrogen cost price though.

6.1.1.3 Applications and target audience

The TEA intends to offer multiple applications: Primarily, the results offer an understanding of cost differences and can therefore be used as evidence in the clarification of possible developments around hydrogen imports and domestic production. The exploration of possible pathways that result from these cost differences is also done later in this report. Additionally, the TEA's inventory analysis can be employed as a verification instrument to cross-check industry statements.

For those involved in hydrogen development, the TEA has a twofold utility. It offers business intelligence, through creating a better understanding of the competition. Simultaneously, it serves as a basis for assessing the feasibility of project expansion in other countries.

Existing and future green hydrogen consumers can gain critical insights regarding sourcing strategies from the TEA. Moreover, for policymakers, the TEA can reveal a policy gap that needs to be overcome to ensure that policy is aligned with climate goals. Also for the public this research is of interest though due to the importance of green hydrogen in limiting climate change.

6.1.1.4 Commissioners

The research is commissioned by the Industrial Ecology masters track of the technical University of Delft and HyCC, a developer of green hydrogen production facilities. The primary objective of the research is to provide valuable insights, without any preconceived outcomes, thereby ensuring an unbiased approach.

6.1.1.5 Scenarios

To create diverse cost scenarios for various import supply chains from different pilot locations, hydrogen production was kept constant, but the performance of the transport assessment indicators was changed. Below are brief narratives for the four evaluated scenarios. It must be noted that in all cases, green hydrogen production costs have considerably declined, consistent with global hydrogen production analyses. Figure 6.1 provides an overview of the relationship between supply chain size and transport costs across the four development scenarios.

In addition to these, scenarios are designed to examine the influence of supply chain design alterations such as shared infrastructure, grid connectivity, alternative shipping fuels, and changes in supply chain size.

1. **The import scenario - Best case scenario**

In this scenario, subsidy plans from the European Hydrogen Bank and H2Global have catalysed innovation faster than ever anticipated. Strong global climate policy further compelled fossil exporters to invest heavily in blue hydrogen facilities. Through this, technological challenges have quickly been overcome, and hydrogen transport costs have dropped incredibly. Import projects have upscaled and many multiple gigawatt projects are now in operation. Both green and blue hydrogen have become globally traded commodities by 2030.

2. **REPowerEU - Most-likely low scenario**

In this scenario, the REPowerEU's ambition to import 10 Mt of hydrogen by 2030 has been achieved. Notable global subsidies have initiated and scaled up import technology, for technologies to have matured by 2030. Green hydrogen exporting countries have made remarkable efforts, and blue hydrogen is increasingly utilised as a carbon-free means to trade fossil energy. These developments enabled substantial cost reductions until 2030, and average supply chains to have reached a gigawatt. A global hydrogen economy may be on the horizon.

3. **Domestic first - Most-likely high scenario**

Hydrogen import is supported by subsidies and price reductions through upscaling pilot projects. Technological and scaling progress has been achieved, but lag behind expectations. There is an evident 'domestic first' approach to hydrogen production, with potential exporters focusing on local usage initially, and European countries prioritising their own hydrogen production. Some gigawatt scale supply chains have been developed, but most industries that will rely on imports have a wait-and-see attitude and rather wait on piped imports.

4. **The unbearable lightness of hydrogen - Worst case scenario**

In this scenario, hydrogen import is viewed as trivial. Europe decides to supply its own hydrogen and a more accelerated hydrogen backbone network renders shipped imports obsolete. Major hydrogen projects primarily aim to create domestic products, possibly trading those, but global climate policies fall short and outside of Europe there is a greater focus on economic growth through fossil exploration. A few pilot projects are realised by 2030, but technological innovation lags significantly behind, impeding the realisation of globally traded hydrogen. Gigawatt scale export projects have not been realised. Due to 'the unbearable lightness of hydrogen' it might never be globally traded by ship.

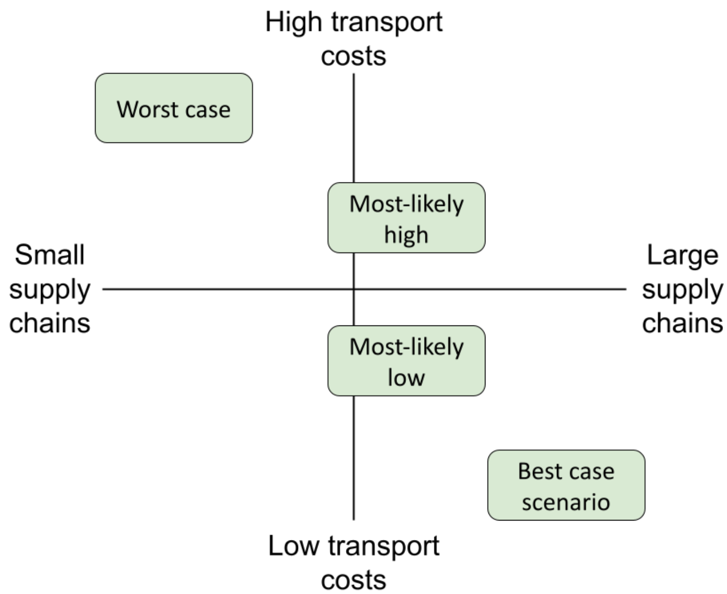


Figure 6.1: The relationship between transport costs and supply chain size across the four development scenarios.

6.1.2 Scope

6.1.2.1 Functional unit and reference flows

The scope of the TEA is to analyse green hydrogen production via water electrolysis using additional green electricity. This additionality ensures that the carbon footprint of local electricity is not worsened and is in line with the rules set for renewable hydrogen in the Renewable Energy Directive of the European Commission (2023a). The hydrogen is assumed to be supplied to the Dutch hydrogen backbone, managed by Gasunie, in the Port of Rotterdam and should deliver a base load (Gasunie, 2023a). Given that the carriers are stored, reconversion facilities inherently supply a base load. However, for domestically produced hydrogen, a base load is established through reserving storage capacity in HyStock - the Dutch hydrogen storage facility within salt caverns (Gasunie, 2023b). To properly compare hydrogen derived from ammonia and LOHC with the pure hydrogen from Dutch electrolysis or liquid hydrogen it is purified post-reconversion.

Given these considerations and the common practice of measuring hydrogen by weight, the functional unit is defined as:
"Delivering one metric tonnes of pure, green hydrogen from a base load supply, produced with additional renewable power, to the Dutch hydrogen backbone at the Port of Rotterdam in the year 2030."

Four alternatives are considered: import via ammonia, liquid hydrogen, or LOHC, and domestic production. These alternatives result in the following reference flows:

1. The delivery of one metric tonnes of pure, green hydrogen from a base load supply, produced with additional renewable power, to the Dutch hydrogen backbone at the Port of Rotterdam in the year 2030 that was imported as ammonia.
2. The delivery of one metric tonnes of pure, green hydrogen from a base load supply, produced with additional renewable power, to the Dutch hydrogen backbone at the Port of Rotterdam in the year 2030 that was imported as liquid hydrogen.
3. The delivery of one metric tonnes of pure, green hydrogen from a base load supply, produced with additional renewable power, to the Dutch hydrogen backbone at the Port of Rotterdam in the year 2030 that was imported as a liquid organic hydrogen carrier.
4. The delivery of one metric tonnes of pure, green hydrogen from a base load supply, produced with additional renewable power, to the Dutch hydrogen backbone at the Port of Rotterdam in the year 2030 that was produced in the Netherlands.

Reference flows 1-3 will each be assessed for the three alternative exporting countries under assessment: Chile, the United States and Spain.

6.1.2.2 System boundaries

To properly address the costs of the proposed reference flows the full cradle to gate costs from raw materials until delivery in Rotterdam have to be assessed. This TEA relies on previous cost analyses of ten process steps, as depicted in Figure 6.2 that shows the system boundaries of all reference flows.

The study's objective is to compare different lifetime costs, and therefore focuses on aspects that vary between the reference flows. Therefore, the analysis is split in two. Initially, the costs associated with hydrogen production are evaluated. This process is identical across all reference flows, but costs differ due to local price variations and renewable availability. Subsequently, transport costs are individually examined for each mode of transport; intermediate transport, conversion, storage, shipping and reconversion.

The study strives to assess best-in-class technology within realistic cost parameters. ISPT (2022) explains that all technology for a hydrogen plant should be on the market by at least 2026 to be able to be in operation by 2030. Accordingly, this study adopts 2026 as the reference year for evaluating available technologies.

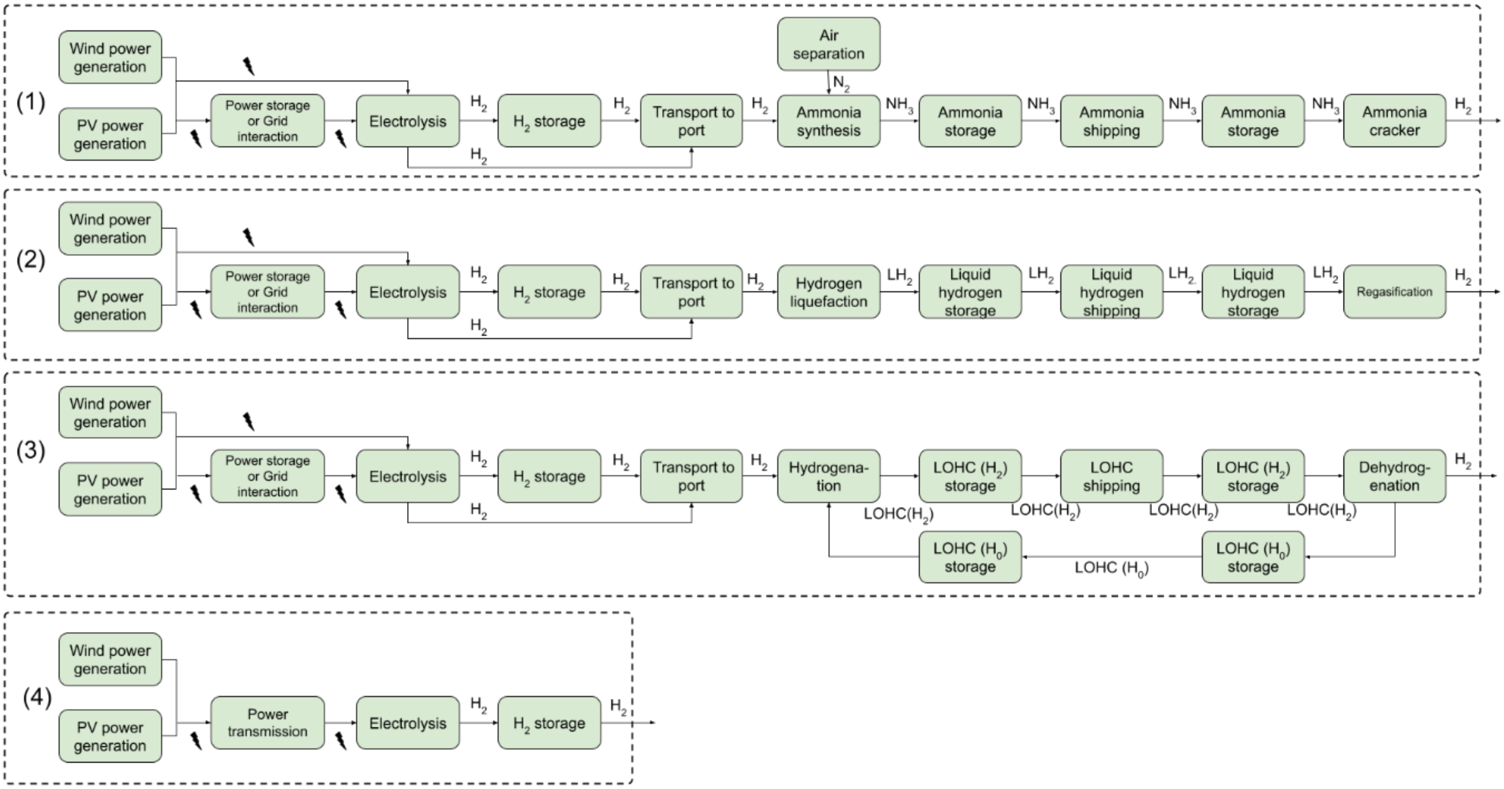


Figure 6.2: The system boundaries of the four reference flows assessed in the TEA.

6.1.2.3 Assessment indicators

Assessment of the total costs of each supply chain element requires various technical and economic indicators. These enable calculation of lifetime costs and benefits (delivered hydrogen), discounted to a net present value (NPV).

The technical indicators include solar and wind availability, losses, system component sizes and energy demand. This energy demand may be supplied externally or within the system boundaries, with external sources such as power from the Dutch grid increasing costs, whereas internal sources like heat from ammonia combustion reduce the benefits through delivering less hydrogen.

Economic indicators include capital and operational expenditures, as well as energy costs when sourced outside the system boundaries. To calculate the net present value, future benefits and costs are discounted with the weighted average cost of capital (WACC). When the WACC is corrected for inflation it is called the real WACC. Table 6.1 gives an overview of all assessment indicators and their units.

Table 6.1: An overview of all assessment indicators and their corresponding units

Technical assessment indicators	**Unit**	**Goal**
Availability of solar and wind	%	Determining the power output at each given hour
Boil-off losses	%/day	Measure the losses that can either be used as shipping fuel or have to be reliquefied.
Process losses	%	Measure the energy losses
Energy demand	kWh/tonnes	Determining the energy input into a process
Energy demand for shipping	kWh/(t*1000 km)	Determining the energy demand of shipping
Sizing of storages or carriers	Tonnes	The size of supply chain elements is used to seek cost correlations
Sizing of plants	Tonnes/year	The size of supply chain elements is used to seek cost correlations
Shipping distance (single trip)	km	Determining the energy demand of shipping and the amount of needed ships
Sailing speed	Km/hour	Determining the energy demand of shipping and the amount of needed ships
Economic indicators	**Unit**	
CAPEX of storages or carriers	EU/tonnes	Determining the total CAPEX
CAPEX of plants	EU/(tonnes/year)	Determining the total CAPEX
Fixed operational expenditures	% of CAPEX	Determining the total OPEX
Energy costs	EU/MWh	Determining the total OPEX
Real WACC	%	Needed to calculate the LCOH
Investment duration	Years	Needed to calculate the LCOH

6.2 Inventory analysis - The discount rate and investment duration

In Appendix 5, a detailed elaboration of the WACC calculations is provided. However, Table 6.2 presents the return on both equity and debt for each evaluated country, alongside the nominal WACC and the real WACC, which has been adjusted for inflation.

A comparison of the Dutch WACC findings of this report with the values from PBL (2023) indicates a 0,5% increase in the return on equity and a 0,6% decrease in the return on debt. A 15-year timeframe is deemed a realistic investment duration for hydrogen projects (PBL, 2023). Further details on the investment duration can be found in Appendix 5.4.

Table 6.2: The nominal and real WACC for different countries.

Country	**Return on equity**	**Return on debt**	Share of debt (gearing)	**Nominal WACC (pre-tax)**	Inflation rate	**Real WACC (pre-tax)**
Netherlands	**14,99%**	**5,40%**	70%	**8,28%**	1,59%	**6,58%**
USA	**14,99%**	**5,40%**	70%	**8,28%**	2,70%	**5,43%**
Chile	**16,79%**	**7,70%**	70%	**10,43%**	2,52%	**7,71%**
Spain	**18,40%**	**9,73%**	70%	**12,33%**	1,32%	**10,87%**
Australia	**14,99%**	**5,40%**	70%	**8,28%**	2,32%	**5,82%**
Morocco	**20,33%**	**12,18%**	70%	**14,63%**	1,30%	**13,15%**

6.3 Inventory analysis - Hydrogen production

6.3.1 Renewables

The initial step of the process is renewable power generation, with a specific emphasis on solar and wind power as explained in Section X.X. Both the benefits and the costs of renewables renewable energy sources will vary depending on the location.

6.3.1.1 Power production

The performance of a solar panel or wind turbine is location-dependent, primarily due to varying levels of wind and solar availability across different regions. Globally, the Renewables.ninja (2023) website provides hourly data on this availability, utilising the wind and solar data from the MERRA-2 model, developed by NASA's Global Modelling and Assimilation Office (NASA, 2023). However, evaluation of power generation from these renewables requires additional inputs.

Wind

Wind speed near the surface is considerably affected by surface friction and obstacles like trees or buildings (TeamCivil, 2017). This influence diminishes until reaching the gradient height, the altitude where surface friction no longer impacts wind speeds (TeamCivil, 2017). Knowledge of the gradient height allows for calculation of wind speeds at lower altitudes. For instance, at sea, the gradient height is around 213 metres, while in urban areas, it extends to about 366 metres (TeamCivil, 2017). Since the hub heights of wind turbines only range up to 150 metres, they fall below these gradient heights (Wiser et al., 2021). As a result, the hub height can influence the wind speed at the hub, thus affecting the power output of a wind turbine.

In recent years hub heights have seen substantial increases, reaching approximately 94 metres onshore and 105 metres offshore (Bilgili et al., 2023; Energy.gov, 2022). Despite wind turbine manufacturers emphasising the importance of standardisation to meet the growing demand, expert opinions predict a rise in hub heights to 130 metres onshore and 150 metres offshore by 2035 (Buljan, 2022; Wiser et al., 2021). This study adopts the estimates provided by Wiser et al. (2021), assuming a linear growth. This assumption yields projected hub heights of 117 metres onshore and 136 metres offshore in 2030. The best performing turbine available within Renewables.ninja is used to retrieve the power output at different wind speeds.

It is important to highlight that the selection of turbines exerts a significant impact on the capacity factor of wind farms. Comparative analysis with data from the Global Wind Atlas (2023) reveals that capacity factors can deviate by as much as 25% lower to 5% higher.

Solar

Photovoltaic (PV) panels capture sunlight most effectively when oriented perpendicularly to the sun. The optimal angle between the sun and a PV panel will therefore change significantly throughout the year. The ideal azimuth, or cardinal direction, changes throughout the day as the sun travels from east to west, while the optimal tilt adjusts with the changing seasons due to the sun's higher position in the sky during summer months.

For fixed panels, the optimal azimuth falls between sunrise and sunset, oriented southward in the Northern hemisphere and northward in the Southern hemisphere. The most effective tilt for PV approximates the geographical latitude of the site, but is precisely calculated through a tool of Beale (2023), of which the results are seen in Table 6.3.

PV panels can also utilise tracking systems to maintain the optimal angle with the sun's position, both on the Azimuth as well as the tilt (Afanasyeva et al., 2018). Single-axis systems generally adjust the azimuth, while dual-axis systems manipulate both azimuth and tilt (Afanasyeva et al., 2018). Though dual-axis systems enhance yield further, they incur higher costs and are less reliable, resulting in the majority of solar trackers to be single axis (Afanasyeva et al., 2018; PVcase Team, 2022). It is seen that PV tracking is even possible in challenging conditions, such as desert environments (Soltigua, 2023). Given the yield improvement from tracking, 80% of utility-scale projects in the United States implemented this feature in 2016 (Roselund, 2017). While panels were significantly more expensive in 2016, new projects such as the NEOM hydrogen project also apply tracking (Hydrogen Central, 2023). Afanasyeva et al. (2018) overall found that single-axis tracking reduces power costs by a global average of 6%. Despite these advantages, tracker selection may be influenced by additional factors such as terrain, land availability and overall solar availability (Afanasyeva et al., 2018). In the Netherlands, land availability emerges as a constraint against tracking, requiring solar panels to be spaced further apart (M. van Duffelen, expert interview, July 27, 2023). However, for large-scale hydrogen export projects, the use of tracking systems is deemed likely (M. van Duffelen, expert interview, July 27, 2023). Consequently, this study assumes that all PV systems involved in exporting projects will employ single-axis solar tracking, while PV systems within the Netherlands will have a fixed mount.

Figure 6.3 illustrates the impact of implementing a tracking system on a PV system in Morocco. The data reveal that tracking contributes to an overall increase in energy availability of 6%, which represents an improvement of over 25% in the system's performance.

Finally, an advised loss factor of 0,1 is incorporated to determine hourly PV power production, as recommended by Renewables.ninja (2023).

Upon comparing the values obtained from the MERRA-2 model with those from the Global Solar Atlas (2023), it is observed that availability discrepancies range between 2-5% for most locations. However, a substantial discrepancy of 20% is identified for the Netherlands, with the MERRA-2 model indicating an availability of 14.5%, in contrast to the 11.7% reported by the Global Solar Atlas (2023). Similarly, the PVGIS-SARAH2 model from the Joint Research Centre (JRC) (2023) also suggests an availability of 11.8%, from which hourly data can be extracted. Given these inconsistencies, the hourly PV dataset from the PVGIS-SARAH2 model is utilized for the Dutch scenario.

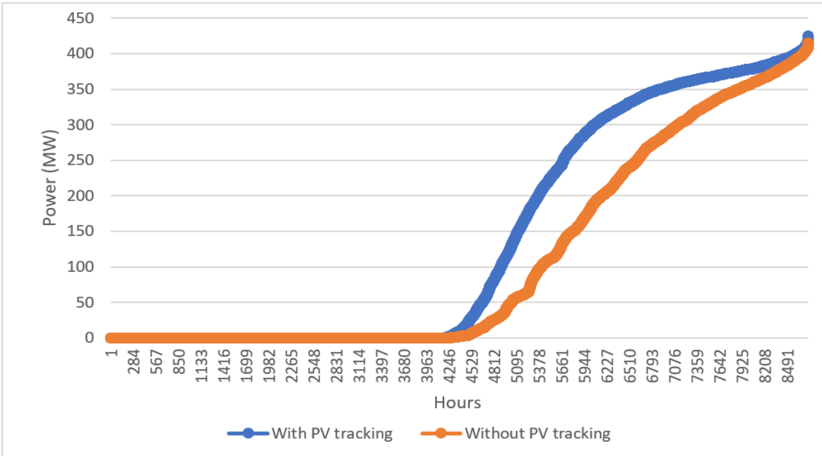


Figure 6.3: The power duration curve of two 500 MW PV systems near Tan Tan Morocco, one with PV tracking and one without.

Power production

Figure 6.4 presents the average power availability across various projects. A notable observation is that all countries, except Chile, surpass the Netherlands in solar power availability. Chile and the Netherlands, however, outperform other countries significantly in terms of wind power. For the Netherlands this is partly explained by the fact that offshore wind is assumed. Overall, wind power demonstrates a higher energy yield per installed megawatt-hour compared to PV.

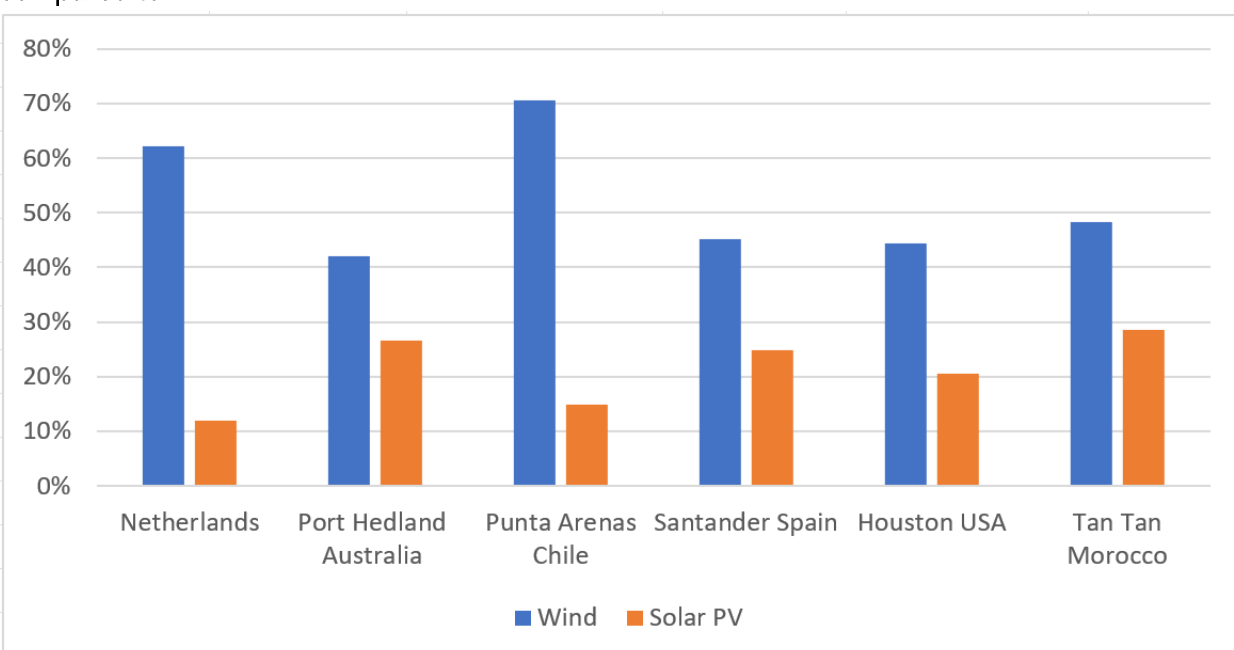


Figure 6.4: The average availability of wind and PV at the different assessed projects.

Figure 6.5 presents the power duration curves for a 500 MW wind farm and PV system located near Tan Tan, Morocco. A striking benefit of wind power becomes apparent from this comparison, specifically, its significantly less intermittent availability pattern compared to PV. A

PV system faces day and night variations and consequently remains unavailable for a substantial portion of the time. The higher availability of wind is on the other hand not seen in higher peaks, but in a more consistent supply. This more consistent supply will therefore lead to more operational hours for the electrolyser, resulting in more overall hydrogen production. Consequently, this will lower the CAPEX of the electrolyser per tonne of hydrogen produced.

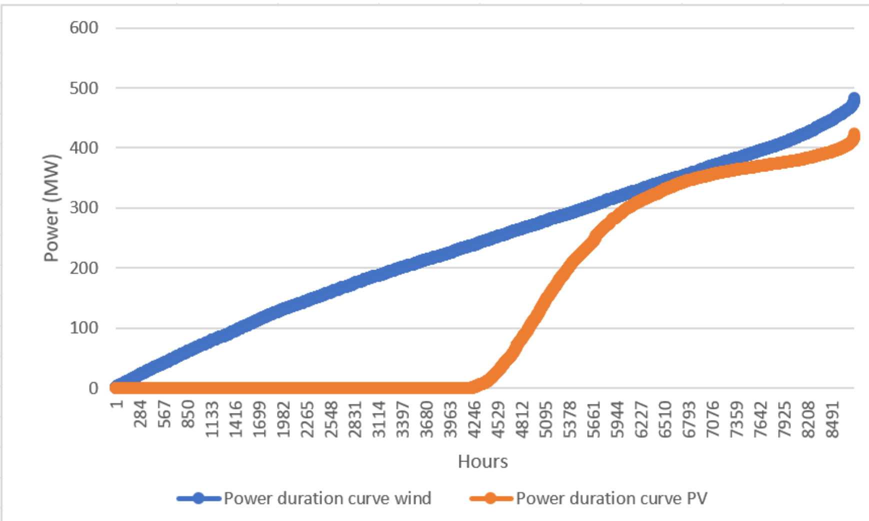


Figure 6.5: The power duration curve of a 500 MW wind park and 500 MW PV installation near Tan Tan Morocco.

6.3.1.2 Costs of renewables

A comprehensive understanding of the development of Photovoltaic (PV) and wind power costs up to 2030 is important. However, according to IRENA (2022e), there are considerable discrepancies in the CAPEX associated with installing these systems worldwide. Consequently, it is also essential to understand the factors shaping these geographical cost differences to incorporate them into the analysis appropriately.

Cost of PV

IRENA (2022e) observes substantial differences in the cost of PV across various regions. For instance, the installation cost per kW for utility-scale solar PV is over 30% lower in Germany compared to the Netherlands. This cost difference is seen throughout all aspects of the supply chain, from hardware and installation to soft costs like permitting and system design (IRENA, 2022e).

Van Duffelen (2023) suggests that current improvements in transport efficiency are lowering the impact of shipping, which already only contributes to 1% of PV cost price (IEA, 2021e). It is therefore assumed that there are no disparities in hardware costs for large-scale projects by 2030. According to van Duffelen, the cost of land lease will show the largest difference with other countries. The cost of land lease is determined by the alternative agricultural value of the land and is notably high in the Netherlands. Furthermore, he mentions that labour costs will likely contribute to cost disparities between different countries. Lastly costs are predicted to decrease until 2030, following the trend of recent cost reductions. (M. van Duffelen, expert interview, 2023)

Firstly, the CAPEX for PV in 2030 is calculated using PBL's (2023) analysis. As this the analysis of PBL is oriented at PV to be built in the coming years, the reference year is 2027, as explained in Section 6.1.1.2.. Within this period, the RMI (2023) anticipates a PV and wind cost drop of about 20% and 7% respectively. Using this cost reduction, the CAPEX of PV in the Netherlands in 2030 is estimated at €386.000/MW. Given that IRENA (2022e) attributes cost reductions to all supply chain elements, it is assumed that each CAPEX component experiences a similar cost decrease, with OPEX declining proportionally to CAPEX.

Installation costs account for roughly 20% of utility-scale PV's CAPEX in the Netherlands, a proportion expected to be constant till 2030 (IRENA, 2022e). Calculating the precise labour cost differences across nations is complex; however, the current averages outlined in Table 6.3 are projected to reflect the labour cost variance for PV installation by 2030. These figures allow for the computation of country-specific PV CAPEX values.

PBL (2023) estimates land lease costs in the Netherlands at €1.667-10.000/MW, which translates to an OPEX of 0,35-2,1% of the CAPEX of €482.000/MW. Comparatively, land lease costs are substantially lower in the US, at approximately €450-4,500/MW (Smart Energy USA, 2023). Also in Spain agricultural land is roughly six times cheaper than in the Netherlands (Eurostat, 2021). While there is no data for the other assessed locations, it can be assumed that land lease costs are even lower in sparsely populated areas such as deserts.

PBL (2023) assumes a fixed OPEX of 2,4% of CAPEX, excluding land lease. It is assumed that land costs generally fall in the lower range for these large-scale projects and represent an additional OPEX of 0,5% of CAPEX in the Netherlands. Considering the uncertain actual cost variations in other nations and a fivefold average cost difference observed in Spain and the United States, a 0,1% contribution is projected for the other assessed countries.

Stein (2018) indicates that tracking systems contribute approximately 7% to PV CAPEX and projects that these costs will decrease together with other components. Consequently, this analysis assumes that the tracking system will add an additional 7% to the PV CAPEX.

Table 6.3: Overview of optimal tilt and costs of PV used in analysis.

Country	Optimal tilt	Labour cost (% of Dutch labour cost) (ERI, 2023; International Labour Organisation, 2021; U.S. Bureau of labor statistics, 2023)	PV CAPEX excluding tracking system. (€/MW)	PV CAPEX with premium for tracking system	PV OPEX (% of CAPEX)
Netherlands	36,2°	100%	€386.000	€ -	2,9%
Australia	21,2°	70%	€363.000	€388.000	2,5%
Chile	41°	18%	€323.000	€346.000	2,5%
Spain	33°	60%	€355.000	€380.000	2,5%
USA	26,6°	90%	€378.000	€404.000	2,5%
Morocco	25,7°	8%	€315.000	€337.000	2,5%

Costs of Wind

Globally wind CAPEX differs significantly, which can be attributed to for example the maturity of the market or hardware costs (IRENA, 2022e). However, the wind industry is a relative global market (B. Ummels, expert interview, September 8, 2023). Therefore, by 2030, it's expected that market and hardware factors won't significantly affect these large-scale projects.

Transportation costs, contributing on average 6% to the CAPEX of onshore wind, could show larger location specific differences than PV, but accurate assessment of freight cost variations across locations is challenging (IEA, 2021e). Therefore, in this analysis, no distinctions in transport costs were assumed among the projects evaluated. However, in reality, transportation costs are likely to be significantly higher in regions without established port or road infrastructure. In particular, for large onshore and offshore wind projects, the development of a large area (hundreds of thousands of m^2) marshalling or pre-assembly harbour with a long and strong quay side and sufficient water depth to allow for large vessels. (B.C. Ummels PhD, expert interview, September 8, 2023).

The land requirement for wind energy is minimal as the space between turbines can accommodate other activities, like solar PV. Hence, this study does not factor in differences in land costs. Moreover, NREL (2022) reports that installation expenses represent a mere 3% of CAPEX, thereby making country-specific cost deviations insignificant. As such, the analysis does not include any CAPEX differences between the countries assessed.

The anticipated wind cost reduction up to 2027, from PBL's (2023) base costs, are expected to be less than that for PV, roughly 7% (RMI, 2023). This can be attributed to a less drastic cost reduction trend in recent years compared to PV, along with an increasingly significant role of rising material costs (IEA, 2021e; RMI, 2023). It is assumed that this cost applies for offshore and onshore wind and that OPEX declines proportionally to CAPEX. Table 6.4 shows the resulting costs for both offshore and onshore wind based on PBL (2023).

In this study, offshore wind is only assessed for the Netherlands and the cost estimates presented here are specific to the Dutch context. It is noted that the Dutch government takes care of all costs for project feasibility, environmental impact assessment, permitting; for offshore site investigations (soil, sea and wind); and also for providing an offshore grid connection in time. Furthermore, the strong winds, the shallow waters of the North Sea and the mature port and main land infrastructure significantly reduce risks and expenses. In contrast, in countries that are moving into offshore wind (Taiwan, USA, and more recently Japan and Australia), offshore wind CAPEX tends to be significantly higher, estimated at 2-3 MEUR euros per MW. (B.C. Ummels PhD, expert interview, September 8, 2023)

Although the values from PBL (2023) are used in this research, industry insights suggest higher maintenance costs for offshore wind, namely more in the range of 4% of CAPEX per year (B.C. Ummels PhD, expert interview, September 8, 2023).

Table 6.4: Overview of costs of wind used in analysis based on PBL (2023) and cost reductions of RMI (2023).

	CAPEX 2023 (EU/MW)	CAPEX 2030 (EU/MW)	OPEX (% of CAPEX/ year)
Onshore wind	1.350.000	1.255.500	1%
Offshore	1.550.000	1.441.500	1%

Grid connection costs

Most current Dutch electrolysis initiatives are based on offshore wind that is transmitted to the shore by the TSO (TKI, 2022). As such, these grid-connected projects incur grid fees, which PBL (2023) estimates at around €144,3/kW annually for Dutch electrolysers.

However, export projects will more likely adopt a 'direct-line' approach, positioning the electrolyser directly next to the renewable energy sources. This eliminates the need for transmission and significant power transformation. Figure 6.6 illustrates the differences between a direct-line electrolyser and a HyCC electrolyser connected to offshore wind via the grid. For the sake of simplification, the model assumes that the cost of electrically connecting the wind or PV sources to the grid is comparable to that of directly connecting these sources to the electrolyser in export-oriented projects. As these costs are included in the cost of wind and PV, no additional costs for the electrical connection are included for the exporting projects.

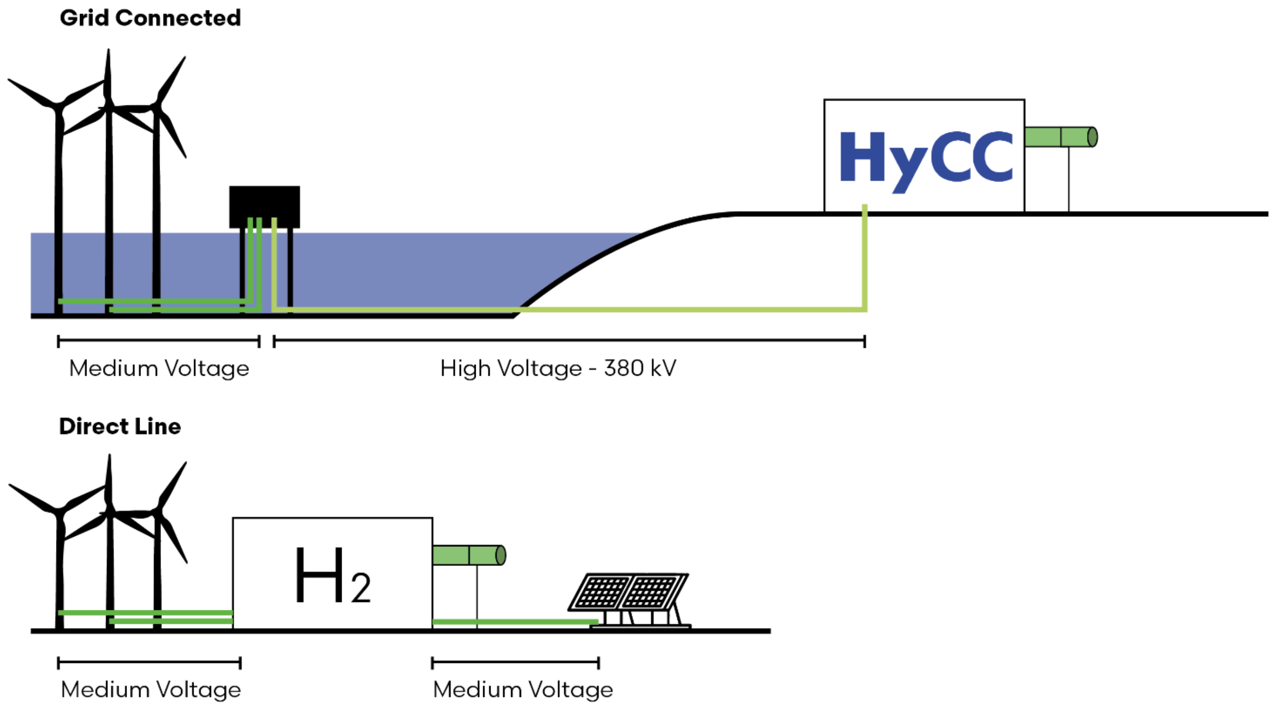


Figure 6.6: The difference between a direct line and grid connected electrolyser (own image).

Power cost

Figure 6.7 presents the levelized costs of electricity (LCOE) across various countries. Despite the higher availability of wind power, solar PV appears to be the more cost-effective renewable energy source in most of these locations in terms of LCOE. Chile stands out with the most competitive wind power costs but, conversely, exhibits higher costs for PV.

The Netherlands were seen to have a high availability of wind power in the North Sea at a highly competitive CAPEX. However, grid expenses significantly inflate costs, contributing €19/MWh to both wind and solar PV. This equates to a hefty 40% addition to the LCOE of wind power.

The influence of varying discount rates can also be seen. For instance, renewable energy sources perform better in Morocco but exhibit lower costs in Australia due to a lower discount rate.

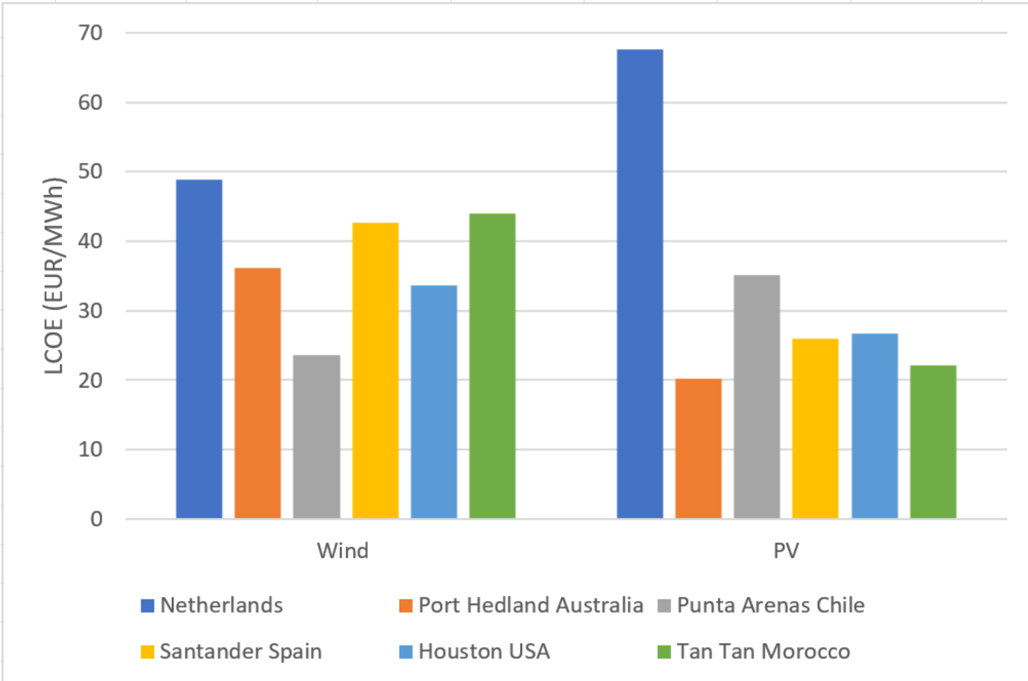


Figure 6.7: The resulting LCOE of both wind and PV for each of the countries assessed, including grid fees in the Netherlands.

6.3.1.3 The optimal power mix for electrolysis

Incorporating the data from this section and the information on power storage and electrolysis discussed in the following sections, the capacity of the renewables can be optimised to minimise the levelized cost of hydrogen (LCOH) production in each country. Figure 6.8 shows the yearly power produced by wind and solar in this optimal scenario for all assessed countries.

The benefits, as described in Section 6.3.1.1, are clearly demonstrated here. Notably, wind is the most important renewable in five of the six assessed countries despite the substantial variations in the Levelized Cost of Electricity (LCOE) among these nations. In those countries where photovoltaics (PV) are significantly less expensive than wind—Australia, Spain, the United States, and Morocco—the wind capacity is complemented by solar PV with approximately a third up to a little more than half of the capacity. In these countries, between 9% and 10,7% of power is curtailed as it couldn't be utilised for storage or electrolysis.

On the other hand, in the Netherlands and Chile, where wind power is less expensive than PV, PV is barely used. Correspondingly, overproduction amounts to 9,9% in the Netherlands and 2,4% in Chile.

Figure 6.9 presents the power duration curves for Spain in this optimised scenario. Again, it can be seen that wind has a higher availability compared to solar. However, the combined power curve, represented by the yellow line, illustrates how both wind and solar complement each other to extend the operating hours of the electrolyser. The power consumed by the electrolyser corresponds to the area below the yellow line and the 1,000 MW marker. Meanwhile, the curtailed power is represented by the area under the yellow line but above the 1,000 MW marker.

In achieving this optimal balance between wind and solar PV, the Netherlands, burdened by the highest fixed costs primarily due to fixed grid connection fees, manages to achieve 6,623 full load hours (FLH). Conversely, in Morocco, where solar PV dominates the power supply, 4,973 FLH are realized. Other countries fall within a range of 5,959 to 6,567 FLH, translating to utilization rates between 68% and 75%.

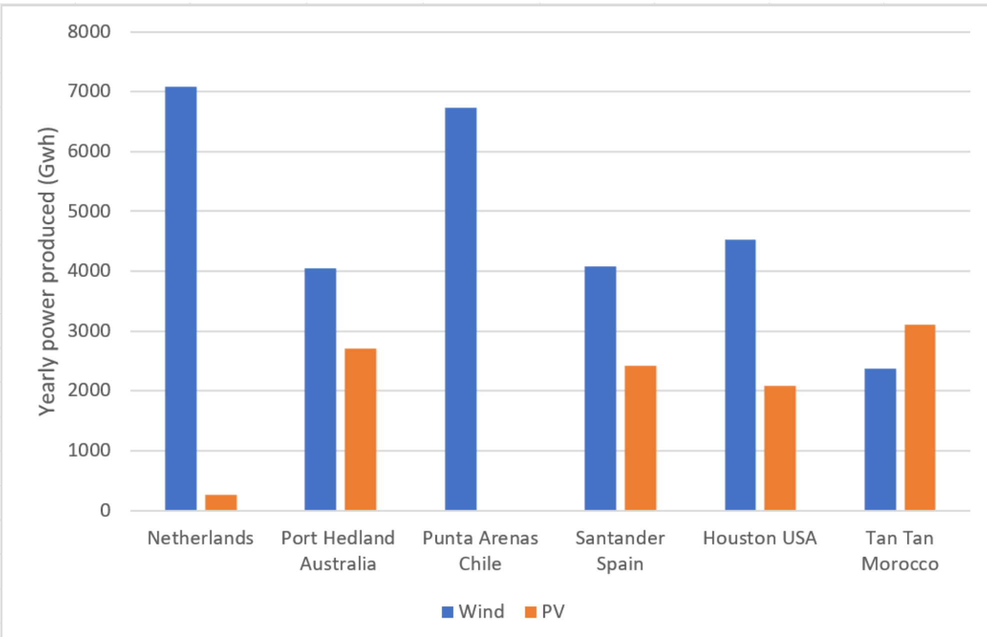


Figure 6.8: The yearly power produced by wind and PV to ensure an optimal LCOH.

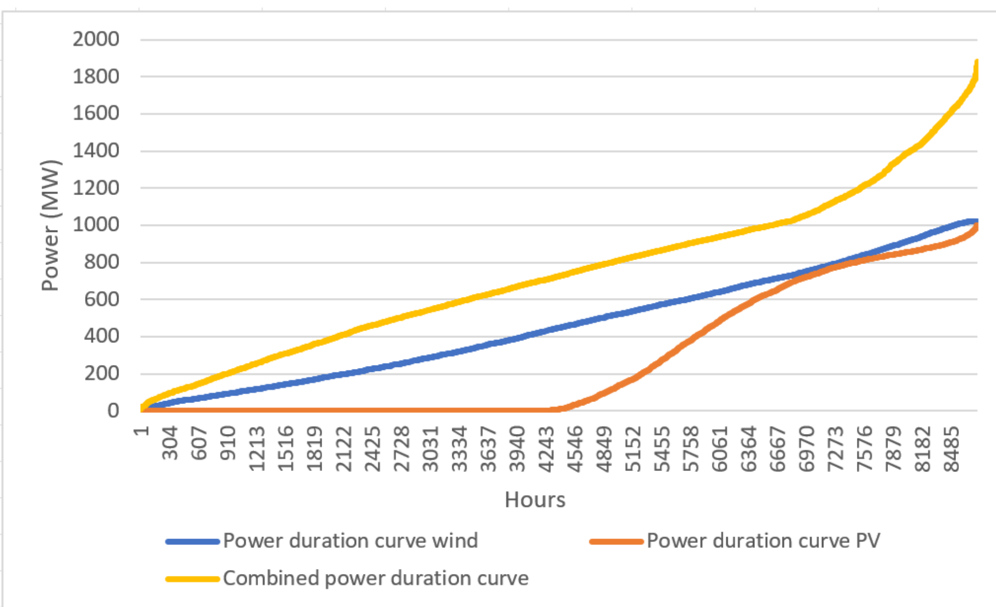


Figure 6.9: the power duration curves for an optimised LCOH in Spain.

6.3.2 Supplying the minimal electrolyser load

Technical limitations may require a minimum operating power for the hydrogen production facility (ISPT, 2022). In Section 6.3.3 it is elaborated that a 10% minimum load is assumed in this research. The intermittent nature of renewable power generation may sometimes fall short of this threshold. When it does it should therefore be assessed how to manage this minimal electrolyser load. The study examines three primary pathways for managing power below the minimal load of the electrolyser: drawing power from the grid, utilizing a battery storage system, or shutting down the electrolyser stack which will increase the degradation of the stack. An in-depth analysis of these alternatives is available in Appendix 6.1, and the model accommodates all three pathways.

For projects in exporting countries, this study finds that shutting down a part of the electrolyser stacks below 10% capacity is the most appropriate strategy. While this approach minimizes costs, it does have a significant drawback: increased wear on the electrolyser stacks (Kojima et al., 2023). This study adopts the assumption from PBL (2023) that such shutdowns result in doubled stack degradation. Conversely, systems connected to the Dutch grid have the option to procure power directly from the grid. A thorough discussion on the rationale behind this system design can be found in Appendix 6.1.

Appendix 6.1 also provides a detailed breakdown of the associated costs for a grid connection or battery system. For the Dutch case, €180/MWh is found to be a realistic cost for the bought power in case of scarce renewable availability.

6.3.3 Electrolyser

6.3.3.1 Electrolyser type

There are various types of electrolysers, with three types of main interest being the alkaline electrolyser (AWE), the proton exchange membrane electrolyser (PEM) and the solid oxide electrolyser (SOE) (IEA, 2022b). Multiple factors need to be taken into account when selecting an electrolyser for a particular system, such as CAPEX, efficiency and power cost (Corbeau & Merz, 2023). Other important considerations include stack degradation, economies of scale and the integration with renewables (Corbeau & Merz, 2023).

Alkaline electrolysis, being the most mature technology, has been widely employed worldwide since the 1900s for chlorine manufacturing and early ammonia production (Smolinka et al., 2022). Although the alkaline electrolyser is the most economical due to its construction from low-cost materials, it falls short in its ability to rapidly ramp up and down to match renewable electricity output directly (Corbeau & Merz, 2023).

The PEM electrolyser represents the second-most developed technology and shows greater flexibility (Corbeau & Merz, 2023). However, its reliance on more costly materials, such as iridium, increases the CAPEX (Corbeau & Merz, 2023). Corbeau & Merz (2023) explain that the efficiency comparison between PEM and alkaline electrolysers remains inconclusive, as opinions on the most efficient technology diverge. ISPT (2022) suggests that the PEM stacks show higher losses, but have a better overall system efficiency due to fewer auxiliary power losses.

The Solid Oxide Electrolyser is a high-temperature electrolyser operating at 700-850 degrees Celsius. It is capable of achieving significantly higher efficiencies than either PEM or alkaline and can ramp up and down in alignment with renewable sources (Corbeau & Merz, 2023). Despite currently having a higher CAPEX than either PEM or alkaline, SOE is a newer technology and constructed from simpler materials than PEM, therefore cost reductions are expected in the future (Corbeau & Merz, 2023). A key issue with SOE is the durability of the stacks (Corbeau & Merz, 2023).

As noted, there is a high level of uncertainty regarding the exact performance of these electrolysers, but the assumptions made by the IEA (2019) for their performance in 2030 are summarised in Table 6.5. It is seen that the solid oxide electrolyser potentially offers an efficiency gain exceeding 10%, however, its stack lifetime may be less than half that of an Alkaline electrolyser, with costs potentially twice as high. Notably, the PEM electrolyser appears to perform considerably less than alkaline in terms of both stack lifetime and CAPEX.

Table 6.5: Presented assumptions of IEA (2019) on electrolyser performance by 2030.

	Alkaline Electrolyser	PEM electrolyser	Solid-oxide electrolyser
Electrical efficiency (% LHV)	65-71%	63-68%	77-84%
Stack lifetime (hours)	90.000-150.000	60.000-90.000	40.000-60.000
CAPEX (USD/kWh)	400-850	650-1500	800-2800

This study adopts the Advanced 2030 design for a hydrogen production facility proposed by ISPT (2022), which utilises a mix of ⅔ PEM and ⅓ alkaline stacks. The PEM section of the plant is projected to operate at a minimum load of 10%, while the alkaline portion is expected to operate at a minimum load of 15% (ISPT, 2022). For ease of modelling and because other scholars, such as the IEA (2019) or de Groot et al. (2022) suggest that a 10% minimal load is also feasible for alkaline electrolysers, it is presumed that the overall minimal load is 10% for the full electrolyser capacity. In Section 6.3.2 it was discussed that for exporting projects a battery system is applied to supply this minimal load, while the Dutch grid-connected electrolyser will buy power from the grid.

6.3.3.2 Costs of electrolyser

The total installed costs for a 1 GW electrolyser plant are estimated to be €730/kW for the alkaline part and €830/kW for the PEM part, averaging €797/kW for the entire plant (ISPT, 2022). The cost breakdown for the alkaline section is illustrated in Figure 6.10, where it is notable that the stacks constitute only a small proportion of the total anticipated hydrogen production facility CAPEX.

The- initial efficiency of the electrolyser is assumed to be 77% for the PEM share of the plant and 75,8% for the alkaline share of the plant (ISPT, 2022). To streamline this analysis, an average efficiency level is assumed based on the ratio of PEM to alkaline stacks in the plant. This calculation yields an average efficiency of 76,6%. It is projected that electrolyser efficiency will decline by 1% annually if the minimal stack load is maintained (ISPT, 2022; PBL, 2023). However, a more accelerated stack degradation rate of 2% is assumed when the plant is fully shut down below this minimal load (PBL, 2023). Economic considerations suggest stack replacement when degradation reaches approximately 10% (ISPT, 2022). Therefore, within the investment duration assessed in this study, a single stack replacement is projected in the 8th year for grid-connected electrolysers. In contrast, two stack replacements are anticipated in the 6th and 11th years under scenarios that entail higher rates of stack degradation.

The complexity of assessing stack replacement costs cannot be understated. While cost reductions are expected, they are likely to plateau at a value representing minimal material and production costs for the specific technology in question. According to ISPT (2022), the estimated costs for AWE and PEM stacks in 2030 are €100/kW and €154/kW, respectively. Separate research from the ISPT report contributors also presents an absolute best case development scenario for 2030, projecting stack costs to decline to €52/kW for AWE and €63/kW for PEM (de Groot et al., 2022). For the purposes of this study, it is assumed that these lower cost estimates approximate the asymptotic values and that these reductions are realised before the first stack replacement. These are therefore assumed to represent the costs for all subsequent stack replacements, averaging stack replacement costs at €59/kW, which signifies a 57% decrease relative to 2030 costs.

Both PBL (2023) and Hydrogen Europe (2022) assume and electrolyser OPEX of 4%, which is considered to remain valid for the year 2030. No value for the waste heat and oxygen produced by the electrolyser is assumed (PBL, 2023).

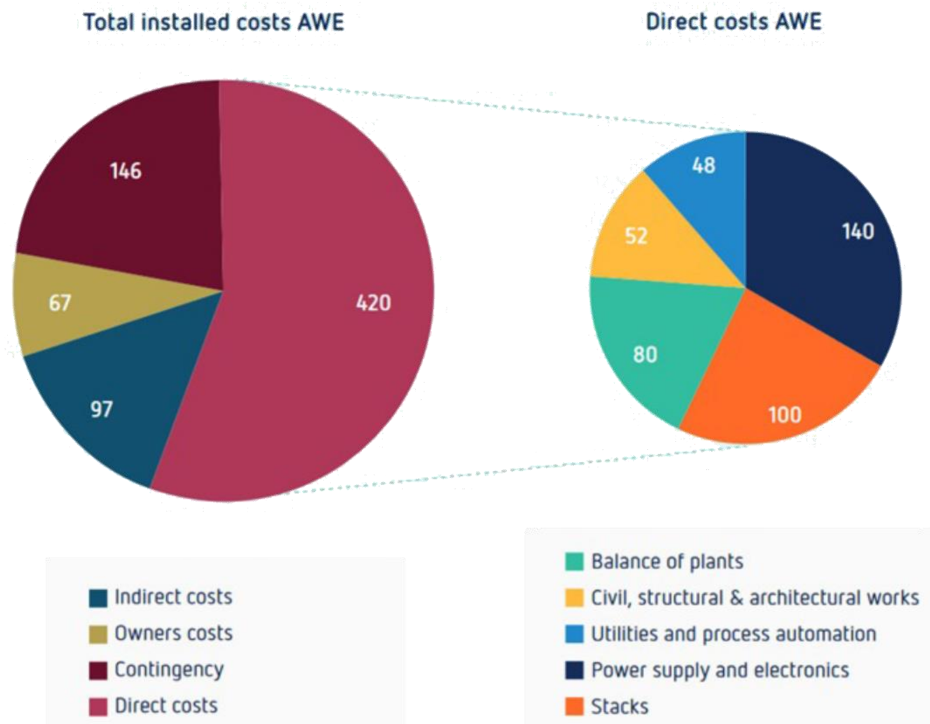


Figure 6.10: Breakdown of total installed costs for an alkaline water electrolyser (AWE) from ISPT (2022).

Expected cost differences of electrolyser

Just as with renewables, there are likely some country specific cost differences for electrolysers. For instance, labour costs may be lower, but also the costs of land. The study by ISPT (2022) indicates that civil work accounts for 7,1% of the total CAPEX. However, the specific proportion of this attributed to labour costs remains unknown, making it challenging to accurately estimate these potential savings.

Moreover, the plot size required is only about 10 hectares, for which land lease costs represent an OPEX of roughly 0,01% of CAPEX, based on the high value for land lease of renewables in the Netherlands. Thus, this cost is negligible when compared to other cost elements.

A more significant cost advantage could potentially be realised in the power components of the electrolyser, which constitute the largest share of direct costs and 17,5% of total costs, as seen in Figure 6.9. The ISPT (2022) design involves an incoming supply of 380 kV that is initially transformed to 66 kV and subsequently to 1,5 kV. The alternating current (AC) is then rectified to the 1,2 kV direct current (DC) needed for the electrolyser stacks.

The high voltage is needed to minimise power losses when transporting power to the shore (Beta Engineering, 2017). However, when the renewable sources are located adjacent to the electrolyser, a much lower voltage is sufficient for transport, thereby reducing the need for transformation and transformation equipment. Furthermore, solar PV generates direct current that could potentially be supplied directly to the electrolyser. Yet, the specific reduction in transformation and rectification demand and its precise impact on electrolyser CAPEX are uncertain (K. da Costa Ribeiro, expert interview, July 26, 2023). Also PBL (2023) does not differentiate in electrolyser CAPEX between direct line and grid connected electrolysers.

Future wind parks in the Netherlands are planned to convert power to high-voltage DC offshore. Therefore, ISPT is researching potential cost savings from skipping the rectification process and using DC-DC transformers, which could shed further light on these types of electrolyser cost savings (ISPT, 2023).

Given the uncertainties about specific cost savings, this study assumes that the electrolyser cost elements are the same in all assessed countries. However, a sensitivity analysis is conducted to assess what a potential cost saving on the power part in the exporting countries might entail for the LCOH.

Freshwater sourcing

Also the supply of freshwater is important to consider, especially given its scarcity in certain countries (IRENA, 2022b). Some researchers, like Pflugmann & De Blasio (2020) even believe this is a dealbreaker for hydrogen production. The solution is desalination of seawater though. According to IRENA (2022b), the added cost of desalination would amount to a marginal increase of approximately 24 euros per tonne of hydrogen for a site situated 50 km from the coastline. Given that this cost is relatively minor in comparison to other expenses examined in this study, the issue of freshwater sourcing has been excluded for the sake of simplicity.

The local levelized cost of hydrogen

Figure 6.11 presents the calculated levelized cost of hydrogen. Under the assumptions of this study, anticipated hydrogen costs in 2030 range between €2328 and €3866 per tonnes. The electrolyser accounts for around €930 to €1612 per tonnes, dependant on the amount of operating hours. The renewables are seen to be the most influential factor in the hydrogen's cost. Significantly, grid connection costs play a pivotal role in the Dutch hydrogen production costs, adding roughly €1200 per tonnes. This makes the Netherlands the costliest producer, with Chile producing hydrogen at about €1500 less per tonne.

It is seen that without grid costs only Chile would be likely to produce hydrogen at a lower cost than the Netherlands, which is attributed to the Netherlands' benefit of low-cost offshore wind and its lower WACC compared to countries like Morocco.

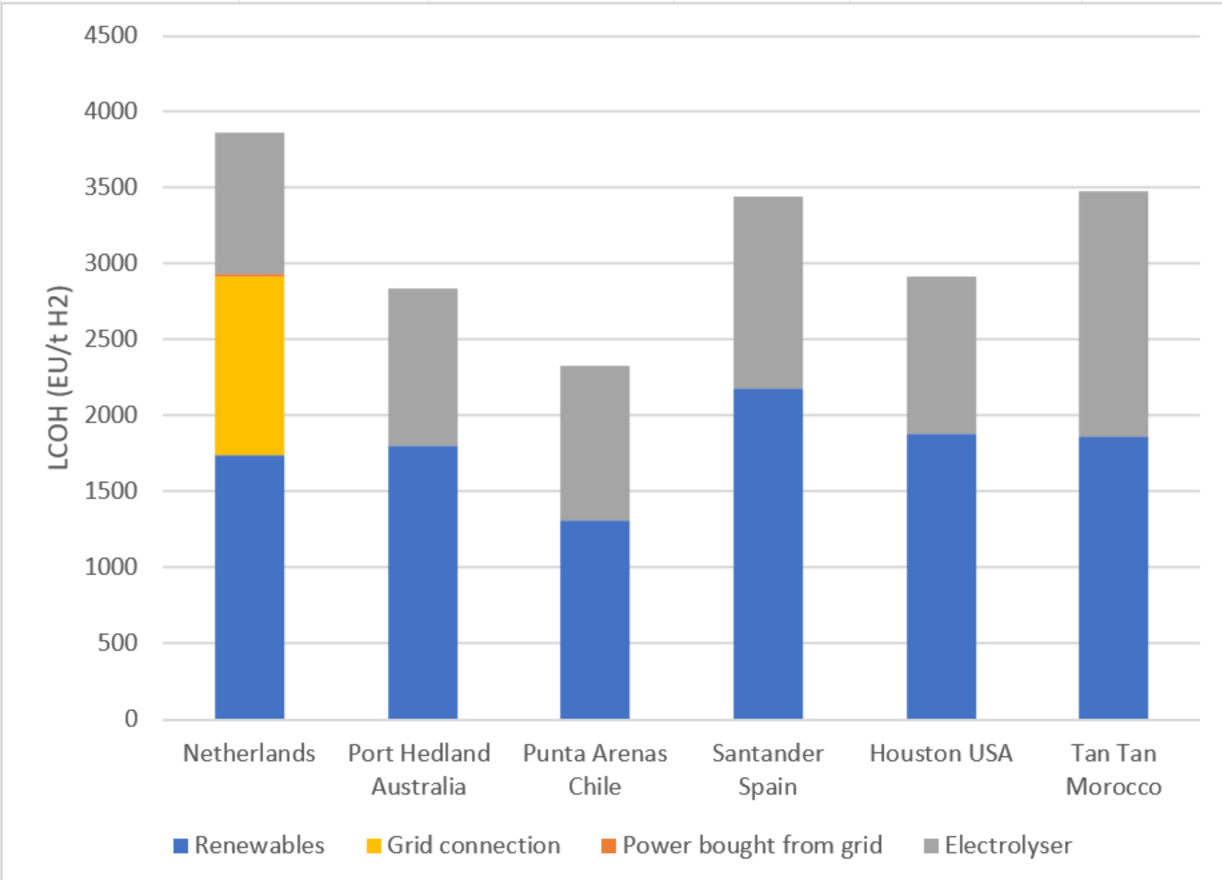


Figure 6.11: The levelized cost of hydrogen in different countries.

6.3.4 Hydrogen storage

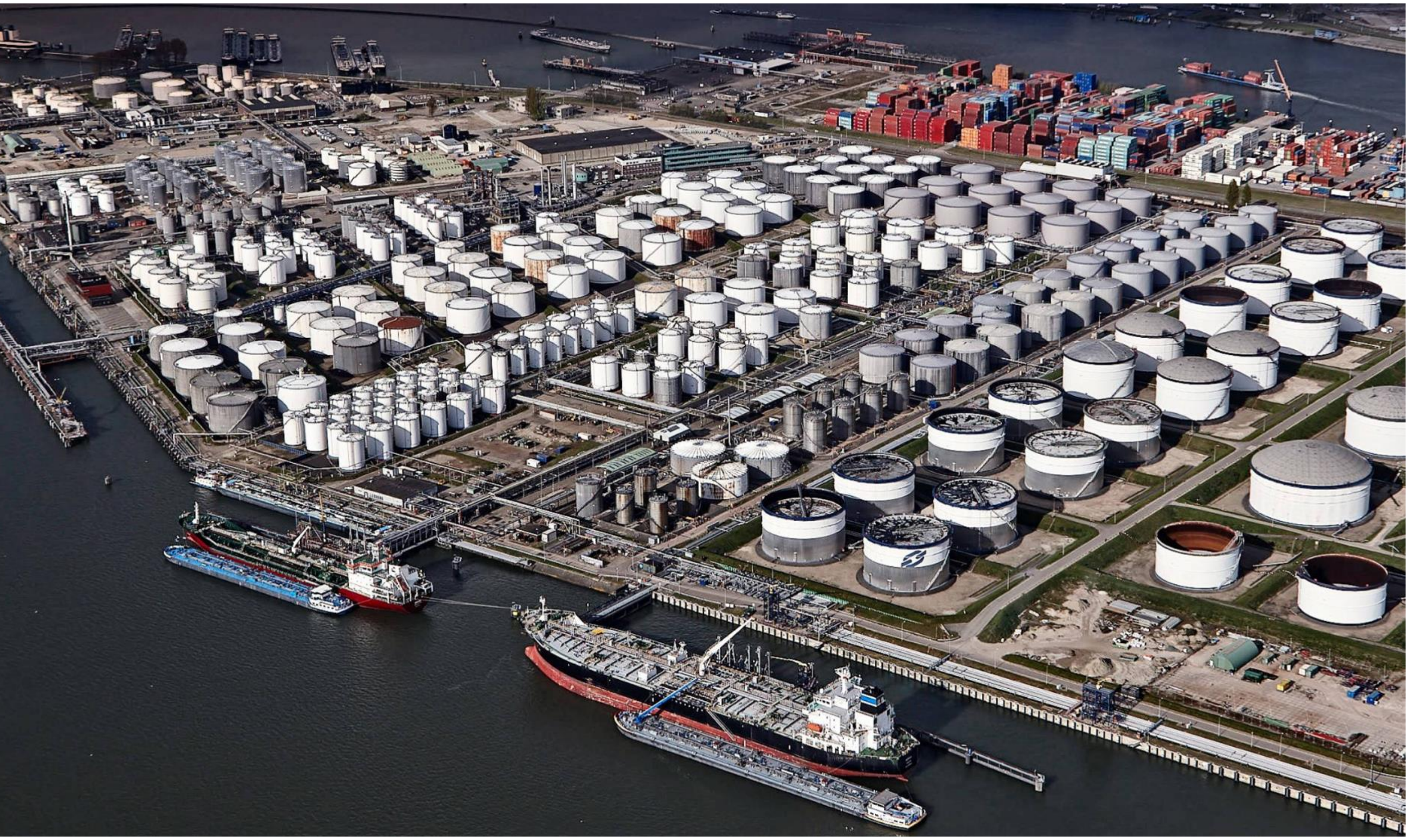
For domestic production, hydrogen storage is needed to be able to supply a baseload to a consumer. Additionally, hydrogen storage becomes necessary when the minimum operating capacity of the conversion plant surpasses that of the electrolyser.

Hydrogen can be stored in tanks at a CAPEX of €470.000 per tonnes or in salt caverns at €8.864 per tonnes (TNO & EBN, 2022). All evaluated sites, except the southern Chile project, have accessible salt formations. In the Netherlands it is found that 283 GWh of storage is needed to supply a baseload.

This data allows the computation of the functional unit for the Netherlands, translating to a cost of €3.923/tonnes for delivering a base-load supply of green hydrogen. The hydrogen storage only added an additional 1,5% to the LCOH.

In other countries, a supplying a minimal operating capacity to conversion plants leads to a smaller storage need. Supplying a minimal capacity 20% to the liquefaction plant for example adds of the ammonia conversion plant led to a hydrogen storage need of 3-11 GWh. A comprehensive breakdown of the system design and the associated storage costs is provided in Appendix 6.2.

6.4 Inventory analysis - Hydrogen transport



In 2030, various modes of hydrogen transport to the Netherlands are expected (TKI, 2022). However, even with the expanded ambitions of the European Hydrogen Backbone following REPowerEU's 10 Mt hydrogen import goal, piped imports to the Netherlands are not projected by 2030 (EHB & Guidehouse, 2022; European Commission, 2022). Consequently, shipped transport is the only feasible import method. Dutch ports primarily anticipate four modes of hydrogen transport: ammonia, liquid hydrogen, liquid organic hydrogen carriers (LOHCs), and synthetic fuels (TKI, 2022).

Synthetic fuels include synthetic kerosine and methanol (TKI, 2022). Nonetheless, these fuels are unlikely to compete as hydrogen carriers, instead serving as end products in sectors such as industry and transportation (Daiyan et al., 2023; JRC, 2022; TKI, 2022). Given the focus of this study on comparing hydrogen delivery methods, synthetic fuels are excluded. The operation and economics of the remaining carriers are explored in this chapter.

Many reports suggest a break-even point exists among these transport modes, depending on the distance of hydrogen transport and the size of the supply chain. For instance, IRENA (2022c) suggests ammonia as the most competitive solution for long distances, while LOHCs perform better in smaller projects, and liquid hydrogen is most advantageous for larger short distance projects. However, numerous other design variables may influence the optimal hydrogen transport mode, such as opportunities for symbiosis, local power prices, repurposable infrastructure, and safety considerations (JRC, 2022; Patonia & Poudineh, 2022).

Table 6.6 and Figure 6.12 provide an overview of the assessed hydrogen carriers their distinct characteristics. Each carrier exhibits unique advantages and drawbacks. DBT fares poorly in terms of energy density, while ammonia outperforms in volumetric density and liquid hydrogen excels in weight density. Additionally, DBT has the highest heat of reaction, implying that it requires the most energy to extract the hydrogen. Liquid hydrogen, with its exceptionally low boiling point, demands complex handling and energy-intensive liquefaction. This low temperature also introduces a health hazard, potentially causing severe burns. It is also highly flammable. Conversely, ammonia, while less flammable, is notably toxic. DBT emerges as the safest carrier in both health hazards and flammability. These health and flammability scores, on a scale from 0 to 4, are derived from the National Fire Protection Association's NFPA 704 standards (Cameo Chemicals, 2023).

Table 6.6: The main characteristics of the assessed modes of hydrogen transport. (Cameo Chemicals, 2023; IRENA, 2022d; ISPT, 2019)

	Ammonia	Liquid hydrogen	DBT (LOHC)
Energy density hydrogen weight	17,8%	100%	6,2%
Energy density weight (MWh HHV/tonnes)	6,25	39,4	1,88
Volumetric energy density (MWh HHV/m^3)	4,81	2,8	1,63
Heat of reaction (MWh/MWh)	0,12	0	0,23
Boiling point (℃)	-33	-253	380
Health hazard (NFPA 704) (n/4)	3	3	0
Flammability (NFPA 704) (n/4)	1	4	1

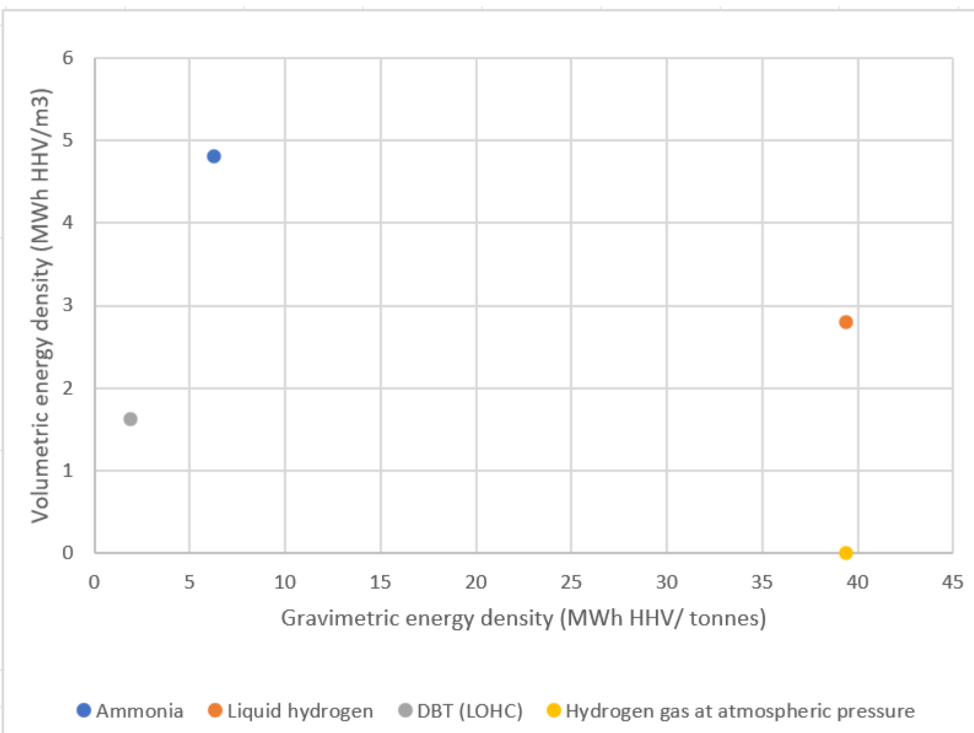


Figure 6.12: The relation between the volumetric and gravimetric energy density of the different carriers.

6.4.1 Intermediate transport

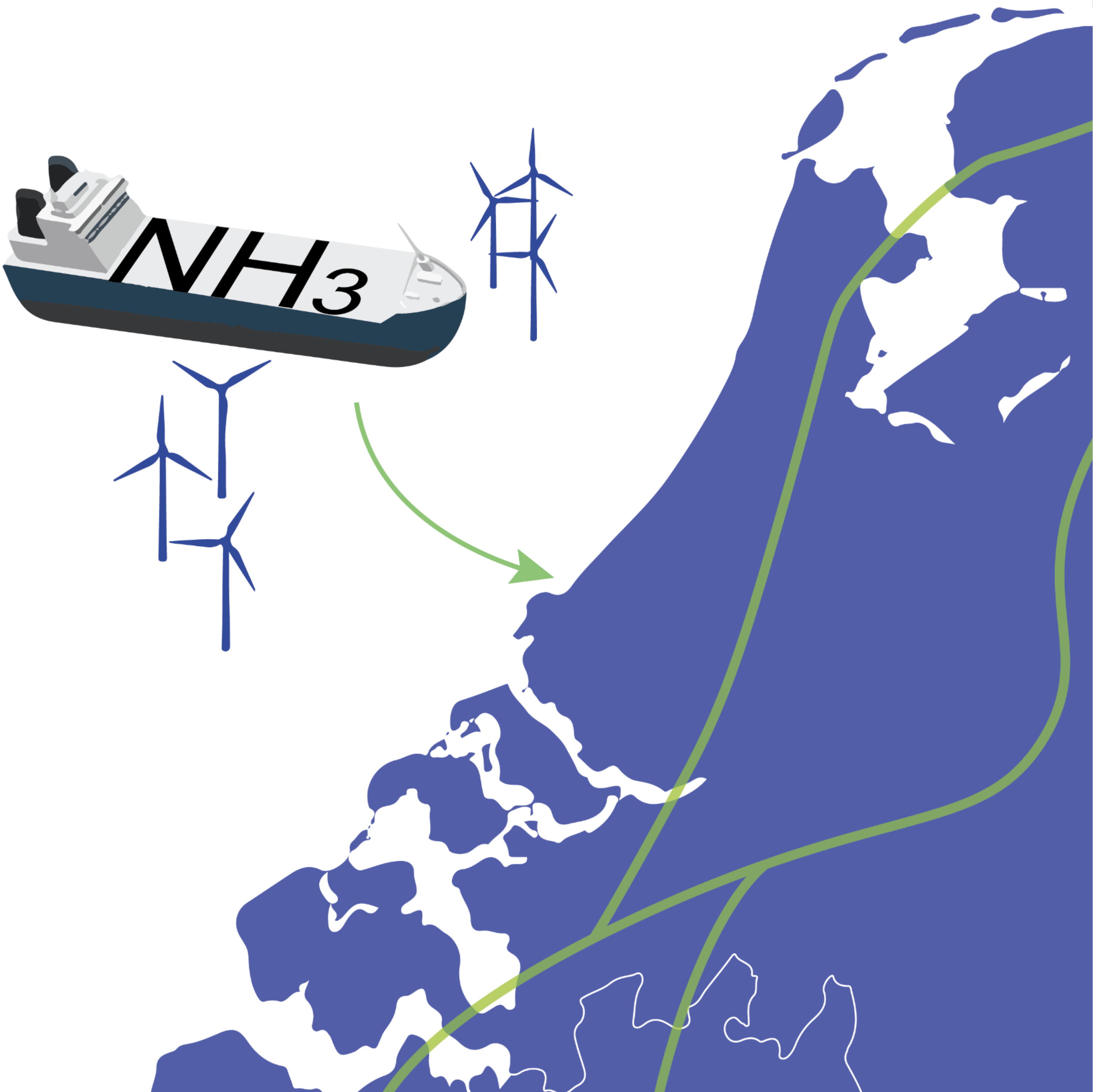
Given that power generation is often located not directly next to exporting ports, intermediate energy transport is a necessary additional step for all three hydrogen import routes. It is in practice possible that power, hydrogen or the carrier is transported to the port. This will thus determine whether the electrolysis and conversion processes take place near the port or close to the renewable power production. When a certain carrier for intermediate transport is chosen it can still differ whether it is transported by pipe, ship or truck.

In this study it is assumed that all transport to port is done through pipelines, as this is eight times less costly than electricity transport (DeSantis et al., 2021). The pipelines can either be new or repurposed and shared or fit-to-size. Table 6.7 presents the assumed pipeline types for each scenario and country, accounting for roughly 0% to 10% of the pre-conversion hydrogen costs. A detailed explanation of the selection of these configurations and associated costs can be found in Appendix 6.3.

Table 6.7: Assumptions taken on intermediate transport for the different scenarios.

Country	Best case	Likely - low	Likely - high	Worst case
Spain	Repurposed, Shared	Repurposed, Shared	New, appropriately-sized	New, appropriately-sized
Other countries	Repurposed, Shared	New, Shared	New, appropriately-sized	New, appropriately-sized

6.4.2 Ammonia



Ammonia (NH3), a combination of nitrogen and hydrogen, has been extensively used in the production of fertilisers, and is predominantly made with carbon-intensive grey hydrogen (IRENA, 2022d). 'Green ammonia' made through water electrolysis offers a path to partly abate these emissions. It is worth noting, though, that approximately 52% of the emissions from current ammonia production are directly utilised as feedstock for urea in the fertiliser production process (Bonnet-Cantalloube et al., 2023). Consequently, approximately half of the current production of grey ammonia can be directly transitioned to green, while a substitute carbon feedstock must be identified for the remaining portion. The potential direct uses extend far beyond traditional applications though. It is seen as highly promising sustainable shipping fuel, but also other novel uses are investigated such as use in power plants and steelmaking (Bonnet-Cantalloube et al., 2023; Max-Plack-Institut, 2023; Xu et al., 2022).

Ammonia can serve as a hydrogen carrier by reconverting the ammonia back to hydrogen in a process called cracking (Bonnet-Cantalloube et al., 2023). The full supply chain of ammonia as a hydrogen carrier is shown in Figure 6.13. An example of the scaling of the elements is seen in Figure 6.14 for the most-likely low scenario. It is seen that the needed capacity for the plants decreases because energy losses are met and because the cracker can operate at a base load.

Though the production of ammonia is well-established, the synthesis with intermittent renewables asks for adjustments in the process (Bonnet-Cantalloube et al., 2023). Direct applications of ammonia can act as stepping stones to establishing supply chains, even before the cracking technology is matured (Bonnet-Cantalloube et al., 2023). Nevertheless, ammonia's toxicity remains a concern (NL Times, 2023). For instance, in the Port of Amsterdam, the proximity to urban areas greatly limits the locations acceptable for ammonia terminals (R. Oorsprong, expert interview, June 1, 2023).

Generally it is believed though that the upscaling of ammonia handling, transportation, and utilisation in various applications can be done safely, but it necessitates comprehensive staff training and the possible implementation of stronger safety measures as parties / people with less ammonia experience will get involved (M. Brouwer, expert interview, July 27, 2023).

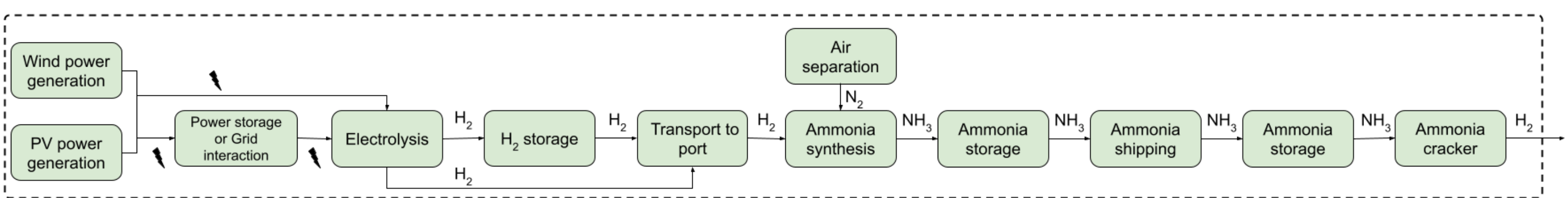


Figure 6.13: The supply chain of hydrogen transported in the form of ammonia.

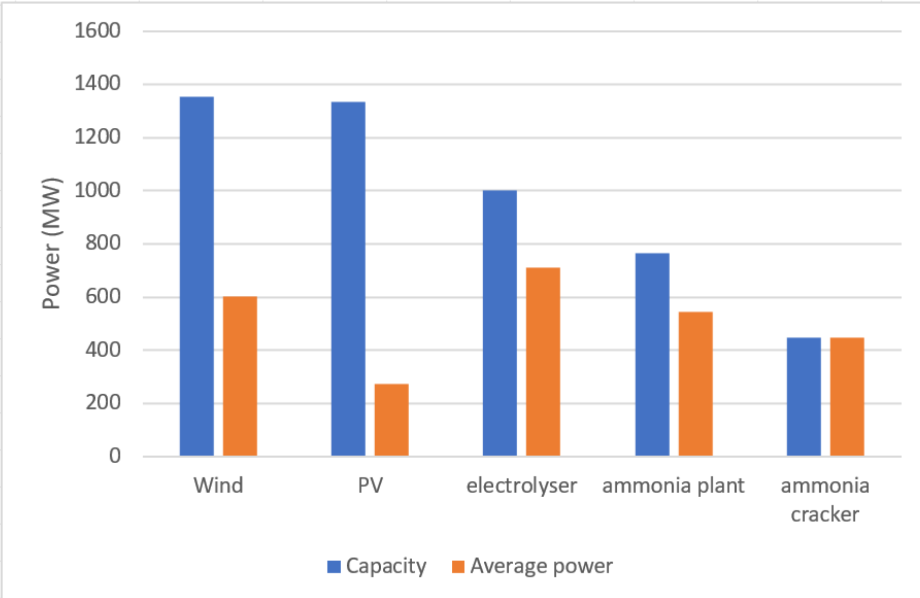


Figure 6.14: The scaling of the supply chain elements in the United States in the most-likely low scenario.

6.4.2.1 Ammonia synthesis

Ammonia production involves the combination of hydrogen and nitrogen, typically through the Haber-Bosch process, first developed in 1909 (Bonnet-Cantalloube et al., 2023). The production of green ammonia necessitates new methods of sourcing both nitrogen and hydrogen, yet the Haber-Bosch process remains the most commonly referenced approach for green ammonia synthesis (Olabi et al., 2023). The main complexity of the Haber-Bosch loop is its flexibility though (Bonnet-Cantalloube et al., 2023).

The process is exothermic, releasing approximately 750 kWh per tonne of ammonia (Morgan, 2013). Given that the reactor requires temperatures around 400℃, the heat generated is sufficient for maintaining the reaction temperature, making the process autothermic (Bonnet-Cantalloube et al., 2023). However, a decrease in reaction speed also reduces heat production, consequently lowering the reaction rate and potentially stopping the process (Bonnet-Cantalloube et al., 2023).

Several strategies exist to address this. Haber-Bosch units could be arranged in series, allowing for unit shutdown during low supply, but this is rarely implemented (Olabi et al., 2023). Alternatively, plant power could be reduced to a minimum of 30-40% of its production capacity (Bonnet-Cantalloube et al., 2023). Yet, both the power scaling and parallel production methods are inefficient. Efficiency steeply declines below 70% capacity, and frequent starting and stopping is energy-consuming (Bonnet-Cantalloube et al., 2023). Therefore, hydrogen storage is likely necessary for integration with intermittent renewable sources (Bonnet-Cantalloube et al., 2023).

The assumption of a minimal 40% load for the ammonia plant is the typical assumption used in the industry, but novel technologies purport to go as low as 10-20% (J. Armstrong, expert interview, June 20, 2023). An example is Haldor Topsoe, which asserts they can build plants capable of scaling down to 10% of nominal capacity (Haldor Topsoe, 2021). Similarly, Thyssenkrupp Uhde recently proposed a plant design operating at capacities as low as 10% (Noelker & Bagga, 2023). However, despite potential CAPEX savings from eliminating hydrogen storage, the risk of efficiency losses might still result in higher overall costs (W.J. Frens, expert interview, 2023). Hence, Proton Ventures, a company specialising in green ammonia, strives to maintain a minimum operating capacity of 50% in their projects, while the average utilization needs to be much closer to the maximum. Determining the optimal size of the ammonia synthesis plant depends on many factors, including, but not limited to; the ammonia plant technology licensor design, the feedstock intermittency profile, and for example the possibility to offload excess/peak power to the national/regional grid (K. Langhout, expert interview, July 25, 2023).

In this study, we assume a minimum operating capacity of 10% for 2030 as a realistic baseline and that this does not significantly alter efficiencies. However, given the possibility that plants may operate at a higher minimal capacity and that hydrogen storage could be utilized to supply a baseload to the synthesis plant, these alternative scenarios are explored in a sensitivity analysis. Although the speed at which the system can ramp up or down could also pose a challenge, it's expected that this is already addressed when supplying the minimum operating capacity (Verleysen et al., 2020). Therefore, ramping speed is not considered in this analysis.

As the reaction itself is autothermic, the primary additional energy demand within the synthesis loop is for pressurising inlet gases to between 100 and 250 bar (Verleysen et al., 2020).

For fossil-based processes, nitrogen is co-produced with hydrogen in the Steam Methane Reformer (SMR) (Bonnet-Cantalloube et al., 2023). Therefore, green ammonia production requires an air separation unit (ASU). The main technologies for air separation are cryogenic distillation and pressure swing absorption (PSA) (Bonnet-Cantalloube et al., 2023). While cryogenic distillation is more economical and energy-efficient, it is not suited for variable production (Bonnet-Cantalloube et al., 2023; Indian Oxygen Plant Company, 2021). Consequently, PSA emerges as a better fit for this application. The entire ammonia synthesis loop is depicted in Figure 6.15.

In Appendix 7.1.1, a thorough examination of ammonia synthesis costs is provided, detailing the performance of assessment indicators across the four development scenarios. It shows a clear cost correlation between the size of the plant and the costs, which resulted in a scaling factor of 0,74. Also on the power demand a clear cost trend is identified.

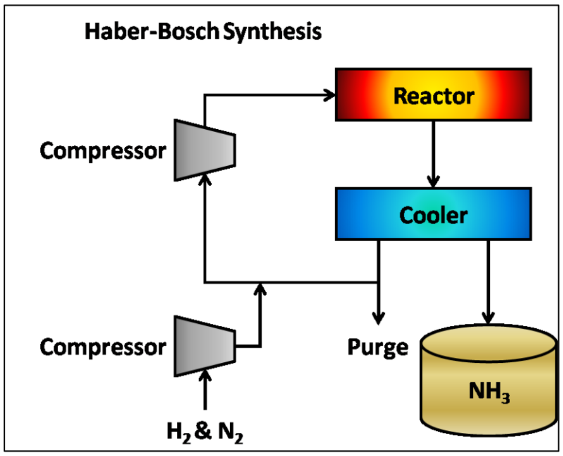


Figure 6.15: The Haber-Bosch synthesis loop (Morgan, 2013).

6.4.2.2 Ammonia storage

Storage is crucial to ensure that carriers do not have to wait on production to be filled. By having an intermediate storage site, carriers can be directly loaded with ammonia. This storage mechanism also serves to balance the seasonal variations in ammonia production, thereby ensuring a steady stream of ship arrivals and departures. An example of this mechanism is shown in Figure 6.16, illustrating the filling of an ammonia storage in Chile. The noticeable spikes represent the departure of ships and the subsequent refilling of the storage site. It is noted that around 16 round trips are required, with overproduction during the southern hemisphere's summer and slow depletion of the storage during winter. Consequently, the minimum storage requirement in the exporting country can be estimated as the sum of storage needed to balance seasonal variations and one ship volume. For the Netherlands, the storage volume could theoretically equal one ship volume, given the steady arrival of ships supplying ammonia. However, it is logical to include a buffer storage in both locations.

In literature, the recommended storage volume is often expressed in terms of ship volumes, typically ranging between one and two. In the model, if the minimum storage capacity exceeds the suggested ship volumes, the storage requirement is set to this higher value. It is worth noting that the one ship volume proposed by TNO (2022) is inadequate for all the considered scenarios due to seasonality.

The process of ammonia storage is well-established. Ammonia is stored in its liquid state at -33℃ and atmospheric pressure (Morgan, 2013). Due to the thermal gradient between the tank's interior and exterior, heat transfer occurs, causing some of the ammonia to boil and escape (Morgan, 2013). This inevitable process, known as boil-off, can be mitigated by reliquefying the gas. This is achieved by compressing the gas to 13 bar and condensing it in a small cooling tower (Morgan, 2013).

In Appendix 7.1.2, a thorough examination of ammonia storage costs is provided, detailing the performance of assessment indicators across the four development scenarios. A steep cost decrease is noticed as storage tank size increases. However, when these per-capacity CAPEX values are converted to absolute values, a paradoxical scenario of total investment decreasing with increased tank size emerges, negating the possibility of applying a scaling factor to the ammonia storage CAPEX.

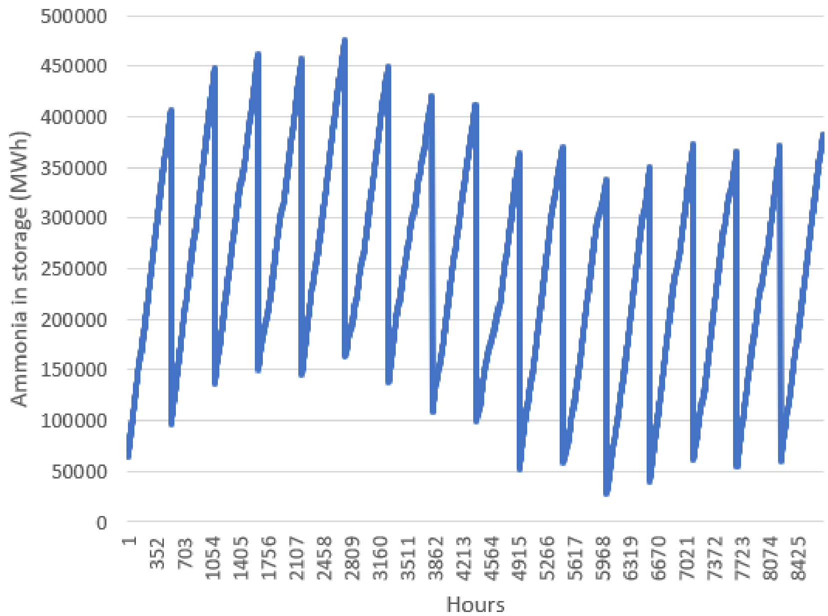


Figure 6.16: The ammonia in storage throughout the year at an export site in Chile.

6.4.2.3 Ammonia shipping

Ammonia shipping is a mature technology, with around 20 Mt of ammonia being transported globally each year (IEA, 2022b). This is accomplished by 40 dedicated ammonia carriers, along with some LPG ships that are ammonia-ready (IRENA, 2022d). As the demand for LPG diminishes, more LPG ships can be converted to ammonia carriers. However, the majority of the forecasted demand will require the construction of new carriers (IRENA, 2022d). An example of an existing ammonia carrier is depicted in Figure 6.16. An interesting aspect for the business case of ammonia carriers is their potential to possibly transport captured carbon dioxide back to the exporting country on the return journey (MOL, 2022). This carbon could then be sequestered in old gas fields or employed in the production of synthetic hydrocarbons such as methanol.

The handling of ammonia on ships is similar to storage practices, as the ammonia must be liquefied, either by cooling to -33°C, pressurising to 8 bar, or a combination of both (IRENA, 2022d). Boil-off losses also occur during shipping, of which it is typically assumed that these are not reliquefied on board the ship (JRC, 2022).

Ammonia can also serve as a fuel for ship propulsion and is considered one of the most promising clean alternatives for long-distance shipping (Bonnet-Cantalloube et al., 2023). It can be combusted directly or eventually used in a fuel cell to power a ship electrically (Bonnet-Cantalloube et al., 2023). A significant advantage of this is that the boil-off gas can be co-fired, preventing wastage. However, the primary challenge for ammonia-powered ships is its toxicity (Bonnet-Cantalloube et al., 2023).

DNV (2022b) indicates that there will likely be a mix of different shipping fuels in the future, and there is still high uncertainty on the role of different fuels. Therefore, more clarity is needed about the likely fuel for ammonia carriers.

The shipbuilder Damen is preparing for various scenarios and believes that the most critical aspect of this preparation is ensuring space in the design of new vessels for potential future propulsion systems. Although LNG was once viewed as a popular transitional solution, it has fallen out of favour for several reasons, including its insufficient sustainability. Ammonia propulsion is seen as viable by 2030, but the technology is not there yet and its toxicity remains a challenge. This might make it suitable for the largest carriers, but methanol is the primary alternative fuel of interest. (P. Spruijt, expert interview, June 26, 2023)

Given that the producer of ammonia engines, MAN, projects their engines to be market-ready by 2025, this analysis assumes the utilisation of ammonia-powered ammonia carriers (EnergyWatch, 2023). However, the model allows for adjustments in the shipping fuel to examine its impact on costs.

The chosen size of a tanker has significant implications on various factors such as the necessary storage size, the ship's capital expenditure (CAPEX), and the fuel demand. Therefore, optimising the ship size to balance these elements would ideally be part of the analysis. However, in the absence of a well-established correlation between ship size and fuel demand and for the sake of simplicity in this analysis, a fixed carrier size of 50,000 tonnes is selected based on the study by JRC (2022). This value is chosen because JRC (2022) provides an in-depth analysis and both IEA (2021a) and ISPT (2019) present values close to this.

In Appendix 7.1.3, a thorough examination of ammonia shipping is provided, detailing the performance of assessment indicators across the four development scenarios. Again costs decrease as carrier size increases, but no trend factor was identified.

Figure 6.17: An existing ammonia carrier from The Maritime Executive (2021).

6.4.2.4 Ammonia reconversion & purification

Ammonia cracking, the process of extracting hydrogen from ammonia, is essentially the reverse operation of ammonia synthesis. Presently, several ammonia crackers capable of handling up to 0,5 GW are operational, though they are primarily employed to produce specific moderators for nuclear reactors (IRENA, 2022d). Retrieval of hydrogen through this method is still in development though.

Before 2030 mainly smaller decentralised crackers are expected, while after this time also larger, central ammonia crackers could arise (M. Stoelinga, expert interview, April 24, 2023). Nonetheless, these decentralised crackers can be shared by multiple stakeholders (M. Stoelinga, expert interview, April 24, 2023). Fluor (2023) shows that the technology for large-scale crackers is available today but that significant cost savings for centralised crackers are not foreseen, as the cracker process unfolds in series.

The process is energy-intensive, requiring at least the reaction heat of the forming reaction, namely 750 kWh per tonne of ammonia (Morgan, 2013). This is equivalent to 12% of the hydrogen's energy content at HHV. Moreover, high operating temperatures imply additional energy losses (IRENA, 2022d). These temperatures largely depend on the type of catalysts used in the reaction. Once the ammonia is cracked, the resulting nitrogen and hydrogen mixture is used to preheat the incoming ammonia in a heat exchanger (Sekkesæter, 2019). Figure 6.18 visually illustrates this cracking process.

Catalysts used in ammonia cracking span across three generations. The first-generation catalysts, based on nickel, operate at temperatures between 600-900°C (IRENA, 2022d). The second-generation catalysts operate at lower temperatures, ranging from 350-600°C; however, they employ critical and costly minerals such as iridium and ruthenium (IRENA, 2022d). The third and most recent generation of catalysts relies on lithium or sodium and operates at temperatures around 250°C. However, they remain at a low Technology Readiness Level (TRL) of 2-4 (IRENA, 2022d).

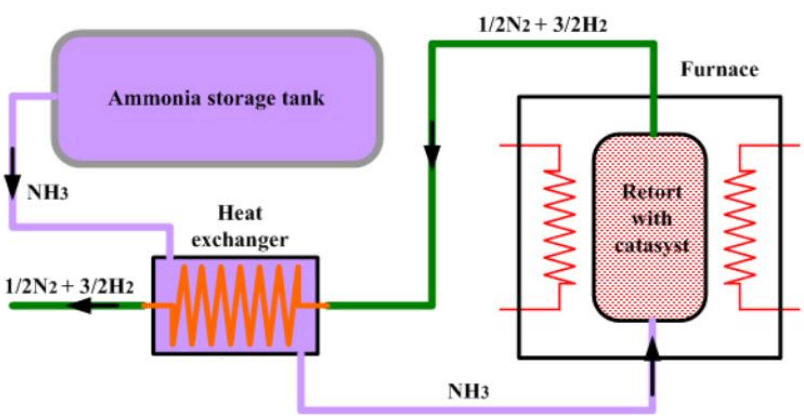


Figure 6.18: The principle of ammonia cracking (Kopeliovich, 2017).

Given the high heat demand, it is not feasible to power the process electrically (Bonnet-Cantalloube et al., 2023). Moreover, in compliance with the Renewable Energy Directive of the EU, the heat cannot be sourced from fossil fuels (Bonnet-Cantalloube et al., 2023). Consequently, hydrogen or ammonia are the most likely fuels to be utilised for this process (IRENA, 2022d).

Efficiency of the reaction is inversely related to the pressure. Hence, lower pressure improves efficiency but necessitates further downstream pressurisation of hydrogen (IRENA, 2022d). The cracker is therefore typically operated within a pressure range of 20-40 bar (IRENA, 2022d; Sekkesæter, 2019).

The stream produced from ammonia cracking, composed of hydrogen, nitrogen, and residual ammonia, is first treated in a scrubber to remove any leftover ammonia, which is subsequently neutralised (Pollution Systems, 2023; Sekkesæter, 2019). The remaining mixture of nitrogen and hydrogen then undergoes Pressure Swing Adsorption (PSA) for further purification (Sekkesæter, 2019). The waste stream from the PSA, instead of being discarded, serves as the primary fuel source for the ammonia cracker. This fuel is supplemented either with the cracked hydrogen or, more likely, with additional ammonia to provide the heat needed for the cracking process (IRENA, 2022d; Sekkesæter, 2019). A visualisation of this process is depicted in Figure 6.19.

In Appendix 7.1.4 a thorough examination of ammonia cracking costs is provided, detailing the performance of assessment indicators across the four development scenarios. A high degree of uncertainty was identified both on the costs as well as the power demand. Furthermore, there is no correlation between cracker size and costs.

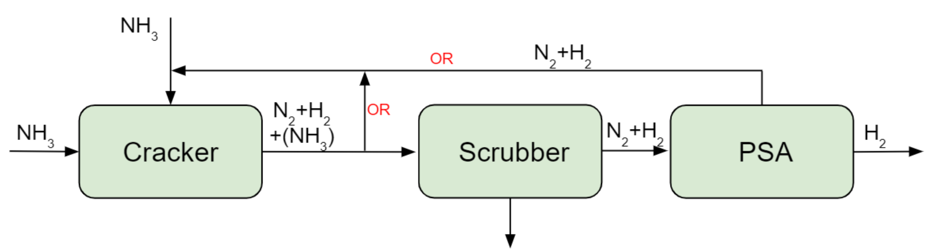


Figure 6.19: Ammonia retrieval process, fueled by hydrogen or ammonia. Adapted from Sekkesæter (2019).

6.4.2.5 Costs of the ammonia supply chain

Figure 6.20 shows the costs of the hydrogen transport for different locations in the most-likely high scenario. The analysis reveals that although the locations nearer to the Netherlands significantly reduce shipping costs, these savings are overshadowed by the lower hydrogen production costs in especially Chile. As the hydrogen is produced more affordably in Chile, supply chain losses also incur lower costs.

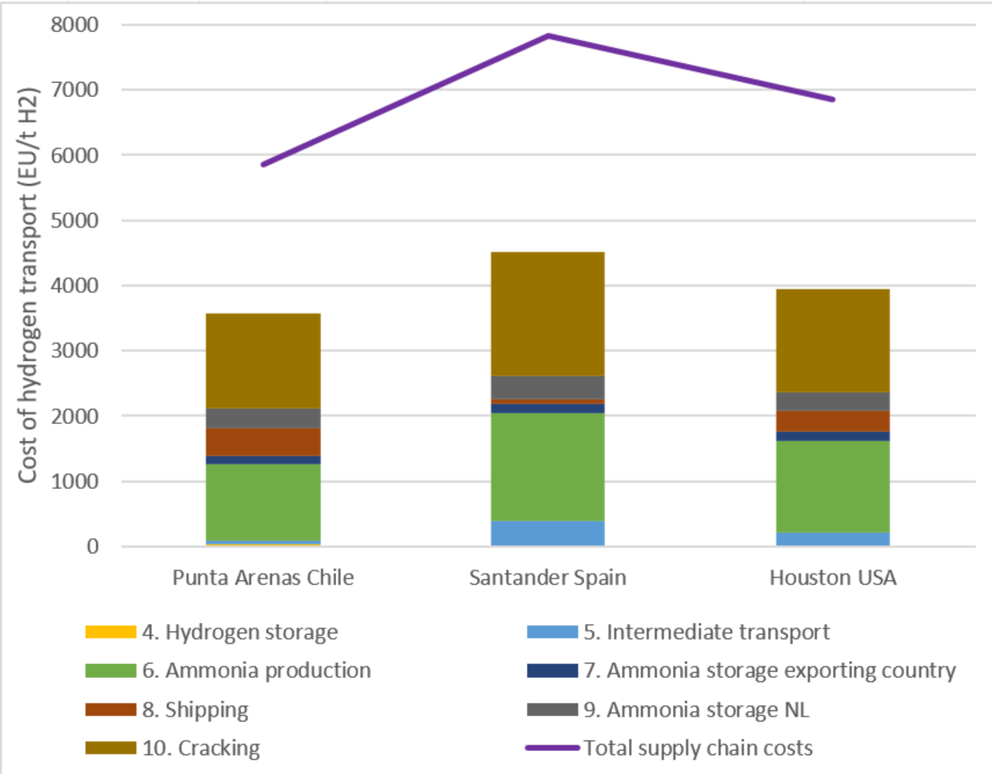


Figure 6.20: The costs of hydrogen transport in the form of ammonia from different locations in the most-likely high scenario.

Figure 6.21 presents the cost comparison of local hydrogen production in Chile and its transportation to the Netherlands as ammonia under various cost scenarios. It reveals transport costs ranging from approximately €1.100 to €7.500 per tonne of hydrogen, which is 46% to 321% of the production costs. For the Gigawatt plant evaluated in this study, the most-likely scenario places transport costs between €1.700 and €3.500 per tonne of hydrogen, which is 71-151% of the production costs.

The analysis further reveals that three key supply chain components primarily determine the transport costs: ammonia production, shipping, and cracking. In contrast, storage and intermediate transport play minor roles. The greatest variability is observed in ammonia cracking costs, exhibiting a 35-fold difference between the best and worst scenarios compared to a 3-fold discrepancy for ammonia production. This is primarily due to the energy inefficiency of the cracker, which operates at only 28% and 32% efficiency in the two highest cost scenarios. In these scenarios 37-42% of the ammonia is consumed in the cracking process. Furthermore, a rise in the costs of other components logically escalates the costs related to energy losses. For ammonia synthesis, the largest uncertainty rests on the CAPEX of the plant due to the fixed energy from the enthalpy of the reaction. In shipping, both the costs of ammonia propulsion and the cost of the ship are comparably important.

Figure 6.21 also reveals that the energy efficiency of transport varies between 80-41%. The most notable efficiency drop (22%) occurs within the most likely scenario. Figure 6.22 further underscores the impact of this drop, indicating that the energy demand nearly fully accounts for the uncertainty within the most-likely scenario. This can be attributed to the common correlation between CAPEX and plant size, and the less frequent correlation between plant size and energy demand.

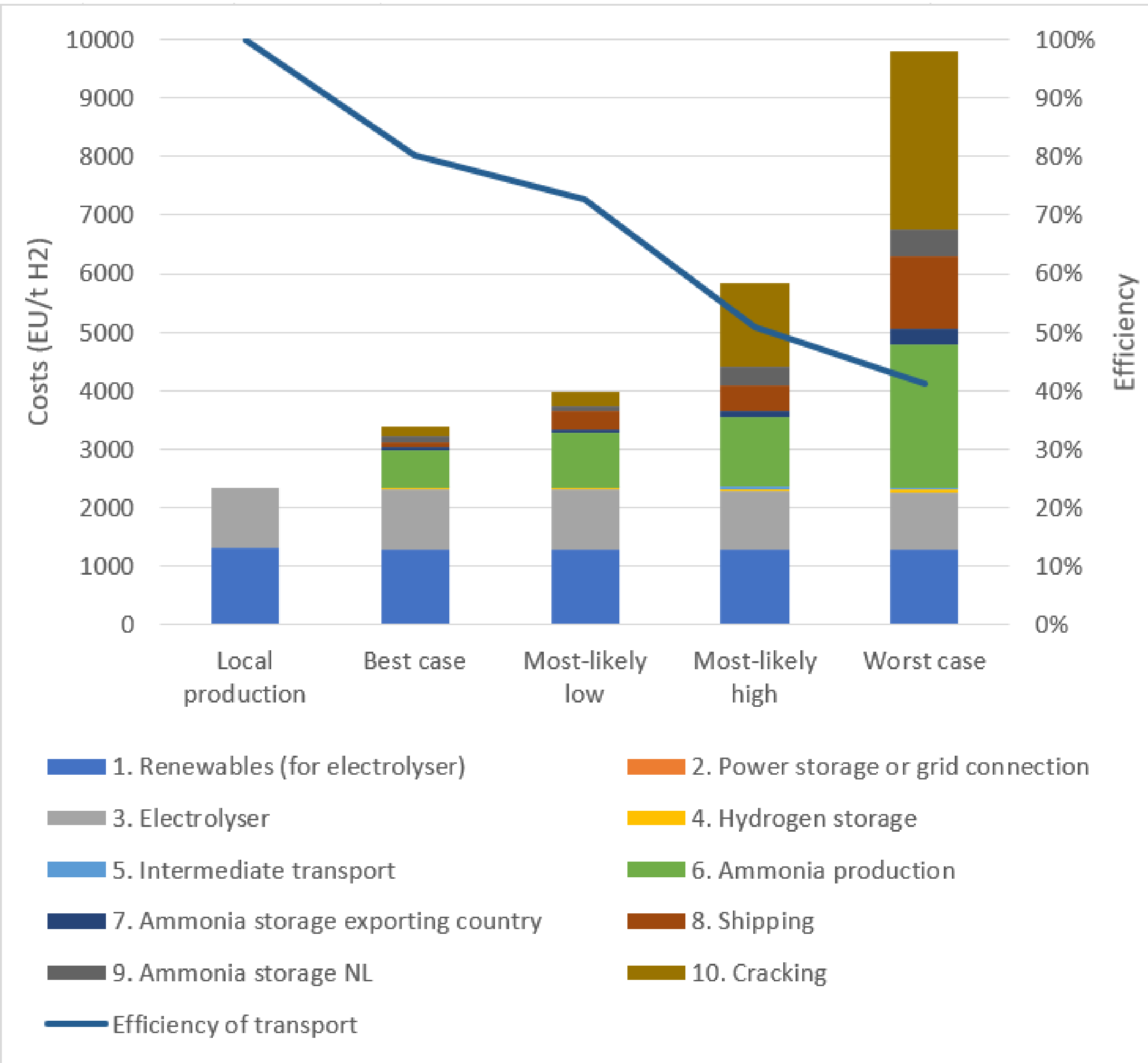


Figure 6.21: The costs of local hydrogen production in Chile versus transport to the Netherlands in the form of ammonia under different cost scenarios.

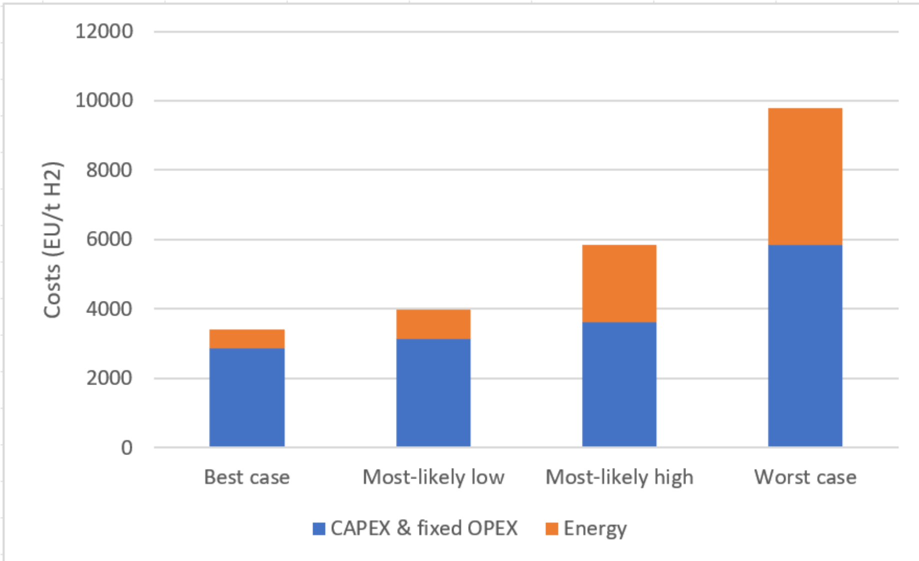
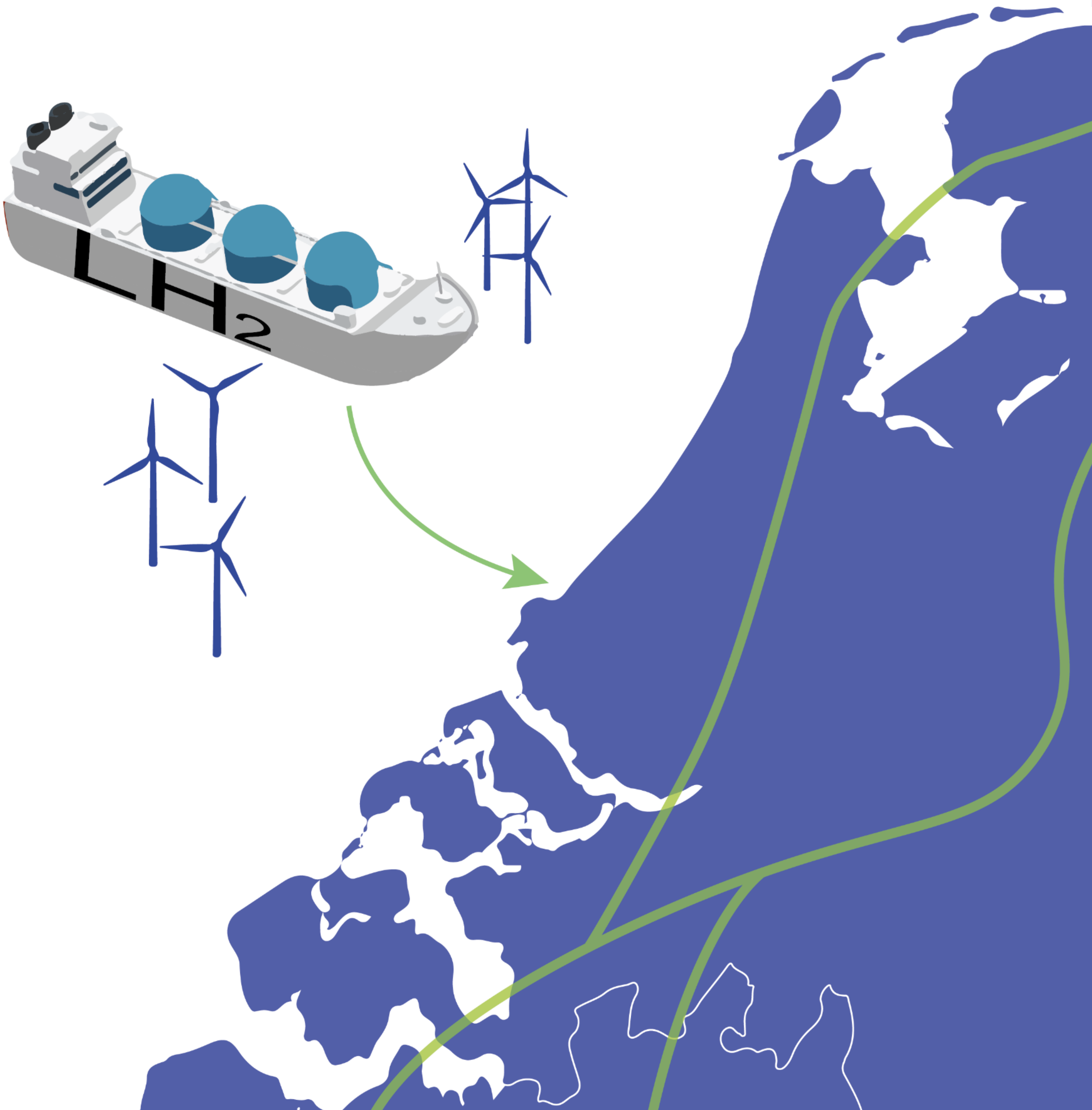


Figure 6.22: The contribution of energy and fixed costs to the cost of hydrogen transport from Chile to the Netherlands in different scenarios.

6.4.3 Liquid Hydrogen



Hydrogen liquefaction, a process with a long history in rocket fuel applications, presents unique advantages and challenges (IRENA, 2022d). The greatest advantage of liquid hydrogen lies in its volumetric energy density of 0,71 kg/L, which is 853 times denser than gaseous hydrogen at atmospheric pressure (IEA, 2019).

However, it also has a significant drawback: its extremely low boiling point of -253°C. This necessitates costly equipment to minimise thermal losses and withstand the low temperatures. The process of liquefaction itself is also highly energy-intensive. Moreover, liquid hydrogen's high flammability introduces potential explosion risks (Cameo Chemicals, 2023; Patonia & Poudineh, 2022).

In contrast to ammonia or LOHCs, liquid hydrogen requires no conversion or reconversion processes. This means the energy demand in the Netherlands for regasification is low, and no purification is required (JRC, 2022). Additionally, the high energy demand for liquefaction occurs in the exporting country, where power is typically cheaper, whereas the other carriers require energy-intensive reconversion processes (JRC, 2022). Furthermore, this high energy demand is met through power, as opposed to reconversion processes that require fuel for heat and result in additional energy loss. Figure 6.23 offers a system diagram of the liquid hydrogen supply chain. An example of the scaling of the elements is seen in Figure 6.24 for the most-likely low scenario. It is seen that the needed capacity for the plants decreases because energy losses are met and because the regasification can operate at a base load.

In terms of transport, liquid hydrogen was the first type to be tested via a pilot project between Australia and Japan in 2020 (IRENA, 2022d). All Dutch ports are preparing for liquid hydrogen imports, with a particularly high level of interest in the Port of Amsterdam, where the toxicity of ammonia presents a challenge (TKI, 2022). The company Zenith is making significant progress in realising liquid hydrogen imports in the area (R. Oorsprong, expert interview, 2023).

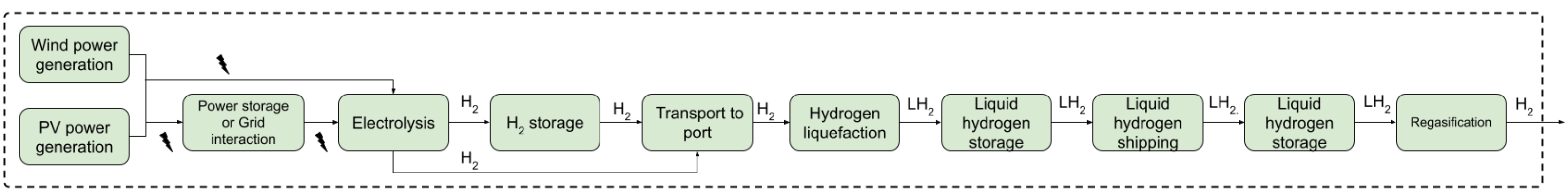


Figure 6.23: A system diagram of green hydrogen delivery through transporting it as liquid hydrogen.

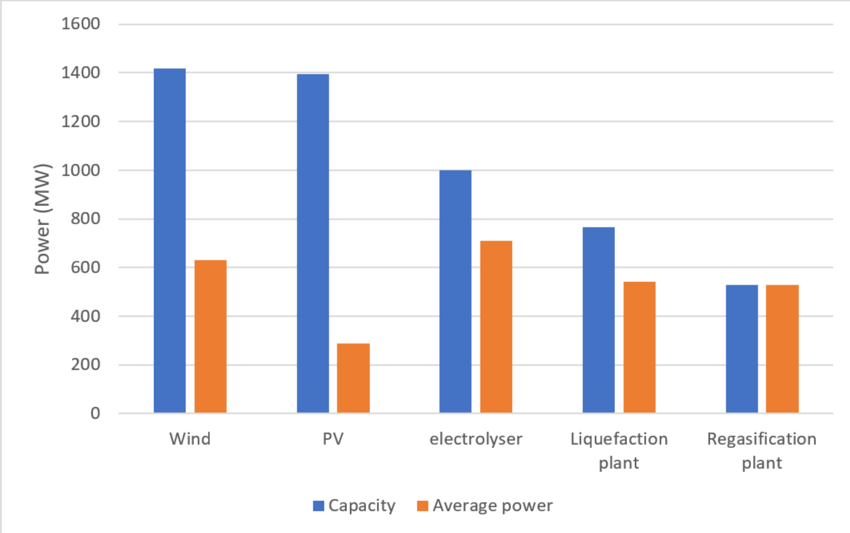


Figure 6.24: The scaling of the supply chain elements in the United States in the most-likely low scenario.

6.4.3.1 Liquefaction

While hydrogen liquefaction is a well-established technology, current plants don't yet meet the sizes required for global hydrogen transport. This necessary upscaling entails technological challenges, particularly in increasing the size of specific components due to the difficult cryogenic conditions of hydrogen (IRENA, 2022d). The liquefaction is done through a combination of compressing and cooling the hydrogen. There are many different approaches to the liquefaction process that differ on for example pressure levels, refrigerants or order of the different steps (IRENA, 2022d).

The cooling process often combines two techniques. Initially, it employs a heat exchanger, where a coolant such as liquid nitrogen, helium, or neon lowers the hydrogen's temperature (Aziz, 2021; IRENA, 2022d). The next step involves cooling via expansion. Gases react to expansion by either cooling or warming, depending on their temperature and pressure (Li et al., 2023). The critical point at which this transition occurs, known as the Joules-Thomson inversion temperature, stands at -73℃ for hydrogen at atmospheric pressure (Li et al., 2023). Below this temperature, expansion cools the hydrogen. Figure 6.25 illustrates a typical liquefaction plant using a combination of heat exchangers and an expansion engine to liquify hydrogen. After liquefaction the hydrogen is generally kept at atmospheric pressure (Aziz, 2021).

Another complexity in hydrogen liquefaction involves its two spin isomers, ortho- and para-hydrogen (Aziz, 2021). These coexist in a dynamic equilibrium dependent on temperature, with the concentration of para-hydrogen increasing as the hydrogen cools, a process that releases heat (Aziz, 2021). To prevent this unwanted heat release during the final liquefaction step, a catalyst promotes ortho-para conversion before the last heat exchanger (IRENA, 2022d).

IRENA (2022d) explains that as a liquefaction plant operates below its nominal load, its efficiency decreases, with 25% capacity identified as the operational minimum. It is assumed, however, that the reviewed reports have already factored in these capacity fluctuations when presenting the energy demand of liquefaction.

In Appendix 7.2.1 a thorough examination of hydrogen liquefaction costs is provided, detailing the performance of assessment indicators across the four development scenarios. Notably, there's a correlation between the plant size and the CAPEX, as well as the energy demand. However, despite this correlation, both elements display substantial uncertainty and no scaling factor has been identified.

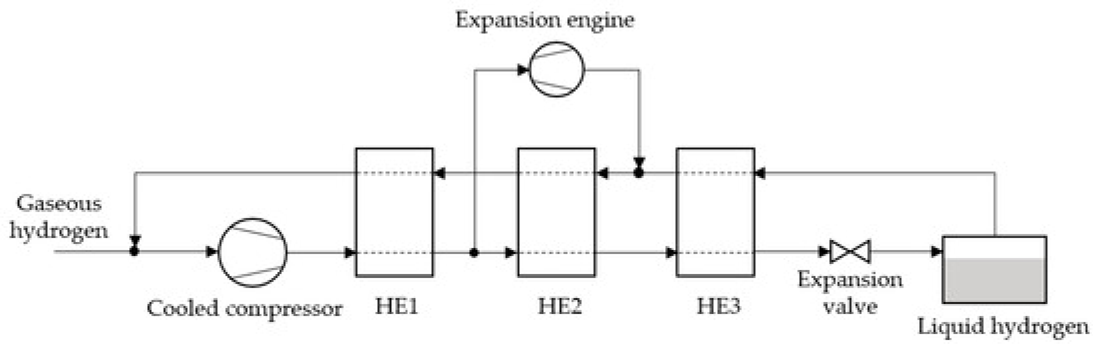


Figure 6.25: A schematic of a hydrogen liquefaction plant from Aziz (2021).

6.4.3.2 Storage

Liquid hydrogen storage is essential to ensure a fast turnover of the substance to the carrier. Storage tanks must be constructed to endure extremely low temperatures and exhibit exceptional insulation due to hydrogen's low boiling point (IRENA, 2022d). Storing liquid hydrogen is a known process due to its application as a rocket fuel. In Figure 6.26 an example of a liquid hydrogen storage tank is seen. The spherical design minimises the surface area, reducing interaction and heat transfer with the environment (Demaco Cryogenics, 2023).

However, there will be energy uptake within the tank that will cause some hydrogen to reach boiling point (Aziz, 2021). This results in evaporated hydrogen or 'boil-off.' The optimal approach to manage this boil-off gas is reliquefaction, which requires a modest power demand and incurs an additional 5-7% in CAPEX (IRENA, 2022d). Factors contributing to boil-off within the tank include heat transfer and ortho-para conversion (Aziz, 2021). Different reports present boil-off rates ranging from 0,03 to 0,8% per day.

Boil-off also occurs when a ship is loaded or unloaded into a storage tank, a phenomenon referred to as the 'flash rate'. The assumed flash rates in various reports vary between 0,6-2,25%. It's presumed that all boil-off is reliquefied, and that this has been adequately accounted for in the power demand and CAPEX assumptions by all reviewed reports.

Just as with ammonia storage the minimal storage volume needed is defined by the seasonal differences in production and the ship volume. In literature, the recommended storage volume is often expressed in terms of ship volumes, ranging between one and two. Given that the liquid hydrogen carrier used in this analysis has a capacity of 11.000 tonnes, the corresponding storage capacity range would be between 11.000 to 22.000 tonnes. In the model, it was seen that one ship volume proposed by TNO (2022) is inadequate for all the considered scenarios due to seasonality. Figure 6.27 shows an example of a liquid hydrogen storage tank throughout the year.

In Appendix 7.2.2 a thorough examination of liquid hydrogen storage costs is provided, detailing the performance of assessment indicators across the four development scenarios. The expected correlation between storage size and CAPEX is only marginally identified and a significant cost uncertainty is seen.

Figure 6.26: A liquid hydrogen storage tank (NASA, 2015).

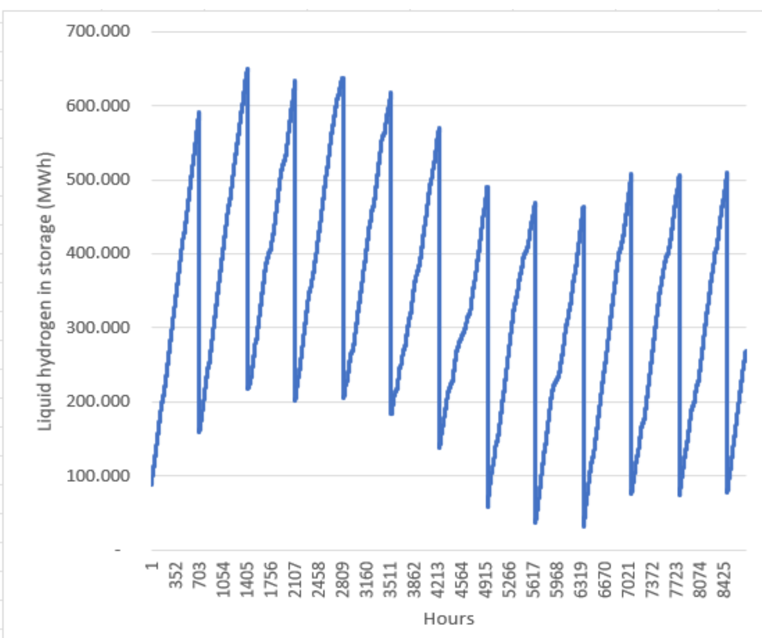


Figure 6.27: The liquid hydrogen in storage throughout the year at an export site in Chile.

6.4.3.3 Shipping

Hydrogen propulsion can be achieved either through a fuel cell paired with an electric motor or by combusting hydrogen in an internal combustion engine (ICE) (IRENA, 2022d). Fuel cells are generally favoured, however, their size is currently constrained and is insufficient for powering large vessels (IRENA, 2022d).

Depending on the fuel used in propulsion some reports, like JRC (2022) assume the boil-off gas will get lost while others suggest that the boil-off gas will act as shipping fuel (IRENA, 2022d). If boil-off exceeds fuel demand, the sailing speed is increased, as it increases the overall fuel demand, but reduces the number of required ships (IRENA, 2022d). The inclusion of this dynamic is outside of the scope of this analysis though. Apart from heat transfer and ortho-para conversion, the ship's movement or 'sloshing' can also cause boil-off by absorbing kinetic energy (Aziz, 2021).

If larger vessels are unable to operate directly on hydrogen, an alternative fuel may be initially used. As discussed in section 6.4.2.3 on ammonia shipping, methanol is the most likely alternative (P. Spruijt, expert interview, June 21, 2023). Nevertheless, not using the potential of boil-off hydrogen would be wasteful, and given that hydrogen vessels are already operational today, it's presumed to be used as fuel by 2030 (IRENA, 2022d). As most reports assume either propulsion with a fossil fuel powered ICE or hydrogen powered ICE it is assumed that the hydrogen will be used in an ICE (IRENA, 2022d; JRC, 2022; Sekkesæter, 2019). One possible other challenge with shipping on the boil-off occurs when the ship isn't operated by the supply chain company or consortium (M. Joon, expert interview, August 7, 2023). In this case, agreements on the boil-off cost for ship fuel must be established.

Similar to ammonia, a single carrier size was selected. Since three separate reports agreed on a ship size of 11,000 tonnes, and two others suggested close approximations, this was deemed the appropriate carrier size.

In Appendix 7.2.3 a thorough examination of liquid hydrogen shipping costs is provided, detailing the performance of assessment indicators across the four development scenarios. It is seen that shipping costs significantly decrease as ship size increases, but no scaling factor is identified.

6.4.3.4 Regasification

The regasification of liquid hydrogen involves warming it up, a process not yet commercially implemented for hydrogen but similar to liquified natural gas (LNG) regasification (Sekkesæter, 2019). Several methods can be used to heat the liquid hydrogen.

One method involves burning a portion of the hydrogen in a combustion vaporizer. While this technique enables quick load fluctuations, which are beneficial in current natural gas systems, it isn't required for the scope of this report (Sea-Man, 2021; Sekkesæter, 2019).

Alternative approaches include using seawater or ambient air to regasify the hydrogen. Ambient air vaporisation is more commonly used on small gasifiers and in places where seawater temperatures fall below 5 degrees Celsius (Sekkesæter, 2019).

An open rack seawater vaporizer is the most prevalent technology for LNG today (Sea-Man, 2021; Sekkesæter, 2019). In this process, water is pumped up and flows past the liquid hydrogen pipes, facilitating heat transfer and thereby causing the hydrogen to regasify (Sea-Man, 2021; Sekkesæter, 2019). Figure 6.28 shows a visual representation of the process.

In Appendix 7.2.4 a thorough examination of liquid hydrogen storage costs is provided, detailing the performance of assessment indicators across the four development scenarios. It is seen that regasification is often neglected in reports, and that there is a significant uncertainty on both costs as well as energy demand.

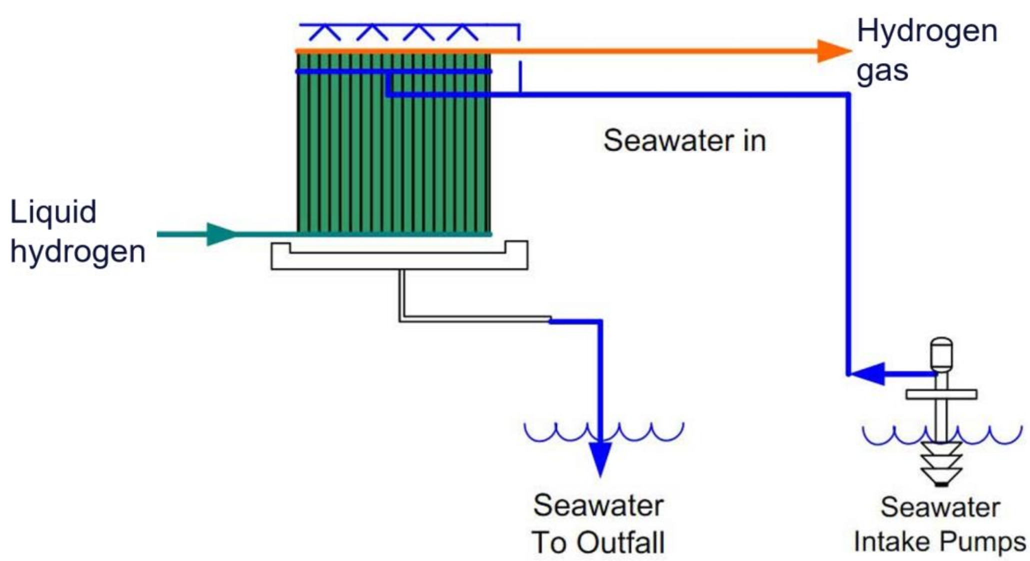


Figure 6.28: An open rack seawater vaporiser for regasification of hydrogen, adjusted from Sea-Man (2021).

6.4.3.5 Costs of the liquid hydrogen value chain

Figure 6.29 illustrates the cost dynamics of hydrogen transport from various locations under the most-likely high scenario. Chile's advantage of lower power costs results in cheaper liquefaction. However, its considerably higher shipping costs—exceeding those from Spain by over €1.400 per tonnes—makes Spanish transport more cost-efficient. Despite this, the final LCOH remains more competitive when sourced from Chile.

In the worst-case scenario, Spain also provides a lower LCOH, whereas Chile emerges as the most cost-effective option in the three other scenarios. In the worst case scenario only the shipping itself is €5.800 per tonnes more costly from Chile than Spain.

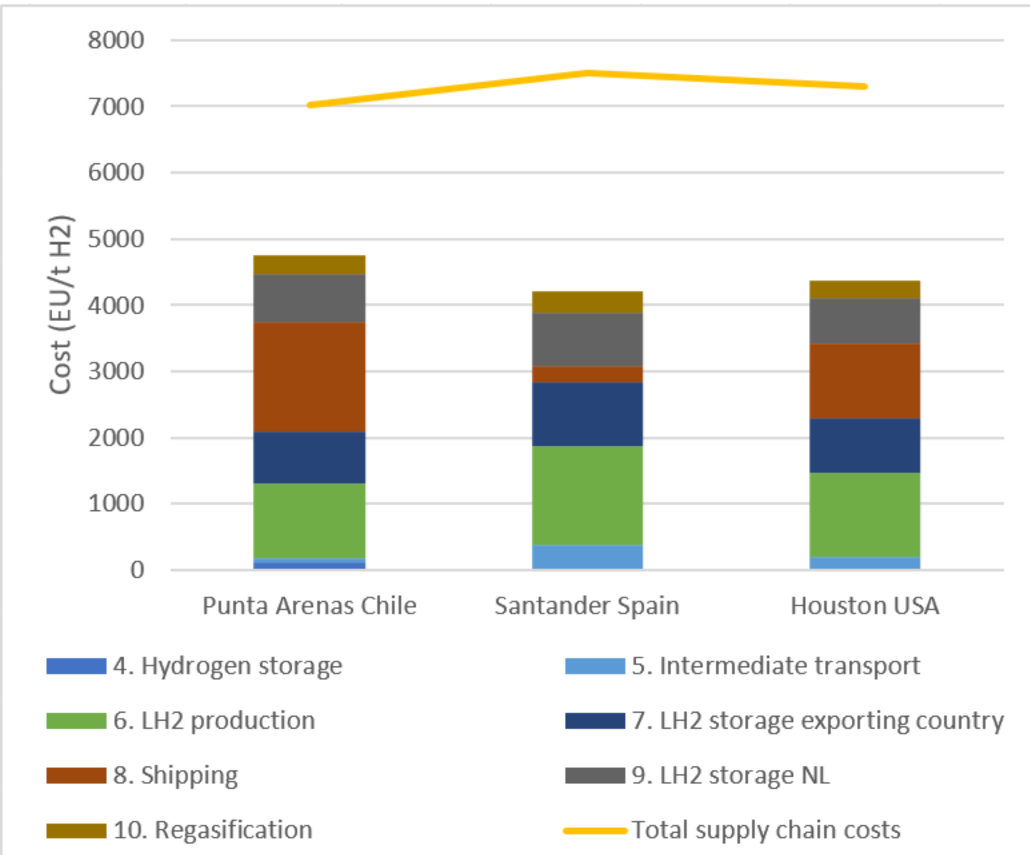


Figure 6.29: The costs of hydrogen transport as Liquid Hydrogen (LH2) from different countries in the most-likely high scenario.

In Figure 6.30, which provides a cost breakdown of both local production and transport from Chile under different scenarios, it is seen that transport costs range between approximately €1.200 and €19.200 per tonnes, with a most likely span of €1.300 to €4.700 per tonnes. Within this most-likely scenario transport costs will add 55-202% on top of local production costs. Energy efficiency varies between 60-84%, with cost uncertainties spread across various elements. The costs of regasification, however, play a minor role.

Figure 6.31 indicates that across all scenarios, the CAPEX and fixed OPEX primarily drive costs, which is attributed to the need for expensive equipment, without conversion or reconversion processes. This also explains the significant contribution of storage to this supply chain's overall costs. While also power demand is an important cost driver for liquefaction, it only accounts for 18-43% of liquefaction costs in the most likely scenarios. Shipping consistently emerges as the largest cost contributor from Chile across all scenarios. This process has the largest effect on energy demand, contributing to about half of the shipping costs from Chile.

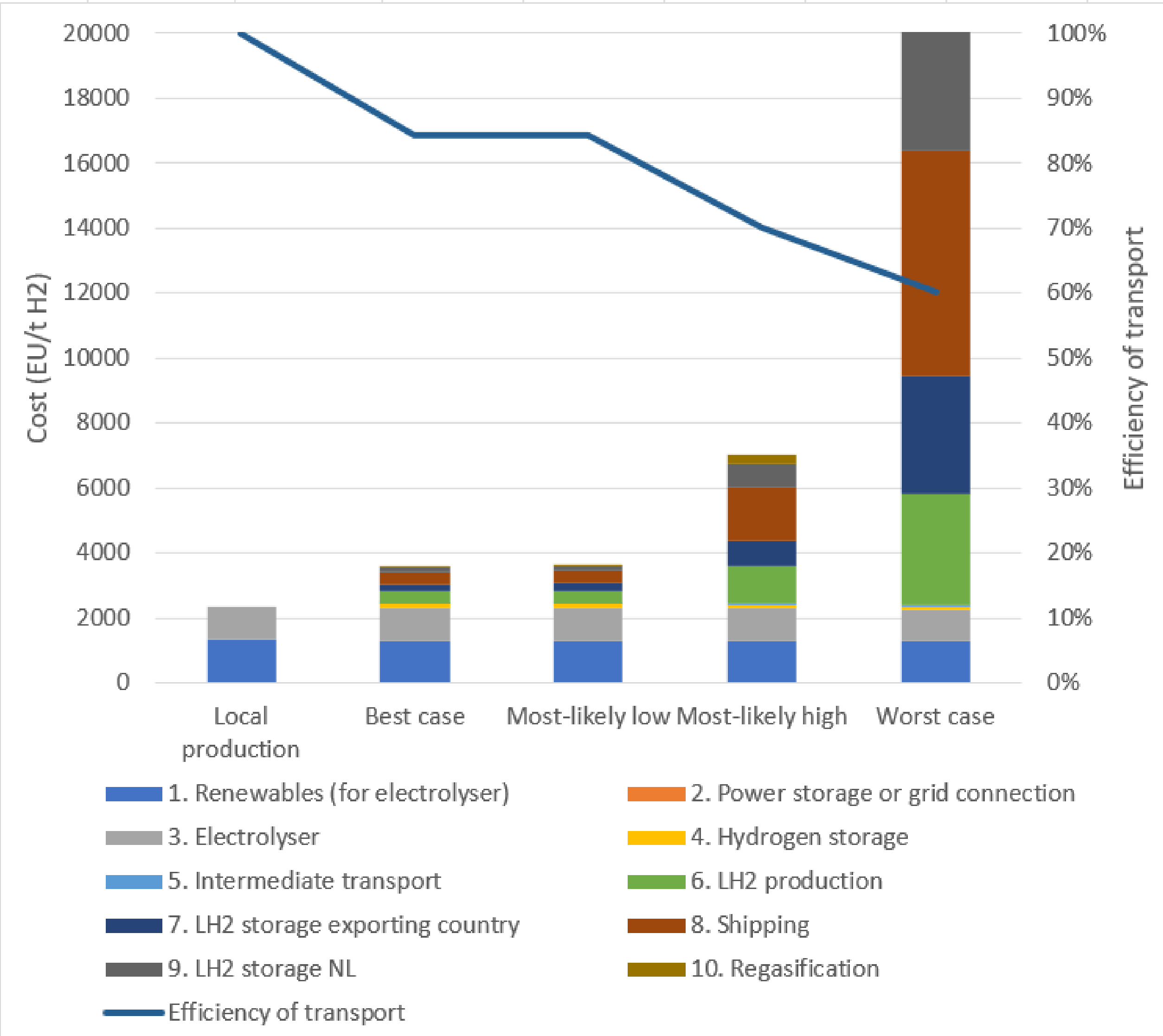


Figure 6.30: Local hydrogen production and the liquid hydrogen supply chain from Chile under different scenarios.

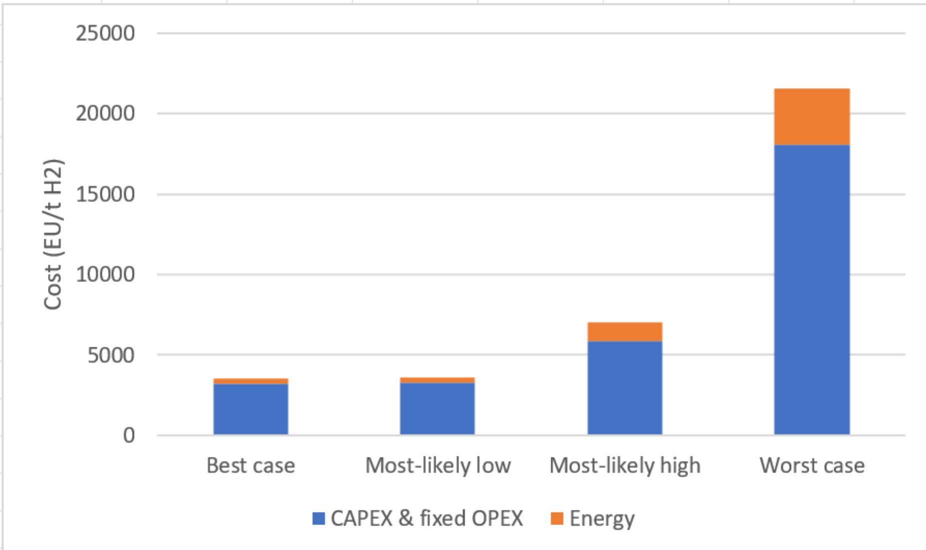
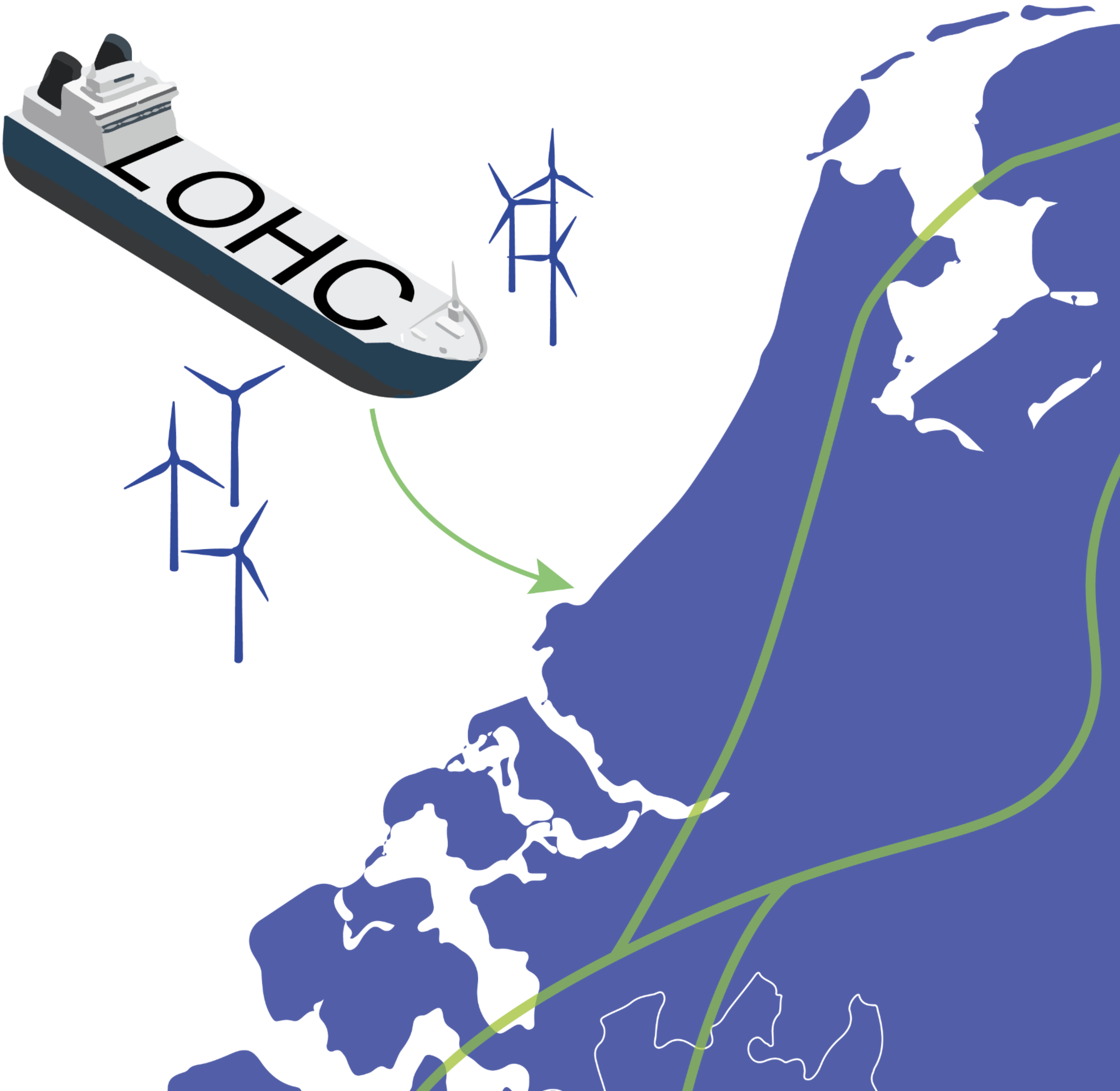


Figure 6.31: The contribution of CAPEX and fixed OPEX to energy in the total costs of the liquid hydrogen supply chain from Chile.

6.4.4 LOHCs - DBT



Liquid organic hydrogen carriers (LOHCs) are substances that can undergo reversible reactions with hydrogen, binding the hydrogen in the exporting country (hydrogenation) and releasing it in the Netherlands (dehydrogenation). Afterwards, the carrier can be transported back to the exporting country for reuse. The advantages are that the volumetric energy density is increased and that it has a liquid state at room temperatures, which eliminates boil-off gases (IRENA, 2022d). Due to its liquid state it can furthermore use existing oil transportation and storage infrastructures with only minor modifications (IRENA, 2022d). These attributes render LOHCs particularly suited for multimodal transport, as needed when moving it to the hinterland by inland ship, rail, or truck (IRENA, 2022d).

However, challenges exist. The mass density of hydrogen is only about 6% of the LOHC's total mass. Also, since hydrogenation is an exothermic process, substantial heat must be applied in the dehydrogenation in the importing country to retrieve the hydrogen. For instance, a minimum of 23% of the hydrogen's energy content at higher heating value (HHV) is required for dibenzyltoluene (DBT), a popular type of LOHC (IRENA, 2022d).

Furthermore, conversion and reconversion processes are currently limited to pilot scale and must be significantly scaled up. Also, the production capacity of LOHCs themselves is insufficient to support the required growth for developing global hydrogen supply chains.

When comparing LOHCs several factors must be considered, such as energy density, reaction heat, toxicity, and flammability. In addition, the LOHC's production plays a significant role as initial stock is required and a certain percentage of the LOHC needs to be replaced after each cycle. The choice of a specific LOHC can be influenced not only by its availability, but also by the cost and environmental impact associated with its production.

Literature mainly discusses two carriers, DBT and Methylcyclohexane (MCH) (ENTEC, 2022; IRENA, 2022d; JRC, 2022; Roland Berger, 2021; Sekkesæter, 2019). While MCH results directly from combining toluene and hydrogen, DBT is produced from toluene and benzyl chloride, which is again derived from chlorine and toluene.

Table 6.8 presents a comparison of the two LOHCs. The benefits of using toluene directly include its wider availability and the lack of an extra conversion step, which together make it a lower-cost LOHC than DBT. DBT, on the other hand, has a slightly lower reaction heat and higher energy density, plus improved health and toxicity profiles. Its reconversion rate during dehydrogenation is also superior (Sekkesæter, 2019).

This research will focus on DBT due to its use in the H2Amsterdam project, a collaboration with the German company Hydrogenious, which aims to import hydrogen to Amsterdam in DBT form (Port of Amsterdam, 2022).

Figure 6.32 shows a system diagram of delivering hydrogen through transport with an LOHC and Figure 6.33 shows an example of the scaling of the supply chain.

Table 6.8: Properties of DBT as compared to MCH according to IRENA (2022d)

	DBT	MCH (toluene)
Heat of reaction (kWh/kg H2)	9,1	9,5
Storage density (kgH2/kgLOHC)	6,2%	6,1%
Price (€/kg)	3,95	0,79
Market size (Mt/year)	0,009	30
Health hazard	0	2
Flammability	1	3

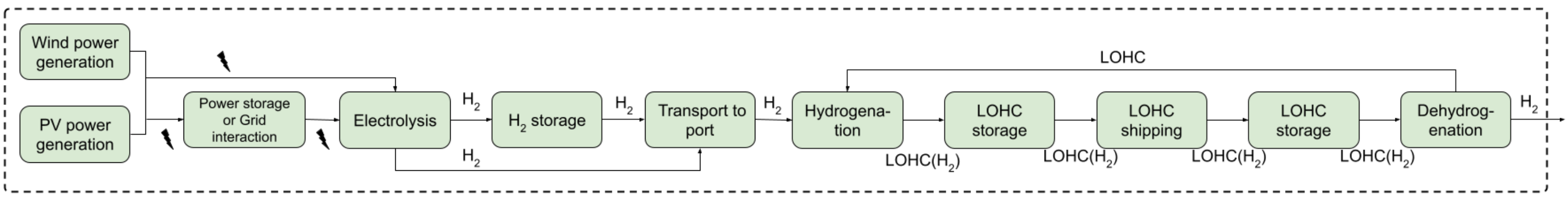


Figure 6.32: The supply chain of delivering hydrogen through transport with an LOHC.

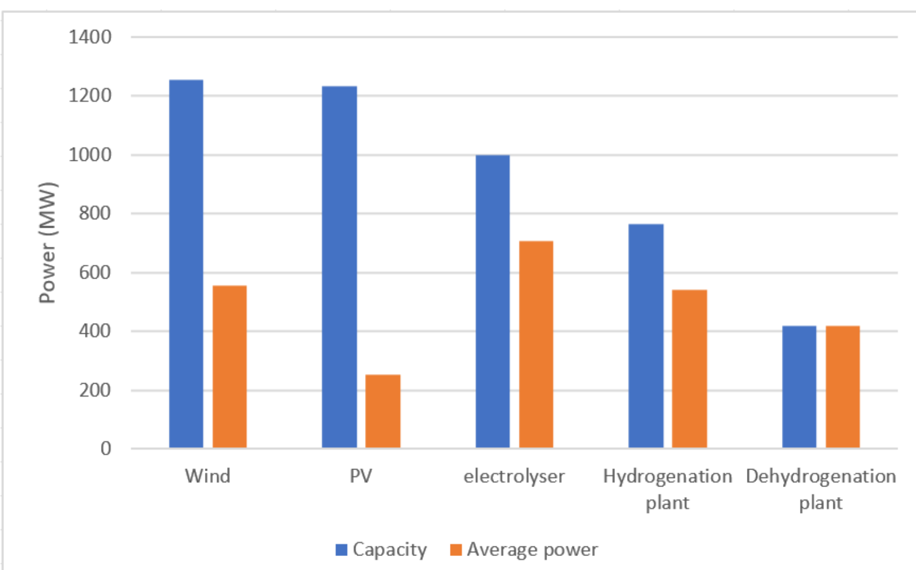


Figure 6.33: The scaling of the supply chain elements in the United States in the most-likely low scenario.

6.4.4.1 Hydrogenation

Hydrogenation is the reaction of the LOHC with hydrogen. Figure 6.34 shows the hydrogenation reaction of DBT. Dibenzyltoluene (C21H20) consists of three interconnected rings: two benzyl rings and a central toluene ring (Aslam et al., 2018).

Each of these rings is composed of six carbon atoms, with each carbon atom capable of forming four covalent bonds. In the rings, the carbon atoms form three of these bonds with their neighbouring carbon atoms, and the fourth with a hydrogen atom. During hydrogenation, the double carbon-carbon bonds in the ring open up to bond with hydrogen atoms. Each ring can accommodate up to six additional hydrogen atoms due to the availability of these open bonds. As a result, a DBT molecule can carry 18 hydrogen atoms when fully hydrogenated (Aslam et al., 2018).

This process is exothermic and releases 9,1 kWh/kg of hydrogen in the form of heat (IRENA, 2022d). This is 23,1% of the energy that is contained in the hydrogen.

Figure 6.35 provides a schematic representation of the entire process. The hydrogen is first pressurised to a level between 20 and 50 bar, and then preheated with the heat generated from the reaction before it enters the hydrogenation vessel (Aslam et al., 2018;). The ideal temperature for the hydrogenation process is 140℃ (Shi et al., 2019).

No limitations from a minimum load are found in literature, and also Hydrogenious, an LOHC project developer, asserts that their system can adapt effectively to intermittent renewable energy sources (Hydrogenious, 2023). Therefore, no minimum load is assumed in the operation of the hydrogenation process.

In Appendix 7.3.1 a thorough examination of hydrogenation costs is provided, detailing the performance of assessment indicators across the four development scenarios. There is a clear correlation between plant size and costs, but no scaling factor is identified.

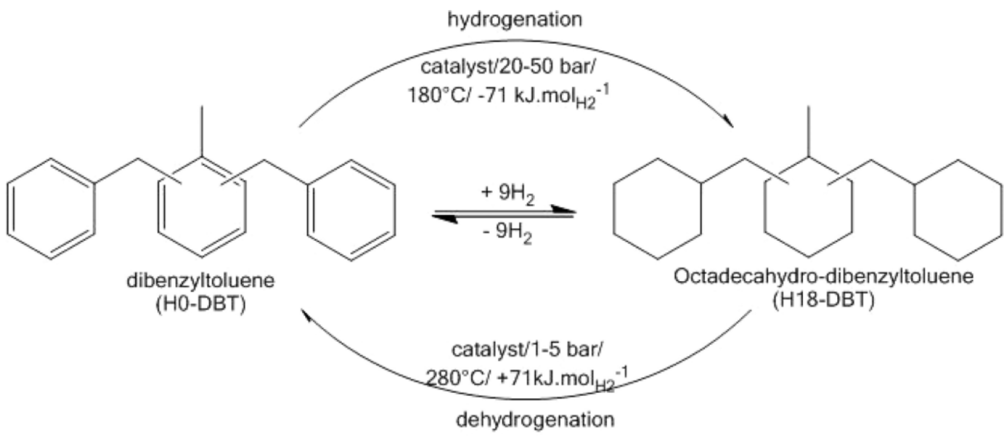


Figure 6.34: The hydrogenation and dehydrogenation reaction of DBT from Aslam et al. (2018).

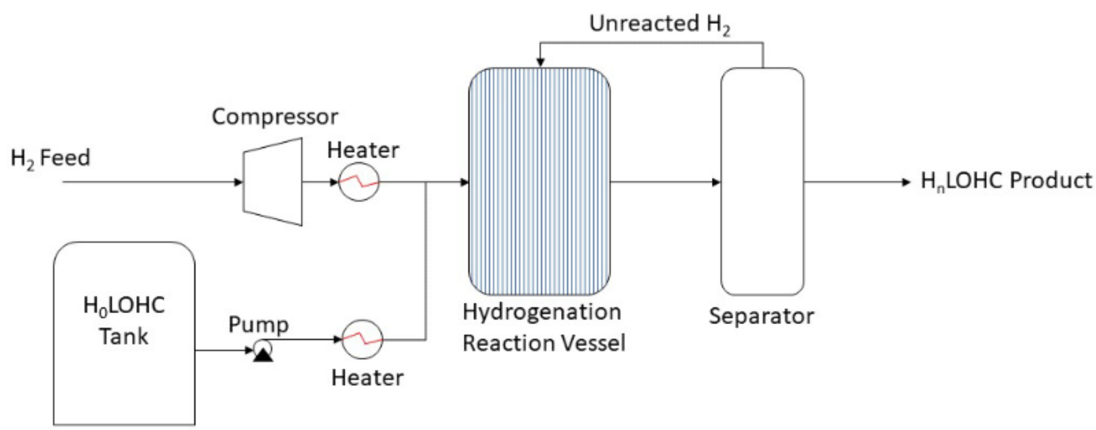


Figure 6.35: Visualisation of the hydrogenation process from Sekkesæter (2019).

6.4.4.2 DBT Storage

Just as for the other modes of transport, storage is crucial to ensure that carriers do not have to wait on production to be filled. By having an intermediate storage site, carriers can be directly loaded with the hydrogenated DBT. This storage mechanism also serves to balance the seasonal variations in hydrogen and thereby hydrogenated DBT production, thereby ensuring a steady stream of ship arrivals and departures.

Storage of LOHCs, such as DBT, is relatively straightforward. They can be stored in existing liquid storage terminals, and there's no need for cooling or pressurisation, making the process much simpler compared to other carriers (IRENA, 2022d). However, the storage demand is higher due to DBT's low energy density, both in terms of weight and volume. Additionally, distinct storage capacities are necessary for hydrogenated DBT and dehydrogenated DBT, effectively doubling the storage requirement (IRENA, 2022d).

Reports typically express the storage need in terms of the desired number of ship volumes. Given a carrier size of 123,000 tonnes and a range of desired ship volumes between 1-2, one storage unit should have a capacity of 123,000-246,000 tonnes.

However, the model adjusts the necessary storage if the proposed capacity proves insufficient. The minimal storage requirement is determined by seasonal balancing needs plus the volume of a single ship. For instance, Figure 6.36 depicts the storage requirement in Chile, where seasonal differences are most significant, showing a minimum storage requirement of 1,7 ship volumes.

In Appendix 7.3.2, a thorough examination of LOHC storage costs is provided, detailing the performance of assessment indicators across the four development scenarios. The costs of storage are known to decrease with an increase in storage size (IRENA, 2022d). However, many studies have not provided concrete tank sizes, complicating this cost assessment.

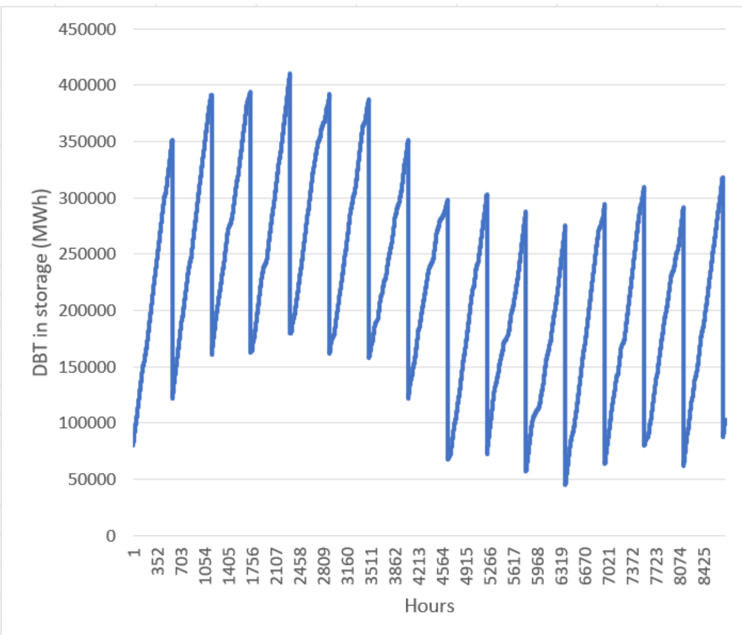


Figure 6.36: The filling of a DBT storage in Chile throughout the year.

6.4.4.3 DBT Shipping

Technology

The advantages and challenges encountered in the context of LOHC storage are similarly reflected in LOHC shipping. The atmospheric liquid nature of DBT facilitates easy handling and storage. However, the low energy density of DBT, owing to its weight and volume aspects, necessitates larger shipping capacities.

Currently toluene is transported in chemical tankers with capacities of up to 59,000 tonnes (IRENA, 2022d). However, DBT can also be safely transported in oil tankers (IRENA, 2022d). Oil tankers, with capacities nearly ten times larger than chemical tankers, can drastically reduce transport costs. IRENA (2022d) notes, though, that the largest oil tankers might not be accommodated in all ports. As Appendix A7.3.3 indicates, most reports assume the use of oil tankers for DBT transport, typically ranging in size from 110,000 to 140,000 tonnes. As their report presents extensive research on shipping costs, the Dayian et al. (2021) carrier size of 123,000 tonnes is selected for this analysis.

Hydrogenious LOHC is developing a method for propelling ships through onboard dehydrogenation of the DBT, with commercial availability projected for 2025 (Hydrogenious LOHC Maritime, 2023). Onboard dehydrogenation, when integrated with a fuel cell, can use the fuel cell's waste heat, presenting a potential advantage (IRENA, 2022d). Green methanol could be a viable alternative to DBT, avoiding the need to cannibalise the product (K. Hughes-Straka, expert interview, July 21, 2023)

Furthermore, the absence of energy losses from boil-off reduces the necessity of using DBT as a shipping fuel. The implications of onboard dehydrogenation for ship capital investment costs remain uncertain, as they are not addressed in the assessed reports. Given these considerations, this analysis assumes that the ship is powered by green methanol.

In Appendix 7.3.3, a thorough examination of LOHC shipping costs is provided, detailing the performance of assessment indicators across the four development scenarios. A clear trend of decreasing costs with a larger ship is seen, but no scaling factor is found.

6.4.4.4 Dehydrogenation

Dehydrogenation is the reverse process of hydrogenation, an endothermic reaction requiring the addition of heat to release the hydrogen. A minimum of 9,1 kWh must be added per tonne of hydrogen output, which constitutes 23,1% of the energy stored in the hydrogen (IRENA, 2022).

The reaction proceeds with the aid of a catalyst, typically palladium or platinum. According to Aslam et al. (2018), this endothermic process should occur at a temperature of 280℃. However, Shi et al. (2019) found that the hydrogen that is recovered significantly increases as the temperature of the reaction rises. The company Hydrogenious LOHC carries out the process at approximately 300℃ (Hydrogenious, 2023).

Different sources can provide the heat for the reaction. It is technically possible to fully supply it electrically, high temperature waste heat can be used, and other alternatives are being examined (K. Hughes-Straka, expert interview, July 21, 2023). Nevertheless, all the reports assessed in this study identified the combustion of hydrogen as the most probable heat source, which is therefore assumed as the heat source in this report.

Figure 6.37 illustrates the dehydrogenation process. The LOHC is preheated before it enters the reaction vessel, and the hydrogen is subsequently separated from the dehydrogenated DBT (Sekkesæter, 2019). Also in this example it is seen that the heat is supplied by hydrogen combustion.

The process does not achieve full efficiency, leading to a portion of hydrogen remaining unretrieved in the LOHC. This unextracted hydrogen is not lost, as the LOHC is returned to the system for re-hydrogenation. As a result, the residual hydrogen simply adds to the system's overall ballast through unusable DBT, rather than constituting a loss of hydrogen (IRENA, 2022d).

Dehydrogenation happens at ambient pressure. This means that once the process is completed, the hydrogen still needs to be pressurised to match the desired pressure of the hydrogen backbone (IRENA, 2022d). Furthermore, Pressure Swing Adsorption (PSA) separation is needed post-process to purify the hydrogen (IRENA, 2022d). This process also experiences losses, which can be combusted to provide heat for the dehydrogenation reaction (IRENA, 2022d).

In Appendix 7.3.4 a thorough examination of dehydrogenation costs is provided, detailing the performance of assessment indicators across the four development scenarios. A significant uncertainty is noticed for both the costs and energy demand and no true scaling correlation. The performance of the assessment indicators are therefore decided based on the interquartile range.

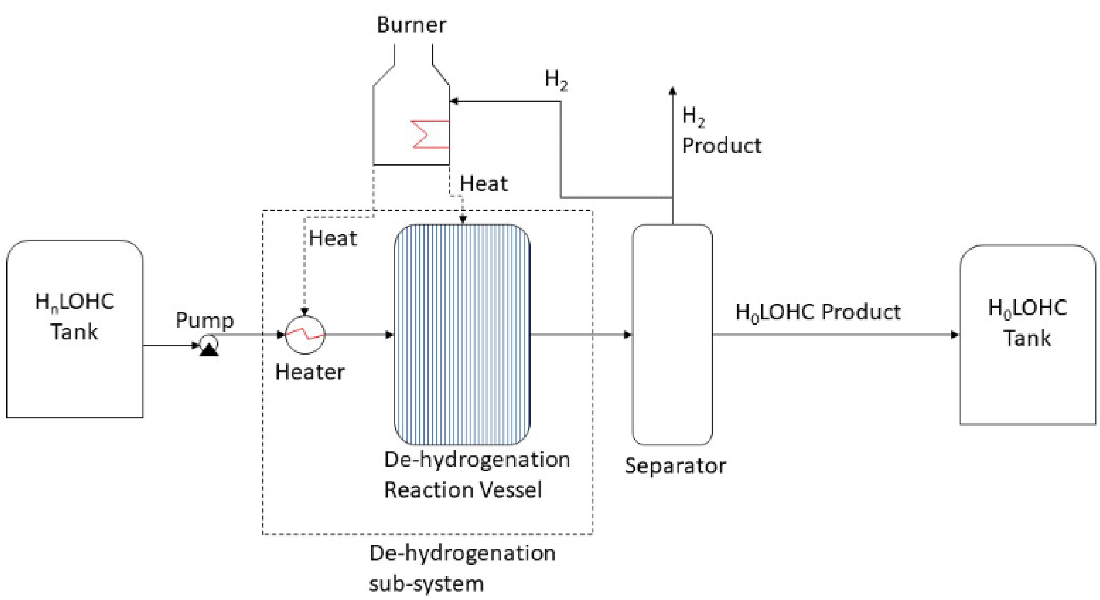


Figure 6.37: Visualisation of the dehydrogenation process from Sekkesæter (2019).

6.4.4.5 Costs of the DBT supply chain

Figure 6.38 presents the cost implications of hydrogen transport from different locations under the most-likely high scenario. It is observed that, again, transport from Chile is the lowest cost despite the higher shipping costs. The shipping element itself in this scenario contributes to a maximum of €1.100 per tonnes in cost differential between countries, which is a maximum €360 per tonnes in the most-likely low scenario. In the worst case scenario shipping alone is €2.100 per tonnes more costly from Chile compared to Spain.

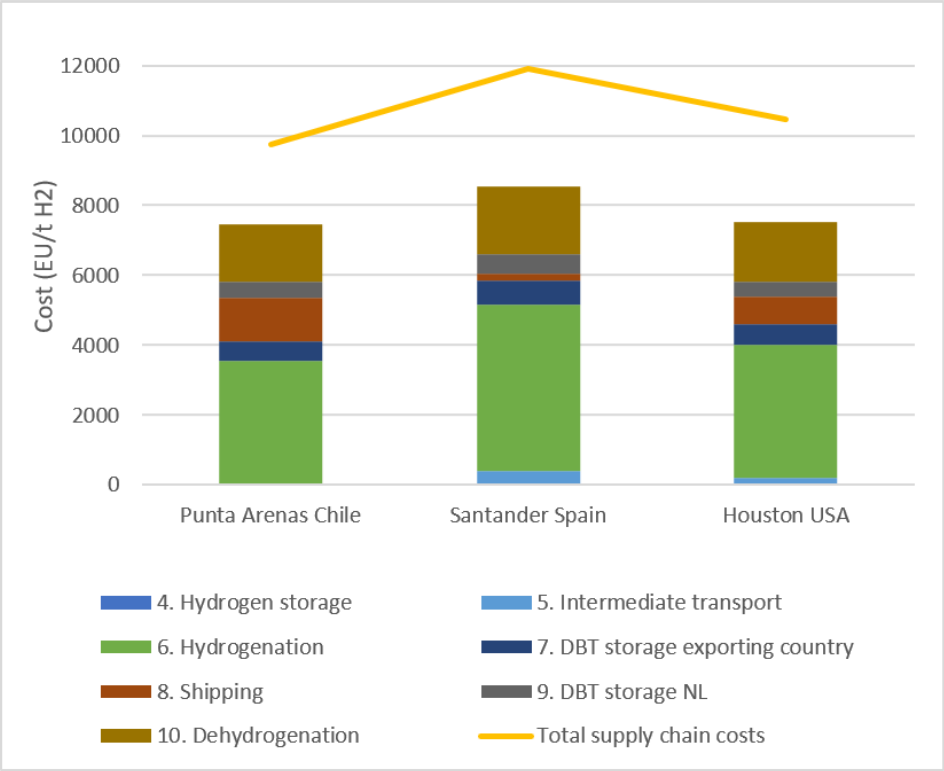


Figure 6.38: The costs of hydrogen transport through the liquid organic hydrogen carrier DBT from different countries in the most-likely high scenario.

In Figure 6.39, which provides a cost breakdown of both local production and transport from Chile under different scenarios, it is seen that transport costs range between approximately €1.500 and €16.400 per tonnes, with a most likely span of €2.200 to €7.400 per tonnes. Consequently, the transportation of the hydrogen adds 97-320% of the local LCOH to deliver the hydrogen in the most-likely scenario's. The efficiency of the DBT supply chain ranges between 74-50% when transporting hydrogen from Chile.

While storage contributes marginally to the overall transport costs, hydrogenation, shipping, and dehydrogenation are the main cost drivers. In hydrogenation, energy loss through the heat of the reaction is the largest cost component in the most-likely scenario, accounting for approximately 53-70% of the cost. From the remaining costs, 86-94% within the most-likely scenario is attributed to the CAPEX of the initial DBT. In the worst-case scenario, a heightened replacement rate causes a cost surge, contributing to 35% of the hydrogenation costs. This cost surge through the larger replacement rate can also be seen in Figure 6.40.

In shipping, fuel costs form the primary driver, contributing between 56-76% within the most-likely scenario. Conversely, in dehydrogenation, the main cost driver stems from energy losses. With the endothermic energy uptake representing 23% of the energy content of the DBT, an efficiency of 44% in the worst-case scenario already results in a 29% overall energy loss.

Figure 6.40 illustrates the influence of fixed costs, energy, and DBT replacement. As previously discussed in the context of hydrogenation, shipping, and dehydrogenation, it becomes evident here as well that the principal source of uncertainty is tied to the energy demand across the different elements of the supply chain.

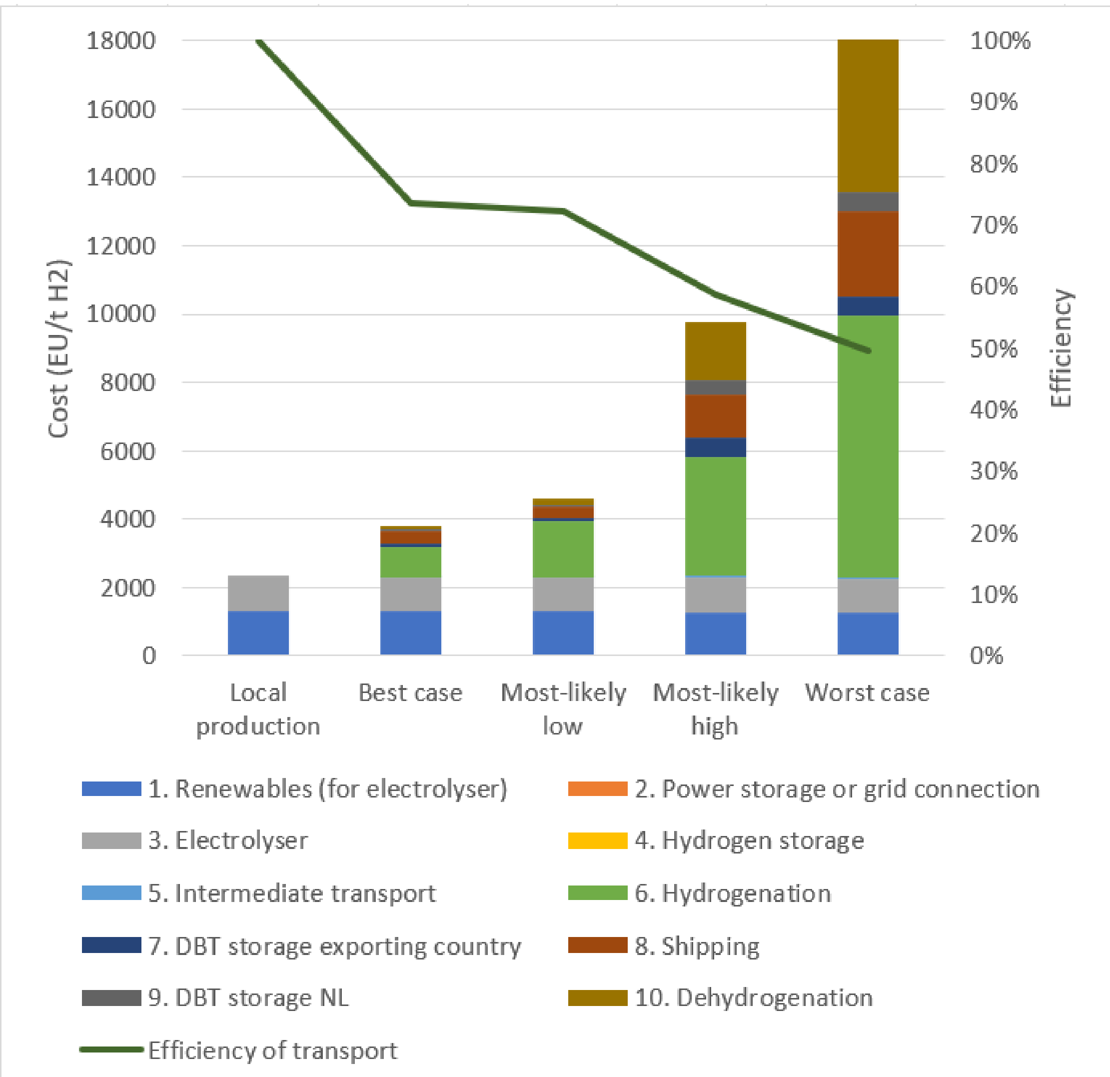


Figure 6.39: Local hydrogen production and the DBT supply chain from Chile under different scenarios.

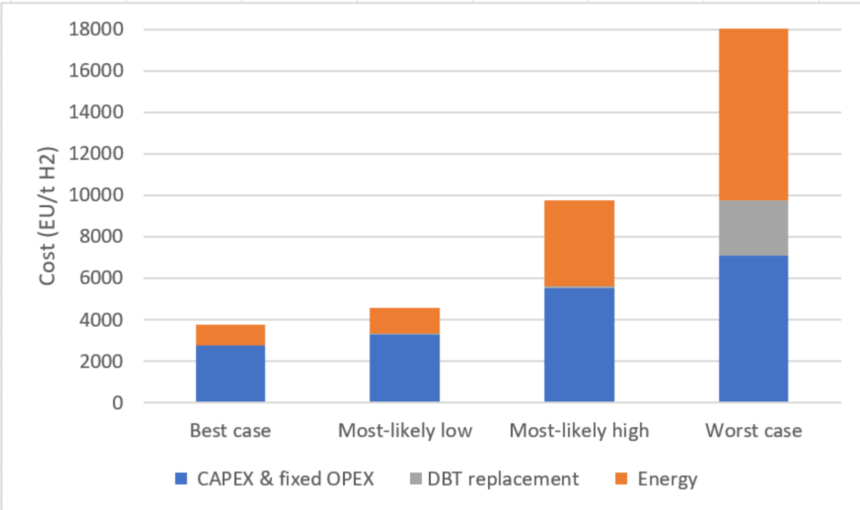


Figure 6.40: The contribution of CAPEX and fixed OPEX to energy in the total costs of the DBT supply chain from Chile.

6.5 Comparison of alternatives

As all reference flows are assessed they can now be compared. The costs of domestic production were identified in Section 6.3.4, while the results of the different carriers were outlined in Sections 6.4.2-6.4.4 Figure 6.41 shows the four alternatives under different scenarios, comparing imports from both Chile (the lowest-cost alternative) and Spain (deemed the most attractive alternative in the MCA).

Based on this analysis, the import costs are competitive in the best-case scenario for liquid hydrogen and ammonia, as well as the most-likely low scenario for liquid hydrogen, only when sourced from Chile. Overall, import is up to 300% more costly than domestic production within the most-likely scenarios. Furthermore, there is no distinct winner among the different import methods. For instance, when importing from Chile, the liquid hydrogen supply chain proves more cost-effective in the most-likely low scenario compared to ammonia. Conversely, in the most-likely high scenario, ammonia is cheaper. The ammonia supply chain also exhibits the least overall cost uncertainty.

Although DBT seems more costly, its most-likely range still overlaps with the ranges of the ammonia and liquid hydrogen supply chain. Given the higher shipping costs of liquid hydrogen, it emerges as more cost-effective from Spain in both of the most-likely scenarios. Additionally, the most-likely cost scenarios of the one-gigawatt project assessed tends to lean more towards the lower end of the overall cost spectrum rather than the higher end.

Comparison between Spain and Chile reveals that lower cost production is a more significant cost driver than distance. As such, import costs from Chile are consistently lower than Spain across all scenarios except the worst-case import scenario of liquid hydrogen.

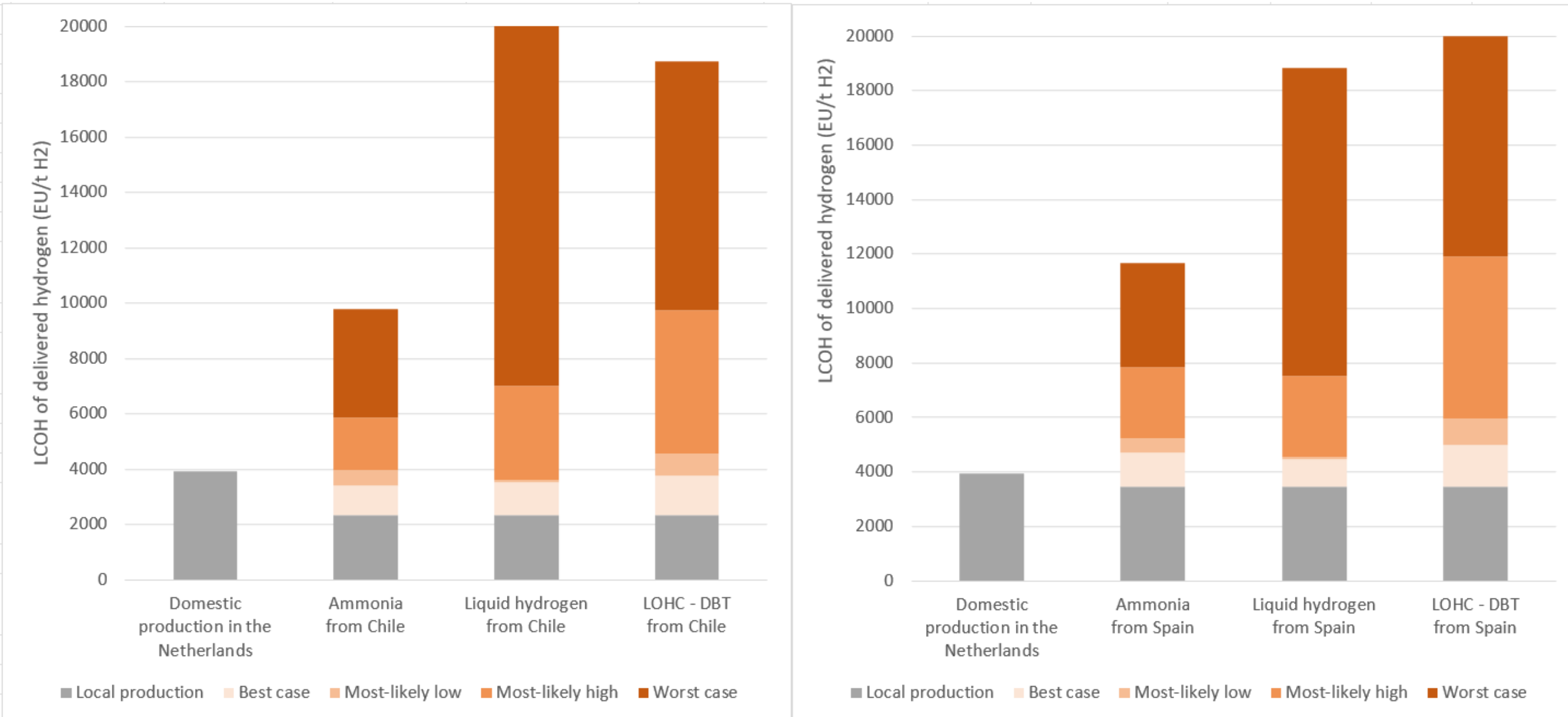


Figure 6.41: Domestic production in the Netherlands versus import from Chile (left) and Spain (right) via different carriers under various scenarios.

Figure 6.42 compares the cost components of the different supply chains from Chile under the most-likely low and most-likely high scenarios. The figure reveals that fixed costs are relatively similar across the three modes of transport in the most-likely low scenario, with energy costs primarily driving the cost difference. Whereas energy costs bear greater significance for DBT and ammonia, fixed costs are the main cost driver for liquid hydrogen, a fact that becomes even more pronounced in the most-likely high scenario. This suggests that the ammonia and DBT supply chains are more vulnerable to energy cost fluctuations, such as a higher hydrogen production price.

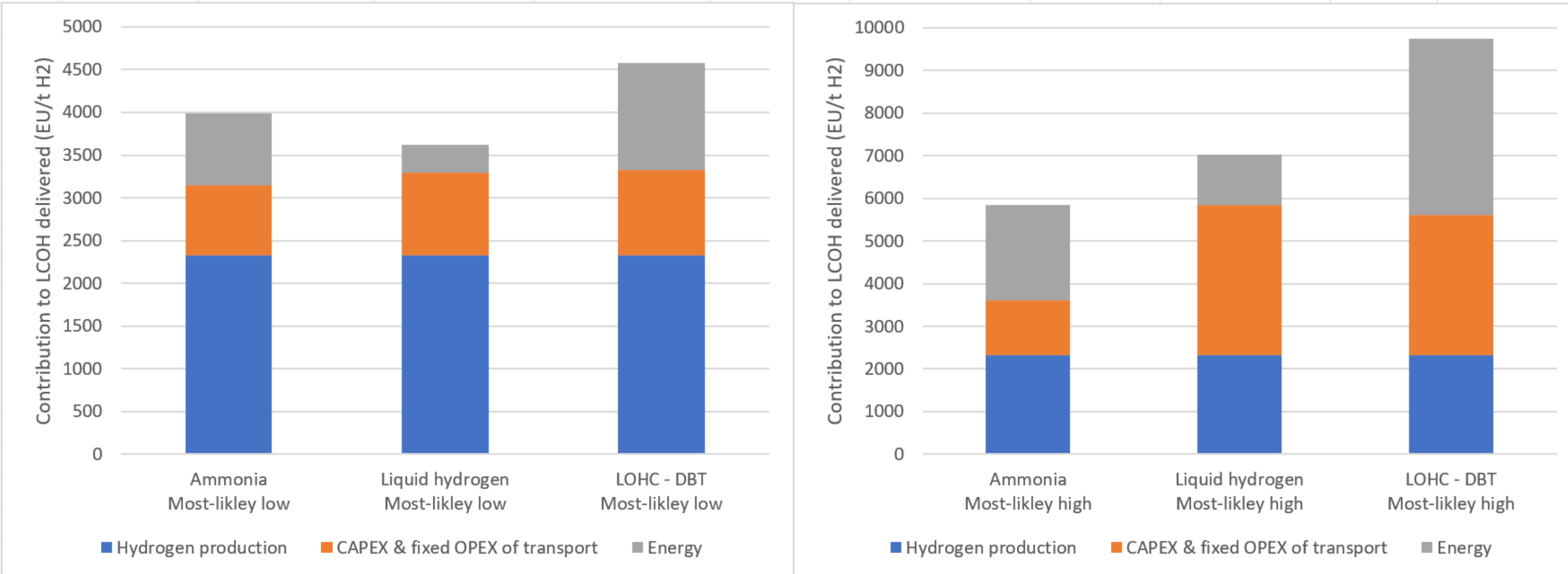


Figure 6.42: Breakdown of hydrogen production costs, CAPEX and fixed OPEX, and energy costs contributing to the overall LCOH of hydrogen delivered in the Netherlands from Chile under the most-likely low scenario (left) and most-likely high scenario (right).

Figure 6.43 further investigates how shipping distance affects the cost price of hydrogen delivery, based on the cost of capital and hydrogen production cost of the United States. The analysis reveals that shipping distance only causes a break-even point in the transport costs for liquid hydrogen and ammonia in the most-likely high scenario. In this scenario, the ammonia supply chain becomes more cost-effective beyond a distance of 4120 km.

Figure 6.44 lastly illustrates the energy efficiency of different modes of transport for hydrogen from Chile. The figure reaffirms the dynamics observed between energy and CAPEX, as liquid hydrogen stands out as the most energy-efficient option. Furthermore, it is seen that ammonia displays the largest uncertainty on energy efficiency, with the efficiency almost halving between the best and worst case scenario.

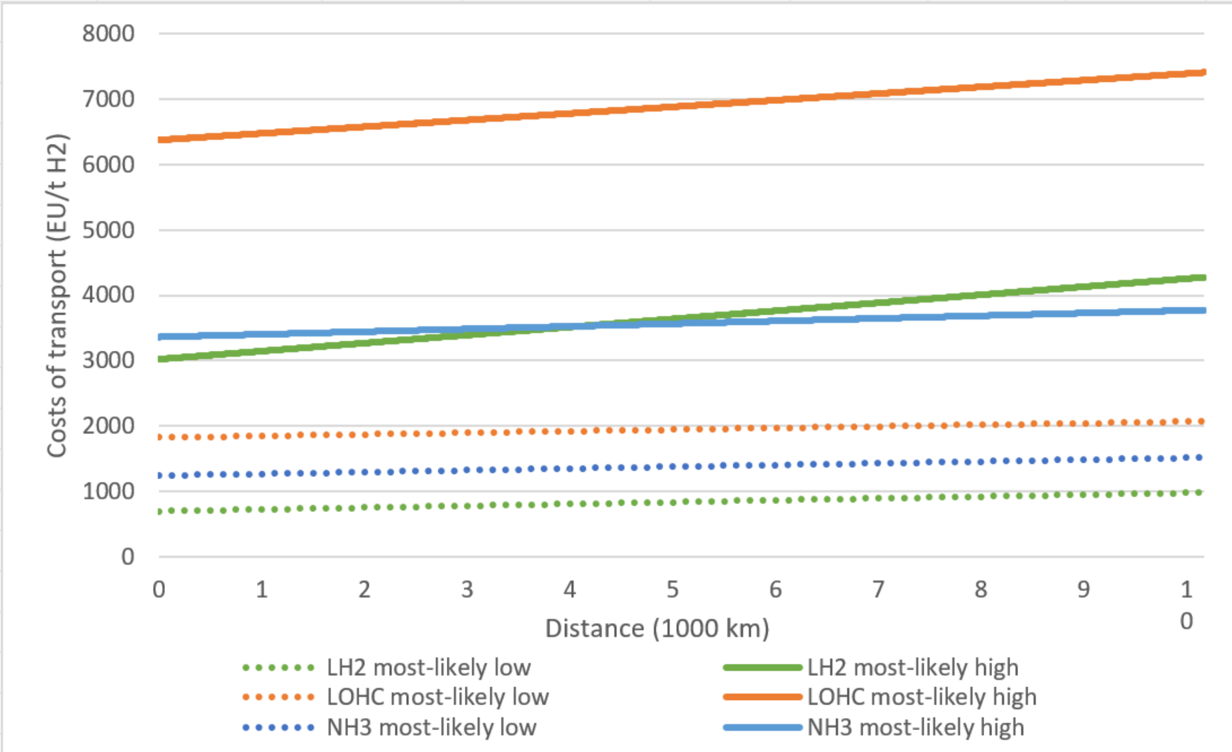


Figure 6.43: The cost of hydrogen transport as compared to the transporting distance based on hydrogen production cost and capital costs of the United States.

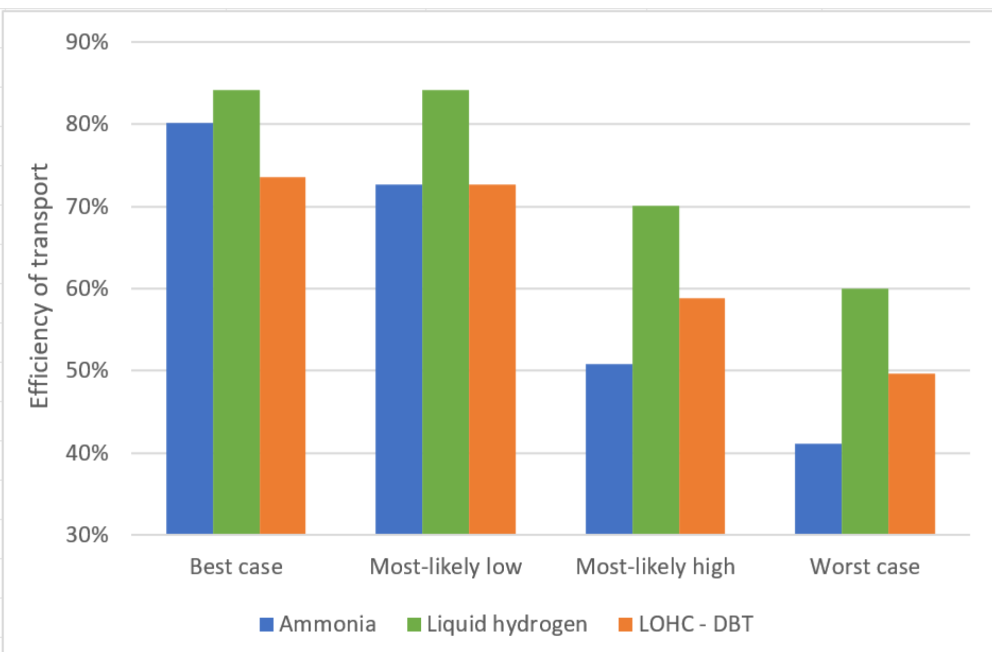


Figure 6.44: The efficiency of transport of hydrogen in different scenarios and modes of transport.

6.6 Sensitivity analysis

The trustworthiness of the study's results can be evaluated through a sensitivity analysis. Since the scenarios already display the sensitivity of input values to the levelized cost of hydrogen delivered, a sensitivity analysis for the assessed transport modes is not necessary. However, it remains intriguing to examine the implications of pipeline import on the cost of hydrogen imports. Additionally, sensitivity analyses are performed on both the cost of capital and the cost of hydrogen production.

6.6.1 The cost of capital

As described in Section 5.2.2.3, the cost of capital plays a pivotal role in renewable energy projects. A challenge lies in appropriately estimating the cost of capital for hydrogen supply chains across different countries, as was seen in Appendix 5. Consequently, Figure 6.45 displays the cost of transport for various countries under a most-likely high scenario, applying the same WACC as the Netherlands. For this sensitivity analysis also Morocco is included as it is a country with a high WACC.

Applying a constant WACC results in a maximum cost difference of 20%, observed in Morocco. This discrepancy makes Morocco more competitive than Chile in both assessed supply chains. Despite the significant difference, the competitive dynamic between import and domestic production remains unchanged. This sensitivity analysis reveals no significant disparities among the various modes of transport.

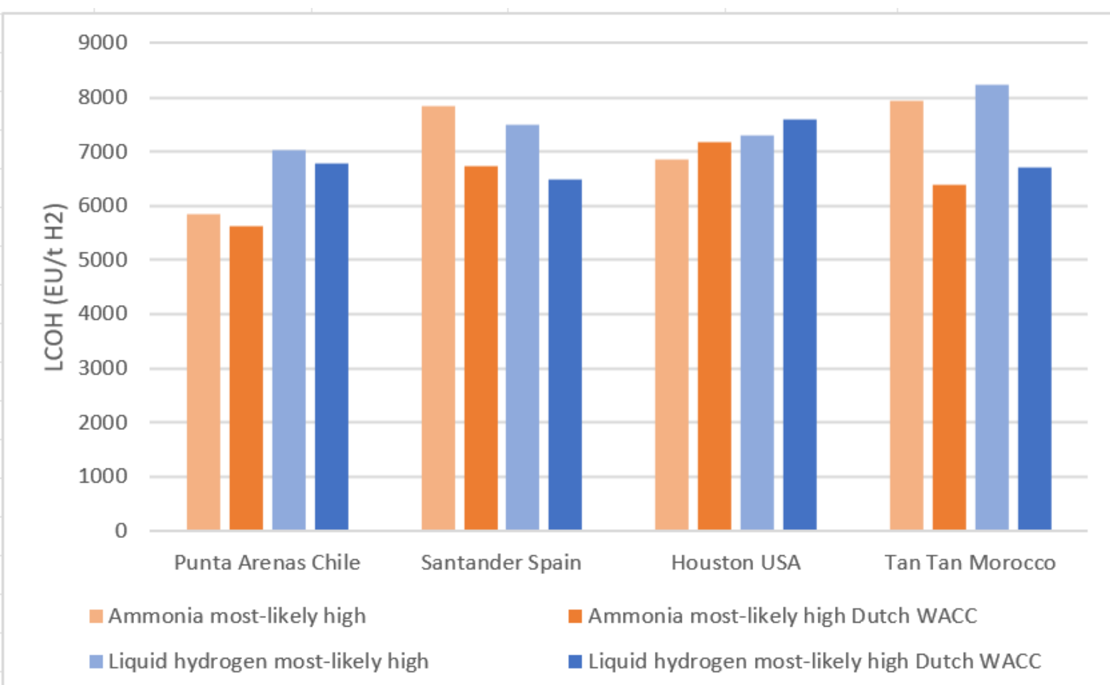


Figure 6.45: Sensitivity analysis of a constant WACC's impact on ammonia and liquid hydrogen supply chain costs in the most-likely high scenario.

6.6.2 Using battery storage to overcome day/night differences of PV

In the model, the option to integrate a battery system to maintain the minimal stack load is available. This approach would reduce the need for stack replacements and, with precise forecasting, can also mitigate the diurnal fluctuations of solar PV. Excess energy can be stored during periods of overproduction and used to supplement hydrogen production during periods where peak capacity is not met. A sensitivity analysis focused on the Spanish context is conducted to explore these dynamics. The analysis considers various battery system sizes and assumes a battery system efficiency of 90%.

Figure 6.46 reveals that incorporating a battery system enhances overall full load hours, thereby reducing the per-kilogram cost contributions of both the electrolyser and renewable sources. However, the analysis shows that these benefits are outweighed by the high investment costs associated with the battery system.

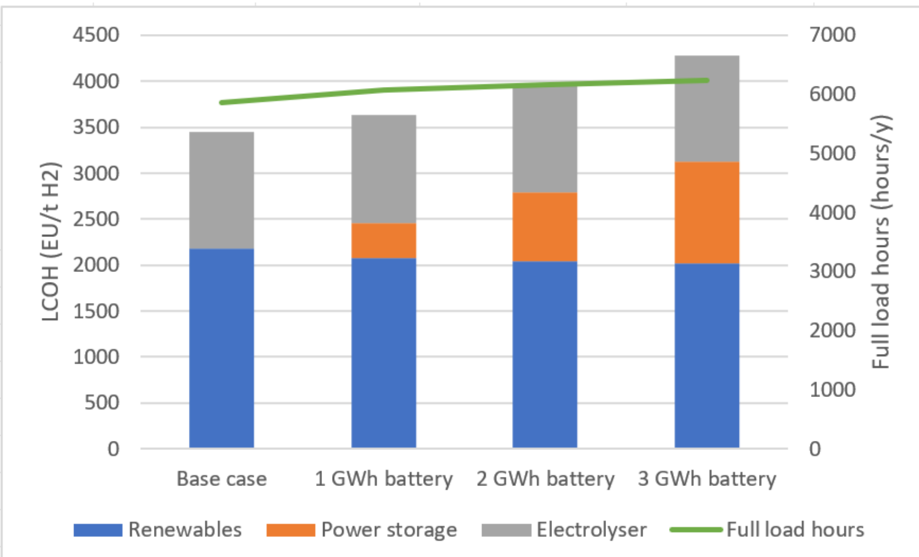


Figure 6.46: The installed wind and PV capacity as well as the LCOH in different scenario's where the battery system is more optimally utilised as well as a scenario where additional battery capacity is placed.

6.6.3 The costs of hydrogen production

The hydrogen production costs are determined by the electrolyser and renewables costs. For both elements there exists considerable uncertainty due to country-specific cost differences and future trends. Given the maturity and established role of wind and solar PV in the global energy system, the costs of a gigawatt green hydrogen factory are particularly uncertain, considering the largest operational plant in Europe is only 20 MW (IEA, 2022c; IRENA, 2022e). Hence, a sensitivity analysis on electrolyser costs is necessary. It is beneficial to explore the impact of country-specific variations in electrolyser costs and the influence of higher electrolyser costs on the hydrogen delivery price.

It was seen that the electric part of the electrolyser accounts for 17% of the plant's total cost (ISPT, 2022). These costs could decrease significantly if renewables are directly connected to the electrolyser. A 90% reduction in the power part of the plant for transport from Chile directly saves

€145 per tonnes of produced hydrogen, with additional cost savings on the energy loss throughout the value chain. Nevertheless, as Figure 6.47 illustrates, this reduction is relatively minor.

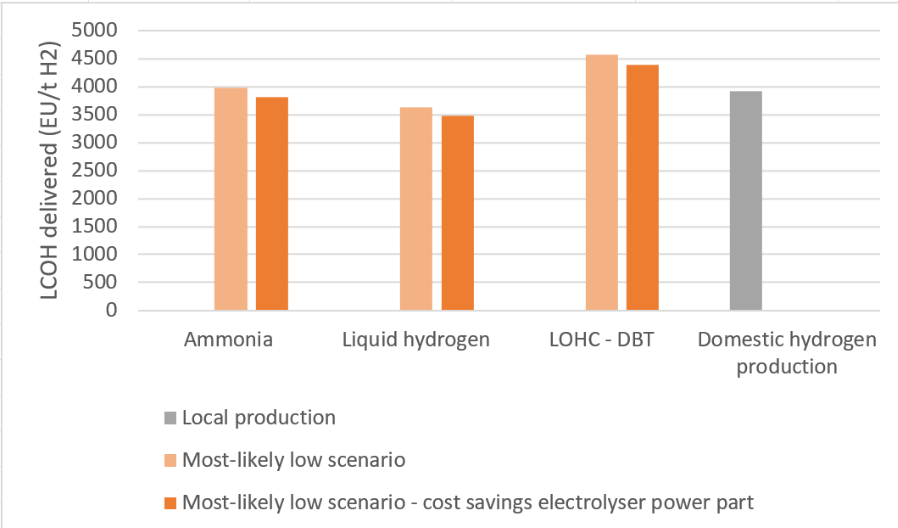


Figure 6.47: Sensitivity analysis on the effect of reducing cost of the power part of the electrolyser in exporting countries, using Chile as an example in the most-likely low scenario.

Recent trends indicate an upward trajectory in the costs for hydrogen production facilities, contradicting the expectation of decreasing costs (S. Kool-Claessens, expert interview, August 1, 2023). Given this, the projections by ISPT (2022) may be overly optimistic in terms of cost. Given this development, it's vital to comprehend how a larger electrolyser cost might affect the results. This is done by implementing the electrolyser costs of PBL (2023) in the model.

PBL (2023) estimates the cost of a green hydrogen plant at €2,200/kW for a 100 MW facility, applying a scaling factor of 0.8. This results in an adjusted cost of €1,388/kW for a gigawatt-scale plant—74% higher than the baseline assumption. For the purposes of this sensitivity analysis, it's assumed that the stack replacement cost would proportionally increase, reaching €103/kW. Incorporating these variables leads to a surge in domestic hydrogen production costs by €689 per tonne, as illustrated in Figure 6.48. The figure also outlines the effect of this cost increment on hydrogen imports from Chile.

Notably, the cost increase is between 13-68% larger for the importing supply chains due to the increased costs of supply chain losses. The liquid hydrogen supply chain, which experiences fewer supply chain losses, exhibits a more modest cost increase in contrast to the ammonia and DBT chains.

A particularly revealing observation emerges when we examine the optimized balance between wind and solar energy, taking Morocco as a case study. Morocco stands out as the only country where solar PV installations significantly outnumber wind installations, given that solar PV costs are roughly half those of wind. Consequently, the affordability of renewables takes precedence over the higher operational capacity that wind energy can offer. However, the introduction of elevated electrolyser costs significantly alters this equilibrium. Figure XX reveals the outcomes of the sensitivity analysis under three scenarios: the base case, the scenario with increased electrolyser CAPEX maintaining a similar wind-to-PV ratio, and a new scenario featuring a re-optimized ratio. A pronounced shift towards maximizing operating hours is evident. Wind capacity more than doubles, solar PV capacity declines by 12%, and full load hours rise by 33%. The graph also shows how this shift elevates the overall cost contributions of renewables while decreasing the per kilogram electrolyser costs.

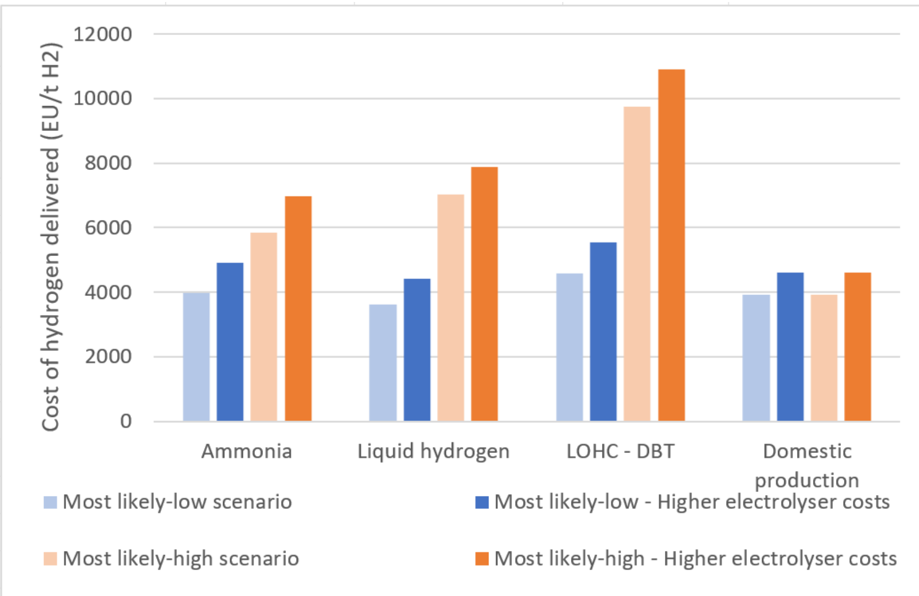


Figure 6.48: Sensitivity analysis that shows the effect of a higher electrolyser cost on the supply chain costs from Chile.

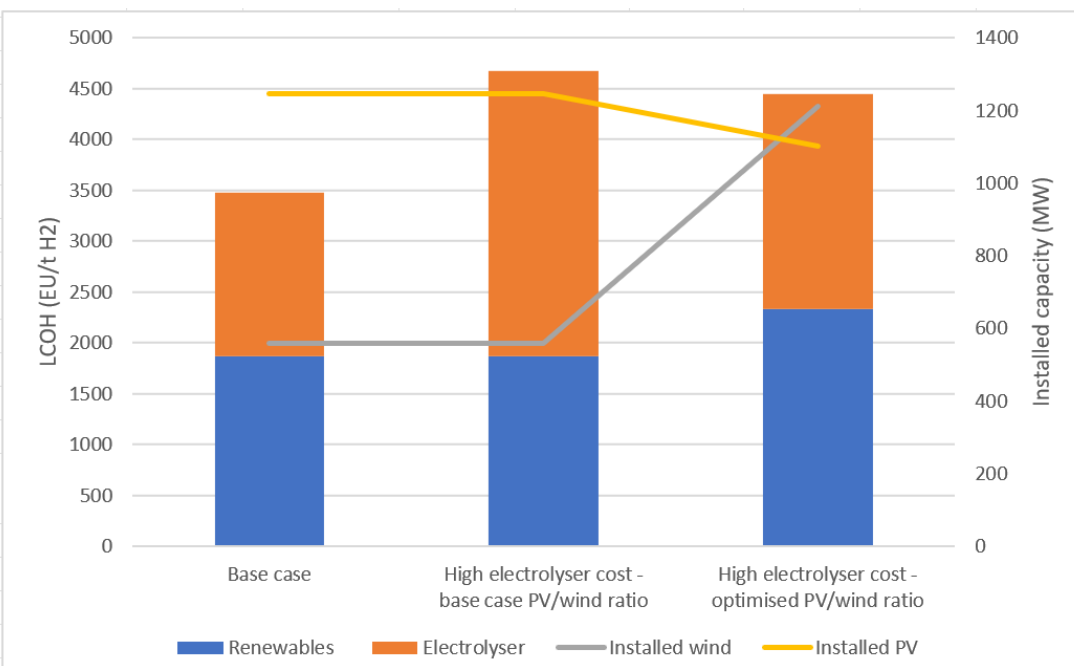


Figure 6.49: The LCOH of hydrogen production in Morocco under different sensitivity scenario's.

6.6.4 Import by pipeline

The diverse scenarios already demonstrate the input data's sensitivity and the substantial uncertainty surrounding the actual costs of importing hydrogen via ship. As pipeline import will be the predominant mode of hydrogen import for Europe in the long run, it's beneficial to examine its impact on the import business case.

Reports by EHB & Guidehouse (2021a, 2022) provide insights into pipeline costs, compression requirements, and the possibility that 60% of pipelines will likely be refurbished. They also assume a steady capacity of 75% and 5000 full load hours for the compressors in their cost calculation, parameters also adopted in this sensitivity analysis (EHB & Guidehouse, 2022). Lastly, EHB & Guidehouse (2021b) propose a ratio between small, medium, and large-scale pipelines, enabling the calculation of an average pipeline capacity, CAPEX, and power demand. These calculations were added to the model for both Spain and Morocco, factoring in a detour multiplier of 1,2 based on the direct line distance, following ISPT (2019). Furthermore, it is assumed that 90% of pipeline the pipeline investment is made under Dutch WACC. It must be noted that this analysis is highly abstracted and serves primarily to provide a cost range for piped imports.

Figure 6.50 reveals the calculated transport costs from Morocco. The findings indicate that, due to higher hydrogen production costs in Morocco, import is more expensive than domestic production. However, pipeline transport outperforms overseas import in all scenarios, with transport costs amounting to approximately €410 per tonne of delivered hydrogen. This result also signifies that pipeline transport is considerably more cost-effective than any import scenario from any country, even when production costs are lower, such as in Chile.

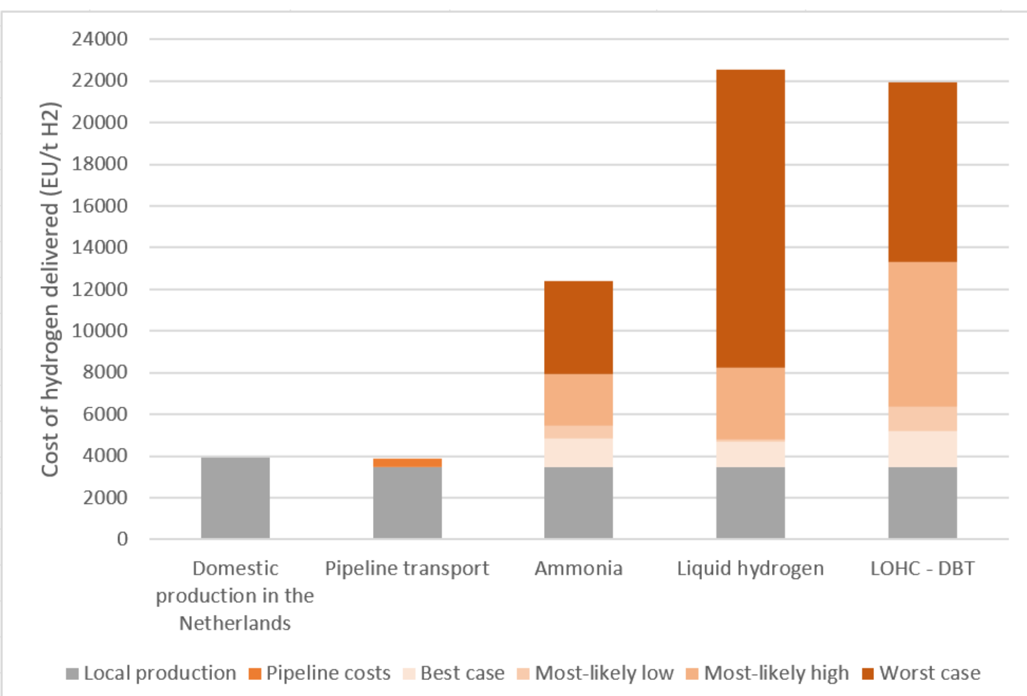


Figure 6.50: Sensitivity analysis where pipeline transport is compared with overseas hydrogen imports.

6.6.5 Ammonia as an end product

As discussed in section 6.4.2, the demand for ammonia as an end product can potentially catalyse the growth of these supply chains. This demand arises not only from the fertiliser industry but also from its prospective use as a bunkering fuel and a fuel for power plants. Therefore, it is interesting to analyse the competitiveness of importing ammonia without its reconversion to hydrogen.

Figure 6.51 presents a comparative cost analysis of green ammonia imported from Chile versus hydrogen production in the Netherlands and versus green ammonia production domestically within the Netherlands, under the most likely low scenario (expressed in euros per tonne of hydrogen equivalent). In this scenario, direct use of imported ammonia proves economically competitive with domestic production in the Netherlands. Moreover, domestically produced green ammonia appears uncompetitive when compared to its imported counterpart.

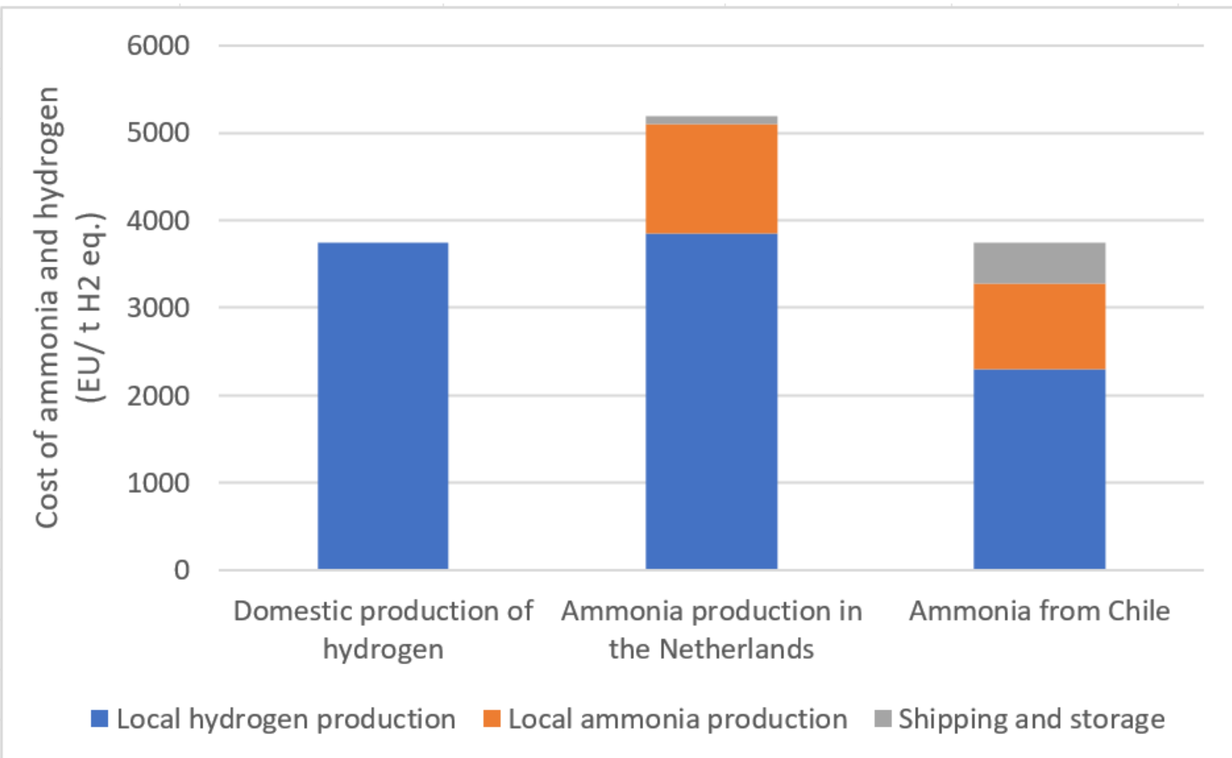


Figure 6.51: Sensitivity analysis of the cost of imported ammonia from Chile in the likely-low scenario versus domestic hydrogen and green ammonia production in the Netherlands.

6.6.6 The flexibility of the ammonia plant

As there are significant discussions on the flexibility of the ammonia plant, two sensitivity analyses were conducted: one examining the effect of a minimal plant load of 40%, and another utilizing hydrogen storage to provide a baseload to the ammonia plant. The results are seen in Figure 6.52 for the most-likely low scenario. The first sensitivity analysis offers modest cost increases—averaging 1-3 euros per tonne in countries with salt cavern storage and €244 per tonnes in Chile.

Among the three countries deemed most likely to be among the initial exporters, operating the ammonia plant at baseload could shrink its required size by up to 33% in Spain. This strategy, however, necessitates a significant increase in hydrogen storage, adding between 180-260 GWh of capacity across various countries. Overall, this scenario could yield substantial cost savings in nations where salt cavern storage is available—up to €95 per tonnes in Spain. Despite these benefits, the model adheres to a standardized methodology for all exporting countries, both for simplicity and because it doesn't significantly skew the broader comparative analysis between imports and domestic production. Because hydrogen storage highly amplifies the case for Chilean exports, the model assumes flexible utilization of the ammonia plant across all countries.

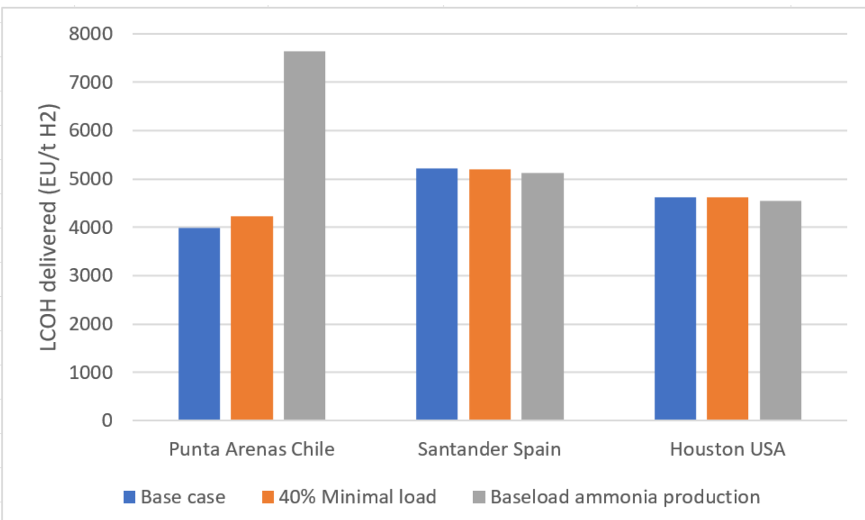


Figure 6.52: The difference between operating the ammonia plant at the minimal load or baseload in the most-likely low scenario.

7. Discussion

This discussion begins with an interpretations section, which interprets the primary findings and situates them within the broader literature. By doing so it will seek to answer both the sub-research questions and the overarching research question. Following this, the report delves into the study's limitations and implications.

7.1 Interpretation

The interpretations section will start with an interpretation of the results that answer the first sub-question, followed by the second sub-question. Through answering both sub-questions the main research question can be answered.

7.1.1 Interpretation of the first developing value chains

The first sub-question that was asked was: *What are potential green hydrogen import value chains to the Netherlands and what criteria shape this?* The investigation revealed a multitude of determining factors, including many non-economical ones, underscoring that the most cost-effective pathway may not necessarily be the initial one to materialise. Foremost among prospective initial importers to the Netherlands are Chile, the United States, and Spain. Below the results and use of an MCA within a TEA are further interpreted.

It was seen that conventional TEA approaches often use an MCA to support the final decision-making process. This thesis, however, was not designed to arbitrate between importation or domestic production but rather to furnish the requisite economic insights for informed policymaking. In ensuring robust options in the TEA, an MCA was employed to select the alternatives within its goal and scope. Notably, in the MCA, 57% of the weight was attributed by the expert group to non-economic factors determining a country's potential to export to the Netherlands. This indicates that the most cost-effective exporter might not necessarily be the initial one. Relying solely on a simple method like a brief techno-economic overview will overlook key aspects, potentially including alternatives in the TEA that may not realistically export to the Netherlands by 2030, hence skewing results and potentially misrepresenting the value proposition of initial imports against domestic production. By factoring in these non-economic aspects in the MCA, the three countries that were included in the TEA are certain to be among the most likely exporters to the Netherlands.

Chile’s good performance in the TEA was expected as its cost-effectiveness played a pivotal role in its MCA ranking. However, its placement among the top three countries of interest was also bolstered by its performance in other criteria. In contrast, for Spain a significantly less attractive economic value proposition was found within the TEA. However, it was deemed a highly probable exporter through its good performance on other criteria in the MCA, its economic value proposition should therefore be considered when comparing imports to domestic production.

Moreover, the comprehensive methodology of this TEA yielded notably different outcomes compared to the initial cost assumptions that served as inputs to the MCA. Consequently, it proves that for a good understanding of potential exporting countries, it's beneficial to apply this TEA approach to a broader range of nations and integrate the findings into a subsequent MCA.

7.1.2 Interpretation of the costs of hydrogen imports

The second sub-question posed was: "*How does the techno-economic performance of different green hydrogen import streams compare with domestic production in the Netherlands in 2030?"* The findings in this report indicate that while there's a considerable uncertainty margin for different import methods, domestic production performs better than overseas import in cost-efficiency across most scenarios. These results are further interpreted below for each of the three sections that were differentiated within the TEA: the determination of the WACC, the hydrogen production and the hydrogen transport.

However, before delving deeper into these sections, the two sub-questions inherently answered the primary research question: "*How can the economic value proposition of the initial green hydrogen import value streams entering the Netherlands be compared with domestic green hydrogen production?"* Among the importing value chains by 2030 will likely be Spain, the United States and Chile. The economic value proposition of importing from these nations is expected to vary, with each of these countries also presenting a broad uncertainty range of green hydrogen delivery costs based on the development scenarios of hydrogen imports. However, when set against domestic production, the levelized costs of hydrogen delivery will exceed domestic production in almost all of the possible development scenarios.

7.1.2.1 The WACC

The TEA begins by examining the Weighted Average Cost of Capital (WACC) for each of the countries, which was between 7,14% and 11,98%. It was observed that the findings for the Dutch WACC were remarkably consistent with the Dutch government's predictions for both the return on equity and return on debt, with a maximum variance of 0,6%. This consistency underscores the applied method's reliability in gauging country-specific WACC for hydrogen projects.

While literature highlights WACC-induced cost variations for PV projects of up to 30% of the costs, the influence of country-specific WACC variances appeared less pronounced in this study. Specifically, sensitivity analysis showed a 20% cost difference for the Moroccan scenario upon applying a Dutch WACC. However, when assessing the economic propositions of different nations, the country-specific WACC played a pivotal role, as it was seen that Morocco can become more competitive than Chile under a standardised WACC. This proves that efforts to reduce the WACC in high-capital-cost nations like as Morocco can significantly alter their economic competitiveness.

7.1.2.2 Hydrogen production

Hydrogen production costs

The observed hydrogen production costs ranged from approximately €2.330 to €3.870 per tonnes, positioned on the higher end of the €1.500-3.650 spectrum identified in the literature review. Multiple factors could account for this discrepancy. Logically, there are variations in CAPEX, OPEX, or capital costs. Other differences arise for example from certain reports possibly not accounting for power wastage in times of overproduction, different efficiencies or not including a minimal electrolyser capacity. A higher hydrogen cost could challenge the development pace of the green hydrogen economy and give a competitive edge to other decarbonization options.

The literature review highlighted a cost difference of €500-1.900 per tonnes between hydrogen production in the Netherlands and the lowest-cost location. This report is in line with these findings, with Chile's production being €1.500 per tonnes cheaper. This finding is critical; a substantially larger or smaller gap in production costs would change how transportation expenses are interpreted, as it sets the "budget" that supply chains can afford to spend on transport and still be competitive with domestic production. In the Chilean context, this budget stands at €1,500 per tonnes.

The main difference in cost stemmed from the Dutch electrolyser being grid-connected, unlike others that utilised a direct line. When excluding grid costs, Dutch hydrogen could potentially outcompete all other countries, except Chile. While it is likely that reports have considered the Dutch grid-connected configuration with offshore wind, other factors could also explain their cost variation. Firstly, some analyses might have overlooked the possibility of using offshore wind for hydrogen production. Additionally, there's a potential overestimation of Dutch offshore wind costs, which was seen to not only have an excellent availability but also to demand around half the CAPEX compared to some other parts of the world. Lastly, the importance of wind in the renewables mix for hydrogen production might have been underestimated.

The importance of wind

Our analysis identified wind availability as a pivotal factor in achieving cost-effective hydrogen production. Even in the four regions where wind power was 25-99% more expensive than PV, it contributed from almost half to more than two-thirds of the renewables mix post-optimization. This dominance of wind can be attributed to its more evenly distributed availability, as compared to the significant day-night fluctuations seen in solar power. Such consistency enables prolonged operating hours for electrolysers, optimised between 4.973-6.623 full load hours annually.

There are many potential reasons why the significance of wind might be undervalued in other reports. For instance, they might not have adequately considered the temporality of renewables, lacked optimization between wind and solar ratios, assumed grid connections, or posited CAPEX assumptions that bettered the case for solar as compared to wind.

The findings underscore the paramount importance of a distributed renewable availability, especially in scenarios where electrolyser CAPEX will be larger than currently assumed, as it will be leading up to 2030. In such contexts, the enhanced operating hours will become even more critical in reducing per-tonne hydrogen production costs and the role of wind will further increase. Sensitivity analysis confirmed this, demonstrating a significant rise in the proportion of wind within the optimised renewable energy mix when increasing the electrolyser costs. This was observed even though wind power was nearly twice as costly as solar in the evaluated scenario. Globally, and even within individual countries, this cost disparity could determine the order in which projects are launched. Specifically, regions with higher wind availability are more likely to initiate projects first.

7.1.2.3 Hydrogen import

The costs of hydrogen imports

The report delineated hydrogen import supply chain costs across four development scenarios. Across different countries and carriers, the best and worst-case scenarios were priced at €3.550 per tonnes and €21.550 per tonne, respectively. Meanwhile, in the 'most-likely' scenarios—where gigawatt supply chains were assumed—the cost spectrum spanned from €3.620 to €11.897 per tonnes. Domestic production costs for a similar scale stood at €3.741 per kilogram. Consequently, imports are only competitive with domestic production in the most optimal scenarios from the most cost effective countries of those that will likely export by 2030. However, in the majority of the evaluated scenarios, they are not economically competitive with domestic production.

Sensitivity analysis further supports this, indicating that cost reductions in the electrolyser's power component in exporting countries does only minimally alter the outlook. However, any increase in the electrolyser's costs will further worsen the case of imports, as hydrogen losses will incur more costs.

Economically, overseas hydrogen imports seem unviable by 2030 unless domestic production hits capacity limits. Given this, most reconversion projects by 2030 are likely to be funded through innovation subsidies, and domestic production will serve as the primary supply. When competing in a level playing field, the competitive edge of domestic production, coupled with the large uncertainties surrounding oversea imports will likely hinder the formation of reconversion projects. As a result, the numerous global ammonia projects in the pipeline are more likely to cater to ammonia demand rather than being reconverted back to hydrogen.

This cost range surpasses the most economical figures identified in the literature review, which spanned from €2,11 to €5,65. Contributing factors include the higher hydrogen production costs in this study and the assessment of a fully renewable system, whereas other studies occasionally integrated fossil fuels, particularly for ship propulsion.

Uncertainty

Many literature studies presented fixed costs, while the approach of this report distinctly outlined the uncertainty range for each supply chain component. This technique allowed for clearer identification of elements with pronounced uncertainty versus those with more consistent costs. The methods used to derive a "most-likely" scenario effectively narrowed down this cost range for the assessed gigawatt supply chain. The approach of encompassing 75-125% of the element size range was particularly effective, though a scaling factor was identified only once. Hence, one might argue that pursuing such scaling factors only complicates the methodology.

The observed discrepancy between the best-case and worst-case costs exceeds the cost ranges presented in reports. This variation can be attributed to the fact that no single report presented the highest or lowest values on every supply chain element. Instead, a high-cost assumption for one element is offset by a lower cost for another. By stacking these uncertainties a more accurate cost uncertainty range is presented in this report.

In terms of specific supply chains, ammonia exhibited the least uncertainty, likely due to its matured application. In contrast, the DBT supply chain faced the most uncertainty within the most-likely scenarios. For DBT this can be explained by the novel nature of its conversion and reconversion plants. For the liquid hydrogen supply chain its shipping is new, but it utilises technologies similar to the liquefied natural gas supply chain, and therefore showed a more predictable cost variation within two most-likely scenarios compared to DBT. This uncertainty poses considerable risks for project developers financing their own supply chains, and heightens the uncertainty of competitiveness against domestic production and alternative hydrogen transport methods. As long as these uncertainties persist, both developers and hydrogen consumers may hesitate to commit, fearing they'll be locked into a less competitive pathway.

The most attractive carrier

Though the analysis did not conclusively identify the most attractive carrier due to inherent uncertainties, DBT typically performed less favourably than ammonia and liquid hydrogen.

In the literature review it was discussed that reports often find relationships between the shipping distance and the most attractive carrier. This relationship was confirmed in this analysis, as liquid hydrogen becomes more economical than ammonia for closer distances and hit a break-even point for the most-likely high scenario at 4120 km. This indicates that closer projects are more likely to import through liquid hydrogen.

Our study highlights a notable other correlation between hydrogen production costs and the ideal carrier. Specifically, liquid hydrogen costs are more influenced by CAPEX compared to ammonia and DBT, which are more affected by energy losses. Sensitivity analysis revealed that as hydrogen production costs increase, the relative appeal of liquid hydrogen therefore grows. In the initial phases of hydrogen development, where the cost of hydrogen are elevated, these findings can be interpreted in two ways. Firstly, elevated costs may confer a competitive advantage to liquid hydrogen supply chains. On the flip side, companies specializing in ammonia and LOHC may mitigate the use of hydrogen carriers in shipping and reconversion by resorting to alternative, potentially less sustainable, energy sources.

Moreover, sensitivity analysis revealed that pipeline imports could facilitate the transportation of hydrogen from Morocco to the Netherlands at an approximate cost of €410 per tonne. This makes piped imports financially comparable to domestic production, and more attractive than shipping in all scenario’s. If future developments lead to greater disparities in CAPEX values for renewables and electrolysers or if the WACC in these regions can be effectively decreased, hydrogen production in Northern Africa will become more economical by more than this €410 per tonne compared to domestic production in the Netherlands. Consequently, when pipeline imports of hydrogen from North Africa are possible, they are likely to outcompete domestic hydrogen production in the Netherlands.

Technology
The TEA highlighted several technological challenges inherent to every importing supply chain. For these chains to be operational by 2030, it was found that the necessary technology must be commercially available by 2026. However, it was found that this timeline doesn't impose significant constraints on system design, given that all critical components are expected to be available by then. Notably, it was found that newer and innovative system elements introduce greater cost uncertainties, elevating the risk.

7.2 Limitations

The results of this Techno-Economic Analysis (TEA) have inherent limitations that can be attributed to the methods used, the scope of the study and the uncertainty that follows from the undeveloped state of hydrogen supply chains and the ex-ante nature of the cost assessments.

7.2.1 Limitations of the method

The primary constraint of the TEA lies in its designated application. This analysis is confined to providing an in-depth economic perspective on hydrogen imports and domestic production by 2030, grounded on feasible technologies from credible countries. Consequently, it should strictly inform economic aspects of decision-making. Some other elements, essential for informed policymaking, are contextualised in Section 8.2.1.

While a TEA provides a snapshot based on current understanding, its dynamic nature is essential to note. The current cost assumptions are a reflection of today's understanding, which is likely to evolve as the 2030 market becomes clearer. To mitigate this, the study is supported by an adjustable model.

Another inherent limitation to a TEA is the many assumptions that have to be made on system design and element costs, further delineated below. Despite the aspiration for objectivity in a TEA, assumptions inevitably introduce a degree of subjectivity from the researcher and consulted experts, especially in nuanced areas like system design.

The methodology employed in determining the 'most-likely' criteria also presents limitations. Primarily, more cost correlations likely exist beyond the element sizing used in this study. Furthermore, the interquartile range, although useful in filtering outliers, may also exclude valuable insights, given that all values were chosen with care by report authors.

Lastly, a significant limitation to the methodology of constructing these four scenarios stems from the assumption that all reports evaluated identical technologies. In practice, minor modifications to a system element could result in a larger CAPEX while reducing energy demand. The approach of this thesis could have therefore led to inaccurate combinations of CAPEX, OPEX and energy demand parameters into the scenarios.

7.2.2 Limitations of the study

The limitations to the study are mainly attributed to the assumptions that had to be made and to the scope of the study

7.2.2.1 Limitations attributed to assumptions made

While the four scenarios adequately demonstrate the inherent uncertainty within the hydrogen supply chain, their validity can be discussed. A key assumption in this study was that all referenced reports accurately conducted a TEA to derive their presented values. Unfortunately, these were seldom evaluated for the expertise of the institution on this topic or the level of detail they used to investigate this cost element. If more time was available, a more thorough validation of the data could have been conducted to exclude potentially faulty values. It is also plausible that an individual value that was excluded through the IQR analysis, may have been more reliable than other values based on its justification. Similarly, some reports focussed on MCH or did not differentiate between LOHCs. In such cases, it was assumed that element costs were comparable for MCH and DBT.

Furthermore, this analysis does not include several considerations. For example, it's ambiguous to what extent the assessed reports incorporated licensing and engineering costs. Also unforeseen costs might be accounted for in some reports but overlooked in others. Additionally, due to significant uncertainties surrounding technical lifespans, end-of-life considerations for various elements were excluded. Collectively, these factors could elevate the overall costs.

Although the most dated report addressed is from 2019, all studies have referenced earlier literature for their cost assumptions, thereby extending the actual timeframe of the raw input data. Given the rapid developments within the hydrogen field, this may potentially introduce issues in some instances. Furthermore, an additional limitation arises from the failure to normalise the reported monetary values to a single point in time. For improved accuracy, the analysis should have adjusted older values for inflation, which could substantially impact the specific inputs used across the different scenarios.

Technological breakthroughs that could significantly impact the development of hydrogen import represent another layer of uncertainty in this ex-ante analysis. Additionally, there's room for optimising battery use, potentially affecting the current hydrogen production cost estimates. The study used hourly data from 2019, presuming it to be representative of an average year by 2030. However, annual weather variations are inevitable.

Also the chosen investment duration of fifteen years warrants scrutiny. It was seen that there is a discernible variance in organisational stances regarding the appropriate duration. For some companies, fifteen years might be an overestimation, whereas governmental projects typically have a longer lifespan. Consequently, infrastructure initiatives, like the pipeline imports examined in the sensitivity analysis, possibly utilise a longer economic lifetime.

Additionally, varying discount rates can result in notable discrepancies across business cases for different exporting countries. Several factors, including policies and subsidies, can influence the actual WACC for these projects.

The assumption that one-gigawatt supply chains are representative for both domestic and import projects may not hold in practice. Import projects could achieve greater scale, potentially benefiting from economies of scale in electrolyser and renewable energy costs. Additionally, multiple variables can affect the CAPEX of renewables. For instance, the assumption that port and road infrastructure is sufficiently developed in all exporting countries, if incorrect, would impact the CAPEX. It was also assumed that connecting renewables to the grid would incur costs similar to those for connecting to the electrolyser; however, actual electrical connection costs may vary and could be lower for direct-line electrolysers.

7.2.2.2 Limitations attributed to the scope

The inventory analysis adequately addressed part of the uncertainty by presenting results in four distinct scenarios, but the trustworthiness of the outcomes is more limited in relation to hydrogen production, where only one scenario was assumed. This limits the usability of the cost range, as alterations in hydrogen production costs will further widen this cost range. However, when considering the comparison of imports versus domestic production, sensitivity analyses on hydrogen production demonstrated that their competitive dynamic remained largely consistent.

The scope of the TEA was also limited in terms of modelling variations to ensure that the considered reference flows are assessed thoroughly. The focus on a finite number of scenarios meant that several practical system design variations, such as different energy sources, the use of a grid connection, or scaling of components, or possibly even the combination of different solutions were not fully explored.

Furthermore, this study is confined to a pre-tax cost comparison and does not account for additional expenses such as the costs associated with the Dutch hydrogen backbone or market entry fees for selling hydrogen.

The review furthermore discussed that also blue hydrogen is seen as an important transition solution. The implications of using blue hydrogen or partly using blue hydrogen on the business case were not explored. Moreover, this TEA limited its scope to three modes of hydrogen import and reconversion, ignoring numerous other feasible alternatives.

This narrow focus also constrains the analysis to a green hydrogen demand. For a comprehensive economic assessment of the most effective decarbonization strategy, it's crucial to consider other solutions, including electrification, biobased solutions or the direct use of ammonia or methanol. Also the production in other countries should be considered.

Notably, the presented costs do not incorporate subsidies. Realistically, both domestic and select export projects could attract subsidies that can significantly alter the economic dynamics. Also other policies such as changes in grid fees for hydrogen producers in the Netherlands could considerably impact the economic outcomes. Moreover, as demand for green power and hydrogen increases and space for renewable energy development in the Netherlands becomes scarcer, the costs of domestic hydrogen production will likely rise.

Lastly, two salient uncertainties discussed in the literature can potentially cause actual costs to exceed model predictions. First, the observed trend wherein large projects frequently surpass their budget suggests that the estimated costs in this study might similarly be vulnerable to overshoots. Secondly, the project-on-project risk can amplify the cumulative risk in hydrogen projects, given that the overall success of a supply chain hinges on the success of each of its constituent components.

7.2.3 Limitations of the use of an MCA in the TEA

A first series of limitations to the use of an MCA in the TEA in this context is caused by the inherent complexity of a country's likelihood of becoming an exporter to the Netherlands. The MCA, despite its effectiveness, faced challenges in criteria selection, quantification, normalisation, and subjective weighting. A comprehensive discussion of the MCA's limitations can be found in Section 5.6.2.

When using the MCA to identify potential exporter countries within the TEA, a notable limitation is the absence of a clear threshold score to determine the likelihood of exporting to the Netherlands. Instead, the MCA provides a ranking. Consequently, the TEA primarily focuses on the top three ranked countries to ensure the inclusion of viable options but doesn't necessarily rule out other high-performing countries from potentially exporting to the Netherlands.

Moreover, the MCA's scope was limited to country selection. In parallel, other determining factors might favour specific carriers, but these were solely chosen based on their significance as alternatives in the literature.

7.2.4 Implications

Policymakers

The findings provide policymakers with a more comprehensive view of the cost associated with both domestic hydrogen production and hydrogen import projects, aiding current and future policy development on hydrogen imports. These results not only guide decisions on the desirability and format of shipped hydrogen but also shed light on the potential extent of policy support required to bridge the cost disparity between overseas hydrogen imports and local production. The analysis pinpoints cost uncertainties within these supply chains and thereby highlights specific elements where policy might accelerate innovation.

Additionally, the observed discrepancy in hydrogen production costs as compared to literature might implicate the need for broader policy adjustments to bolster hydrogen initiatives. Lastly, the inventory analysis itself also offers a lens to put claims by companies or other stakeholders regarding hydrogen imports in perspective.

Project developers

This research furnishes project developers with a preliminary assessment of the economic viability of potential exporting projects, shedding light on critical decisions such as carrier and country selection. Additionally, the study identifies technological and economic challenges specific to supply chain elements that need to be further investigated to gauge a project's economic viability. Those in advanced stages of project development can gain insights into the competitive landscape and potential economic dynamics with rivals. Furthermore, the inventory analysis could aid them in evaluating supplier quotations, comparing them with estimated costs for particular element sizes. Developers of projects in the Netherlands will find this analysis beneficial in forecasting the interplay between their ventures and imports by 2030.

For all project developers the results can aid in stakeholder or government communication to defend their competitive stance. Furthermore, also for project developers the inventory analysis itself also offers a lens to put claims by companies or other stakeholders regarding hydrogen imports in perspective.

Hydrogen consumers

Prospective and existing hydrogen consumers envisioning procurement in 2030 will find this study valuable in estimating potential hydrogen costs to evaluate the future competitiveness of their hydrogen own products. Considering the projected higher costs of imports compared to domestic production by 2030, it's vital for consumers to plan their hydrogen sourcing strategy. This includes gauging the potential of shipped imports against evolving pipeline imports post-2030. Additionally, for future consumers, this research can inform decisions on production facility locations and the choice between hydrogen use and other decarbonisation pathways.

Research

For researchers this study highlights those areas of high uncertainty where their research could create clarity, as well as those costly areas where technological breakthroughs can significantly alter the costs of importing supply chains.

Apart from implicating fields of valuable future research the TEA implicates the importance of a thorough approach and the inclusion of specific elements that were found to be influential in this research, such as the grid connection costs, the location specific WACC or the optimisation between wind and solar PV.

Furthermore, the study suggests that integrating an MCA within a TEA can be valuable, especially when dealing with a broad array of alternatives. In the context of hydrogen imports the findings underscore the significance of thoroughly selecting which alternatives to include. Consequently, this research points to numerous potential areas for in-depth exploration to accurately quantify criteria pivotal to the evolution of international hydrogen supply chains.

Implications of MCA

Individually the MCA can also have significant implications, as was discussed in Section 5.6.3. It underscores specific criteria that are important for a country's hydrogen export progression, which show focus points for Dutch and foreign policy in improving a country's export potential. For stakeholders such as project developers and consumers, these evaluated criteria shed light on potential non-economic challenges worth considering in the preliminary phases. Moreover, they offer an early indication of countries likely to emerge as hydrogen exporters before 2030.

8. Conclusions and recommendations

8.1 Conclusions

This study unravels the economic interplay between domestic green hydrogen production in the Netherlands and potential imports for 2030. While ammonia and liquid hydrogen appear to have a slight economic edge over DBT, there's no definitive front-runner among transport modes. Gigawatt-scale importing supply chains by 2030 are projected to deliver hydrogen to the Netherlands at costs ranging from similar to thrice that of domestic production. It can thereby be concluded that there is a large uncertainty range around the import of hydrogen and that domestic production of green hydrogen is likely to be more economical than imports by 2030.

The competitive advantage of domestic production primarily stems from the abundant wind resources in the Dutch North Sea. Clearly, consistent wind availability is pivotal for economically viable hydrogen production. Across various countries studied, wind's widespread availability, in contrast to solar PV, led it to provide between approximately half to all of the energy required for optimal hydrogen generation, even in regions where solar power costs were half that of wind.

It was furthermore concluded that these initial value chains are not perse the most economical value chains to form. A significant 57% of the evaluation weight was attributed to non-economic factors, underscoring their crucial role in the forming of importing supply chains. It can therefore be concluded that a solely techno-economic viewpoint is insufficient in assessing the forming of these supply chains, but that a systems perspective is essential. Factoring in non-economic considerations, Chile, the United States, and Spain especially emerge as probable early exporters to the Netherlands. Among these, Chile appears to offer the most cost-effective hydrogen.

8.2 Recommendations

8.2.1 Recommendations on the use of the study in policymaking

When integrating these findings into either governmental or corporate strategies, several facets from both the literature review and TEA must be considered.

Initially, it's imperative to recognize that these development scenarios are not merely contingent upon organic evolution; rather, they will be actively shaped by governmental support. Given the limited timeframe for these supply chains to materialise and the uncertainty about the most cost-effective mode of transport, it is recommended to at least foster the forming of pilots and innovation across all potential supply chain solutions. However, when evaluating the role of shipped imports, factors beyond the techno-economics should be considered.

Sensitivity analysis indicates that pipeline imports emerging after 2030 are likely to be more economically viable than shipped imports. Consequently, I recommend accelerating pipeline imports to bolster the competitiveness of Dutch industries reliant on hydrogen, both within and outside Europe. However, two critical factors supporting shipped imports were identified in the literature review that also shouldn't be sidelined.

One is the path dependence identified in Dutch ports and the importance of hydrogen in maintaining their long-term significance. Understanding the opportunity costs of a lost position if shipped hydrogen imports don't materialise is essential. Another key factor is the security of supply as emphasised in the REPowerEU plans. Consideration must be given to whether sole reliance on pipeline imports will ensure a sufficiently diversified range of exporting countries.

To reinforce the significance of our ports as energy import hubs, I recommend prioritizing the overseas importation of hydrogen-derived products like sustainable aviation fuels, methanol, or ammonia. By eliminating the reconversion step, the competitive position of these end-products over pipeline imports is improved. From a security of supply standpoint, it's advisable to recognize early on the importance of a diversified hydrogen supply and the fact that this will likely come at a premium. I therefore recommend to seek European backing for reconversion projects accordingly.

Safety is also a vital consideration, as it was found that both liquid hydrogen and ammonia present significant challenges. Although it's determined that these can be handled safely, further examination of the differential utility brought by these safety considerations when comparing alternative hydrogen acquisition methods is recommended.

Sustainability was recognized in the literature review as a key driver for green hydrogen development, and should remain central in policy-making. However, this study offers a limited view on sustainability, focusing merely on the energy efficiency during transport and overlooking numerous life cycle impacts inherent to various supply chains. Life Cycle Assessment is therefore recommended to better identify these impacts.

Given that some of these elements are non-monetizable, multi-criteria analysis might again be a valuable tool to compare both domestic production and different modes of imports on desirability, but also to compare hydrogen itself with the discussed pathways.

I recommend that if the actual price development deviates from initially forecasted cost reductions, this should not impede the growth of green hydrogen. Governments should aim to bridge the cost gap for critical industries through both supply and demand-side subsidies combined with strong regulations. Given that grid fees constitute a significant portion of domestic green hydrogen production costs, and onshore electrolysers contribute to grid balancing, it may be worth reconsidering whether they should bear the full grid fee. Accelerating the development of offshore electrolysis is another suggested measure to mitigate high grid connection fees.

Lastly, if importing products made with hydrogen proves more economical than importing the hydrogen itself it should be considered what the implications are of ceasing the production of specific goods in the Netherlands and importing these. Should a socialised premium be required to retain these industries in the Netherlands, it's advisable to consider their local value and contributions to security of supply before decision-making.

8.2.2 Recommendations on improving the study and fields of future research

A deeper exploration of importing supply chain configurations is recommended, which can be done by broadening the scope of sensitivity analyses. This includes pathways where a portion of the energy comes from fossil sources, or those that incorporate heat integration between neighbouring industries. Furthermore, it is valuable to look into pathways where hydrogen isn't strictly the end product but where its derivatives are imported such as sustainable aviation fuels or methanol. It is also recommended to further explore local production cost differences within nations and the effects of utilising hydro or geothermal power for hydrogen production. For the case of domestic production it is interesting to explore how the electrolyser costs will change when offshore electrolysis is applied, especially given its capability to offset grid connection expenses.

Moreover, regularly updating the model is recommended to account for advancements in research and practice, ensuring that the understanding of green hydrogen's economic proposition remains accurate.

When deciding on decarbonisation pathways also the exploration of other solutions is valuable. A comprehensive approach demands an evaluation of alternatives like carbon capture, electrification, and biobased solutions. Here, both imported and domestically-produced blue hydrogen is also valuable. Also transitioning a process to another country and importing the end-products is worthwhile to include.

To improve the use of the MCA for choosing alternatives within the TEA, it is recommended to broaden the scope to other countries using the TEA model and consequently integrate these cost values into the MCA. Moreover, the potential application of an MCA to evaluate various transport modes in terms of their probability to establish importing supply chains, deserves exploration. It is lastly recommended to also explore the integration of domestic production into the MCA on the likelihood of supply chains to form.

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Appendix

Appendix 1: Literature review

Appendix 1.1: Review of different hydrogen import cost studies.

Table A.1.1: Overview of different hydrogen import cost studies and some of their differences.

	Reference year	Most cost competitive hydrogen transport at a distance of 10.000 km	Inclusion of full supply chain	Full disclosure	Shows uncertainty range	Include domestic prodcution in NL for 2030	Inclusion of WACC	GH2 production	Lowest presented import cost	Highest presented import costs
HyChain 2, ISPT (2019)	2050	Pipeline	yes	yes	no	yes	old data	-	2100	
Daiyan et al. (2021)	2030	Ammonia (17000 km)	No	no	yes	no	No	3600	5650	9100
JRC (2022)	2030 - 2035	Liquid hydrogen/ LOHC	no	yes	no	no	Simplified	1500-3500	2700	6350
TNO (2022)	2030	Ammonia	yes	no	yes	yes	Simplified	2800	4000	8300
IEA (2021)	2030	Ammonia	No	no	no	no	-	-		
IRENA (2022d)	2030	Ammonia	yes	no	yes	no	simplified	1000	2500	7500
EHB and Guidehouse (2021)	2030	LOHC	No	yes	no	no	no	1500-2000	2100	3300
DNV (2020)	N.d. / 2025	-	No	yes	yes	no	no	-		
ENTEC (2022)	2030	Ammonia	No	yes	no	no	simplified	1000	2300	3500
Sekkesæter (2019)	2025	Ammonia	No	yes	no	no	No		0,8 + prodcution	4,82 + production

Roland Berger (2022)	2025	LOHC - DBT	No	No	No	yes	No	2000	4300	4800
Wijantana et al. (2019)	2030	Ammonia (2030), liquid hydrogen (2050)	No	yes	no	no	-	-	2100	2460
Patonia and Poudineh (2022)	2030	LOHC - MCH	No	yes	yes	no	-	-	2900	3900

Appendix 1.2: Production cost difference

Table A.1.2: The cost price of hydrogen production in different locations to find the maximum cost difference between Dutch and foreign hydrogen.

country	IEA (2019) - Long term	PWC (2023a) - 2030	IRENA (2022b) - 2050	Roland Berger (2021) (Eu/kg - 2025)
	($/kg)	(EU/kg)	($/kg)	(EU/kg)
Netherlands	3,4	2,75	2,30	4,2
Maximum difference	**€1,44**	**€0,5/kg**	**€0,86**	**€1,9/kg**
Spain	2,4	2,75	1,70	2,70
Norway	2,8	2,5	2,30	3,20
Australia	2,4	2,75	1,25	2,80
United States	2,2	2,75	1,50	2,70
Canada	2,8	2,75	1,25	3,20
Morocco	2,0	2,75	1,90	2,60
Egypt	2,0	2,50	1,90	2,60
Namibia	2,0	2,75	1,50	2,60
Chile	1,8	2,25	1,25	2,30
Saudi Arabia	2,0	2,50	1,90	2,60
Oman	2,0	2,50	1,90	2,60

Appendix 2: Full explanation of system diagram used for MCA

In this Appendix additional explanation is given of the system diagram that formed the basis of the Multicriteria analysis as well as supporting information to some of the criteria. The System diagram is again presented in Figure A2.1.

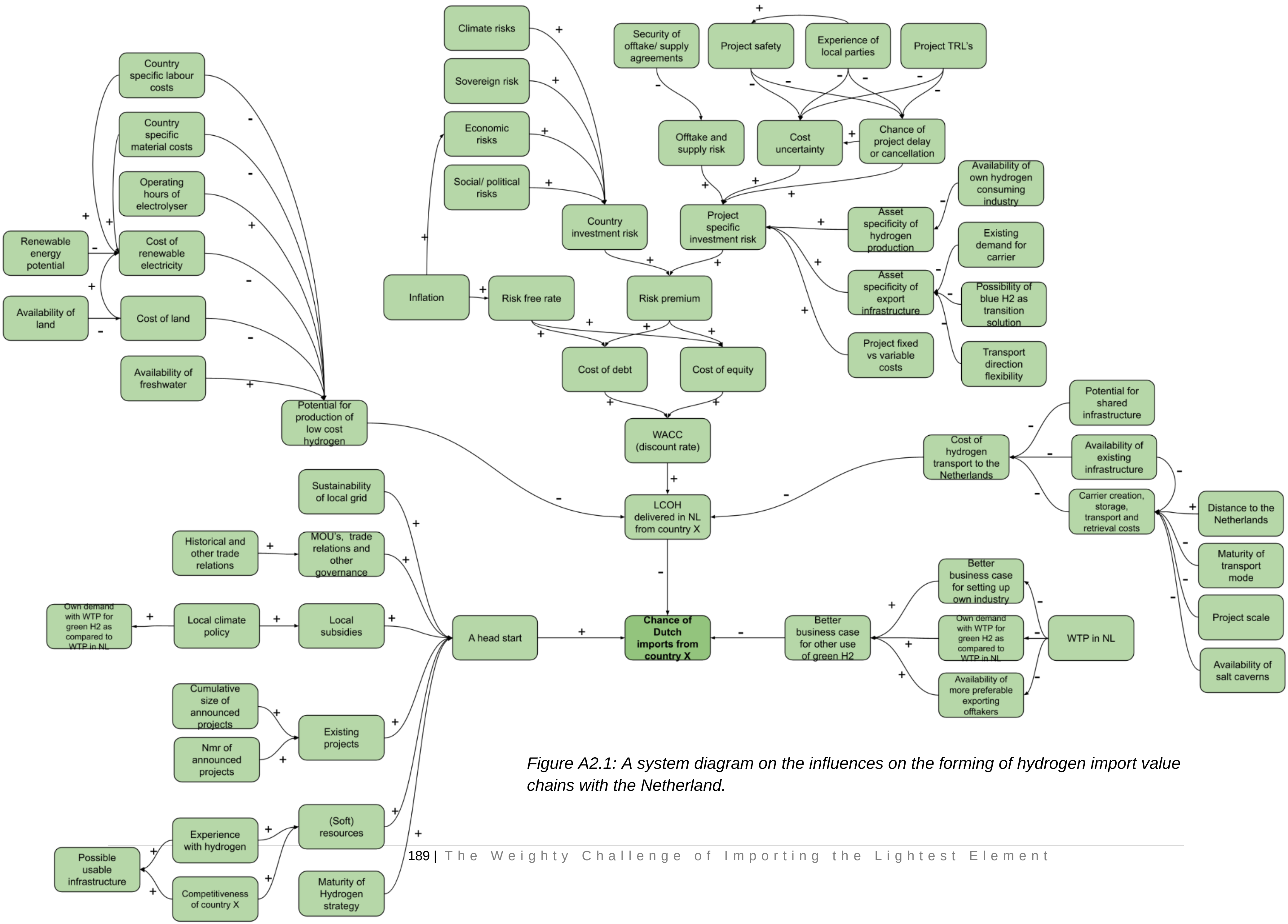

Figure A2.1: A system diagram on the influences on the forming of hydrogen import value chains with the Netherland.

A2.1 Levelized cost of hydrogen delivered to the Netherlands

Cost factors such as land, labour, and materials specific to each country also impact hydrogen costs. For example, will land availability influence the cost of land and will more developed countries generally have a higher labour costs. Also the availability of freshwater is a factor of influence. Some scholars such as Pflugmann & De Blasio (2020) believe this as a dealbreaker for hydrogen production. The solution is desalination of seawater though. IRENA (2022b) recognises that even with significant transport from shore to an electrolysis site the process will only take up 1-2% of energy consumption and cost around 0,05 $/kg of hydrogen. The effect of water scarcity is therefore low and not seen as limiting the potential for low-cost hydrogen production. Figure A2.2 shows the section of the system diagram that affects the potential for the production of low cost hydrogen.

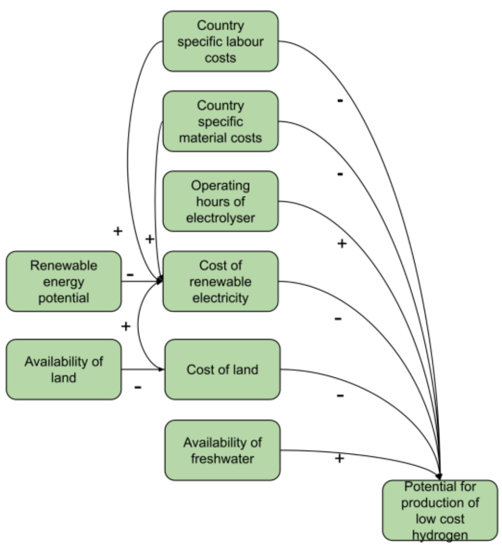

Figure A2.2: The section of the system diagram that affects the potential for the production of low cost hydrogen

A2.1.1 Weighted average cost of capital

The weighted average cost of capital (WACC) consists of a share for the return on the debt and return on the equity of the investment. The ratio between the debt and the equity is called the gearing (Hargrave et al., 2022). The WACC significantly impacts the costs of renewable energy projects. An example is that the IEA (2021a) acknowledges that the WACC accounts for 20-50% of the levelized cost of solar electricity. Simplified, the costs of capital encompass two aspects: the minimal return on investment in a risk-free scenario and a risk premium to account for the inherent investment risk (Hargrave et al., 2022). The risk-free rate includes a factor for inflation plus the return on short-term government bills (Hayes et al., 2023). Investment risk refers to the probability of incurring losses compared to the expected project return (Chen et al., 2022). A risk premium is paid to address this probability. The risk premium combines factors related to country-specific risks and project or sector-specific risks. Figure A2.3 shows the section of the system diagram that affects the WACC.

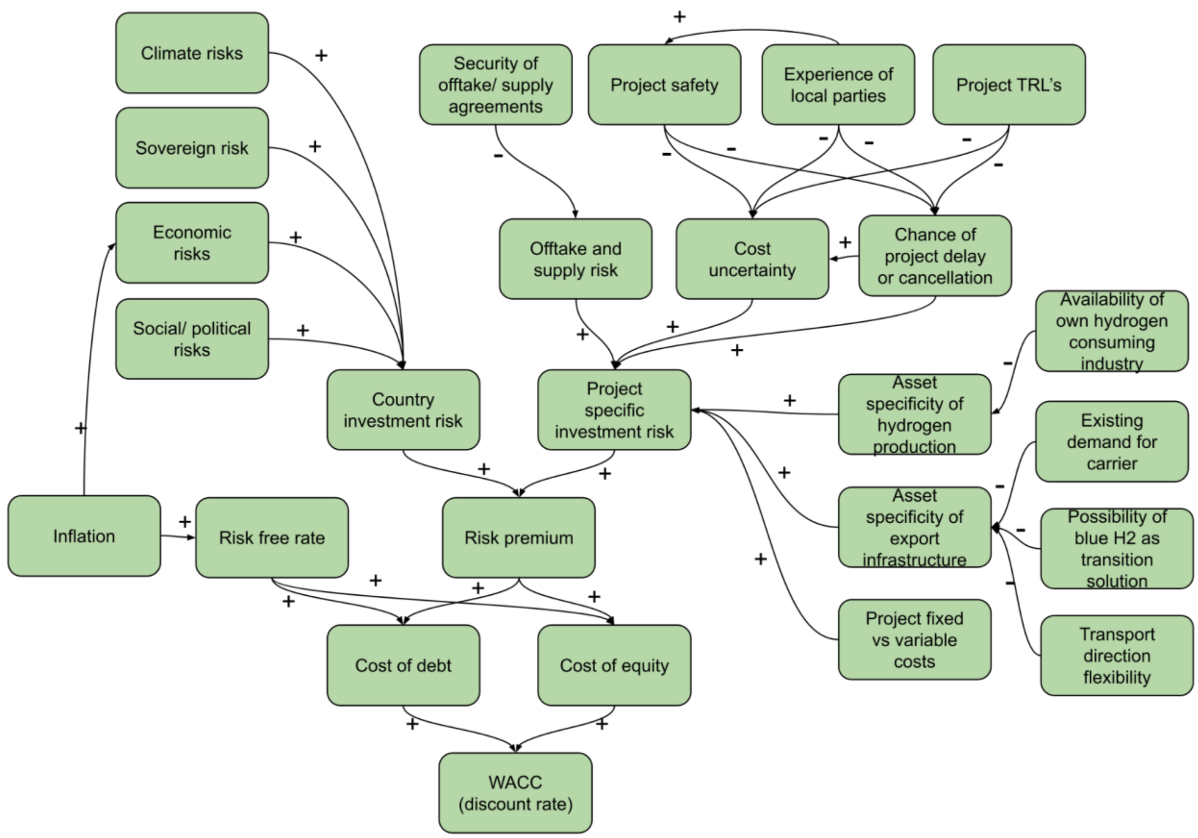

Figure A2.3: The section of the system diagram that affects the WACC.

A2.1.2 Country risk

Country specific risk can play an important role in WACC calculations. Steffen (2020), for example, finds that the WACC for solar PV projects in non-OECD countries can be 40% lower than that in OECD countries. Ondraczek et al. (2015) also identify even more substantial differences in WACC when evaluating PV projects, with a WACC of 4,3% for the Netherlands compared to an average of 14,1%. Steffen (2020) concludes that while a trend of higher WACC in developing nations is observed, significant variations exist among countries with similar economic development.

To account for country-specific risk, WACC calculations incorporate a country risk factor, which remains consistent across projects within a given country. Various institutions, such as the OECD, trade firms, and insurance companies present what they believe should be this factor (Allianz Trade, 2023; Atradius, 2023; OECD, 2023). It encompassess political, economic and sovereign risks (Perry, 2022). Sovereign risk specifically addresses the possibility of government payment defaults, while economic risks pertain to a country's economic stability, including inflation levels (EDUCBA, 2022). Political risks encompass factors such as frequent government changes or civil wars. Perry (2022) lastly explains that also climate risks, such as earthquakes are taken into account.

A2.1.3 Project risk

Project-specific risks also impact the WACC, as recognized by Steffen (2020) and the IEA (2021b). They for example see that solar PV projects tend to have a lower WACC compared to onshore wind energy projects, which, in turn, have a lower WACC than offshore wind projects.
On the construction and operation side, project timing, quality, and cost certainty play important roles (Thomson Reuters, 2014). Steffen (2020) sees that the level of development of the technology is an important influence to this. Additionally, project safety considerations, such as those raised by the DCMR (the environmental protection agency of the Rotterdam region) regarding large-scale ammonia imports can lead to project delays and increased costs (NL Times, 2023;Thomson Reuters, 2014). The experience of involved parties is also considered significant (Thomson Reuters, 2014). The security that supply or offtake agreements give is furthermore an important consideration (Thomson Reuters, 2014). Also the ratio between fixed and variable costs can also influence the WACC, as capital costs may become sunk costs while variable costs can be avoided (Tuovila et al., 2022).

These risks are project specific rather than country specific, and will thus not be quantified in this analysis. However, note that the country-specific transport distance will indirectly impact financing costs by influencing the mode of transport.

A last aspect influencing project risk is asset specificity, as explained by Williamson (1979). Asset specificity refers to the degree to which a specific asset can be repurposed for other uses. In hydrogen supply chains, several factors can lower asset specificity. For example, if a country has significant hydrogen consumption, such as the United States, Saudi Arabia, or Canada, it can serve as an alternative offtaker for hydrogen if the exporting value chain encounters difficulties (Sönnichsen, 2020). This effect may be even larger in countries with a specific demand for a hydrogen carrier, as is the case with Morocco, a large importer of ammonia (Atchison, 2022). Hydrogen projects within a country may not be located close to hydrogen production sites. For instance, in Canada, hydrogen demand is concentrated around inland refineries, while most large-scale hydrogen projects are situated on the east coast (Auch, 2017; Hy2Gen, 2023; Parkes, 2022; Penrod, 2023). Transportation challenges may persist, thus still result in sunk costs for projects. Additionally, local demand may compete with exports, which may not favour the likelihood of a country becoming an exporter. This conflicts with the advantage of local demand for the hydrogen and can therefore lead to confusion for workshop participants. IRENA (2022d) furthermore recognizes the advantage of experience with hydrogen, including the presence of companies, workers, and knowledge that can assist in setting up hydrogen exports. An own current hydrogen demand is therefore also considered as providing a head start, which would lead to double counting. Given the difficulty of properly quantifying this aspect, the potential for double counting, and the confusion it may cause, it is not included in the MCA.

Another example of asset specificity is the ability to use blue, fossil based, hydrogen as a transition solution. This enables the realisation of the exporting infrastructure for a lower cost product. If cost reductions of green hydrogen fall behind, it serves as a backup solution to retain the blue hydrogen value chain. A large pipeline project between Norway and Germany that will initially transport blue hydrogen exemplifies this (Radowitz & Collins, 2023). Similarly, fertiliser producer OCI is constructing a large-scale blue ammonia facility with the promise of later transitioning to green ammonia (OCI, 2022). However, it is important to note that significant capital expenditures are required for carbon capture and storage facilities. This means that blue hydrogen is only a short-term transition solution when alternative buyers for the blue hydrogen can be found. In the OCI project the blue hydrogen is delivered by Linde, who could for example believe the blue hydrogen can later be sold to the local market. Another school of thought is that these blue projects are not truly a transition solution but that they aim at securing long term use of fossil assets (McKenna et al., 2022). Through all these complications this criterion can not truly be quantified and is therefore omitted.

In terms of hydrogen transport, the mode of transportation impacts asset specificity. The demand for ammonia as an end product instead of carrier is an example of this. If the reconversion of ammonia to hydrogen proves to not be economically competitive, the infrastructure for exporting green ammonia will not be sunk costs. The flexibility of shipping compared to pipelines also reduces asset specificity, as shipped hydrogen can be redirected to meet changing demand in different countries.

A2.2 A head start

An aspect that was not included in the head start was the sustainability of the local grid.
The sustainability of the local grid can also offer a head start. If a grid connection is available, it can serve to increase operating hours or maintain a minimum capacity for production plants during periods of low renewable availability. When this power has a lower carbon footprint it directly leads to a reduction in the carbon footprint of the hydrogen. However, this is feasible only if a substantial grid connection is available at the hydrogen production site, which is often remotely located. Furthermore, the sustainability of the grid power during periods of low renewable availability may be a subject of debate, as this low availability of renewables likely affects neighbouring areas as well at these times.

An advanced green electricity system can, however, foster social acceptance of hydrogen exports. As discussed in Section 5.2.2.2, hydrogen export is sometimes viewed as diverting renewable energy away from developing areas. However, this concern becomes less of an issue when renewables are already widely implemented. Due to the uncertainty of this aspect's direct impact and in order to limit the number of variables requiring weighting in the head start section, this criterion is not included in the MCA.
Figure A2.4 shows the section of the system diagram that affects the head start of a certain country.

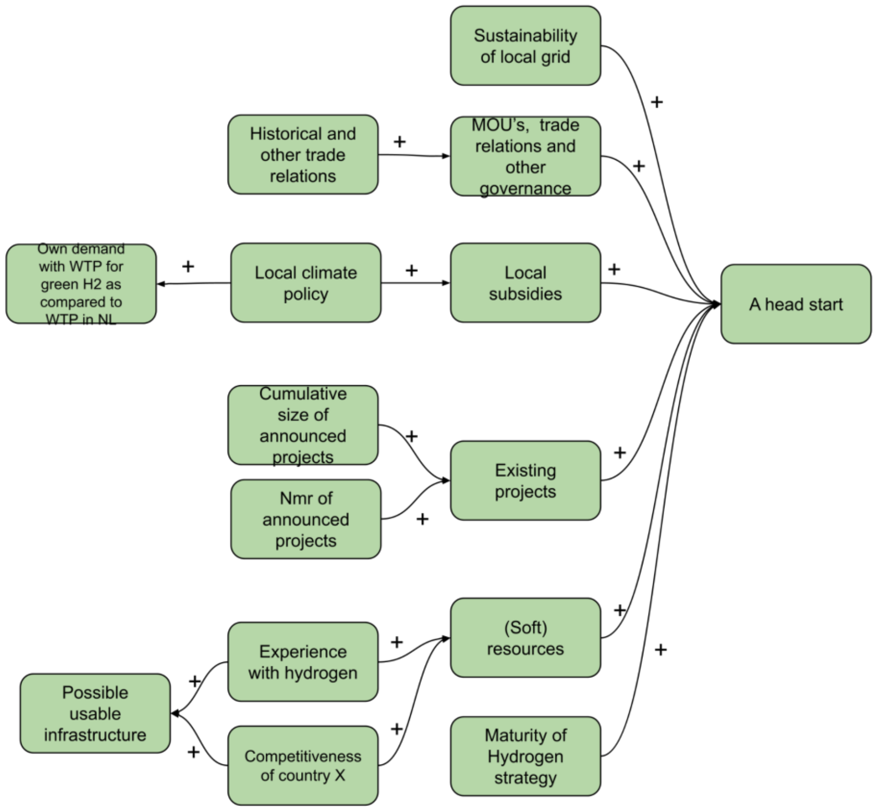

Figure A2.4: the section of the system diagram that affects the head start of a certain country.

A2.2.1 Bilateral agreements & trade relations

Notable examples of MOUs are the support for the establishment of Dutch value chains can be observed in Namibia, where the public organisation Invest International is investing €40 million in the development of a hydrogen economy (Invest International, 2023). Additionally, more and more agreements on hydrogen collaborations between nations are being signed. For instance, there was a Memorandum of Understanding (MoUs) established with Saudi Arabia in May 2023 (Reuters, 2023b). A similar MOU was signed in June 2023 with Spain during a visit of a large delegation of the Dutch government including the king (Biogradlija, 2023b).
IRENA (2022a) recognizes nine other similar bilateral agreements, as depicted in Figure A2.5. Furthermore, port organisations are also engaging in agreements, such as the Port of Rotterdam's collaborations with many projects around the world of which projects in Mauritania and Spain are an example (Biogradlija, 2023a; Prevljak, 2022).

Apart from the discussed forms of trade agreements is another form of political support received by the countries that are specifically mentioned in the REPowerEU ambition for the import of 10 Mt of renewable hydrogen, namely northern Europe, the Mediterranean region, and Ukraine, are examples of this (European Commission, 2022).

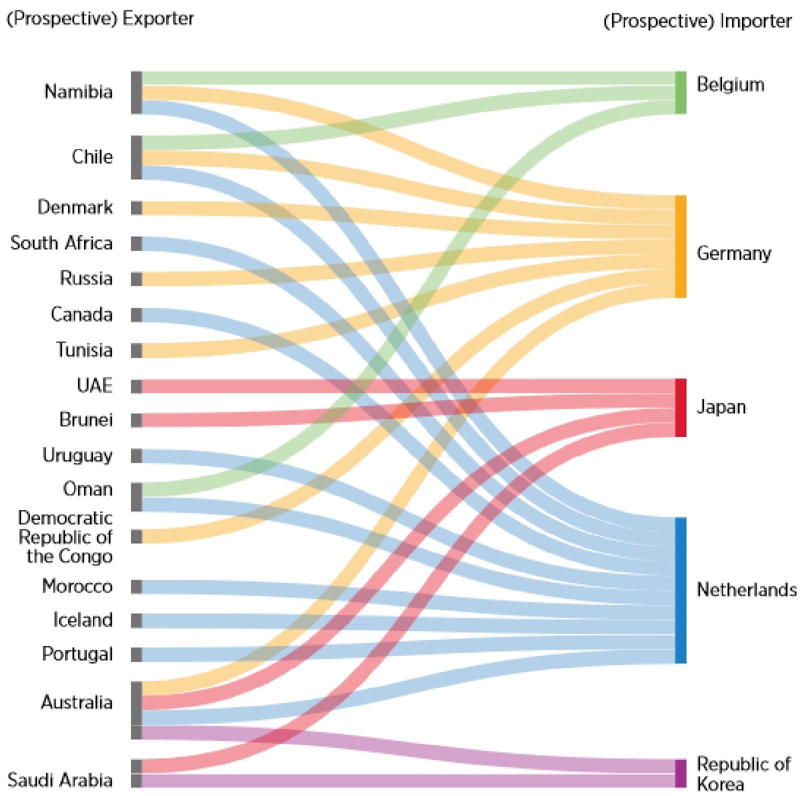

Figure A2.5: Global trade relations as recognised by IRENA (2022a).

A2.2.2 Local subsidies

Some amendments to the known subsidies are for example Canada that offers a 40% production tax reduction for hydrogen production and is planning a 12,6 billion USD hydrogen support package (Fowler et al., 2023; IEA, 2022b). Hydrogen Central (2023) furthermore indicates that Spain has already dedicated 1555 million euros to hydrogen development, including 450 million euros to a project in northern Spain (Reuters, 2023a). Australia lastly has a hydrogen headstart programme worth approximately 1,33 billion USD, along with various other support projects totaling around 650 million USD, including a specific hydrogen trade subsidy (Australian Government, 2023; IEA, 2022a).

A2.2.3 Existing projects in the pipeline

Figure A2.6 shows the proposed capacity and number of projects for a larger number of interesting countries. Australia is the frontrunner in terms of proposed electrolyser capacity and the number of projects, followed by the U.S., Argentina, Chile, Oman, Egypt, Spain, and Denmark. Among South American countries, Argentina and Chile possess considerable proposed capacities, yet the fewer projects in Argentina decrease the probability of realisation. The same can be concluded for the projects in Mauritania and Kazakhstan.

Figure A2.7 depicts the proposed hydrogen production of all projects that have a capacity larger than 100 MW and an expected online date over time. It is seen that most assessed countries have a presented production capacity of 1-2 Mt per year, with Australia and Chile at the forefront. Conversely, Saudi Arabia, Morocco, Namibia, and Norway lag behind. In Norway, Namibia, and Morocco, the largest projects will come online post-2030, while in Saudi Arabia, only the NEOM project has been announced. It can lastly be concluded that the capacity growth is expected to be relatively spread over time.

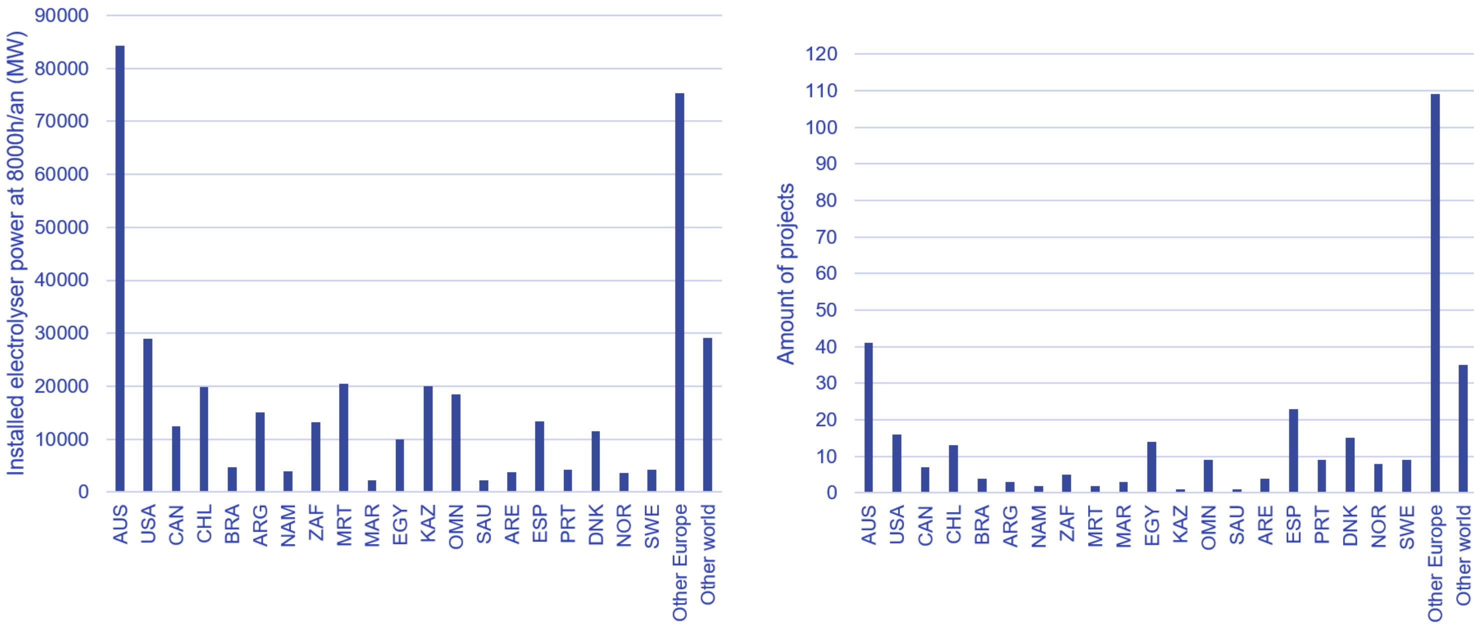

Figure A2.6: All proposed projects with a >100 MW capacity from different countries.

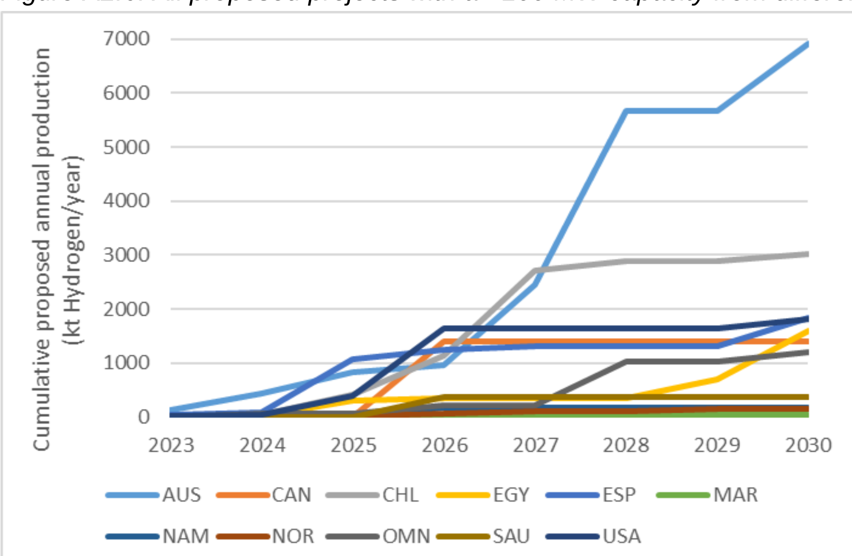

Figure A2.7: The proposed hydrogen production of all projects that have a capacity larger than 100 MW and an expected online date over time.

A2.2.4 (Soft) resources

Additional soft resources that are not included within the GCI include experience with hydrogen or related projects, and availability of (repurposable) infrastructure, wherefore the criterion of experience with hydrogen is amended (IRENA, 2022b). Mainly current fossil exporters will have an advantage here. Also trade relations, geopolitics, and local sustainability policy mentioned as important factors (IRENA, 2022b). Figure A2.8 shows all soft resources recognised by IRENA (2022b).

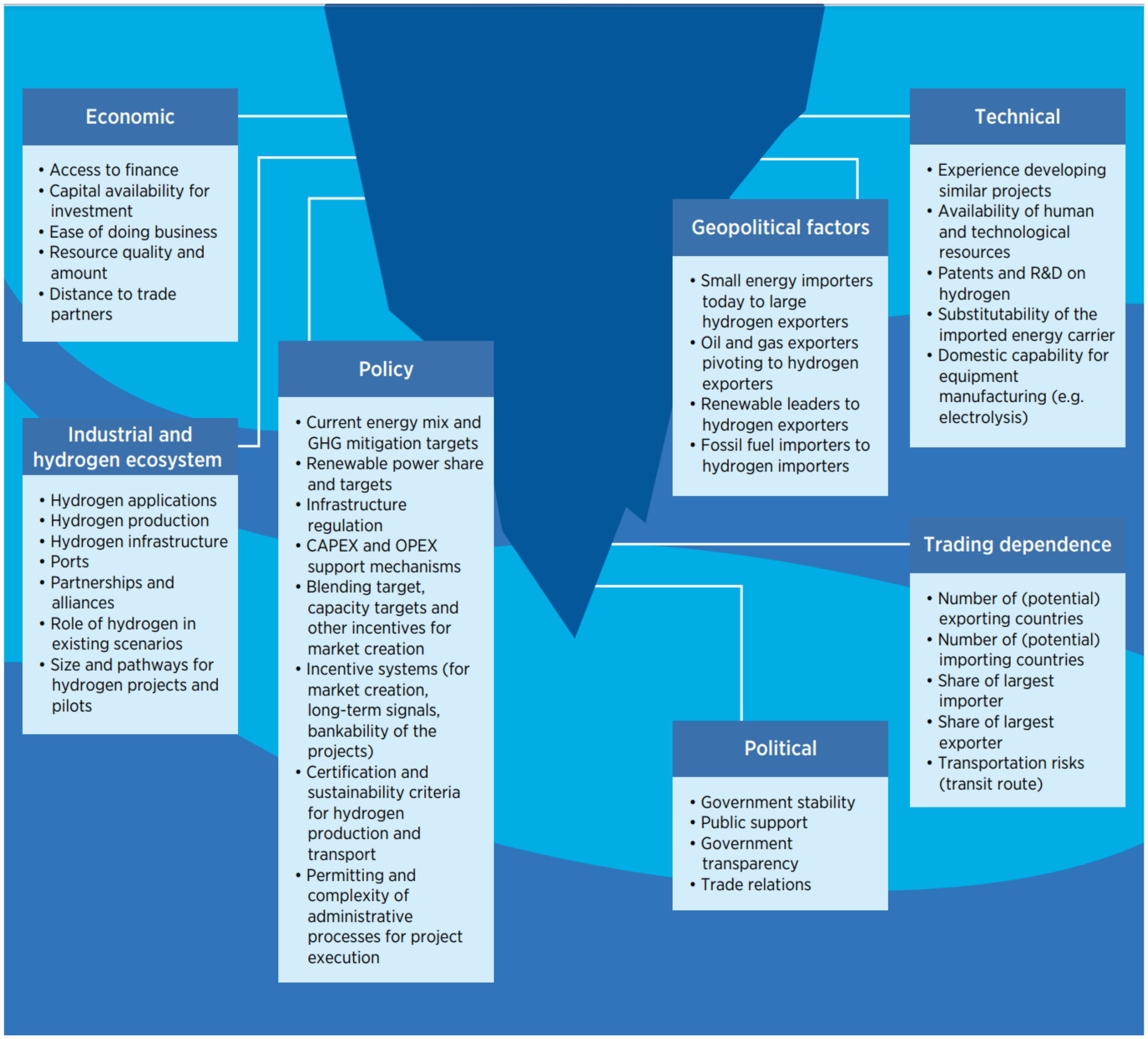

Figure A2.8: All soft resources recognised by IRENA (2022b).

Appendix 3: MCA weighing participants

Table A3.1: participants of the MCA

Name	**Function**
Stephanie Kool-Claessens	Manager Commercial Business Development
Xander Japin	Commercial Business Developer
Willem Frens	New Business Developer at HyCC
Rutger Oorsprong	Strategic Advisor at Port of Amsterdam
Roman van Riel	Business Development Manager Electrification and Hydrogen at Port of Rotterdam
Marthe Fruytier	Business Analyst New Energy at the Port of Rotterdam
Christopher Christiaansen	Consultant at Darel energy transition consultancy
Robin van Laar	Intern Global ammonia trade at Quo Mare
Robert Peeters	trainee at Ministry of Economic Affairs and Climate - Unit Hydrogen
Carla Robledo	Senior Policy Advisor at Ministry of Economic Affairs and Climate

Appendix 4: Sensitivity analysis to MCA

Table A4.1: Quantification and normalisation of the criteria for local subsidies

Country	Local financial support		Sensitivity analysis: M$/b$ GDP (1EUR= 0,92$)
	(IEA, 2022a, 2022b; IRENA, 2022a)	Normalised	
Spain	~1555 MEU	1	1,2
Norway	9 MEU H2 infra + ~111 MEU H2 + NH3 production (Reuters, 2021)	0,5	0,27
Australia	1,33 b USD + ~349 M USD H2 hubs + ~206 M USD Advancing H2 fund + ~100M USD hydrogen trade program	1	1,3
United States	3 USD/kg tax credit (IRA has no cap, but Clifford (2023) expects ~100 b USD)	1	4,3
Canada	40% production tax discount + ~12,6 b USD announced between 2023-2035 (Fowler et al., 2023)	1	6,3
Morocco	0	0	
Egypt	0	0	
Namibia	0	0	
Chile	50 M$	0,5	0,16
Saudi Arabia	0	0	
Oman	0	0	

Appendix 5: The costs of capital (WACC)

The weighted average cost of capital (WACC) is highly important in the costs of hydrogen value chains, as also elaborated on in Appendix A2.1.1 on the multicriteria analysis. For solar PV projects, the capital costs can account for up to 50% of the electricity price, with the WACC varying notably across countries (IEA, 2021c; Perry, 2022). Such variations stem from country-specific risks, including economic and political stability (Perry, 2022). Additionally, different technologies can have varying premiums based on differing risk profiles (IEA, 2021c; Steffen, 2020).

In levelized cost calculations, future profits and expenses are discounted using a specific factor to reflect their present value. This factor accounts for the potential earnings if the funds were invested otherwise, often referred to as opportunity costs. Since WACC embodies this minimal return on an investment, it's utilised as the discount factor in such analyses (Hargrave et al., 2022).

Formula A5.1 elucidates the WACC computation. It always comprises factors for both equity and debt, with the latter typically being lower (Hargrave et al., 2022). This is attributed to the preferential claim debt has over equity during returns, hence equity inherently bearing greater risk (Hargrave et al., 2022). The share of debt in an investment is also known as the gearing (Hargrave et al., 2022). While this ratio varies, The Investopedia Team (2023) posits that a gearing below 66,7% is typically desired, with an exemption for the manufacturing industry. PBL (2023) notes that the gearing for renewable projects in the Netherlands often ranges from 60-95%, with a presumed 70% average for hydrogen projects, a value adopted in this report.

Lastly, for post-tax LCOH evaluations, the debt factor is adjusted by the tax shield, reflecting the ability of companies to deduct debt costs from their pre-tax income, effectively reducing the actual debt cost. Corporate tax rates are publicly accessible, with sources like Enache (2022) providing comprehensive listings.

$$WACC = E\% * Re + D\% * Rd \quad (A5.1)$$

E%	Share of equity
Re	The return on equity
D%	The share of debt, or gearing
Rd	The return on debt
Tc	Corporate tax rate

A5.1 Return on equity

The Capital Asset Pricing Model (CAPM) is often employed to compute the return of equity, illustrated in Formula A5.2 (Hargrave et al., 2022). The CAPM comprises the risk-free rate (often represented by long-term government bonds), the expected market return (typically based on a broad stock market index like the S&P 500), and a beta factor that adjusts for specific industry risks (Kenton et al., 2023). Emerging and innovative sectors, such as hydrogen, are generally more volatile and have higher betas (Kenton et al., 2023). The difference between the expected market return and the risk-free rate is called the market risk premium.

$$Eri = Rf + \beta*(Erm - Rf) \qquad (A5.2)$$

Re	Expected return on investment, or return on equity.
Rf	Risk-free rate
β	The industry Beta
Erm	Expected market return
(Erm - Rf)	The market risk premium

The risk-free rates for hydrogen projects in different countries can be approached by correcting the United States treasury bill with the inflation differential as presented by Damodaran (2023). This is a valuable proxy because this bond is seen as the lowest possible investment risk (Hayes et al., 2023). As of July 2023, the U.S. treasury bill yielded 3,95%.

The S&P 500's historical average return, approximating 10.05% over the past twenty years, serves as the expected market return (Kenton et al., 2023; Mitchell, 2023).

Determining the beta for the clean hydrogen sector is challenging. While the beta of some publicly listed companies is known, many companies in hydrogen are general energy companies that also possess fossil assets, which will skew the figures. Blackridge (2023) presents a list of the largest companies in green hydrogen wherefrom the listed, pure-play hydrogen firms are filtered: Bloom Energy, NEL, Mc Phy, Plug Power and Adani. These companies yield an average beta of 1,81 (Yahoo! Finance, 2023).

In addition to market risk, investments face country-specific risks that necessitate accounting for a country risk premium. Within the CAPM framework, this premium is integrated by adding the country risk to the expected market return, as depicted in Formula A5.3 (Picardo & Kelly, 2020). As detailed in Appendix 2.1.2, the country risk premium encompasses a myriad of factors, such as sovereign, political, and economic risks. In this study, the country risk premium is derived from Damodaran (2023).

$$Re = Rf + \beta*(Erm + CRP - Rf) \qquad (A5.3)$$

Re	Expected return on investment, or return on equity
Rf	Risk-free rate
β	The industry Beta
Erm	Expected market return
CRP	Country risk premium

Table A5.1 shows the results of the calculations on the return on equity. It is noted that the Dutch figure aligns with PBL's (2023) 14,5% recommendation for hydrogen subsidies.

Table A5.1: the return on equity for different countries.

Country	Risk-free rate	Beta	Expected market return	Country risk premium	**Return on equity**
Netherlands	3,95%	1,81	10,05%	0%	14,99%
USA	3,95%	1,81	10,05%	0%	14,99%
Chile	4,99%	1,81	10,05%	1,46%	16,79%
Spain	5,91%	1,81	10,05%	2,76%	18,40%
Australia	3,95%	1,81	10,05%	0%	14,99%
Morocco	7,01%	1,81	10,05%	4,32%	20,33%

A5.2 Return on debt

The cost of debt comprises the risk-free rate and a premium for the risk that a bank or another credit giver takes, which is also called the credit spread (Vaidya, 2020). The credit spread thus reflects the difference in risk between lending to the government versus a company (Vaidya, 2020).

Rd = Rf + Cs

Rd Return on debt
Rf Risk-free rate
Cs Credit spread

Determining the precise return on debt is intricate. In practice, the return on debt arises from dialogues, where factors such as project equity-to-debt ratios, corporate financial health, loan duration, and project risk are considered. Generally, higher equity proportions reduce debt costs. (M. Abbink, expert interview, June 28, 2023)

With the average cost of debt of the listed hydrogen companies the credit spread can be approached. This is done by subtracting the risk-free rate of that country from the corporate bonds in that country, as seen in Formula A5.4.

Cs = Rdx - Rfx (A5.4)

Cs Credit spread
Rdx Return on debt in country x
Rfx Risk free rate in country x

Assessing the relevance of companies with fossil assets in calculating the credit spread poses challenges. Diversified portfolios might lower lending risks, but might not genuinely reflect hydrogen projects' risk factors. For this analysis, larger companies with fossil assets are presumed to have lower debt costs and are thus incorporated. This led to amending the following companies on top of the companies used to calculate the industries Beta: Shell, Airproducts, Linde, Airliquide, Reliance Industries and Sinopec (Blackridge, 2023). Their cost of debt, sourced from Value Investing (2023) and adjusted for their respective country risk-free rates, resulted in an average credit spread of 1,45%. The calculations reaching this average credit spread is found in Table A5.3.

Although many scholars, such as Picardo & Kelly (2020) or Vaidya (2020), apply the country risk premium solely to equity in the WACC, this seems an oversight. Given the European Central Bank's (2018) identification of sovereign risk as influential to debt cost, and EY's (2022) acknowledgment of country risk's pertinence to both equity and debt, this analysis includes the CRP in the return of debt calculations. EY's (2022) method is adopted, where the country risk premium is adjusted by a factor of 0,86 and added to the cost of debt. This approach is found in Formula A5.5.

$$Rd = Rf + Cs + 0{,}86 * CRP \qquad \text{(A5.5)}$$

Rd	Return on debt
Rf	Risk-free rate
Cs	Credit spread
CRP	Country risk premium

Table A5.2 depicts the computed return on debt values. Notably, the Dutch value again aligns with PBL's (2023) 6,0% estimation.

Table A5.2: The return on debt for different countries.

Country	Risk-free rate	Credit Spread	Country risk premium	**Return on debt**
Netherlands	3,95%	1,45%	0%	**5,40%**
USA	3,95%	1,45%	0%	**5,40%**
Chile	4,99%	1,45%	1,46%	**7,70%**
Spain	5,91%	1,45%	2,76%	**9,73%**
Australia	3,95%	1,45%	0%	**5,40%**
Morocco	7,01%	1,45%	4,32%	**12,18%**

Table A5.3: Calculation of the credit spread of the green hydrogen industry.

Company	Return on debt	Country listed	Risk-free rate of that country	Credit spread
Plug Power	6,65%	USA	3,95%	2,70%
Mc Phy	5%	USA	3,95%	1,05%
Bloom Energy	6,7%	USA	3,95%	2,75%
Shell	4,85%	UK	4,68%	0,17%
Air Products	4,45%	USA	3,95%	0,50%
Air Liquide	4,25%	France	4,55%	-0,30%
Adani	12%	India	6,64%	5,36%
Linde plc	4,45%	UK	4,68%	-0,23%
Reliance industries	8,55%	India	6,64%	1,91%
Sinopec	5%	China	4,81%	0,19%
Average credit spread				1,45%

A5.3 The real WACC

The combined return on debt and equity is incorporated into the WACC formula detailed in Appendix 5.1. For accurate discounting with WACC, inflation considerations are vital (PBL, 2023). There are two methods to account for this: either adjust future cash flows by the inflation rate and use the nominal WACC, or adjust the nominal WACC directly by the inflation rate to yield the real WACC (PBL, 2023). Long-term average inflation rates, spanning a minimum of ten years from CEIC (2023) are utilised in Formula A5.6 for real WACC calculation. While inflation data over the identical periods would be ideal, the desired uniformity isn't achievable with the available resources. Table A5.4 outlines the nominal and real WACC across various countries. Appendix 5.5 delves into additional factors that may influence the WACC but are omitted here for the sake of simplicity.

1 + Real WACC = 1 + Nominal WACC / 1 + Inflation rate   (A5.6)

Table A5.4: The nominal and real WACC for different countries.

Country	Return on equity	Return on debt	Share of debt (gearing)	Corporate tax	**Nominal WACC (pre-tax)**	Inflation rate	**Real WACC (pre-tax)**
Netherlands	14,99%	5,40%	70%	25,8%	**8,28%**	1,59%	**6,58%**
USA	14,99%	5,40%	70%	21%	**8,28%**	2,70%	**5,43%**
Chile	16,79%	7,70%	70%	27%	**10,43%**	2,52%	**7,71%**
Spain	18,40%	9,73%	70%	25%	**12,33%**	1,32%	**10,87%**
Australia	14,99%	5,40%	70%	30%	**8,28%**	2,32%	**5,82%**
Morocco	20,33%	12,18%	70%	31%	**14,63%**	1,30%	**13,15%**

A5.4 Investment duration

Once the WACC is determined, another pivotal element is required for the calculation of the levelized cost of hydrogen: the period over which equity and debt holders expect a return on their investment. According to PBL (2023), a 15-year timeframe is a realistic investment duration for energy transition projects. However, in practice some projects might also face shorter payback periods of 11 to 14 years because a shorter duration generally implies a reduced risk for investors (PBL, 2023).

Government-related projects often operate on different timelines, with extended payback periods. For instance, Gasunie, the Transmission System Operator for the Dutch gas grid, adopts a 30-year investment duration for compressor stations and roughly 50 years for pipelines (Gasunie, 2021).

A5.5: Risk reduction that will affect WACC

Transaction costs and vertical integration

In Appendix 2.1.2, Williamson's (1979) delineation of asset specificity and uncertainty was explored, emphasising their impact on a project's risk and consequently, its WACC. Williamson identifies transaction costs as pivotal, encompassing expenses associated with information acquisition, negotiation, and enforcement of contracts in multi-stakeholder supply chains, such as those for hydrogen.

To mitigate these transaction costs, Williamson (1979) recommends strengthening ties between parties, achievable through vertical integration strategies like acquiring other companies needed in the supply chain, forming joint ventures or through long-term contracts (Williamson, 1979). Such measures can mitigate offtake risks, bolster trust, and facilitate resource and information sharing. Given the pronounced uncertainty and asset specificity in emerging hydrogen import value chains, such enhanced integration is likely to be seen.

Government involvement

Governments play a crucial role in reducing project risks and thereby the WACC. Measures ranging from CAPEX/OPEX subsidies, which drive down product costs, to broader strategies and regulations, serve to decrease capital costs and enhance project feasibility. For instance, the Dutch SDE++ operates as a contracts-for-difference mechanism, offsetting uncertainties such as the uncertain cost of carbon emissions within the European Emission Trading System (EU ETS) (EC, 2022b; PBL, 2023). Furthermore, the EU Carbon Border Adjustment Mechanism (CBAM) furthermore creates a level playing field for European producers under the ETS, minimising the risk of off-takers sourcing outside Europe (EC, 2022a). National hydrogen strategies solidify development targets, reducing legal and regulatory risks in exporting countries. MOUs further reflect collaboration intent, reducing potential interruptions due to governmental interventions. The effect of these measures on the WACC will likely differ per country and are difficult to assess.

Appendix 6: Supplying the minimal electrolyser load, Intermediate transport and hydrogen storage

A6.1 Supplying the minimal electrolyser load

Technical limitations may require a minimum operating power for the hydrogen production facility (ISPT, 2022). The intermittent nature of renewable power generation may sometimes fall short of this threshold. When it does it should therefore be assessed how to deal with the minimal electrolyser load.

For grid-connected electrolysers, they can maintain the minimum operation by purchasing power during periods of low generation, and conversely, sell surplus energy during overproduction.

However, when assessing the direct-line electrolysers expected in the export projects, there are three approaches: Complete shutdown of the electrolyser, reserve a grid capacity equivalent to the minimum load, or use power storage to manage the minimal load.

If the electrolyser operation falls below the minimal load, it is possible to shut down the stack, but this significantly intensifies the stack degradation (Kojima et al., 2023; PBL, 2023). According to PBL (2023), this could lead to an annual doubling of degradation rates from 1% to 2%, necessitating more frequent stack replacements. For this scenario, it is assumed that stack replacements will be economically justifiable in the 6th and 11th years of operation. As the green hydrogen economy matures, further cost reductions are anticipated, making it increasingly likely that subsequent stack replacements will incur lower costs compared to the initial stack purchase (De Groot et al., 2022).

Another option is reserving grid capacity the size of the minimal load. However, in practice it is seen that reserving a grid connection, if it is even available, can be prohibitively expensive. Therefore a grid connection will likely not be used to produce the minimal capacity, but a smaller grid connection could serve as an emergency backup to prevent a full shut down (K. Langhout, expert interview, July 25, 2023).

Furthermore, sustainability poses a challenge. When local renewable energy production is low, it's expected to be similarly low in neighbouring wind and solar parks. Even in regions with ample existing hydropower, cannibalising these resources for export does not constitute a long-term sustainable solution (K. Langhout, expert interview, July 25, 2023).

Alternatively, a battery system could provide stored power to the electrolyser when required. While this could mitigate the intermittency of solar PV, the substantial upfront investment costs for the battery system remain a challenge. Considering the trade-offs associated with battery systems and grid connections, shutting down the electrolyser stacks emerges as the most cost-effective solution for export projects. For projects in the Netherlands that are already connected to the grid, however, it is probable that the grid would supply the minimal capacity required.

A6.1.1 Cost of power storage

The largest cost component of large-scale utility battery storage systems are the battery cells, accounting for roughly half of system costs (NREL, 2023). A cost outlook from the National Renewable Energy Laboratory of the United States is used as a reference, with the cost price of utility scale electric power storage capacity at around €290/kWh by 2030 (NREL, 2023). This price is assumed to be consistent globally. Although an average efficiency of 85% is realistic, efficiency loss was neglected for ease of modelling in this analysis (NREL, 2023). The OPEX is 2,5% of CAPEX and no replacement is needed as the battery has a 15 year lifetime (NREL, 2023).

The storage requirement is determined through modelling using hourly renewable energy data. A buffer capacity of an additional 10% is incorporated into the required storage. The analysis indicates that a storage capacity of 471-1.354 MWh is necessary, accounting for 3-6% of the LCOH of the hydrogen produced across the studied locations.

Figure A6.1 presents the state of depletion of the battery systems in Spain and Chile, reflecting the power utilised compared to a fully charged battery. While more spikes are seen throughout the year in Chile, the storage in Spain is needed for one specific 'dunkelflaute' in winter, when renewable availability is low for a longer time. It is highly inefficient to maintain power storage that is so minimally used, especially as seen in Spain, but also to a lesser extent in Chile.

One possible mitigation is to utilise the storage to extend the electrolyser's operating hours, potentially by using the battery to bridge day and night variances in PV. However, also consuming power when the load exceeds the minimum 10% could risk depleting the battery when it is most needed, making this evaluation complex and beyond the scope of this analysis.

Alternative solutions could include a full or near shut down of the electrolyser during peak times, or possibly deploying a hydrogen-based backup generator to power the electrolyser with its own stored product. However, these proposed solutions also fall outside the scope of this research.

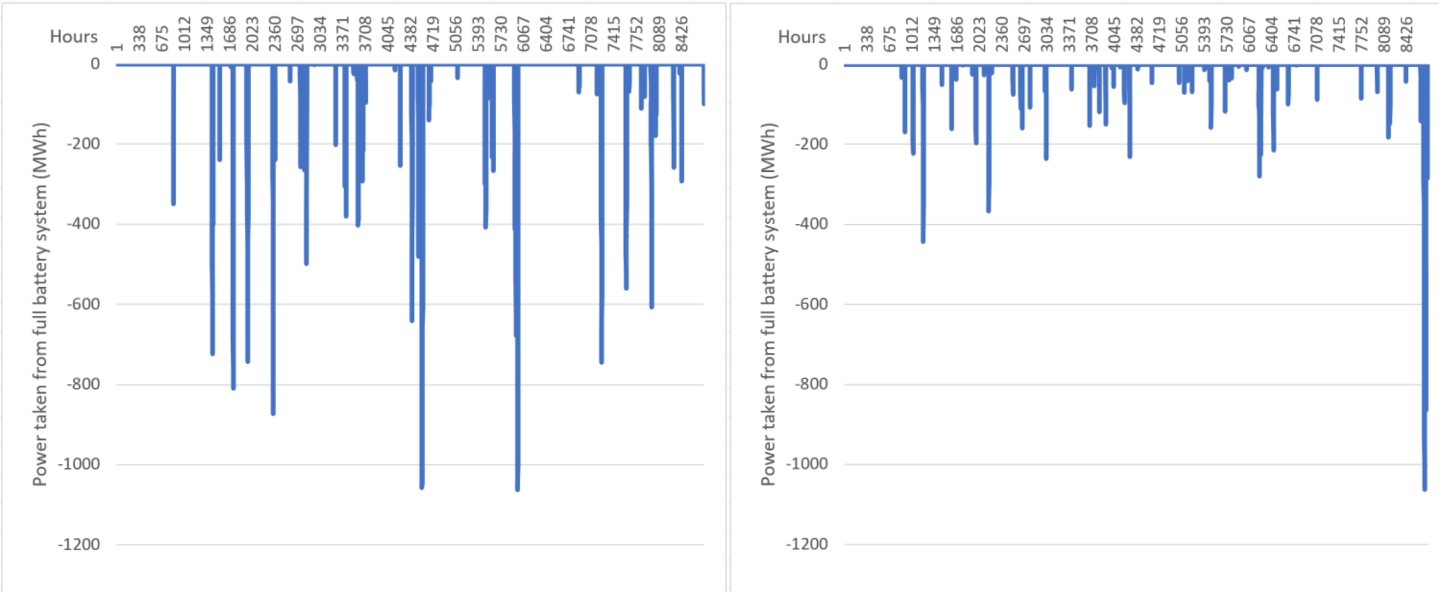

Figure A6.1: The emptiness of the battery system in Chile (left) and Spain (right) for every hour

A6.1.2 Costs of utilising the grid

For Dutch electrolysis projects, supplying the minimal load is assumed to be done through buying power from the grid. A possible advantage of grid interaction is the ability to sell excess power. However, determining the value of this power during overproduction is complex, given that neighbouring renewable power generation will also perform well. On the other hand will prices likely peak when there is a low availability of renewables for the same reason. An example of extremely low prices is found in southern Australia, which experienced negative power prices over 20% of the time in summer (Hannam, 2023).

Predicting this with absolute accuracy is difficult, but a viable approach could involve analysing the merit order in these different countries (F. Hassan, expert interview, July 24, 2023). A merit order, as demonstrated in Figure A6.2, depicts the hierarchy of power sources based on their costs. During peak renewable periods, the total demand is probably covered by renewables, which generally bid at zero marginal costs (Cludius et al., 2014). Therefore, prices are likely to hover around zero or even become negative. Conversely, during periods of scarce renewable availability, nearly all other power plants would need to operate, setting the costs at the highest level within the merit order. This could be represented by the fuel oil plants in Figure A6.2's example.

For the 2030 Dutch scenario, it's presumed that power sold during peak renewable times will hold no value. Determining the cost of purchasing power from the grid presents challenges. Power from biomass is seen to be the most costly form of power production in the Netherlands in 2022 with a cost of €180/MWh (PWC, 2022). To simplify this analysis this value is assumed to represent the cost of grid power during periods of limited renewable availability in 2030. It must be noted that the issue of the sustainability of the power mix remains, but given that it is only needed occasionally and that only the minimal load is demanded it is for this research assumed that all produced hydrogen is green.

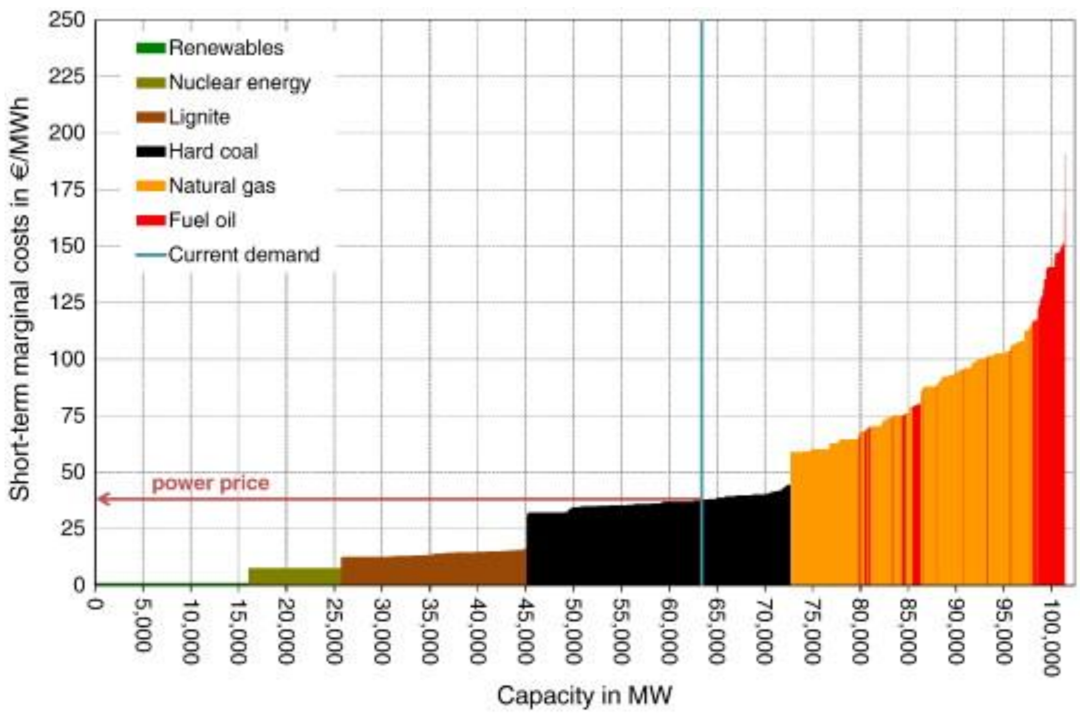

Figure A6.2: An example of a merit order (Cludius et al., 2014).

A6.2 Hydrogen storage

For domestic production, hydrogen storage is needed to be able to supply a baseload to a consumer. Additionally, hydrogen storage becomes necessary when the minimum operating capacity of the conversion plant surpasses that of the electrolyser.

Generally, hydrogen storage is achieved in one of two ways: in storage tanks or salt caverns (TNO & EBN, 2022). After 2030 storage in depleted gas fields is likely also possible (ENTEC, 2022). Salt caverns are large-scale storage spaces carved out from subterranean salt formations, and are currently used to store natural gas (TNO & EBN, 2022). In the Netherlands hydrogen will be stored collaboratively in salt caverns by Gasunie (2023b). For export projects, it could be deliberated if such shared infrastructure is feasible with the scale of initial projects. However, for this project it is assumed viable. The ability of using salt caverns is geographically contingent on the existence of underground salt formations. Figure A6.3, from Donadei & Schneider (2022), outlines these subterranean salt formations globally. Notably, all evaluated export locations have an accessible salt formation, except for Chile, where the assessed project is situated in the south.

TNO & EBN (2022) approximate the CAPEX of salt cavern storage around €8864 per tonnes hydrogen storage capacity. These encompass the production of the cavern and the facilities, but also the cushion gas to initially fill the cavern. In separate research TNO (2022) concludes that the CAPEX of tank storages is €470.000 per tonnes, which is over 50 times more than the cost of storing hydrogen in salt caverns.

These costs, for both salt caverns and tank storages, are assumed to be consistent across all countries and representative for the costs for storage in 2030.

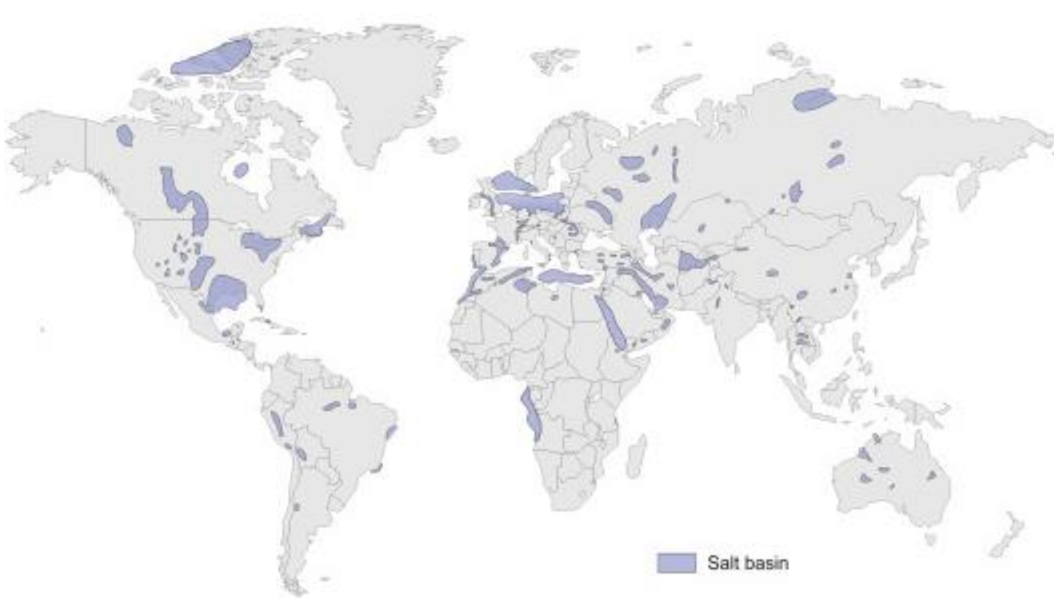

Figure A6.3: World map of underground salt deposits where hydrogen storage in salt caverns can be applied from Donadei & Schneider (2022).

Costs of hydrogen storage

The final cost component for deriving the functional unit of domestic hydrogen production is the costs of hydrogen storage to maintain a baseload supply to the Dutch hydrogen backbone. Figure A6.4 depicts the storage filling pattern throughout the year, starting from a 50% filled state. An additional buffer capacity of 10% is assumed for all hydrogen storages. Consequently, it is determined that a hydrogen storage capacity of 211 GWh is necessary in the Netherlands, which is filled during wind-abundant winters and utilised in the summers.

This data allows the computation of the functional unit for the Netherlands, translating to a cost of €3.741/tonnes for delivering a steady supply of green hydrogen. The hydrogen storage only added an additional 1,2% to the LCOH.

In the other assessed countries, the impact of hydrogen storage on the overall supply chain cost was minimal, as storage was not needed to supply a baseload. For ammonia production, a 40% minimum load led to a storage demand of 6-17 GWh. Even in Chile, which had the highest demand for hydrogen storage but lacked salt caverns and relied on tank storage, the cost of tank storage to supply a 40% minimum load was around half the cost of the battery system and contributes to about 6% of the costs of the hydrogen cost before conversion.

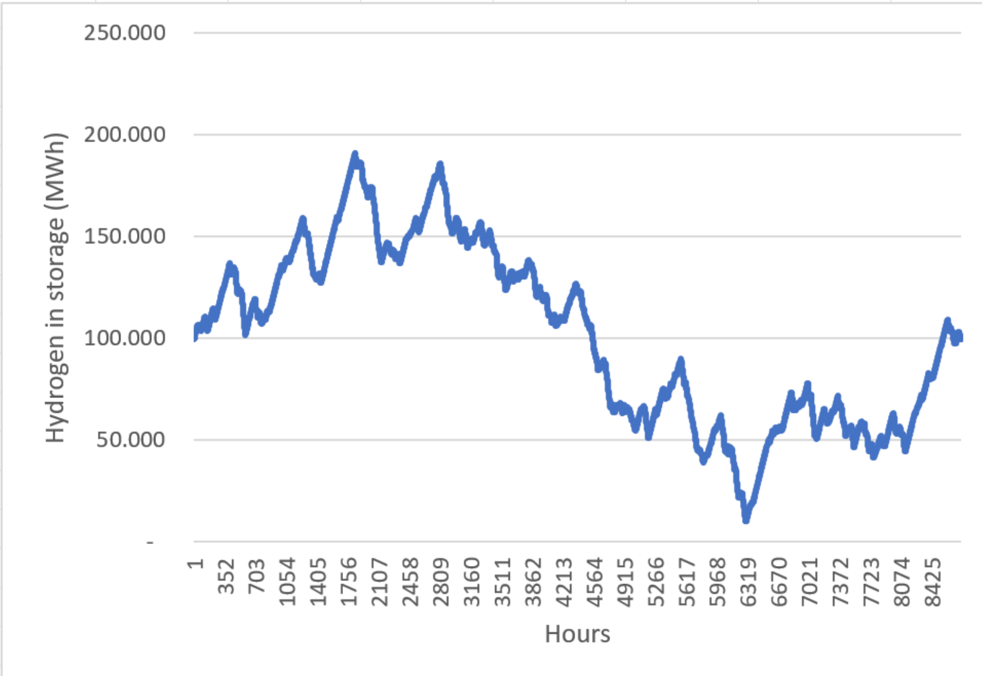

Figure A6.4: The hydrogen in storage for the reserved storage capacity in the Netherlands.

A6.3 Intermediate transport

Given that power generation is often located not directly next to exporting ports, intermediate energy transport is a necessary additional step for all three hydrogen import routes. It is in practice possible that power, hydrogen or the carrier is transported to the port. This will thus determine whether the electrolysis and conversion processes take place near the port or close to the renewable power production. When a certain carrier for intermediate transport is chosen it can still differ whether it is transported by pipe, ship or truck.

Interestingly, among the reviewed reports, only Daiyan et al. (2021) and ISPT (2019) consider intermediate transport in their analysis, which may be due to its relatively minor contribution to total costs.

The choice of transport can depend on several factors including distance, supply chain size, spatial constraints, the ability to repurpose or reuse infrastructure, safety considerations, or possibilities for heat integration (W.J. Frens, expert interview, 2023). As power transport is eight times more expensive than hydrogen transport, it is assumed for simplification that all transport to port occurs via hydrogen pipeline (DeSantis et al., 2021).

EHB & Guidehouse (2021) conducted an extensive analysis assessing the costs of pipeline hydrogen transport. Key design variables for hydrogen transport via pipelines include the pipeline's diameter and whether the pipelines are newly built or repurposed from existing natural gas infrastructure.

The smallest pipeline assessed by EHB approaches the size needed for a 1 GW electrolyser when operating at an operating capacity of 75% (EHB & Guidehouse, 2021). The advantage of this lower operating capacity is that over 4 times less compressor capacity and power is needed (EHB & Guidehouse, 2021). For assessing shared infrastructure projects a 48 inch pipeline is assumed that can transport up to almost 20 GW of hydrogen at HHV (EHB & Guidehouse, 2021). Distances to port are found through Google Maps (2023). It was found that between 33-236 km of intermediate transport was needed.

The cost of hydrogen transport to port

The availability of repurposable pipelines and shared infrastructure is uncertain and highly location-specific. Natural gas usage is projected to decrease marginally in Europe but remain constant or grow elsewhere. (EIU, 2023). Therefore, in the most likely scenario, repurposable infrastructure is only anticipated in Spain, and in the best-case scenario, in other countries.

Given the expected expansion of export projects, it's plausible that shared infrastructure will be available in the best and most likely-low scenario. However, in other scenarios, a smaller project-sized pipeline is assumed. Table A6.1 gives an overview of these scenarios.

The costs of intermediate transport, using newly constructed pipelines of an appropriate size, range between 1-10% of the pre-conversion hydrogen costs, with Spain registering the highest due to the longest pipeline length. Figure A6.5 shows these costs under different scenarios in Spain. It is seen that large cost savings can be achieved by repurposing pipelines, but that even larger savings are realised by utilising shared infrastructure.

Table A6.1: Assumptions taken on intermediate transport for the different scenarios.

Country	**Best case**	**Likely - low**	**Likely - high**	**Worst case**
Spain	Repurposed, Shared	Repurposed, Shared	New, appropriately-sized	New, appropriately-sized
Other countries	Repurposed, Shared	New, Shared	New, appropriately-sized	New, appropriately-sized

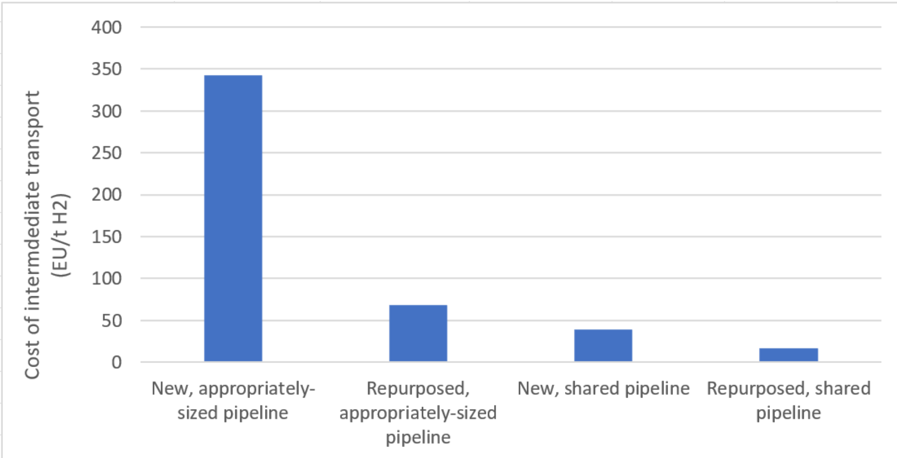

Figure A6.5: the costs of intermediate hydrogen transport from the HyDeal project to the Port of Santander in Spain.

Appendix 7: The costs of hydrogen imports

A7.1 Ammonia

A7.1.1 Costs of ammonia conversion

The assessment indicators needed to assess the costs of an ammonia synthesis plant are the CAPEX of the plant, the fixed OPEX and the energy demand. The paper review reveals that with an increase in plant size, costs generally tend to decrease, as illustrated in Figure A7.1. Excel modelling affirms this observation, yielding a 99.2% certainty for a scaling factor of 0,74, which provides enough proof for the most-likely scenario in this analysis.

The fixed OPEX ranges between 1,5-3% of CAPEX annually, with only the 1,5% falling outside of the most-likely scenario. On the matter of energy demand, a clear trend is noticeable, as seen in Figure A7.1. The IQR analysis revealed a most-likely cost range between 611-980 kWh/t NH3. Table A7.1 shows the assessed scenarios in this analysis.

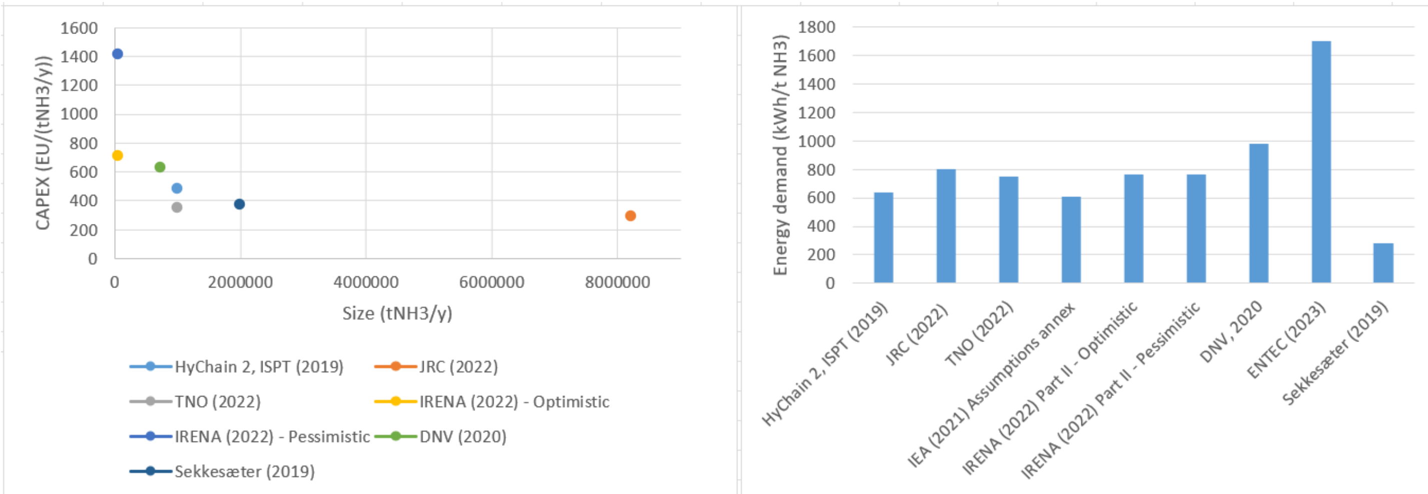

Figure A7.1: Left: Ammonia synthesis CAPEX assumptions compared with the plant size. Right: Assumptions on the ammonia synthesis energy demand.

Table A7.1: Scenarios for the assessment indicators of ammonia synthesis.

Process	**Best case**	**Likely - low**	**Likely - high**	**Worst case**	**Unit**
CAPEX	350	$y = (17419x^{0,7383})/x$		1419	€/(tNH3/y)
OPEX	1,5%	2%	3%	3%	% of CAPEX
Power demand	280	611	980	1700	kWh/tNH3

A7.1.2 Costs of ammonia storage

The assessment indicators needed to assess the costs of an ammonia storage tank are the CAPEX of the tank, the fixed OPEX, the energy demand for reliquefaction, and the storage capacity needed expressed in ship volumes. The CAPEX values depicted in Figure A7.2 suggest an apparent trend of decreasing costs with increased tank size. However, when these per-capacity CAPEX values are converted to absolute values, a paradoxical scenario of total investment decreasing with increased tank size emerges, negating the possibility of applying a scaling factor to the ammonia storage CAPEX.

Storage requirements range between 1-2 ship volumes. Given that a single ship volume is insufficient in all scenarios, the most-likely range stands at 1,5-2 ship volumes for exporting countries. Despite most reports assuming equivalent storage sizes for both exporting and importing countries, a most likely storage size of 1-1,5 ship volumes is assumed for the Netherlands, considering the constant ammonia supply.

As discussed in Section 6.4.2.3, the chosen ship size is 50,000 tonnes of ammonia. Therefore, the probable storage ranges from 50,000-100,000 tonnes, corresponding to CAPEX extremes of €340-909/t NH3. As this already represents a size range, these values are chosen as the most likely values.

All presented fixed OPEX values are between 2-4%, with no distinct most-likely values. Boil-off rates consistently fall at 0.03% or 0.04% per day, with the energy required for reliquefaction between 10-20 kWh per tonne of NH3 going through storage, as reported by four out of the five studies.

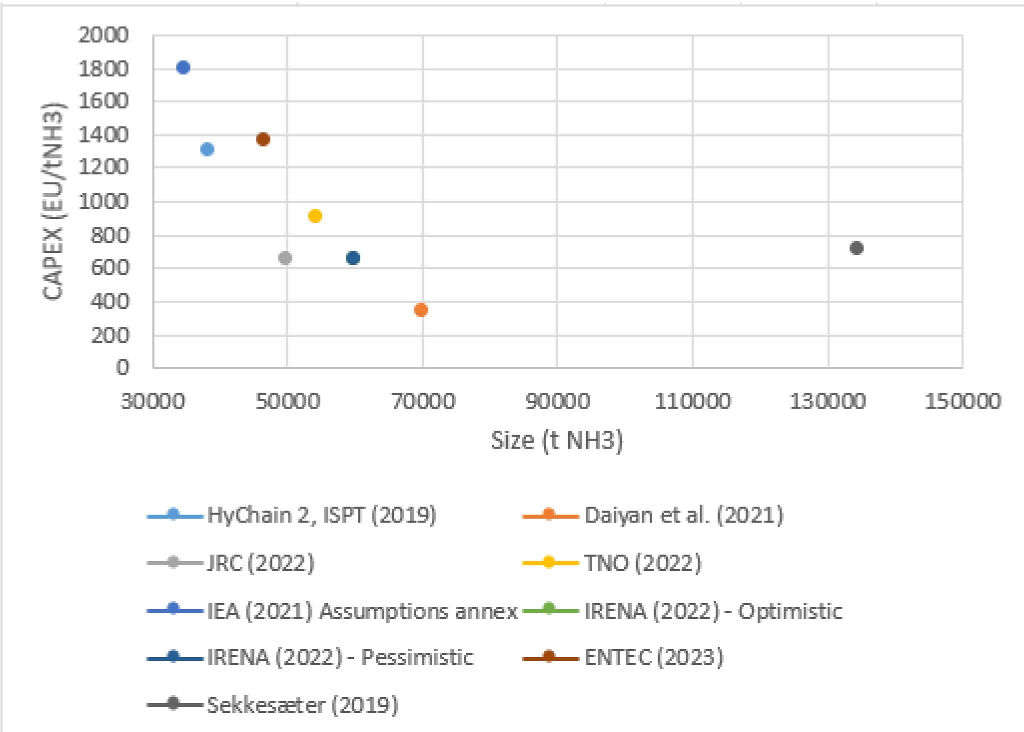

Figure A7.2: Cost assumptions on the cost of ammonia storage as compared to the tank size.

Table A7.2: Scenarios for the assessment indicators of ammonia storage

Process	Best case	Likely - low	Likely - high	Worst case	Unit
CAPEX	340	340	909	1787	€/tNH3
OPEX	2	2	4	4	% of CAPEX
Power demand	10	10	20	145	kWh/tNH3
Storage needed	1	1,5	2	2	Ship volumes
Storage needed	1	2	1,5	2	Ship volumes

A7.1.3 Costs of ammonia shipping

In assessing the cost of ammonia shipping, the assessment indicators include the CAPEX and fixed OPEX of the ship, fuel consumption, and shipping distance. To reach the yearly CAPEX the availability of the ships is needed, the sailing speed and the time spent in port.

It is expected that the costs of ammonia carriers decrease with the increase in ship size, yet no clear trends can be observed from Figure A7.3. The costs cited for a 75-125% capacity range from the 50,000 tonnes carrier is €1400/t NH3 and €1407/t NH3 capacity. This seem to be viable costs as three more reports present similar costs.

Fixed OPEX assumptions are most-likely between 4 and 4,7% of CAPEX. Meanwhile, boil-off loss assumptions differ greatly among different reports, from 0,004% to 0,2% per day. Only the 0,2% of CAPEX was excluded from the analysis.

Determining the energy demand for shipping is a complex task due to different factors including limited data availability, different ship sizes, varying sailing speeds, and different fuels used for propulsion (IRENA, 2022d). As the fuel use is highly connected with the scale of size of the ship the 75-125% method is applied. This results in a most-likely fuel consumption between 24-28 kWh/(t*1000km). Lastly, it's assumed that ships are available 95% of the time and spend an average of 1,5 days in port, and that the sailing speed is 30 km/h (JRC, 2022; Daiyan et al., 2021).

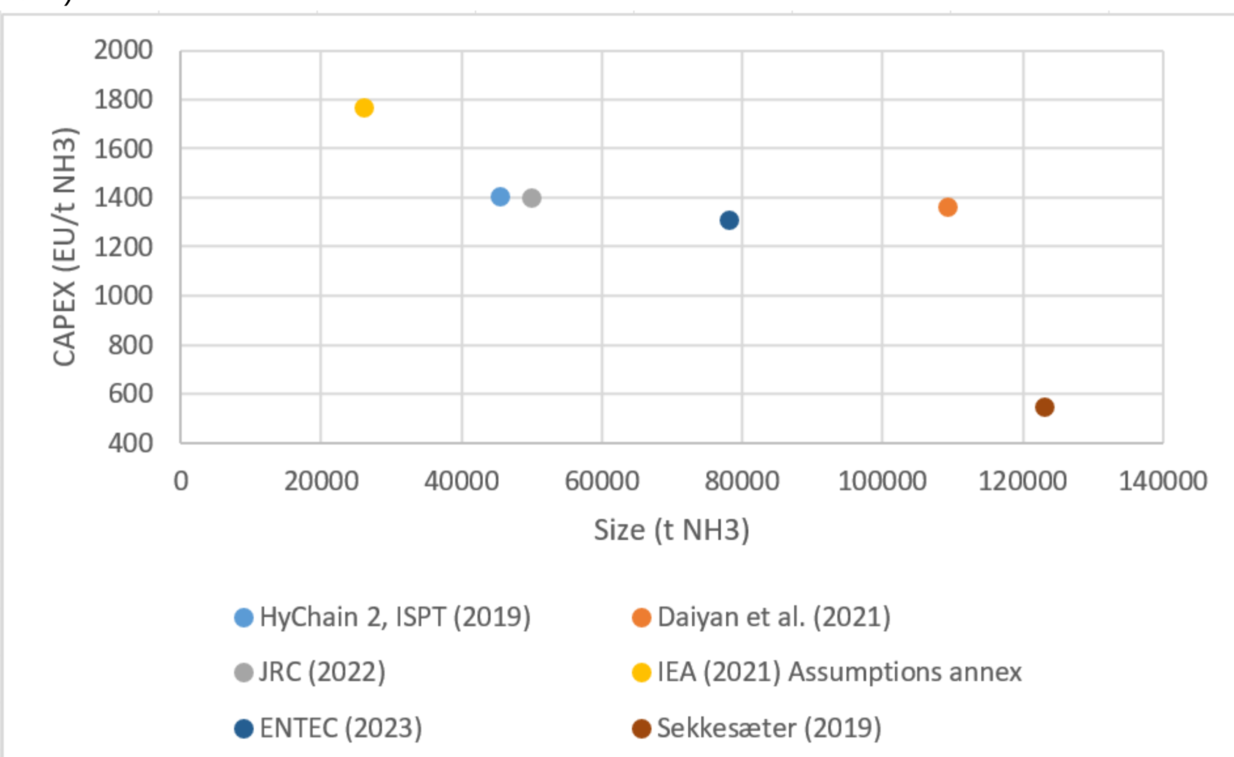

Figure A7.3: Cost assumptions on the cost of ammonia carriers as compared to the carrier size.

Table A7.3: Scenarios for the assessment indicators of ammonia shipping

Process	**Best case**	**Likely - low**	**Likely - high**	**Worst case**	**Unit**
CAPEX	546	1400	1407	4870	€/tNH3
OPEX	2,5	4	4,7	10,7	% of CAPEX
Fuel consumption	8	23,7	27,8	27,8	kWh/(t*1000 km)
Boil-off	0,004	0,004	0,08	0,2	%/day

A7.1.4 Costs of ammonia cracking

In assessing the costs of a hydrogen cracker, key indicators include the CAPEX, fixed OPEX, power demand, heat demand, and the efficiency of both the cracking and the Pressure Swing Adsorption (PSA) process.

There is no consensus on the CAPEX of the ammonia cracker, as illustrated in Figure A7.4. Furthermore, there was no correlation found between size and costs, as was also suggested by Fluor (2023). The uncertainties surrounding these ex-ante costs could be attributed to the high level of assumptions that have to be made. For instance, some apply a scaling factor based on lab-scale experiments, while others estimate costs based on existing Steam Methane Reforming (SMR) units (IRENA, 2022d). These variations make it difficult to determine a most likely scenario. Given the high uncertainties a most-likely range between €754-2.216/ t H2 was found.

Figure A7.4 further illustrates substantial uncertainties concerning energy demand. Some reports apply an efficiency factor over the energy required for the reaction, while others adopt a more comprehensive approach by evaluating the various elements involved in the reaction. Sekkesæter (2019) presents an unrealistic energy demand that implies a 100% energy efficiency, and is therefore excluded. As a result, a range between 5.515-14.400 kWh/t H2 or 14-37% of the energy content of the hydrogen was found.
The PSA power demand and OPEX assumptions of all reports were included in the most-likely range. Regarding process losses, a cracker efficiency of 98-99% and PSA efficiency between 85-90% was deemed most likely.

Table A7.4 gives an overview of all assessment indicator performances for the different scenarios.

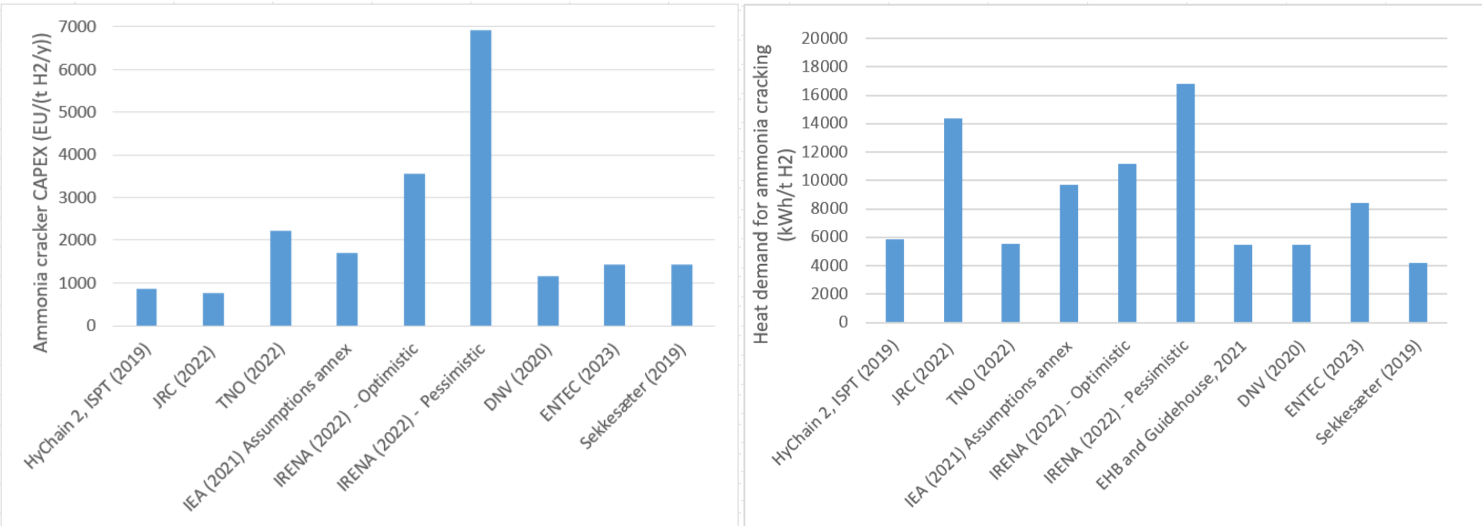

Figure A7.4: Assumptions on ammonia cracker CAPEX (left) and energy demand (right)

Table A7.4: Scenarios for the assessment indicators of ammonia shipping

Process	**Best case**	**Likely - low**	**Likely - high**	**Worst case**	**Unit**
CAPEX	754	754	2.216	6.907	€/(t H2/year)
Fixed OPEX	2,5	2,5	4	4	% of CAPEX
Heat demand	4.221	5.515	14.400	14.400	kWh/t H2
Power demand	1.500	1.500	4.900	4.900	kWh/t H2
Cracker efficiency	99	99	98	90	%
PSA efficiency	90	90	85	85	%

A7.2 Liquid hydrogen

A7.2.1 Costs of liquefaction

To assess the cost of hydrogen liquefaction the CAPEX and fixed OPEX of the plant are important assessment indicators as well as its energy demand.

The assumptions on the liquefaction plant CAPEX as compared to the plant size are seen in Figure A7.5. IRENA (2022d) proposes that plant costs will decrease as plant capacity increases, but in Excel more accuracy is found with a linear scaling of costs rather than the existence of a scaling factor. Consequently, plant costs are evaluated based on the plant size. For a 766 MW plant, translating to around 155,500 t H2/year, no specific plant within the 75-125% size range is available. Therefore, a 60-140% size range is taken, resulting in a cost range between TNO (2022) and IEA (2021). This most-likely range closely aligns with the costs presented in three other reports. Although repurposing LNG liquefaction plants in the future could significantly lower CAPEX, the demand for LNG is not projected to decrease within this research's timeframe, rendering this possibility out of scope (IRENA, 2022d).

The minimum power demand for the liquefaction process is 2.700 kWh/kg with an inlet pressure of 20 bar (Aziz, 2021; IRENA, 2022d).However, energy efficiency expectations vary across reports. IRENA (2022d) explains that also energy efficiency increases with plant size, which trend is also seen in Figure A7.6. Adopting a similar approach, the values around the evaluated plant size are considered, which notably includes Sekkesæter (2019) and JRC (2022). This is due to Sekkesæter (2019) suggesting a larger plant that demands more energy, while JRC (2022) suggests a smaller, less energy-intensive plant. A most likely range is found between 6.100-6.760 kWh/t H2. No outliers were found for an OPEX of 2,5-4% of CAPEX.

Table A7.5 gives an overview of the performance of all assessment indicators within the different scenarios.

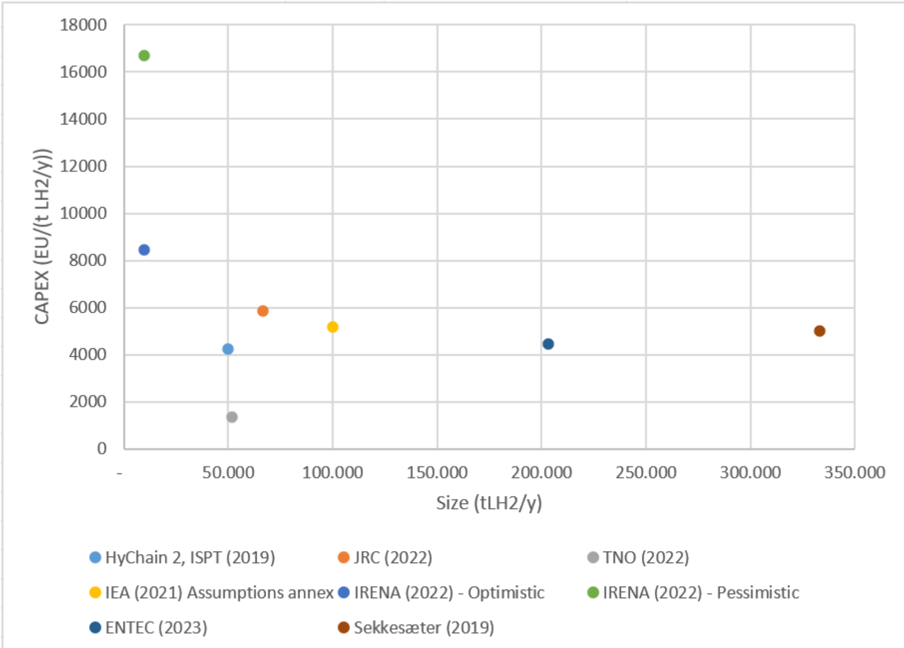

Figure A7.5: Liquefaction plant CAPEX as compared to size.

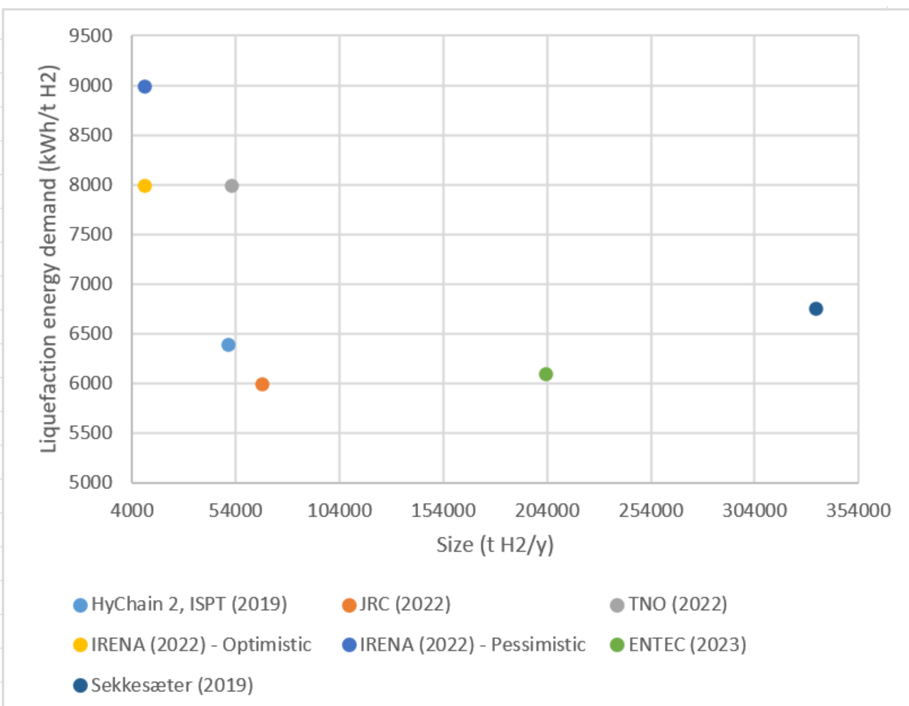

Figure A7.6: Assumptions on the liquefaction energy demand as compared to plant size.

Table A7.5: Scenarios for the assessment indicators of hydrogen liquefaction.

Process	**Best case**	**Likely - low**	**Likely - high**	**Worst case**	**Unit**
CAPEX	1.346	1.346	5.152	16.690	€/(t H2/year)
OPEX	2,5	2,5	4	4	% of CAPEX
Power demand	6.000	6.000	6.760	11.819	kWh/t H2

A7.2.2 Costs of liquid hydrogen storage

The assessment indicators needed to assess the costs of a liquid hydrogen storage tank are the CAPEX of the tank, the fixed OPEX, the energy demand for reliquefaction, and the storage capacity needed expressed in ship volumes.

Handling low temperatures brings about cost uncertainties when scaling up liquid hydrogen storage, as pointed out by IRENA (2022d). Figure A7.7 presents the CAPEX assumptions across different reports, plotted against storage size. Not only do these cost assumptions vary significantly, but the expected correlation between CAPEX and storage size is only marginally observable. Since the storage tank size ranges between 11,000-22,000 tonnes, the report by Sekkesæter (2019) is considered, alongside smaller storage tanks suggesting lower costs. This leads to a most-likely cost range of €13.352-29.547/tonnes LH2.

The energy required for reliquefaction is estimated to be between 100-600 kWh/tH2 that goes through storage and the OPEX is between 2-4% of CAPEX. The assumptions regarding the required storage size for liquid hydrogen are copied from those made for ammonia, with 1,5-2 ship volumes for the exporting country and 1-1,5 ship volumes for the Netherlands. Table A7.6 provides an overview of the performance of all assessment indicators for the different scenarios.

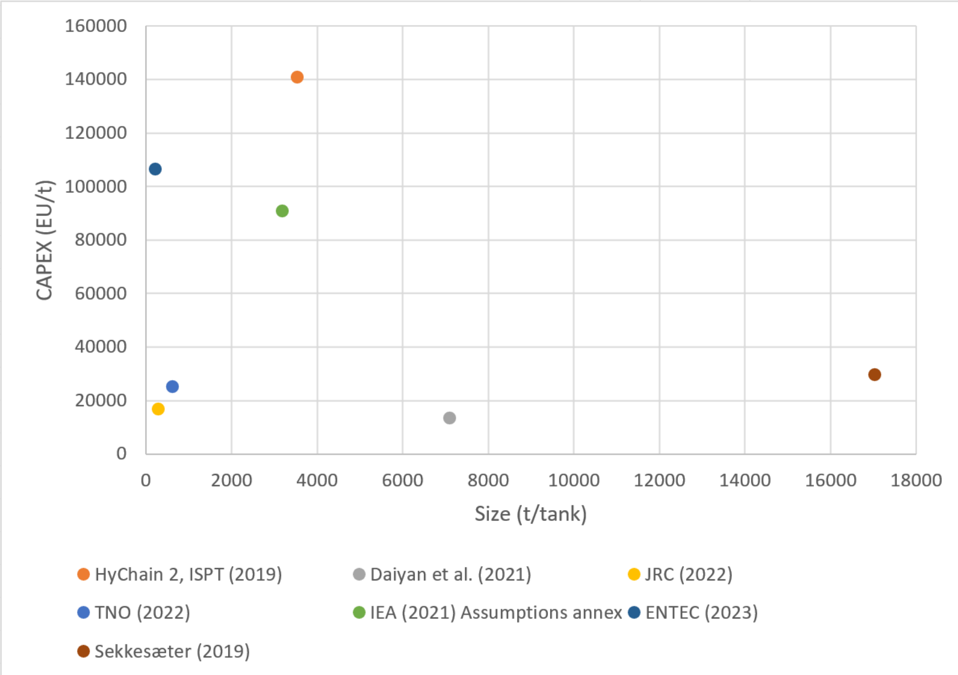

Figure A7.7: Liquid hydrogen storage CAPEX assumptions as compared to their size.

Table A7.6: Scenarios for the assessment indicators of liquid hydrogen storage.

Process	**Best case**	**Likely - low**	**Likely - high**	**Worst case**	**Unit**
CAPEX	13.352	13.352	29.547	140.865	€/t LH2
OPEX	2	2	4	4	% of CAPEX
Power demand	100	100	600	600	kWh/tLH2
Storage needed exporting country	1	1,5	2	2	Ship volumes
Storage needed Netherlands	1	2	1,5	2	Ship volumes

A7.2.3 Costs of liquid hydrogen shipping

Figure A7.8 shows the CAPEX assumptions as compared to ship sizes. Although ship costs are seen to decrease as ship size increases, no clear scaling factor is identified. Applying the method to select the most-likely scenario, all cost values presented for ship sizes within the range of 75-125% of 11,000 tonnes are considered. This analysis results in a cost range of €16,823 to €43,678 per tonne H2.

Fixed OPEX values range between 2-4% for six out of seven reports. The fuel use remains highly uncertain though. Only four reports provide a usable energy demand, with significant variations between them of 8-414 kWh/(t*1000 km). The lowest estimate reveals a uniform fuel usage per tonne across all carriers, which is highly unlikely in practice. For the other presented values, ship size, shipping fuel, and shipping speed influence the result, but the specific reasons for this wide cost range remain unclear. Based on the capacity inclusion range of 75-125% of the assessed ship size, the most likely fuel demand for this carrier is within 72-415 kWh/(t*1000 km).

Lastly, just like for ammonia, it is assumed that ships are available 95% of the time and spend an average of 1,5 days in port (Daiyan et al., 2021). A sailing speed of 30 km/h is assumed (JRC, 2022). Table A7.7 shows all values for the different scenarios.

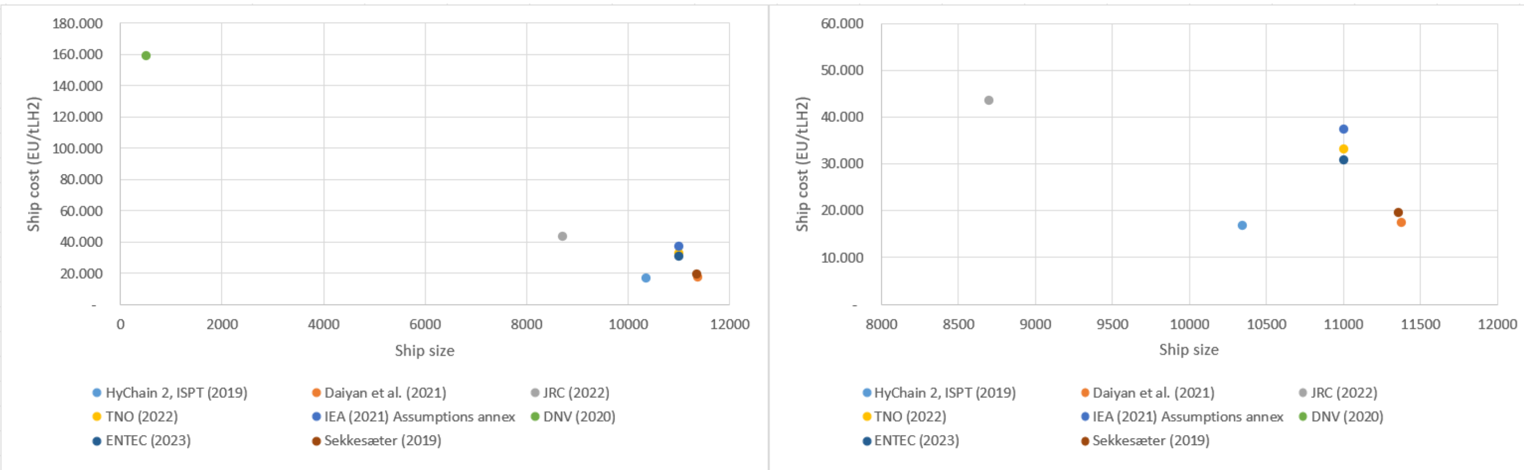

Figure A7.8: Assumptions on a liquid hydrogen carrier CAPEX as compared to its size.

Table A7.7: Scenarios for the assessment indicators of ammonia shipping

Process	**Best case**	**Likely - low**	**Likely - high**	**Worst case**	**Unit**
CAPEX	15.845	16.823	43.678	159.554	€/t LH2
OPEX	2	2	4	9,5	% of CAPEX
Fuel consumption	8	72	415	415	kWh/(t*1000 km)
Boil-off	0,2	0,2	0,2	0,89	%/day

A7.2.4 Costs of liquid hydrogen reconversion

Interestingly, many reports tend to overlook the subject of regasification due to its comparatively minor role in the value chain (ENTEC, 2022; IEA, 2021a; TNO, 2022). Reports that do discuss the CAPEX and energy demand aspects often overlook the sizing of the regasification system, leading to an absence of correlation between size and CAPEX or energy demand. Figure A7.9 displays both energy demand and CAPEX values for the regasification unit, showing a lack of consensus on the anticipated costs of regasification.

Using the interquartile range (IQR) method for selecting the most likely cost, only IRENA's (2022d) pessimistic scenario is excluded from the CAPEX range, with all other values included. The OPEX is estimated to range between 2.5-3% of the CAPEX. Table A7.8 provides a comprehensive overview of the performance of all assessment criteria across the different scenarios.

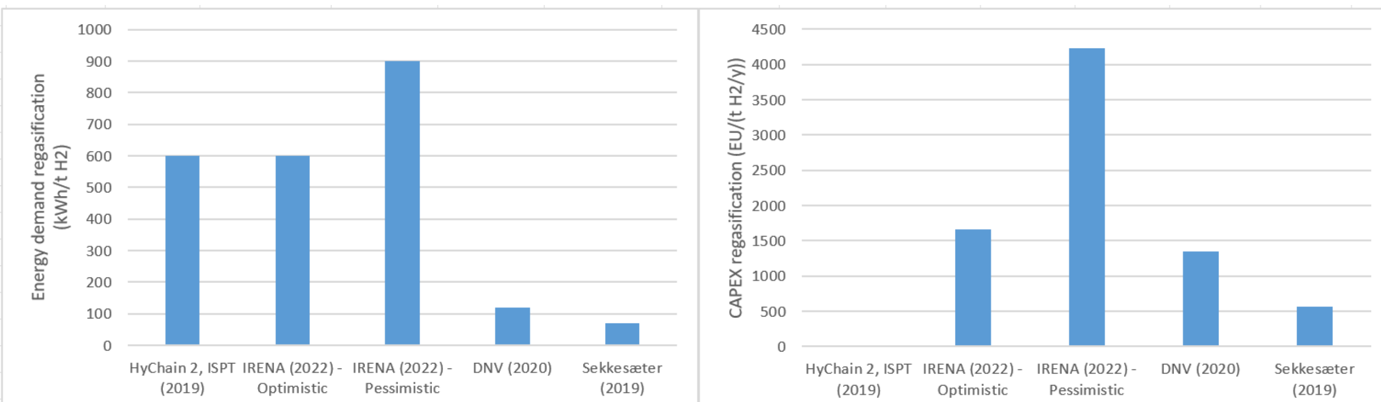

Figure A7.9: Energy demand (left) and CAPEX assumptions (right) for a liquid hydrogen regasification unit.

Table A7.8: Scenarios for the assessment indicators of hydrogen regasification.

Process	**Best case**	**Likely - low**	**Likely - high**	**Worst case**	**Unit**
CAPEX	18	18	1656	4228	€/(t H2/year)
OPEX	2,5	2,5	3	4	% of CAPEX
Power demand	70	70	900	900	kWh/t H2

A7.3 LOHC - DBT

A7.3.1 Costs of hydrogenation

To address the cost of hydrogenation the CAPEX, fixed OPEX and energy demand of the plant are important assessment indicators, but also the cost of the DBT, the initial DBT needed and its replacement rate.

According to IRENA (2022d), the CAPEX of the hydrogenation plant benefits from economies of scale, a trend also seen in Figure A7.10. However, a scaling factor is identified with only 70% certainty, so it isn't incorporated into this analysis. Instead, a likely cost is estimated based on the costs within 75-125% of the plant size. The plant is expected to have a capacity of 766MW, which equates to an annual DBT production of 3,26 million tonnes. In absence of cost data within this range, a 60-140% range is utilised and TNO's (2022) value is identified as the most probable cost.

The OPEX likely falls between 1,5-4% of CAPEX, and no exclusion for the energy demand was determined through interquartile range (IQR) analysis. It is assumed that the initial DBT requirement is half the total tank storage volume.

Low carrier costs presented are exclusive to toluene and hence, not representative of DBT. Therefore, the likely scenario for DBT falls between €1650-4000/tonnes. In the IQR analysis, a most-likely replacement rate of 0,1 is identified. Table A7.9 summarises all assessment indicators for the various scenarios.

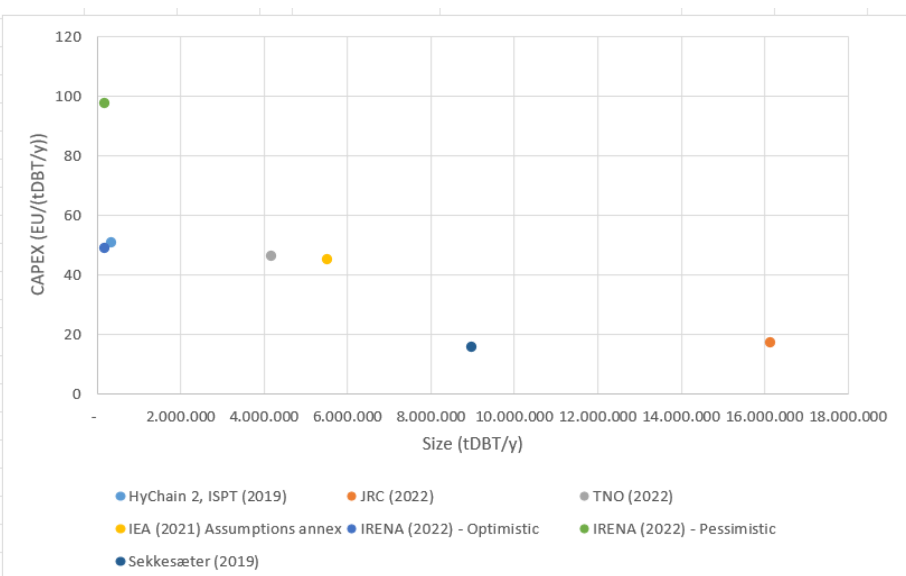

Figure A7.10: Hydrogenation CAPEX as compared to plant size.

Table A7.9: Scenarios for the assessment indicators of hydrogen liquefaction

Process	**Best case**	**Likely - low**	**Likely - high**	**Worst case**	**Unit**
CAPEX	15,9	46	46	97	€/(t DBT/year)
OPEX	0,2	1,5	4	4	% of CAPEX
Power demand	20	20	125	125	kWh/t DBT
DBT cost	300	1650	4400	4400	€/t DBT
Replacement rate	0,1	0,1	0,1	3,6	%

A7.3.2 Costs of DBT storage

Evaluating the costs of a DBT storage tank requires several assessment indicators: the CAPEX of the tank, the fixed OPEX, potential power demand, and the needed storage capacity expressed in ship volumes.

The costs of storage are known to decrease with an increase in storage size (IRENA, 2022d). However, many studies have not provided concrete tank sizes, complicating comparisons and necessitating the use of the interquartile range (IQR) method, which doesn't exclude any of the presented values. Similarly, no outliers are identified for fixed OPEX. The energy demand for DBT storage is notably low, or even zero.

Given that a single ship volume is insufficient in all scenarios, the most-likely range stands at 1,5-2 ship volumes for exporting countries. Despite most reports assuming equivalent storage sizes for both exporting and importing countries, a most likely storage size of 1-1,5 ship volumes is assumed for the Netherlands, considering the constant DBT supply.

Table A7.10 summarises all assessment indicators for the different scenarios.

Table A7.10: Scenarios for the assessment indicators of DBT storage

Process	**Best case**	**Likely - low**	**Likely - high**	**Worst case**	**Unit**
CAPEX	145	145	743	743	€/t DBT
OPEX	0,7%	0,7%	4%	4%	% of CAPEX
Power demand	0	0	10	10	kWh/t DBT
Storage needed	1	1,5	2	2	Ship volumes
Storage needed	1	2	1,5	2	Ship volumes

A7.3.3 Costs of DBT shipping

In evaluating the costs associated with DBT shipping, key assessment indicators include the CAPEX and fixed OPEX of the ship, fuel consumption, and shipping distance. Factors such as the ship's availability, sailing speed, and time spent in port are also considered in determining the annual CAPEX. Given that the engine is powered by methanol, the cost of green methanol is another important assessment factor.

Figure A7.11 shows the cost assumptions as compared to the size of the ship. Although a clear trend of decreasing cost with increasing carrier size is observed, a scaling factor is only identified with 89% certainty. Therefore, the most likely cost range for the carrier is derived from reports that presented capacities within 75-125% of the assessed capacity of 123,000 tonnes. The most likely scenario appears to be bracketed by the values presented by the IEA (2021) and JRC (2022).

Both IEA Bioenergy (2020) and Mikulski et al. (2018) project a cost of €500-600 per tonne for green methanol, equivalent to approximately €78,6-94,33 per MWh, which is assumed to be representative for the cost price in 2030.

Outliers in OPEX and fuel demand are excluded through interquartile range (IQR) analysis. Lastly, just like for ammonia and liquid hydrogen, it is assumed that ships are available 95% of the time and spend an average of 1,5 days in port (Daiyan et al., 2021). A sailing speed of 30 km/h is assumed (JRC, 2022). Table A7.11 shows all assessment indicator performances for the different scenarios.

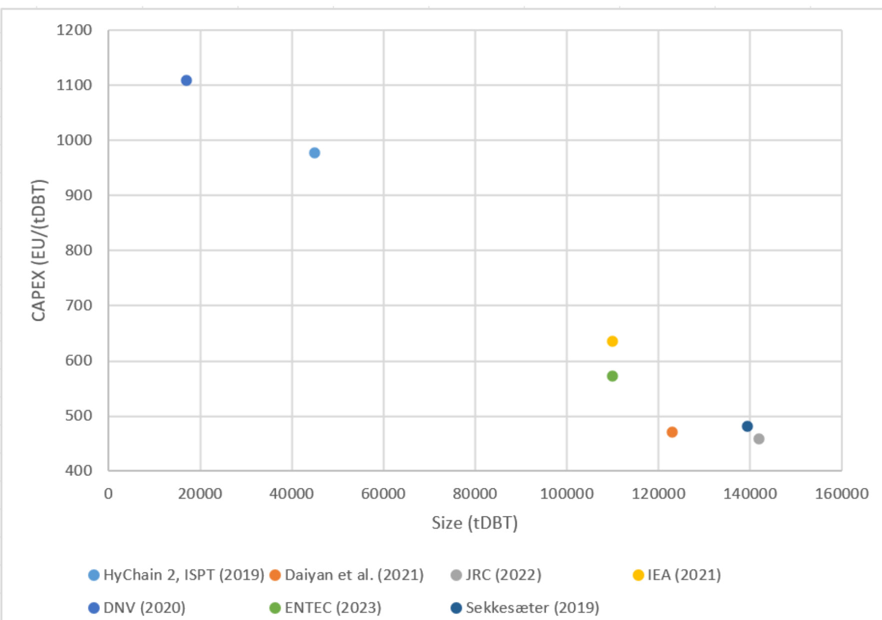

Figure A7.11: Assumptions on the CAPEX of a DBT carrier as compared to its size.

Table A7.11: Scenarios for the assessment indicators of DBT shipping.

Process	Best case	Likely - low	Likely - high	Worst case	Unit
CAPEX	458	458	636	1903	€/t DBT
OPEX	2,5	2,5	5,7	19	% of CAPEX
Fuel consumption	8	8	33,11	33,11	kWh/(t*1000 km)
Fuel cost	78,6	78,6	94,3	94,3	€/MWh

A7.3.4 Costs of dehydrogenation

In assessing the costs of dehydrogenation, key indicators include the CAPEX, fixed OPEX, power demand, heat demand, and the efficiency of both the dehydrogenation and the PSA.

IRENA (2022d) highlights that there is only a minimal advantage of scale associated with the dehydrogenation process, as the process occurs in a series. In Figure A7.12 some scaling advantage can be recognised. However, the primary observation is the significant degree of cost uncertainty. Therefore, to identify the most likely CAPEX, outliers are excluded using the IQR method.

Energy demand represents the most substantial cost component of dehydrogenation. Figure A7.12 presents the assumptions regarding energy demand. For the most-likely scenario these assumptions are filtered using the IQR method. Also the assumption of Sekkesæter (2019) is excluded, as it presents only the enthalpy of the reaction, which is highly unlikely. Also for the other assessment indicators the IQR is used to retrieve the most-likely scenarios. An overview of the performance of the assessment indicators in the different scenarios is found in Table A7.12.

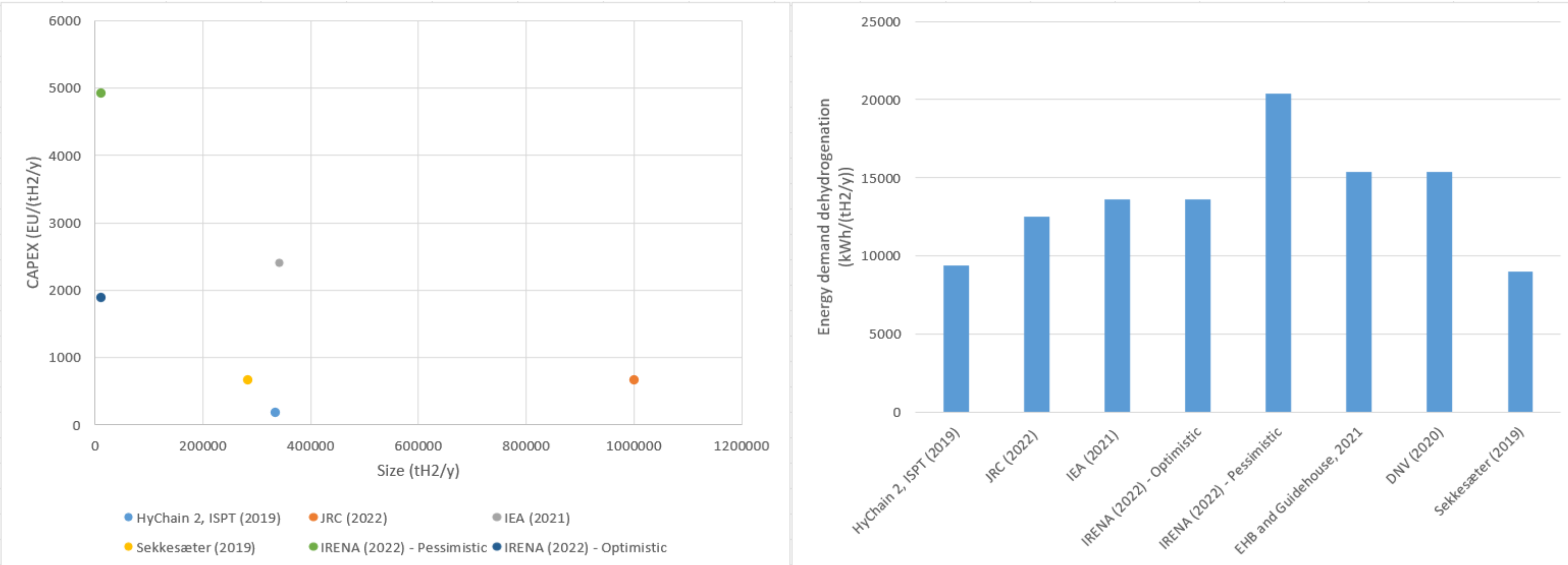

Figure A7.12: An overview of the presented assumptions on the CAPEX as compared to the plant size (left) and the energy demand (right).

Table A7.12: An overview of the performance of the assessment indicators for dehydrogenation in the different scenarios.

Process	Best case	Likely - low	Likely - high	Worst case	Unit
CAPEX	186	186	2401	4928	€/(t H2/year)
Fixed OPEX	1,5	1,5	4	6	% of CAPEX
Heat demand	9.012	9.370	15.364	20.400	kWh/t H2
Power demand	1.500	1.940	2.000	2.000	kWh/t H2
Dehydrogenation efficiency	98%	98%	90%	90%	%
PSA efficiency	99%	98%	90%	90%	%

Appendix 8: interviews

Abbink, M. (2023, June 28). *Interview with Maas Abbink, Investment Analyst at Invest NL*.

> Discussed methodologies for analyzing investments and determining the Weighted Average Cost of Capital (WACC)

Armstrong, J. (2023, June 20). *Interview with Josie Armstrong, Senior Principal—Green hydrogen and ammonia at AFRY* .

> Explored global trends in clean ammonia, key countries of interest as identified by AFRY, and lingering challenges in clean ammonia development.

Brouwer, M. (2023, July 27). *Interview with Mark Brouwer, the owner of UreaKnowHow.com*.

> Addressed ammonia safety, current challenges, and the implications of developing ammonia as an energy vector.

da Costa Ribeiro, K. (2023, July 26). *Interview with Karla da Costa Ribeiro, Senior Development Electrical Engineer at HyCC*.

> Discussion on the possible implications of bypassing a grid connection on electrolyser costs.

Frens, W. J. (2023). *Interview with Willem Frens, Owner BA2C Europe/ Latin America and Business Development New Markets & Technologies at HyCC* .

> Extensive discussions on international hydrogen projects, specifically focusing on ammonia, and their system design, challenges, and opportunities.

Fruytier, M. (2023, June 27). *Interview with Marthe Fruytier, Business Analyst New Energy at the Port of Rotterdam* .

> Discussion on global hydrogen import projects, with special emphasis on Namibia.

Hassan, F. (2023, July 24). *Interview with Feres Hassan, product specialist at Dexter Energy*.

> Discussion on power price forecasting and assumptions for peak and low availability scenarios.

Hughes-Straka, K. (2023, July 21). *Interview with Katarina Hughes-Straka, Business development manager at Hydrogenious LOHC*.

> Addressed supply chain design and development challenges of hydrogen imports via the energy carrier LOHC.

Japin, X. (2023, May 3). *Interview with Xander Japin, former hydrogen business developer at Port of Rotterdam*.

Discussion on hydrogen imports and on what countries are of particular interest for the Port of Rotterdam. Insights on specific bottlenecks within certain countries.

Joon, M. (2023, August 7). *Interview with Martijn Joon, Terminal Director at Zenith Amsterdam*

Explored liquid hydrogen imports, discussing supply chain design and economic and technological hurdles.

Kool-Claessens, S. (2023, August 1). *Interview with Stephanie Kool-Claessens, Manager Commercial Business Development at HyCC.*

Weekly discussions on the development of the domestic hydrogen market as well as on overall research design and execution.

Langhout, K. (2023, July 25). *Interview with Klaas Langhout, Business Development Director at Proton Ventures* .

Explored ammonia project development and importation, including supply chain considerations and market challenges.

Mannien, M. (2023, May 23). *Interview with Marijn Mannien, Export Support at KOTRA, the Korea Trade-Investment Promotion Agency*.

Discussed the willingness to pay in Korea and the development of hydrogen and hydrogen imports in the region as well as the general business attitude of these countries.

Oorsprong, R. (2023, June 1). *Interview with Rutger Oorsprong on hydrogen import developments in the Port of Amsterdam.*

Discussion on hydrogen imports to the Port of Amsterdam area and challenges within the area due to safety constraints.

Peeters, R. (2023, June 21). *Interview with Robert Peeters, trainee at Ministry of Economic Affairs and Climate—Unit Hydrogen*.

Discussion on the stance of the Dutch government on hydrogen imports and their approach to accelerate it.

Spruijt, P. (2023, June 21). *Interview with Pieter Spruijt, Technology specialist alternative fuels at Damen Shipyards*

Discussion on the shipping fuels of the future and what possible dynamic could develop between these different clean shipping alternatives.

Stoelinga, M. (2023, April 18). *Interview with Mark Stoelinga, Business Manager Hydrogen at the Port of Rotterdam*.

Discussion on the hydrogen import strategy of the Port of Rotterdam and what elements are helping them in developing imports from specific regions

Ummels PhD, B. C. (2023, September 8). *Interview with Bart Ummels, Expert & Owner at Scale Offshore Renewable Energy and Lecturer Offshore Wind Energy at TU Delft* .

Discussion on the development and challenges for offshore wind in the Netherlands and how the challenges for the development of both offshore and onshore wind differ globally.

van Duffelen, M. (2023, July 18). *Interview on developments in solar PV and cost differences around the world*.

Discussion on the development of utility scale solar PV and location specific challenges that might exist.

van Riel, R. (2023, May 30). *Interview with Roman van Riel, Business Development Manager Electrification and Hydrogen at Port of Rotterdam*.

Discussion on hydrogen imports with a specific focus on the USA region.