Hydrogen Import Terminal

Providing insights in the cost of supply chain elements of various hydrogen carriers for the import of hydrogen

TU Delft

mtbs

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Preface

This report presents the results of my research, in partial achievement of my master's degree in Hydraulic Engineering completed at the Delft University of Technology. Whilst I have learned a lot during my comprehensive research, I equally realize there are endless learning moments in the academic world and in life in general. I am grateful for all those who have supported me along the adventure of my research. I would like to thank in especially four persons, which all contributes to my thesis committee.

Firstly, I would like to thank Mark van Koningsveld, who has been integral in creating codes and always kept me motivated. I would like to thank him for all his time and effort in this thesis and his help of building a good structure code, so that other people can use my code afterwards. I am really thankful for all the programming skills I have learned because of him and the first experience I had with Python was really great.

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It was really great to have such a committee which was so involved in the thesis. Again, thank you a lot for all the good times, effort and new skills I have learned during this master thesis.

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Executive Summary

The world population is growing and therewith facing a lot of problems, such as a growing energy demand and climate change (UN, 2017). These problems force society to make a transition, from a system driven by fossil raw materials to a sustainability-based system. The Paris Agreement of 2015 set the target to lower the Carbon Dioxide (CO_2) emissions by 40% in 2030 compared to 1990 (European Commission, 2016). Hydrogen can play a part in shifting from fossil fuels to more sustainable energy flows, as a renewable energy carrier, to decrease the CO_2 emissions. However, the major obstacle of hydrogen use is the low volumetric energy density at room temperature and atmospheric pressure. Therefore, hydrogen must be compressed, liquefied or attached to a carrier to use it for storage or transportation purposes. The most cost-effective method to import hydrogen is yet unknown (Li et al., 2019), and therefore a better understanding of the costs of the hydrogen supply chains are essential.

Several studies have researched the cost parameters and technologies of the individual hydrogen supply chains (Yang & Ogden, 2007; Reuß et al., 2017; Obara, 2019). In these studies, however, the cost parameters of hydrogen carriers for the international import of hydrogen are neglected (Li et al., 2019). A comparison of the international import of the various hydrogen carriers by vessels and pipelines has not been addressed in these studies. Therefore, this research focuses on (i) identifying the costs related to the different supply chains for hydrogen imports and (ii) the development of a parametric model that provides more insight into the impact of these supply chain costs on the total costs of imported hydrogen. The main research question is: "What is the most cost effective way to import hydrogen into the port of Rotterdam to supply the future hydrogen demand in the Netherlands, given a selected set of hydrogen carriers and export locations?" The objective of this research is to: (1) understand the different costs for each individual element of the supply chain, (2) design a hydrogen supply chain that integrates the individual elements into a single framework to be able to compare the different carriers to each other and (3) create a more profound perspective on the investment decisions for a hydrogen import terminal. A case study for the port of Rotterdam is performed to validate the operation of the general supply chain for a specific case, resulting in a more in-depth understanding of the import terminal.

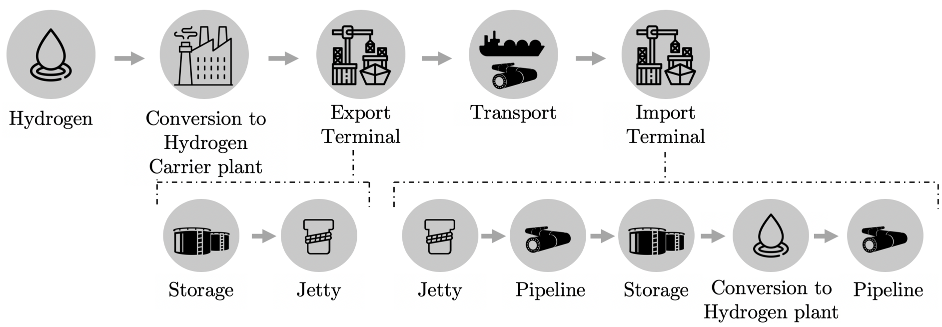


Figure 0.1: Supply chain elements overview

The elements that are included in this research can be found in Figure 0.1. The first element in the supply chain study is hydrogen, whereby grey, blue and green hydrogen are included. The second element of the supply chain is the conversion to hydrogen carrier plant. This research covers four hydrogen carriers: ammonia, MethylCycloHexane (MCH), liquid- and gaseous hydrogen. The export terminal contains a liquid bulk terminal design, including a storage and jetty. The considered transport possibilities are pipelines, for gaseous hydrogen, and vessels for ammonia, MCH and liquid hydrogen. The last element in the supply chain, the import terminal, covers a jetty, pipeline, storage and conversion to hydrogen plant.

This research is divided into two parts: the general supply chain and the import terminal. The first part, gives insight into the investment- and operational costs for all different elements of the supply chain, given a certain volume, hydrogen carrier and export/import location. The objective is to assess the costs of the hydrogen supply chain for any selected set of preferred parameters. The import terminal, the second part, serves as a case study, where the input values of the supply chain model are used. The objective is to financially valuate the terminal design and to make an explicit cost assessment with more in-depth knowledge on the import terminal.

The cost price given in Figure 0.2, refers to the first objective and differs per selected demand and combination of the export and import country. The costs refers back to the elements of the supply chains, with Brazil as export country and the Netherlands as import country. This combination was randomly chosen, every other combination is possible within the model. In most cases, the production costs have the highest share of the total cost, except for gaseous hydrogen where the transportation costs dominate. For ammonia, the import terminal is responsible for the largest share of costs due to the high Hydrogen (H_2) retrieval costs. The same applies for the supply chain of MCH. The largest costs of liquid hydrogen are related to the conversion plant; a process that causes high energy costs. The largest share of the costs of gaseous hydrogen is transport, due to the high investment costs of new pipelines and the long transportation distance. To conclude, for ammonia and MCH the import terminal costs are the highest, for liquid hydrogen the conversion plant costs and for gaseous hydrogen the transport costs.

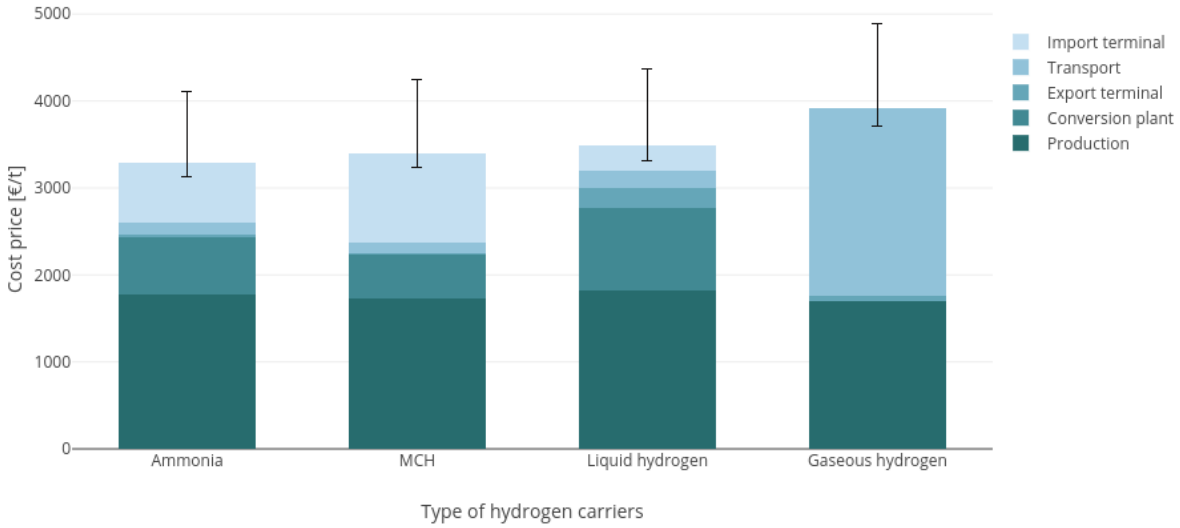


Figure 0.2: Cost price of the supplied hydrogen with a demand of 700,000 t/y, from Brazil to the Netherlands

In Figure 0.3, the supplied hydrogen costs of the various hydrogen carriers are outlined. The costs of ammonia and MCH are always lower than the costs of liquid and gaseous hydrogen, for the specific combination of export country and import country that was assessed. As the demand increases, the hydrogen costs decline. This decline holds till the demand reaches an amount of about 500,000 t/y for ammonia, MCH and liquid hydrogen, in which the capacity is fully utilized. For gaseous hydrogen, this decline continues for values beyond 500,000 t/y. Ammonia is almost always preferred above MCH, due to the previous developed technologies and experience in the field. Increasing the volume means that the costs decrease, whereby the hydrogen costs of MCH decrease almost equally compared to the costs of ammonia. The discrepancy in costs, between MCH and ammonia, is negligible. All in all, the hydrogen costs for ammonia, MCH and liquid hydrogen decreases as long as the demand increases, up until an amount of 500,000 t/y, whereby for gaseous hydrogen this decline holds for values beyond this amount as well.

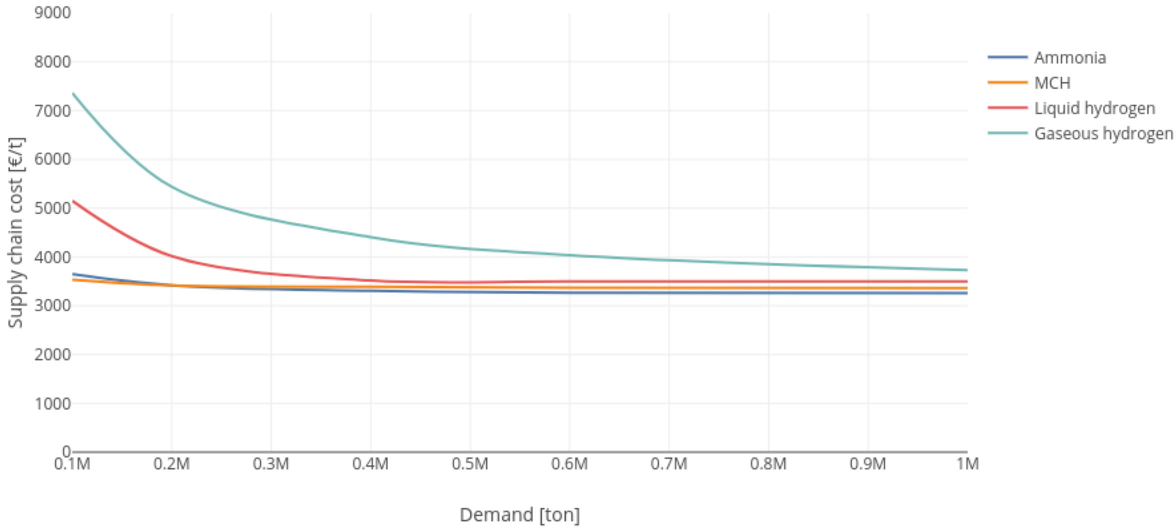


Figure 0.3: Cost price of the hydrogen supply chains varying with demand, from Brazil to the Netherlands

In Figure 0.4, the various cost prices for the supplied hydrogen are shown for the different hydrogen carriers per scoped country for the import in Spain. These cost prices depend on the country specific parameters and the distance of transportation, which can have a significant influence on the cost price. Another notable parameter are the costs of the production of hydrogen, which vary for the different export countries. The different cost prices are plotted in line with the distance of the various export countries.

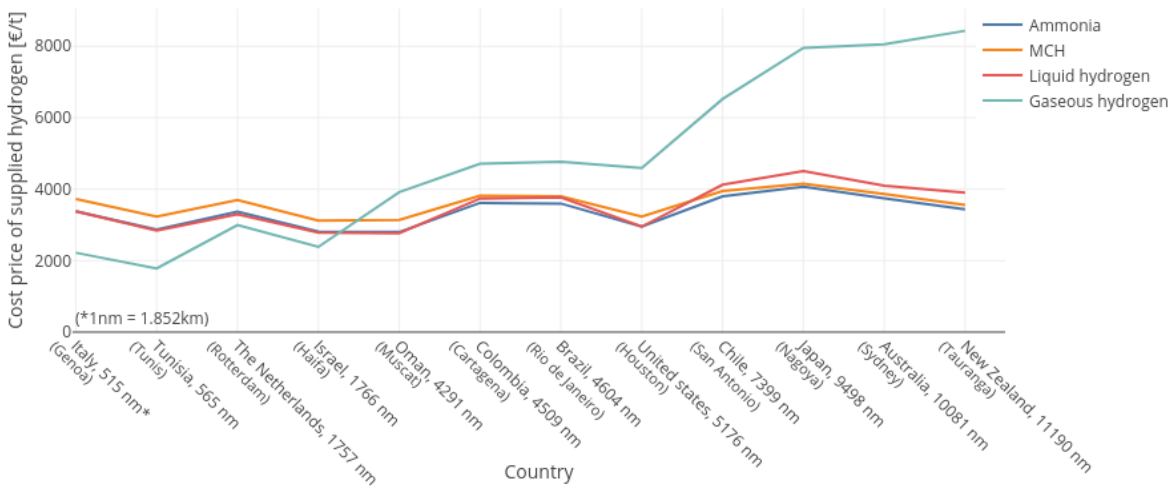


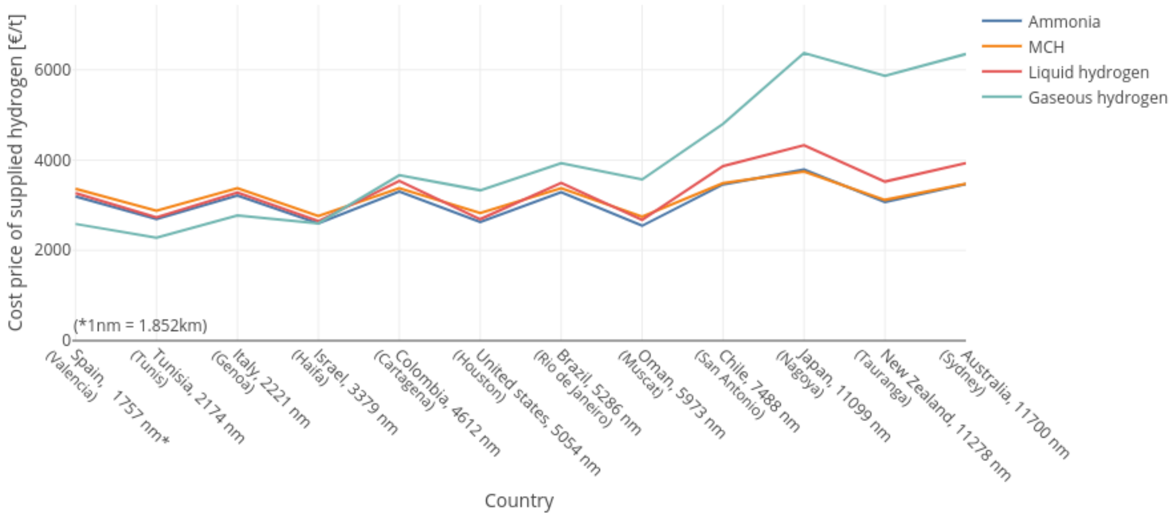
Figure 0.4: Cost price of the supplied hydrogen for the import in Spain varying with the countries, with a demand of 700,000 t/y

The most cost effective way to export hydrogen to Spain is from Tunisia with gaseous hydrogen with a cost price of 1.8 €/kg. For short distances up to 3,500 nm, gaseous hydrogen is the preferable option. Due to the low transportation costs, gaseous hydrogen can compete with the other hydrogen carriers. Investigating liquid hydrogen, it appears that the investment costs are high compared to ammonia and MCH. For short distances the costs for liquid hydrogen are almost equal to ammonia. Ammonia is preferred above MCH, due to the low costs of the well known technologies.

However, ammonia is not a preferred commodity from an environmental perspective because of its greenhouse gas characteristic and indirect contribution to global warming (Lechtenböhmer et al., 2018). For long distances the costs of MCH are almost equal to ammonia, due to the fact that production and distribution of ammonia contains more hydrogen losses. In general, for distances up to 3,500 nm gaseous hydrogen is preferred and for intermediate or long distance ammonia. The discrepancy in costs between ammonia, MCH and liquid hydrogen is almost negligible. Regarding the second objective, it can be stated that it makes no difference when choosing one carrier, or the other at ammonia, MCH and liquid hydrogen for intermediate to long distances.

When zooming in on the import terminal in Rotterdam, a specific framework for the terminal is established. This contains an explicit business case with more in-depth knowledge, capable of translating a demand into a terminal design. The MCH import terminal has the highest costs due to the high energy costs of the H_2 retrieval plant. In the ammonia terminal, the largest costs originate from the energy costs of the H_2 retrieval as well and in the liquid hydrogen terminal the largest costs originate from the investment costs of the storage. The import of hydrogen with ammonia, MCH and liquid hydrogen as carrier does not require a lot of space in the port of Rotterdam, because the strategical storage can be done in salt caverns located in the hinterland. These conclusions refer to the third objective; for the import terminal of ammonia and MCH, the H_2 retrieval plant are the highest costs and for liquid hydrogen storage are the highest costs.

The optimal hydrogen import supply chain for the estimated demand of Rotterdam is obtained from gaseous hydrogen exported from Tunisia with a cost price of 2.3 €/kg (see Figure 0.5). This cost price is based on new pipelines. When using the existing pipelines from Tunisia to the Netherlands, this cost price can be significantly reduced. The domestic cost price of the production of hydrogen in Tunisia is 1.3 €/kg. With gaseous hydrogen as hydrogen carrier, an import terminal is redundant and therefore there will not be any space requirements in the port. The domestic cost price of the hydrogen production in the Netherlands is 1.7 €/kg. This cost price does not include any transportation to the grid and therefore the actual price can be higher. When the cost price of the import hydrogen declines and the domestic cost price increases, the imported hydrogen can compete with domestic production. Furthermore, the import of sustainable energy is required to fulfil the energy demand in 2030, in order to transform to a sustainable society (Van Wijk et al., 2019). The optimal way to import hydrogen into the port of Rotterdam is by transporting gaseous hydrogen with pipelines from Tunisia.



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Acronym & Symbol list

AEC Alkaline Electrolysis Cell

ATR AutoThermal Reforming

CAPEX Capital Expenditure

CCS Carbon Capture and Storage

DWT Deadweight Tonnage

FAST Flexible, Appropriate, Structured and Transparent

FCEV Fuel Cell Electric Vehicle

ha Hectare

HSCND Hydrogen Supply Chain Network Design

HSC Hydrogen Supply Chain

IEA Internation Energy Agency

ktoe Kilo Tonne of Oil Equivalent

LNG Liquefied Natural Gas

LPG Liquefied Petroleum Gas

LOHC Liquid Organic Hydrogen Carriers

MTBS Maritime & Transport Business Solutions

nm nautical mile

OPEX Operating Expenses

PEM Polymer Electrolyte Membrane

PJ PetaJoule

POX Partial Oxidation

SMR Steam Methane Reforming

SOEC Solid Oxide Electrolysis Cells

VLCC Very Large Crude Carriers

WACC Weighted Average Cost of Capital

NH_3 Ammonia

MCH MethylCycloHexane

LH_2 Liquid Hydrogen

H_2 Hydrogen

CO_2 Carbon Dioxide

1 Introduction

The world population is growing, which is one of the key drivers of global issues such as growing energy demand and climate change (UN, 2017). These problems lead the human population to make a transition; from a system driven by fossil raw materials to a sustainability-based system. The Paris Agreement of 2015 set the target to lower the CO_2 emissions by 40% in 2030 compared to 1990 (European Commission, 2016). Renewable energy projects, such as wind and solar parks, are rapidly being built to replace fossil fuels. The major obstacle of electricity production from renewable sources is that they are intermittent and therefore lead to a mismatch between the supply and the demand of energy. Energy distribution and storage in the form of hydrogen production is a potential candidate to overcome this problem. However, due to its low volumetric energy density, hydrogen must be compressed, liquefied or attached to a carrier to use it for storage or transportation purposes. At this moment, though, the most cost-effective method to import hydrogen is unknown (Li et al., 2019). Therefore, this research focuses on the various options and cost effective ways to import hydrogen for the entire supply chain and in specific the import terminal with a cash flow approach.

At the moment, green hydrogen is not financially competitive, due to the high production costs and low efficiency. Therefore, significant reductions are needed in the cost of production and distribution in order to achieve a more sustainable hydrogen supply. The primary upside of using hydrogen as a energy source or fuel, is its ability to store electrons and the possibility of long distance transportation (EIA, 2019). A contribution to this is the positive cost development of green hydrogen compared to fossil fuels, due to tax on CO_2 emissions and the falling cost of renewable energy and the electrolyser technologies used to convert it to hydrogen. Due to these advantages, hydrogen is expected to be a substantial part of our primary energy supply in the future. In order to enable the establishment of a hydrogen supply chain at this moment, hydrogen will be produced from fossil fuels at first and eventually from renewable energy (ISPT, 2017).

1.1 Background

With the Paris Agreement of 2015, the parties of the United Nations Framework Convention on Climate Change reached an agreement to combat climate change and to accelerate and intensify the actions and investments needed for a sustainable low carbon future (UNFCCC, 2017). This resulted in the need to decrease the CO_2 emissions by at least 40% (UNFCCC, 2017). In order to accomplish this 40% decrease, a shift from fossil fuels to more sustainable energy flows is needed. The global energy system must therefore undergo a transformation to achieve lower CO_2 emissions in 2030. Yet, renewable electricity consists of electrons that are hard to store and transport. Hydrogen can be the missing link in the energy transition, because it can facilitate transportation and storage of electrons (Van Wijk et al., 2019). Even more, it can replace fossil fuels without the need to fully change end-use technologies (Council & of Engineering, 2004). Hydrogen is an energy carrier which is produced by other energy sources, such as biomass, fossil fuels and renewable energy. Green hydrogen, produced by renewable energy, could play a key role in facilitating three positive outcomes (IRENA, 2018b):

1. De-carbonization;
2. The integration of large amounts of variable renewable energy;
3. The decoupling of variable renewable energy generation and consumption through the production of transportable hydrogen and hydrogen carriers.

All these aspects will contribute to the transformation from a system driven by fossil raw materials to a sustainability-based system, in which hydrogen can play a central role (Van Dorsser, Taneja, & Vellinga, 2018). Although green hydrogen is not financially feasible at this moment, it can be a competing energy supply in the near future (Van Wijk et al., 2019).

To achieve this goal, three things will need to change (ISPT, 2017):

1. A decline of production costs of electrolysers;
2. An increase of the renewable energy supply;
3. A global increase of the CO_2 price.

Although hydrogen is a promising fuel, it still contains technical and financial challenges. The costs of the electrolyser form a big part of the problem, whereby R&D efforts have already led to cost reductions from 1990 to 2017 (Saba et al., 2017). In 1990s the cost estimations were in a range between 306 and 4748 €$_{2017}$/kW$_{HHV-Output}$ and today it is narrowed towards values of 397 and 955 €$_{2017}$/kW$_{HHV-Output}$ (Saba et al., 2017). A lot of progress between 2013 and 2017 has been made with the use of hydrogen in cars, whereby 6,475 hydrogen cars were sold (Kane, 2018). In order to keep developing in the future, an important improvement should be made in the infrastructure. This can already be done for blue and grey hydrogen, originate from natural gas (Van Wijk, 2018). Blue hydrogen also originates from natural gas with CO_2 emissions, only the CO_2 is stored underground (Van Wijk, 2018). Once the infrastructure for grey and blue hydrogen is available, a switch to green hydrogen is easily made when it is financial promising.

Japan has already committed itself to grey and blue hydrogen regarding this subject, following the tsunami and the nuclear disaster at Fukushima in 2011 (Mehta, 2018). To be able to encourage the rest of the world to make the same commitment, the logistic chains of hydrogen and coherent costs need to be clarified in a feasibility study. When the costs of the potential supply chains of hydrogen are intelligible, the integrated costs of a terminal can be determined. The realisation of such a study is in the interest of different firms. One of them is MTBS, who was involved in this research; an international finance and strategy advisory firm, that offers entrepreneurial business solutions to clients in the maritime and transport sector. MTBS anticipates an increase of hydrogen demand regarding potential port projects around the globe.

1.2 Problem statement

Energy distribution and storage in the form of hydrogen production is a potential candidate to accomplish the decrease of CO_2 emissions. However, to use hydrogen for distribution or storage, it must be compressed, liquefied or attached to a carrier due to its low volumetric energy density. At this moment, though, the most cost-effective method to import hydrogen is unknown (Li et al., 2019). The implementation of the import of hydrogen as an energy flow requires a better understanding of the needed infrastructure.

At this moment it is unknown what the costs of the supply chains of the different hydrogen carriers are in the various situations. Therefore, the different supply chains of hydrogen cannot be compared to each other and the one being most cost-effective cannot be identified. Even more, it is unknown how volume and distance affect the supply chain and what the contribution of the supply chain elements to the cost price per ton is. This price is the cost price considered from a supply chain perspective.

An important link of the supply chain is the import terminal, due to the crucial connection between sea and land transport, which supports the economic activities in the hinterland. The investment decisions of these supply chains for a specific import terminal are at this moment not fully clear. Therefore, knowledge about this link is crucial.

To summarize, at this moment the western world is in an energy transition, which requires a shift its supply chains. To generate this switch, knowledge on these aspects is needed. A better understanding of the cost price of the needed infrastructure for the import of hydrogen is necessary. MTBS is interested in producing knowledge to advice ports on the transformation. In order to get a better view on the cost price of importing hydrogen, research that examines the hydrogen supply chain and import terminal is needed. Therefore, this research focuses on identifying the cost parameters that are attached to the different hydrogen carriers supply chains for international import of hydrogen to make the cost price of the import of hydrogen transparent.

1.3 Research gap

Before this research was conducted, the research gap had to be defined. For this purpose, multiple research articles were examined. Research that covers a similar topic to the present one, are examined in this section. At first, an overview of existing research is given and the insights that can be gained from them. Subsequently, elements are presented that are relevant and thus taken into account. Both steps will ultimately result in the definition of the research gap.

At this moment, there is a lot of research to hydrogen because it can, among other thing, play a part in the Paris Agreement of 2015. Existing research states that mathematical optimization methods are the most effective ones to address the question of future hydrogen infrastructure design (Dagdougui, 2012). Next to this, it shows that the future Hydrogen Supply Chain (HSC) network is somewhat similar to the existing petroleum infrastructure in terms of production, distribution, and storage (Almansoori & Shah, 2006). The consideration of demand uncertainty in the HSC network may lead to significant changes in the structure and cost of the optimal HSC network (Almansoori & Shah, 2012). Low-cost HSC networks are found in high density urban areas, which reinforces the strategy of an initial staged or regionalized infrastructure roll out in large, dense urban areas (Yang & Ogden, 2007). When zooming in on hydrogen carriers and elements of the supply chain it can be concluded that the total efficiency of an ammonia system can be 22.5% and the total efficiency of a MCH system can be 18% (Obara, 2019). Liquid hydrogen as a seasonal storage medium offers no advantages compared to Liquid Organic Hydrogen Carriers (LOHC) or cavern storage, since lower electricity prices for flexible operations cannot balance the investment costs of liquefaction plants (Reuß et al., 2017). Results show that (1) Steam Methane Reforming (SMR) plants are preferable above electrolysis plants due to their large capacities, (2) Liquid Hydrogen (LH_2) storage facilities are rather used than H_2 storage facilities, and (3) transportation via tanker trucks rather than via tube trailers and pipelines (Kim et al., 2008). Lastly, the optimal design of the future HSC network of Great Britain starts with small-size plants together with using the hydrogen currently produced by chemical processing plants (Almansoori & Shah, 2009).

Based on these insights gained from earlier research, a three-step process had been identified. Firstly, the method had to be analyzed and shaped (Dagdougui, 2012). Secondly, the structure of the future hydrogen supply chain had to be analyzed (Almansoori & Shah, 2006). And thirdly, the hydrogen carriers for this research were selected based on former research, whereby the efficiency was examined (Obara, 2019). From existing studies, insights concerning the production, distribution and storage were gained, such as storage costs, the SMR as preferred production method and pipeline characteristics (Almansoori & Shah, 2012; Kim et al., 2008; Reuß et al., 2017). The results, regarding the fluctuation in cost price as function of demand, of the study by Yang were compared with this research (Yang & Ogden, 2007). The characteristics of the pipeline transport for gaseous hydrogen were validated with Moreno-Benito (Moreno-Benito et al., 2017).

While earlier research has produced knowledge on cost aspect of individual technologies of the HSC network, several aspects have been neglected so far. Earlier studies do not cover all elements of the intercontinental trade of hydrogen (Almansoori & Shah, 2006). Thereby, vessel transport and terminals were out of scope. The studies sometimes cover only one element of the general supply chain and therefore a comparison between the different supply chains cannot be made. Also, they neglected multiple hydrogen carriers. In these studies, the cost parameters of all the hydrogen supply chain element were not fully covered (Yang & Ogden, 2007; Reuß et al., 2017). A recently published paper gives an overview and reviews existing papers that pertain to the Hydrogen Supply Chain Network Design (HSCND) models published in scientific journals (Li et al., 2019). In this paper, the authors indicate that a "comprehensive study that encompasses all the echelons of an international HSC network" is lacking (Li et al., 2019). Accordingly, further research on this aspect is needed. This study demonstrates that the HSCND models currently focus on the use of domestic feedstocks for hydrogen production. International trades of hydrogen, however, may also provide win-win opportunities to both exporting and importing countries. Therefore, the main focus of the present study is the comparison of hydrogen carriers by international import of hydrogen.

To summarize, there are several studies on the cost parameters and individual technologies of hydrogen supply chains. Yet, in these studies the financial parameters of different hydrogen carriers of the international import of hydrogen have been neglected. A comparison of the international import of the various hydrogen carriers by vessels and pipelines are not covered in these studies. Insight into the build-up of the cost price of the imported hydrogen, concerning the supply chain, is yet to be gained. To fill this research gap, this research focuses on the cost price of the international import of hydrogen over sea with various hydrogen carriers by pipelines and vessels.

1.4 Research questions

The questions related to this research, consist of one main research question with two sub-questions. The sub-questions cover the hydrogen supply chains in general and the individual hydrogen import terminal located in Rotterdam. The port of Rotterdam has been chosen, due to their focus on clean, renewable and sustainable energy and due to the fact that it is the largest port in Europe (Castelein et al., 2019). In order to get a better view on the cost price of importing hydrogen, research is necessary in order to examine the hydrogen supply chain and import terminal. Therefore, this research focuses on identifying the cost parameters that are attached to the different hydrogen carrier supply chains for the international import of hydrogen, to make the cost prices of the import of hydrogen insightful. This objective can be summarized in the main question, noted as:

What is the most cost effective way to import hydrogen into the port of Rotterdam to supply the future hydrogen demand in the Netherlands, given a selected set of hydrogen carriers and export locations?

To answer this main research question, two sub-questions are answered. First the general supply chain is examined:

What is the impact of the selection of the export terminal and hydrogen carrier on the cost price of the imported hydrogen (on system level)?

A research on system level contains a feasibility study with a cashflow approach, whereby the financing is excluded. The cash flow approach is used for the valuation of the project, which divides the timescale of development into periods to which the cost flows can be more precisely applied. The selected hydrogen carrier types are ammonia, MCH, liquid hydrogen and gaseous hydrogen, see Paragraph 2.1.2 for a more in-depth analysis.

For this research, various locations around the world have been selected because of their high potential for the export of hydrogen (see Section 2.2). To answer this sub-question, the elements and calculation structure of the elements of the different hydrogen carriers need to be valuated, as well as the potential export countries.

To analyze the case study of an individual hydrogen import terminal in Rotterdam, the Netherlands, a more in-depth study is performed. The research question coherent to the import terminal is:

What are the integrated costs for the import terminal in Rotterdam for different hydrogen carrier types (on terminal level)?

The terminal level consists of a feasibility study with a cash flow approach, with a more in-depth analysis of financial parameters such as inflation and interest rate. The hydrogen carriers which are covered in the import terminal are ammonia, MCH and liquid hydrogen. Gaseous hydrogen enters the import country through pipelines and therefore an import terminal is unnecessary. To answer this second sub-question, the cost aspects of an individual hydrogen import terminal in the port of Rotterdam is modelled. With this model, the integrated cost of a hydrogen terminal can be analyzed and the cost of the supplied hydrogen can be estimated.

1.5 Research objective

The main objective of this research is (i) identifying the costs related to the different supply chains for hydrogen imports and (ii) the development of a parametric model that provides more insight into the impact of these supply chain costs on the total costs of imported hydrogen. The objective of the graduation company, MTBS, is providing insight into the cost parameters of the business cases of importing hydrogen, which can be used for feasibility studies for import terminals.

To fulfill this objective, the research will define different supply chains of hydrogen. Even more, a robust model is made for the comparison of the chains, when for example, changing the export country. With this model several questions can be answered, such as the optimal supply chain route (i.e. the route with the lowest import cost). The supply chain can be optimized for different throughput volumes, hydrogen carriers and export locations. The model allows (1) to analyze the individual technologies of the elements of the hydrogen supply chain, (2) to adjust demand rates and import countries and (3) to determine the optimal supply chain of importing hydrogen for a given throughput.

The second objective is to assess the feasibility for an individual import terminal in the port of Rotterdam. Using a different model for this terminal makes it possible to analyze the investment strategy in order to minimize the import cost of hydrogen. Another purpose of this model is to gain insight into various aspects, such as space requirement.

This research discusses the cost parameters of the hydrogen supply chain, whereby a more in-depth analysis will be made for the import terminal. Therefore, two models are developed; the analysis of the general supply chain and a specific cash flow model for the individual import terminal. Where possible, the available costs of the components are used and where necessary, estimates are made using a cash flow analysis.

1.6 Research scope

The first link of the supply chain is hydrogen in the export country and the last link is the conversion back to hydrogen in the import terminal of the import country. Therefore, the import supply chain is defined from hydrogen to hydrogen. The included aggregation state of the hydrogen carriers are liquid and gas, eliminating the use of solid materials. The hydrogen carriers are ammonia, methylcyclohexane (an oil product), liquefied- and gaseous hydrogen. The links of the different hydrogen supply chains for each carrier are examined on a high level and therefore the specific techniques are not thoroughly explored. The comprehensive scope of the model is defined in Chapter 2, based on a literature study.

1.7 Research method

Due to the mathematical nature of the research questions, and in order to account for the substantial uncertainty in key input data, custom built parametric models are used to conduct analyzes. A model for this research needs to contain high level data structures, due to the preliminary state of the problem. The essential characteristic of a model should be the abstraction of information, analysis, simulation and validation. Parametric models are used for the feasibility study, with a cash flow approach. A parametric model has a fixed number of parameters capturing all its information about the data within those parameters (DesignTech, 2016). The benefits of this method is that it is easier to make assumptions about the data (DesignTech, 2016). The cash flow approach is used for the valuation of the project, which divides the timescale of development into periods to which the cost flows can be allocated. The future cash flows are discounted by the cost of capital to give their present values. Discounted cash flow is a valuation method used to estimate the value of an investment based on its future cash flows (J. Chen, 2018).

The research contains two models to answer the main research question and to fulfil the research objective; the general supply chain model and the terminal investment model. The general supply chain model gives insight into the costs for all the different elements, given an annual hydrogen throughput. This model includes a general terminal, without taking into account factors as inflation, finance and tax to generate an exploratory feasibility model. Therefore, a pre-tax, pre-finance model is defined instead of more in-depth analysis such as a bankable feasibility. The import terminal investment model will serve as a case study, where the input values of the supply chain model will be used. They will be used in a specific framework for the terminal in Rotterdam to gain a cost price with more in-depth knowledge, to assess the feasibility for an import terminal in the port of Rotterdam (post-tax, post-finance). In this case, factors like inflation will be taken into account to generate a cash flow model.

The two programming tools that were used for the construction of the models are Excel and Python. Excel is user-friendly and can be reviewed systematically, however it has less capability regarding non-linear computations. Python's benefits are its easy implementation of probabilistic calculations and solid structure. Another reason to use Python is the great capacity to solve large amount of mathematical problems and that it is a shareware. Using Matlab for these computations would be an option as well, but since Python has a better user friendliness and is more widely used, resulted in the choice for Python above Matlab. Due to these reasons, Excel is used for the overall model of the supply chains, of which the data is later used in Python for further enhanced calculations for the single hydrogen import terminal.

A part of the research method is to collect data regarding the selected input parameters of the model. The input parameters of the elements and cost factors of the supply chain are based on:

1. A literature study;
2. The Hychain model of the company ‘Kalavasta’, which evaluates the import costs of renewable electricity, hydrogen and hydrogen carriers;
3. Database of MTBS;
4. Interviews with experts.

This data collection has been done with the help of data sheets. Quantitative data (statistics and qualitative data), such as knowledge of the concept, is obtained with the help of a literature study. Information regarding the method and cost components of the elements, is gathered from papers, studies and presentations from business people and researchers. The model of the company ’Kalavasta’ has been used for the first set-up of the model. This model evaluates the import costs of renewable electricity, hydrogen and hydrogen carriers. Hereby, the applied cost parameters of the supply chain elements and the calculation structure of the model has been evaluated and practiced. This model is conducted in cooperation with DOW, Vopak, ECN (part of TNO), Port of Rotterdam and Yara and therefore this model contains a lot of perspectives. Eventually, all cost parameters obtained from the Kalavasta model are validated and adjusted using a literature study. For additional confirmation, this data has been cross checked with interviews. Interviews usually yield detailed data and new insights. The database of MTBS is used for cost parameters of the terminal, the terminal design, the methodology for the traffic forecast, the import trade of the Netherlands. For a more in-depth explanation on which data is used for the various input parameters see Appendix B.

1.8 Report outline

This research consists of seven chapters. In Chapter 2, the elements of the hydrogen supply chain will be evaluated, with the help of a literature study. Also, the scope of the research is outlined. Chapter 3 introduces the calculation structure of the general supply chain model and of the import terminal investment model. It introduces both models, focusing on the model outline and calculation structure of the elements of the supply chain. Chapter 4 gives an analysis of the results of the general supply chain model. The cost of the different elements of the supply chain are discussed as well as the effect of the various input parameters and distance. In Chapter 5, the cost price of the hydrogen import terminal is defined and reflected upon. Whereby, the optimal hydrogen import supply chain for the port of Rotterdam is defined. In Chapter 6, the discussion and conclusions will be drawn by answering the main research question, but also critically reflecting on the assumptions. Lastly, Chapter 7 is dedicated to recommendations for further research, regarding the hydrogen import supply chain.

2 Literature study concerning the hydrogen supply chain

At this moment, the financial parameters of different hydrogen carriers for the international import of hydrogen are unexplored. To provide a good method, a couple of aspects are altered such as the elements of the supply chain and the countries. Therefore, in this chapter the elements of the parametric hydrogen supply chain model will be evaluated, to identify them for every hydrogen carrier. First, the elements of the supply chain are discussed (see Section 2.1). Second, an analysis is carried out to see which countries are suitable as export/import terminal (see Section 2.2). The last part of this chapter will discuss the conclusion regarding the scope (see Section 2.3).

2.1 Definitions of the supply chain elements

In this section the different elements of the supply chains are evaluated, which are shown in Figure 2.1. During the analysis it will become clear which elements will be included in the supply chain and what their characteristics are.

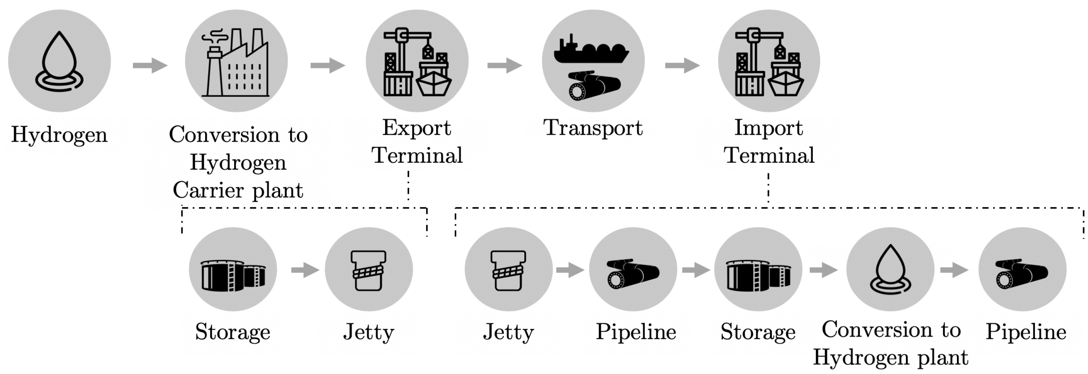


Figure 2.1: Supply chain overview

The supply chain starts with the existence of hydrogen in an export country. The next element is the conversion to the hydrogen carrier, whereby the hydrogen is converted to various hydrogen carriers. The third element in the supply chain is the export terminal, including storage and loading of the vessels. Next is the transportation of hydrogen, which can be conducted by vessels or pipelines. The last element of the supply chains is the hydrogen import terminal. The import model consist of a jetty, pipelines, storage and a H_2 retrieval plant.

2.1.1 Hydrogen

Determining the possible import route starts by analyzing the costs of hydrogen, concerning the hydrogen sources and production methods. There are a lot of different hydrogen sources, such as natural gas and renewable energy. If the electricity used for the hydrogen production originates from renewable energy, it is called green hydrogen (Van Wijk, 2018). This green hydrogen is a carrier of renewable energy without CO_2 emissions. Hydrogen can also originate from natural gas, resulting in grey hydrogen with CO_2 emissions. The third type of hydrogen is called blue hydrogen, which also originates from natural gas with CO_2 emissions, but this time the CO_2 is stored underground which is defined as Carbon Capture and Storage (CCS) (Van Wijk, 2018).

At this moment fossil fuels are dominating our energy consumption, which can be seen in Figure 2.2. The global energy production in 2016 consists of 48% natural gas, 30% oil, 18% coal and 4% electrolysis (EIA, 2019). In other words, around 95% of the energy production is fossil-fuel based (Van Beek et al., 2017). The purity of hydrogen with fossil fuel sources is less than the purity of hydrogen created by renewable energy, due to the impurities of fossil fuel. When hydrogen is produce with fossil fuel, an extra step is included to ensure that the hydrogen contains a high purity.

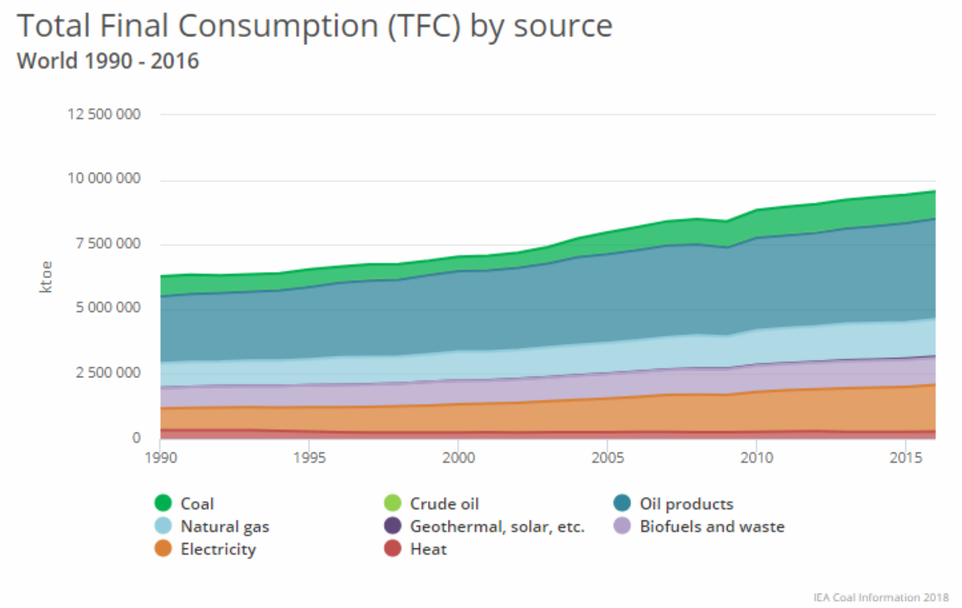


Figure 2.2: Global energy consumption in ktoe divided by source (EIA, 2019)

The production capacity of sustainable energy is globally growing (see Figure 2.3). With technical innovations, a rapid decline of renewable energy cost is established (IRENA, 2018a). In 2017 the first offshore wind project was offered at market prices in Germany without requiring subsidy (EIA, 2019). It is expected that the costs of renewable energy will decrease further in the future, with the prospect that the costs of solar PV in 2020 will be 50% of that in 2015-2016 (EIA, 2019). With these renewable energy prices, it will become competitive with other energy sources.

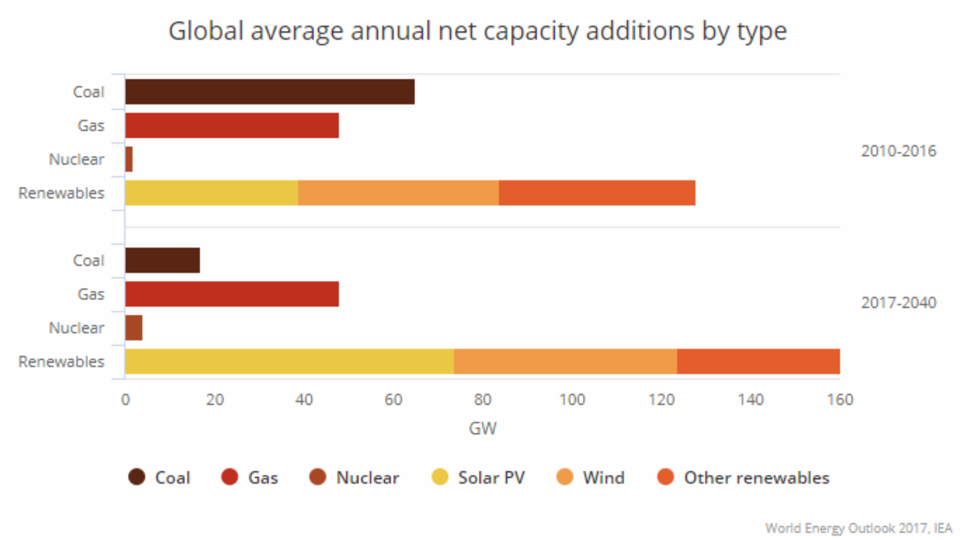


Figure 2.3: Global average net capacity by type (EIA, 2019)

At this moment hydrogen produced by natural gas is more cost effective than by renewable energy. But due to technical innovations and more CO_2 tax implementations, renewable energy can be competitive in the near future. For these reasons, the include sources of hydrogen are renewable energy as well as natural gas, considering the lowest costs at various moments.

The production of hydrogen can be done with various techniques, such as AutoThermal Reforming (ATR), Partial Oxidation (POX), SMR, Polymer Electrolyte Membrane (PEM) and Alkaline Electrolysis Cell (AEC). SMR is the most common way regarding natural gas sources (EIA, 2019). Hydrogen from electrolysis is mainly produced with AEC (Taibi et al., 2018). Other reasons to choose the AEC method are the low capital cost, its great availability and the fact that it is widely used already for large-scale industrial applications since 1920 (Schmidt et al., 2017). For an in-depth explanation about the hydrogen sources and these production methods, see Appendix A1 and Appendix A2.

2.1.2 Conversion to hydrogen carrier

Hydrogen is difficult to store because of the low density and low boiling point. Therefore, it is stored under high pressure or under a temperature of -253 °C (Brynolf et al., 2018). Storing hydrogen by binding it to another substance could be favourable for the transport/storage of the feedstock, due to lower storage space and a reduction in transportation cost (Gasunie, 2018). Hydrogen can be attached to a lot of substances, such as methanol, ammonia, formic acid, ethanol, dibenzyltoluene, methylcyclohexane and sodium borohydride. The four carriers of hydrogen in this research are Ammonia (NH_3), MCH, LH_2 and H_2. The two hydrogen carriers, H_2 and LH_2, were chosen for this research because they are a pure form of hydrogen, with no efficiency losses during its transformation. The other two hydrogen carriers were chosen because of their auspicious storing conditions and because research has found them to be of great potential (Ozawa et al., 2018). MCH has a lot of similar storing conditions to oil and NH_3 is very similar to Liquefied Petroleum Gas (LPG), so a comparison can be made with existing supply chains. Dibenzyltoluene, methanol, formic acid, ethanol and MCH consist of similar characteristics. At this moment the first hydrogen supply chain is generated with MCH by Chiyoda (Chiyoda corporation, 2017). Therefore, this commodity has a large potential and information is available. Due to these reasons, the other commodities are excluded of this research, such as dibenzyltoluene, ethanol, formic acid and ethanol. The hydrogen carriers are chosen such that they all contribute to liquid bulk, for that reason sodium borohydride (dry bulk) has been left out of scope. See Appendix A3 for the properties of the enclosed commodities.

Ammonia is one of the potential feedstocks due to the CO_2 neutral electricity storage, generation of electricity on a large scale without a limitation of the scarcity of materials or storage space and the fact that in a single step thermal cracking only gives hydrogen and nitrogen as byproducts (ISPT, 2017; Abashar, 2018). Ammonia has a high volumetric storage efficiency regarding H_2, a favourable energy density and low cost of nitrogen sourcing (ISPT, 2017). On the other side, decomposing ammonia to release the hydrogen requires significant energy which can cause a serious barrier (Te Roller, 2018).

MCH is a reaction product of hydrogen and toluene, which can be recycled. MCH is stable at room temperature and atmospheric pressure and can be stored and transported using conventional petrochemical equipment (Hinkley et al., 2016). MCH is able to survive transportation over long distances and storage over long periods of time. The heat consumption of the endothermic dehydrogenation is less than that of ammonia (Irfan Hatim et al., 2013). However, the hydrogen content and volumetric storage efficiency are low. The dehydrogenation of MCH had been considered as difficult in the past (Mizuno et al., 2017). Yet, the Chiyoda Corporation has developed an innovative catalyst for dehydrogenation in 2014 (Chiyoda corporation, 2017).

Liquefied hydrogen has a temperature of -253 °C, which is very energy intensive and has a high volumetric storage efficiency. Liquid hydrogen is recognized as an established commodity in industry, nonetheless technology development is still necessary, such as the up-scaling of its production and the construction of vessels for transportation (Hinkley et al., 2016). Kawasaki Heavy Industries Ltd. is developing the first liquefied hydrogen cryogenic vessel for marine transportation, which would be able to operate by 2020.

Hydrogen gas can be transported with a pressure of 700 bar at ambient temperature with a high power to power efficiency (Rivarolo et al., 2018). The most common method to transport and store hydrogen gas is hydrogen compression and storage in high-pressure tanks or in salt caverns (Hydrogen Europe, 2018). Hydrogen gas has a high energy consumption and contains disadvantages regarding safety (highly flammable), despite the fact that the technology is well known (Rivarolo et al., 2018). A pipeline network would be an option for the comprehensive and large scale use of hydrogen (Hydrogen Europe, 2018).

2.1.3 Export terminal

The export terminal consist of a liquid bulk terminal layout due to the concerning hydrogen carriers, taking into account the storage and jetty. The size of the storage area for oil and liquid gas depends on the number and dimensions of the tanks and the distance between these tanks. Oil tanks, such as a conventional chemical tank for MCH, contains safety criteria. A safety criteria is that each tank is surrounded by a concrete or earth wall at specified distance and height, that whenever a full tank collapses, the oil can be contained within the bund (Ligteringen & Velsink, 2012). Ammonia is stored in a refrigerated tank with a capacity of 15,000 to 60,000 ton and liquefied hydrogen in a cryogenic tank (ISPT, 2017). Liquid hydrogen storage is more dangerous than oil storage, therefore a safety zone and a special safety provision is needed (Wang et al., 2018).

Hydrogen gas can be stored in salt caverns. Salt caves storage concern a series of caves leached from the deep, thick layers of rock salt (Engie, 2018). Leaching is a process whereby minerals are extracted from a solid substance by means of dissolution in a liquid (Engie, 2018). Hydrogen gas is injected and stored under high pressure, in gaseous form (Engie, 2018). Storage of hydrogen in salt caverns is an established practice (Crotogino, 2016). A constrain might be the availability of salt caverns for hydrogen storage (see Figure 2.4). In the Netherlands, storage of hydrogen gas in salt caverns is possible in large quantities (Van Wijk, 2017). Near Veendam, there are ten salt caverns, whereby at least three of which can be made available for hydrogen storage (Van Wijk, 2017). Salt caverns can have geometric volumes up to 1,000,000 m^3 (Oldenbroek et al., 2019). A salt cavern of 500,000 m^3 has a capacity of approximately 3,733 ton H^2 at a pressure of 180 bar (Oldenbroek et al., 2019). For an in-depth explanation about salt caverns, see Appendix A4.

The loading of the vessels is performed by shore-based pumps, such as hoses and loading arms, with a net hourly loading capacities of 10% of their deadweight tonnage (Ligteringen & Velsink, 2012). Unloading is performed by ship-based pump. Due to the liquid state of the commodity, offshore loading by means of pipelines and hoses is allowable. In case of MCH, this can be done through sub-marine pipelines and floating single-point moorings (Ligteringen & Velsink, 2012). The technology for sub-marine cryogenics pipelines and single-point moorings for refrigerated gases, such as ammonia and liquid hydrogen, has not yet been developed (Prescott, 2017).

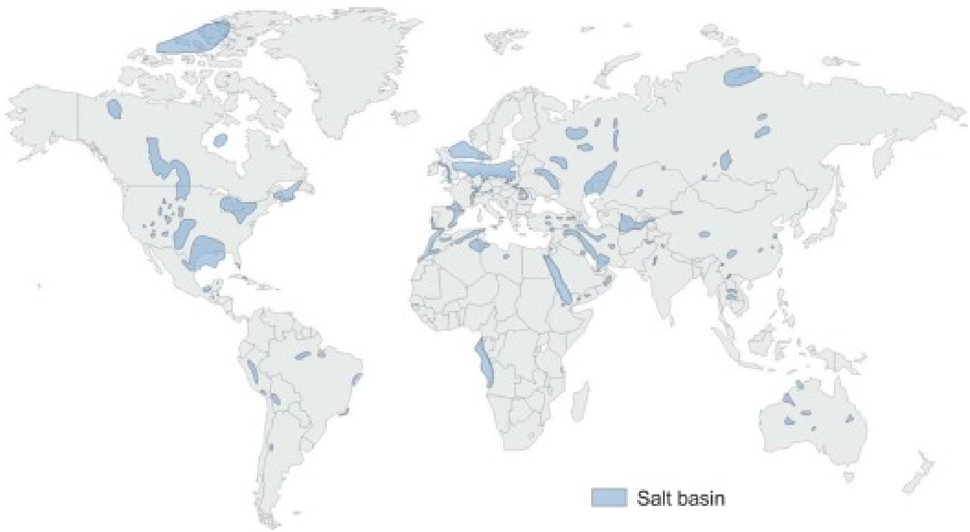


Figure 2.4: Map of underground salt basins worldwide (Donadei & Schneider, 2016)

2.1.4 Transport

It is plausible that hydrogen will be imported from regions with favorable circumstances, such as the MENA region (Middle East and North Africa). The transportation of hydrogen can be done in multiple ways, for example over sea with pipelines or vessels, or over land with trucks or pipelines (Wulf & Zapp, 2018). This report only discusses the transportation of hydrogen overseas with pipelines and vessels, due to the field of study and the scoped oversea trade of hydrogen. The existing pipelines used for natural gas can be used for the transportation of hydrogen with (almost) no adjustments (Hermkens et al., 2018). In 2016 worldwide there existed more than 4,500 km of hydrogen pipelines, of which 2,600 km originated from the USA (Shell Deutschland Oil GmbH, 2017). If the infrastructure is absent, a number of issues have to be taken into account while constructing pipelines over a long distance (Van Niekerk, 2018):

- The need to cross "transit countries" which increases costs;
- There is a need to follow the geography of the ground which can be expensive or challenging, for example crossing an area with mountains;
- The need for the market to accept the full flow through the pipeline as soon as it comes into service, as long-distance pipelines are only financially feasible if they can transport large quantities of gas.

A vessel can be used for the transportation of hydrogen over a long distance. This is done when the port does not want any dependency on a certain location (occurs with a pipeline, due to its life span) and/or the port having an unfavorable geographical location (Wulf & Zapp, 2018). The different feedstocks of hydrogen contains all different characteristics, therefore corresponding types of vessels are required (Ligteringen & Velsink, 2012; Kawasaki Heavy Industries, 2018):

- Ammonia is transported with a LPG vessel (with a temperature of -33 °C and a capacity of 10,000 to 266,000 m^3);
- MCH is transported with chemical tankers/oil tankers (with ambient pressure and -temperature containing a capacity of 20,000 to 442,000 ton);
- Liquefied hydrogen with a liquefied hydrogen carrier (expected to be operating in 2020 with a temperature of -253 °C.

2.1.5 Import terminal

The most important parameters for a terminal design are cost, safety and reliability (Ligteringen & Velsink, 2012). A main factor of a terminal design is how the feedstock is imported, considering different storages and methods for the conversion to hydrogen. Another important factor is the throughput of the terminal, which determines the capacity and the possible expansion of the terminal. The terminal design of importing hydrogen is a liquid bulk terminal or a dry bulk terminal. Due to the selected hydrogen carriers, only a liquid bulk terminal will be included in this section. For an elaboration of the dry bulk terminal see Appendix A5. Compressed hydrogen gas does not enter the port, but is connected to the gas pipeline system which is for a big part already existing in the Netherlands (Van Wijk, 2018). Therefore, the hydrogen import terminal is only designed for ammonia, MCH and liquid hydrogen and not for gaseous hydrogen.

The unloading of liquid bulk will be performed by ship-based pumps. The unloading capacities of a liquid bulk terminal are rather high and have capacities up to approximately 25,000 t/h for crude oil, like MCH and 25,000 m^3 per hour for Liquefied Natural Gas (LNG)/LPG (Ligteringen & Velsink, 2012; Petitpas & Aceves, 2018). Vessels smaller than 250,000 ton can unload 10% of their dead weight tonnage per hour (Ligteringen & Velsink, 2012). The included jetty design is a L-shape jetty (see Figure 2.5). The transportation from the vessel to the storage will be done with pipelines.

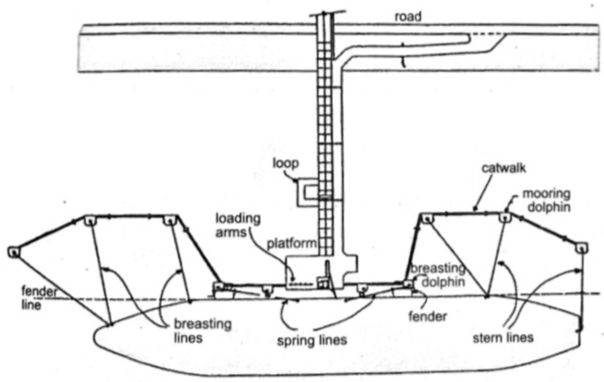


Figure 2.5: The design of a jetty from above (Ligteringen & Velsink, 2012)

For safety reasons, it is preferable that the storage of the liquid bulk is conducted at a distance of other activities. A temporary storage is included in the import terminal, prior of the H_2 retrieval plant. Seasonal and large scale storage will take place in empty salt caverns, whereby all the commodities are converted back to hydrogen gas. Compressed gas which enter the import country through a gas pipeline system, is also stored for seasonal and large scale storage in empty salt caverns. Therefore, the supply chains of the hydrogen carriers are equivalent and thus comparable. This is a stage after the import terminal and therefore outside the scope. In Paragraph 2.1.3, the storage of the different hydrogen carriers are discussed.

Dehydrogenation of the hydrogen carrier occurs while processing ammonia and MCH, which is an endothermic reaction. The decomposition of ammonia is a single step endothermic reaction (Abashar, 2018):

$$2NH_3 \Longleftrightarrow N_2 + 3H_2 \quad [\Delta H = 54.6kJ/mol] \tag{2.1}$$

The endothermic reaction can take place for example in a single fixed bed membrane reactor or in a cascade of multi-stage fixed bed membrane reactors with inter-stage heating (Abashar, 2018). The dehydrogenation process of MCH was developed by Chiyoda Corporation using a simple tubular reactor with a catalyst in the fixed bed (ChiyodaCorporation, 2014).

The toluene, C_7H_8, is extracted from the MCH, C_7H_{14} (see Equation 2.2). Different experiments proved that a fixed-bed reactor is a suitable catalyst for MCH dehydrogenation reaction (Abashar, 2018). A fixed-bed reactor is a cylindrical tube filled with catalyst pellets with reactants flowing through the bed and being converted into products.

$$C_7H_{14} \Longleftrightarrow 3H_2 + C_7H_8 \quad [\Delta H = 205kJ/mol] \tag{2.2}$$

2.2 Evaluating countries as import/export location

In this section, the export and import countries are selected on different assumptions. They are specified on four conditions: (1) The first conditions is the need to be spread around the world; (2) The second conditions is that they need to have a high potential for transporting hydrogen; (3) The countries needs to have a port, therefore the location have direct access to sea/ocean; (4) The last conditions is that the country has natural gas sources and low renewable energy prices.

With the first conditions, the need to be spread around the world, various distances are taken into account. The second item is that they have potential to transport hydrogen, otherwise the country is left out of the scope. The third condition is that they need to contain a port, due to the fact that sea transport is included and road transport is excluded. The last condition is that the countries need to have low renewable energy prices in 2050 and therefore, green hydrogen export can be possible in the future (Terwel & Kerkhoven, 2018). An in-depth analysis is conducted into the potential of renewable energy per selected country, including wind and sun energy (see Appendix B2). To include grey hydrogen in the research, natural gas is needed. Therefore, it is desired that the countries have access to their own natural gas production or import natural gas (Enerdata, 2018). With this, the available sources are defined and a specification of the criteria of the countries can be found in Appendix B1. The global generation of renewable electricity needs to expanded significantly to export large quantities. Most countries does not yet contain a plan to fulfil this expansion (Terwel & Kerkhoven, 2018). Norway seems the only country which is likely to export small quantities before 2030 (Terwel & Kerkhoven, 2018).

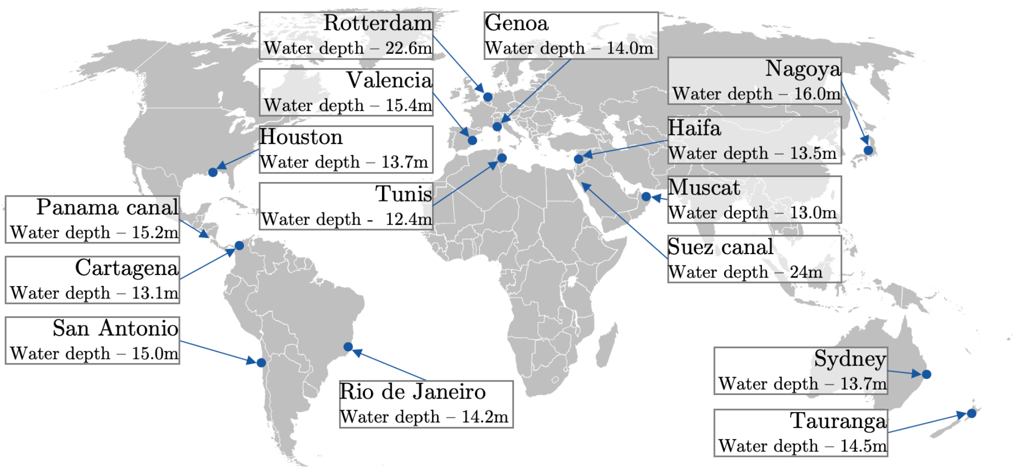


Figure 2.6: The different import/export terminals and canals around the world (IHS, 2019)

In Figure 2.6, the different scoped import/export terminals around the world and crossing canals are shown. The depth of the liquid bulk terminal at the various ports and canals can be found in Figure 2.6. As can be seen, the lowest water depth is in Tunis with a depth of 12.4m. The water depth of the Panama canal consist of 15.2m. When evaluating the vessels of the supply chain, the geographical boundary conditions of the terminals and canals can be recognized.

2.3 Conclusion

This section addresses the scope of the research (see Table 2.1) regarding the supply chain elements and countries, whereby insight in the characteristics of the elements are given. Providing an answer to the identification of the elements for every hydrogen carrier.

Supply chain	Applied methods	Out of scope
Hydrogen	Fossil fuels (SMR) and renewable energy (Alkaline)	ATR, POX and PEM
Conversion to hydrogen carrier	NH_3, MCH, LH_2 and H_2	Sodium borohydride and remaining
Export terminal	Liquid bulk terminal lay-out	Dry-bulk lay-out
Transport	Vessel and pipelines	Road transportation
Import terminal	Liquid bulk terminal lay-out	Dry-bulk lay-out

Table 2.1: Scope of the model

The first facet of the supply chain is hydrogen, produced from natural gas or renewable energy. The four carriers of hydrogen in this research are NH_3, MCH, LH_2 and H_2. NH_3 and MCH are produced with a conversion plant. LH_2 on the other hand, is liquefied from gaseous hydrogen. Gaseous hydrogen does not need to convert, so there is no need for a conversion plant. The interacting of the different chains for every possible carrier is shown in Figure 2.7. The export terminal includes storage and a jetty with loading equipment. Storage of MCH has been done in oil tanks, ammonia is stored in a refrigerated tank, liquid hydrogen in a cryogenic tank and hydrogen gas is stored in salt caverns. The considered modes of transport are pipelines (gaseous hydrogen) and vessels. Ammonia is transported with a LPG vessel, MCH with a chemical tanker and liquid hydrogen with a liquefied hydrogen carrier. The chosen import terminal design is a liquid bulk terminal. In the import terminal design only the unloading, transport, storage and conversion to hydrogen gas is included. Only temporary storage is included in the import terminal.

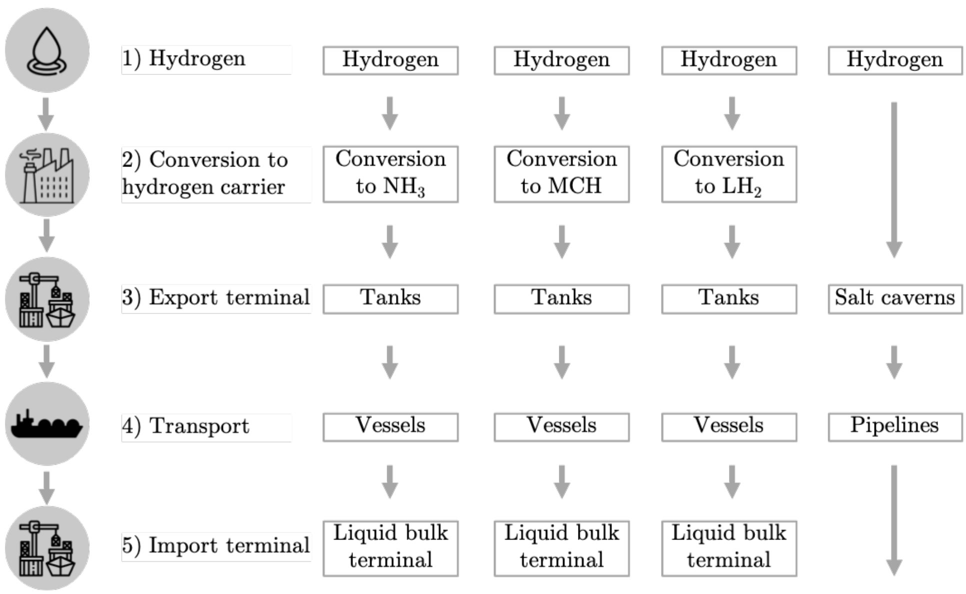


Figure 2.7: Supply chain of the different hydrogen carriers

3 Models setup

This research uses two models to answer the main research question and to fulfill the research objective; the general supply chain model and the import terminal investment model. The general supply chain model provides insight into the costs of each of the elements in the supply chain, given an annual demand and predefined import & export locations. The terminal investment model enables a more granular assessment of the hydrogen cost price for a specific case study; the selected case study concerns a hydrogen import terminal in the port of Rotterdam. This chapter addresses the question of how the elements of the general supply chain and import terminal are modeled. In Section 3.1, the structure of the general supply chain is evaluated. In Section 3.2, the structure of the terminal investment model is analyzed. Lastly, the conclusion regarding both models is given in Section 3.3. The assumptions made in the models are found through solid reasoning. Altering them could result in a slight difference in the output.

3.1 Setup of the general supply chain model

In this section, first the modelling objective will be discussed. Subsequently, in Section 3.1.2 the model design and implementation are outlined, in which the layout of the model is given and the triggers and boundary conditions are discussed. Subsequently, the import location and demand are analyzed in Section 3.1.3. Afterwards, the elements of the supply chain are elaborated in Section 3.1.4, whereby the input values and calculation structure can be found in Appendix B and Appendix C respectively. The validation of the model can be found in Appendix E.

3.1.1 Modelling approach & objective

The first model of this research is the general supply chain model. The cost parameters of importing hydrogen are evaluated with a model, capable of generating a supply chain design and corresponding cashflows for multiple hydrogen carriers and export/import locations. The objective of this model is to give insight in the costs of the hydrogen supply chain for any selected set of preferred parameters.

The model contains the overall supply chains of the different hydrogen carriers with a high level of financial analysis. It should be noted that this is a cost model and not a pricing model. The Flexible, Appropriate, Structured and Transparent (FAST) standard is used to built the financial model. The general supply chain model is therefore flexible, appropriate, structured and transparent (FAST Standard, 2018).

- Flexible - “To be effective, the structure and style of models require flexibility for both immediate usage and the long term”.
- Appropriate - “Models must reflect key business assumptions directly and faithfully without being cluttered in unnecessary detail”.
- Structured - “Rigorous consistency in layout and organisation is essential in retaining the model’s logical integrity over time, particularly as a model’s author may change”.
- Transparent - “Effective models are founded upon simple, clear formulas that can be understood by other modellers and non-modellers alike”.

The financial performance of a supply chain is evaluated using the cash flow statement that result from the supply chain design. A cash flow model is a financial statement with aggregated data regarding all in- and outflows of cash regarding a company's ongoing activities during a certain period (J. Chen, 2018). The cash flow statement is established by translating the various investments and operational expenses into cash flows during the project period. Following the fluctuations in hydrogen demand, the model ascertains the need to expand any of the components of the supply chain, resulting in additional investment costs and increased operational costs. Each new asset contains operational expenses, such as labour, energy and maintenance costs. The argumentation for the use of a cash flow model is given in Section 1.7. The supply chain elements contains two major cash flows, Operating Expenses (OPEX) and Capital Expenditure (CAPEX). The hydrogen cost price can be constructed with discounted cash flows over the project's period. The discounted cash flows express the present value of cash outflows over a project's lifetime (J. Chen, 2018). They are generated with a discount rate, which contains different approaches such as a Weighted Average Cost of Capital (WACC), risk free interest rate plus a certain risk premium with a required profit margin or rate prescribed by the government or a development bank (Van Dorsser, 2018). WACC represents the investor's opportunity costs when taking the risk of investing in a company (J. Chen, 2018). The WACC is adopted as discount rate, which is suitable for large companies in which a relative small investment does not change its financing structure. The risk free interest rate plus a certain risk premium can provide a more favorable observation, although more specific information is often requested. Therefore, in order to generate a high level view, the WACC is used including an adjustment for inflation and without taking into account the tax. So, the WACC with its real values and pre-tax is adopted in the model, and therefore adjusted for changes in general price levels.

The cost of the supply chain drives the key performance indicator for the project's financial performance. By evaluating the financial implications of various hydrogen supply chains, the model provides insight into the optimal supply chain for a given import country. The optimal hydrogen supply chain is defined as the supply chain that minimizes the logistics chain cost while ensuring that hydrogen demand can be accommodated. Therefore, the objective of this model is to give insight in the costs of the hydrogen supply chain for any selected set of preferred parameters.

3.1.2 Model design & implementation

In Figure 3.1, the overall overview of the model is visualized. The model defines the most cost effective option for the import of hydrogen while ensuring that the demand can be fulfilled. The determination of the import costs starts by defining the links and methods of the different supply chains with the corresponding cost elements. The different elements of the supply chain are connected since a certain volume is connected to the capacity of the different elements of the supply chain and the scale-up possibilities. The elements of the supply chain consist of the conversion to hydrogen carrier, export terminal, transportation and import terminal. The export terminal consists of storages and jetties and the import terminal consists of jetties, pipelines, storages and H_2 retrievals. The supply chain model is a parametric dimensioning of the logistic chains, assessing the import cost as a function of distance, volume, hydrogen carrier, input values and constraints:

$$\min_{costprice} \quad f(location, volume, hydrogencarrier, inputvalues, constraints) \tag{3.1}$$

The financially most advantageous supply chain can be recognized for a discrete number of import countries. Using this model, different supply chains can be identified for each combination of input parameters and an optimal supply chain regarding the minimum cost price can be recognized.

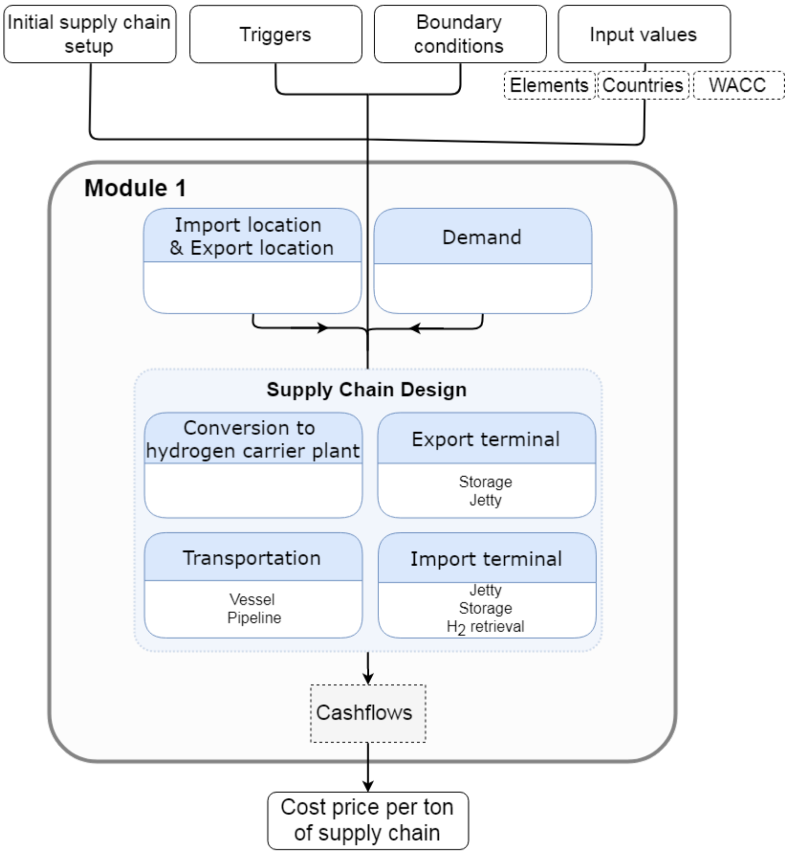


Figure 3.1: Overall outline of the general supply chain model

Initial supply chain setup

A project may use the existence of older supply chain elements, which already features certain supply chain assets at the start of the development. This is called a brownfield deployment, which occur when an entity purchases or leases an existing facility to begin new production. For the reinvestment of assets in this initial supply chain setup, it is required to examine the lifetime of the assets. On the other side, a greenfield deployment is the investment and configuration of a network where none existed before (Rouse, 2008). In this model the existing supply chain infrastructure (or the initial supply chain set up) is modeled as a greenfield deployment.

Triggers

When demand increases, the residual capacity of an asset will decline, reducing the performance of an asset. Design assumptions linked to the individual performance of assets are therefore referred as performance triggers within this research. Performance triggers are important for evidence-based conservation's to make decisions about when and how to intervene in systems (Cook et al., 2016). When triggering the assets on reactive mode, the investment starts when the allowable trigger is exceeded. When triggering on future base, the expansion is already satisfied when the trigger exceeds its allowable limit.

The type of performance triggers used in the general supply chain model are the forward-looking decisions. Forward-looking decisions do not take into account long-term consequences (Bonfiglioli & Gancia, 2013). The triggers are based on perfect foresight. Expansions are based on future demand volumes and are therefore implemented in the year in which demand exceeds capacity, minus the number of years required for construction. Therefore, the throughput is always equivalent to the demand. For example, in 2025 the capacity of the conversion to hydrogen carrier plant is not sufficient anymore and therefore the trigger will react in 2022, since the construction period is three years. Accordingly, the demand will always be achieved.

Boundary conditions
In order to be able to compare the different supply chains, it is important to establish the same set of boundary conditions for each separate supply chain. The work method for all supply chains is equivalent. The design assumptions of the different elements in the supply chain are based on data collection from multiple interviews with experts and employees of companies such as Gasunie, port of Rotterdam and Vopak. The adopted boundary conditions are:

- A design assumption is that the import demand is always fulfilled. As the import demand increases over the years, the residual capacity of the different elements will decline. Therefore, whenever the capacity is insufficient to accommodate demand, expansions are triggered for the elements that constrain demand.
- The supply of hydrogen is assumed to have no boundaries, because of this there is no volume restriction on the export supply. This assumption is not based on common practice, but this is assumed for the simplicity of the model.
- The conversion plant and storage are located in the export country and therefore is assumed that it contains the export country input parameters such as labour. The transportation is in-between the export and import country and for this reason, contains the most favourable parameters of the selected export and import country. The cashflows of the import terminal are derived with the parameters from the importing country.
- The WACC is considered as method for the discount rate and is derived on a company base for the gas sector with real values (see Paragraph 3.1.1). Many companies in this sector are vertically integrated and control all elements in the supply chain, therefore only one WACC is taken into account and not multiple WACC's for the various elements of the supply chain. When studying the elements separately, the elements will contain a WACC based on a company in the country in which the element is located. It is common practice that each company mostly prefers their own selected WACC, which presumable differs from the WACC's given in the model. In Appendix D, a more in-depth explanation and calculation structure of the WACC is given.

Input values
The input values for the model can be time-, place- and concept varying. The input values contain the costs of the different elements of the supply chain and general information such as electricity- and hydrogen prices. The selected countries are included in the supply chain model as export and import locations. For each country, different aspects are included such as wages, distance and discount rate. The data is obtained from a literature study, interviews with experts and employees of companies, from the MTBS database and the model of Kalavasta, named "HyChain II, the cost implications of importing renewable electricity, hydrogen and hydrogen carriers into the Netherlands from a 2050 perspective". The elaboration on these databases are given in Section 1.7 and the input values are given in Appendix B, with the corresponding data sources.

3.1.3 Import location & demand

The import location is selected from one of the pre-defined countries (see Section 2.2). For each of these import locations, the most favourable combination between an export location and a hydrogen carrier can be established. Every import location has a coherent demand, which can be set manually before running the model. To give an example, the demand of the import terminal in Rotterdam has been evaluated below, which is also the country of the case study.

For the estimated demand in the port of Rotterdam, a long term cargo projection has been made. A long term cargo projection can be made either with the use of assumptions, forecastings or scenarios (Van Dorsser, 2018). The selected method for this projection is forecasting, which consists of a level 1 approach (see Figure 3.2). The aim of forecastings is to provide a single reliable expectation of the future system, based on trend extrapolation techniques and expert judgment (Van Dorsser, 2018).

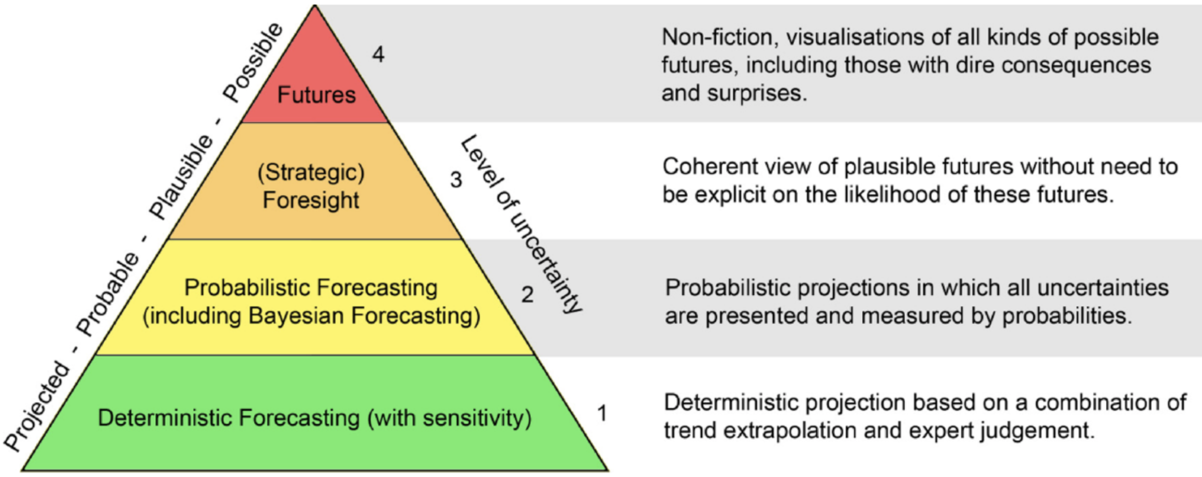


Figure 3.2: Improving the link between the futures field and policy making (Van Dorsser, Walker, et al., 2018)

The demand in Rotterdam is based on the energy and hydrogen demand in the Netherlands, together with the domestic production of hydrogen. The transit demand will not be taken into account. The entire import of hydrogen into the Netherlands is assumed to take place in Rotterdam. At first, the energy demand in the Netherlands is outlined based on Van Beek (Van Beek et al., 2017). The second step is to recognize the share of hydrogen of this energy demand, with the help of Van den Noort (Van den Noort et al., 2017). The third step is to investigate the domestic production of hydrogen established by Hers (Hers et al., 2018). The last step is to subtract the domestic production of hydrogen from the hydrogen demand to generate the hydrogen import demand. The values outline a very rough estimation of the potential import demand for hydrogen in Rotterdam, the Netherlands. The global hydrogen demand of 2018 is given in Figure 3.3.

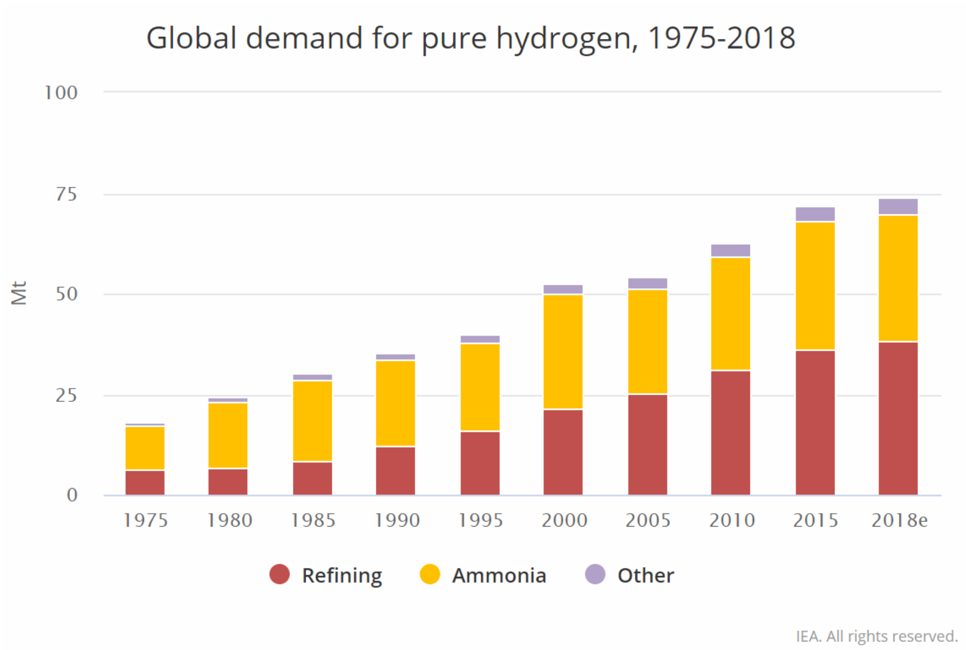


Figure 3.3: Global demand for pure hydrogen, 1975 - 2018 (Birol, 2019)

Energy demand

The energy demand in the Netherlands (see Table 3.1) will be around 2,981 PetaJoule (PJ) in 2020 and 2,829 PJ in 2030 (Van Beek et al., 2017). A linear relationship is assumed between these numbers. By using the energy more efficiently, the energy demand decreases. Therefore, it is shown in the table that the energy demand will decrease from 2,981 PJ in 2020 to 2,829 PJ in 2030 and 2,629 PJ in 2040.

	Realisations				**Projections**		
Year	2000	2010	2015	2017	2020	2023	2030
Primary energy consumption [PJ]	3204	3389	3085	3040	2981	2971	2829

Table 3.1: Energy consumption (in PJ) (Van Beek et al., 2017)

Hydrogen demand

The share of the total energy demand that is attributed to hydrogen is based on an estimate where the development of the current non-energetic application of hydrogen is supplemented with a very indicative estimate for various energetic applications in the Netherlands. The indication of the demand of hydrogen is based on the market use of hydrogen in (Van den Noort et al., 2017):

- Raw material for industry, slightly decreasing due to a decrease in refining processes, including use in steel industry;
- High temperature heating ($\geq$ 250 °C) in industry;
- Fuel for mobility;
- Flexible gas-fired power stations and combined heat and power to support the variable production of renewable electricity;
- Low temperature heating in houses.

The assumed hydrogen demand is 120 PJ per annum in 2019 and 710 PJ per annum in 2050 (see Figure 3.4). Figure 3.4 shows an overview of the indicative estimates of possible demand for hydrogen in the Netherlands in a climate-neutral energy supply system. The red line indicates the hydrogen demand at this moment (Van den Noort et al., 2017). With this figure it is assumed that the hydrogen demand is 130 PJ in 2020, 280 PJ in 2030 and 540 PJ in 2040.

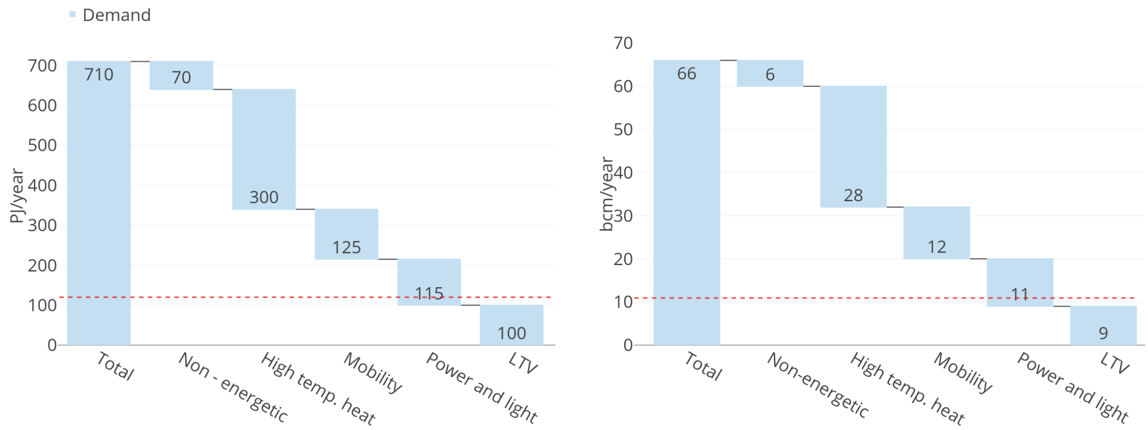


Figure 3.4: Hydrogen demand (Van den Noort et al., 2017)

Domestic hydrogen production

The production of hydrogen in the Netherlands contained around 96 PJ in 2018 and is assumed to be 168 PJ in 2030 (Hers et al., 2018). Therefore, the domestic hydrogen production with a linear relationship is assumed to be 108 PJ in 2020 and 228 PJ in 2040.

Hydrogen import demand

In Table 3.2 and Figure 3.5, an overview of the assumed hydrogen import demands for the coming years in the Netherlands is shown. These assumptions are based on the values of the energy demand (Van Beek et al., 2017), hydrogen demand in (Van den Noort et al., 2017) and domestic hydrogen production (Hers et al., 2018). The hydrogen import demand is determined by subtracting the domestic hydrogen production from the hydrogen demand, whereby the demand is converted from PJ to ton. This is a high-level indication of the import of hydrogen in Rotterdam, taking into account that the entire import of hydrogen in the Netherlands will take place via Rotterdam, without including a transit demand. The import of hydrogen in 2030 is estimated to be 800 kton, which is in line with a statement of the article "Towards a green hydrogen economy South-Holland, a vision for 2030". It stated that the import of hydrogen in 2030 via the port of Rotterdam will be around 700-1000 kton (Van Wijk et al., 2019).

$$Hydrogen\ demand = share * energy\ demand$$
$$Hydrogen\ Import\ demand = hydrogen\ demand - domestic\ production\ hydrogen$$

Hydrogen import demand - the Netherlands	2020	2030	2040
Energy demand - Domestic [PJ]	2,981	2,829	2,629
Hydrogen demand - Domestic [PJ]	130	280	540
Hydrogen production - Domestic [PJ]	108	168	228
Total import hydrogen demand - Base case [PJ]	22	112	315
Total import hydrogen demand - Base case [ton]	154,286	798,548	2,251,632

Table 3.2: Hydrogen import demand in the Netherlands, based on: (Van Beek et al., 2017; Van den Noort et al., 2017; Gigler & Weeda, 2018b; Hers et al., 2018)

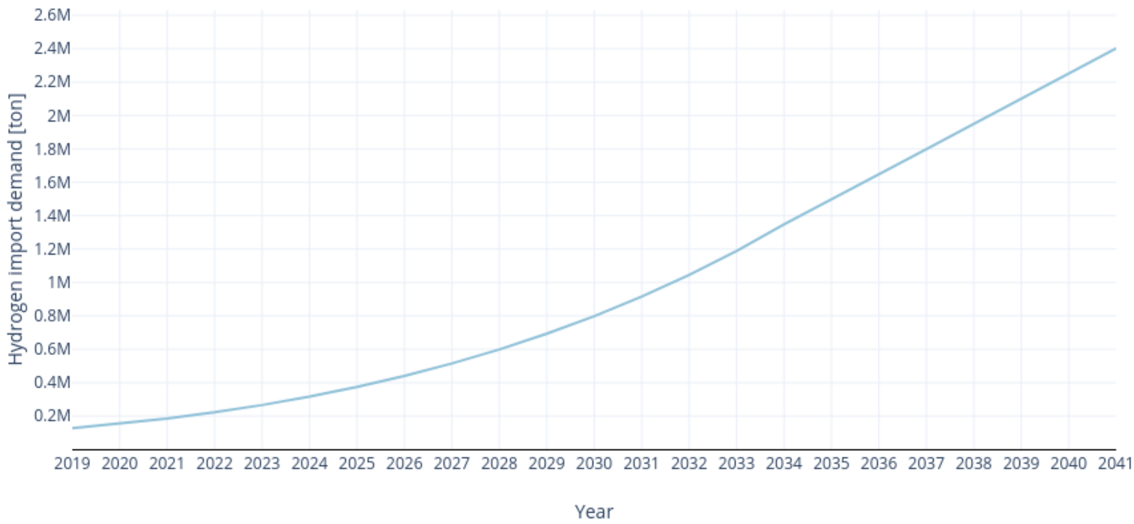


Figure 3.5: Hydrogen import demand in the port of Rotterdam, based on: (Van Beek et al., 2017; Van den Noort et al., 2017; Gigler & Weeda, 2018b; Hers et al., 2018)

3.1.4 Supply chain elements

The model contains all scoped elements of the supply chain with corresponding cost input parameters. This data was gathered through a literature study, company visits, MTBS projects and contact with various experts. In Figure 3.6, the model outline is visualized, with the various supply chain elements that fall within the scope of this research. For the input values and in-depth sources see Appendix B and for the calculation structure see Appendix C.

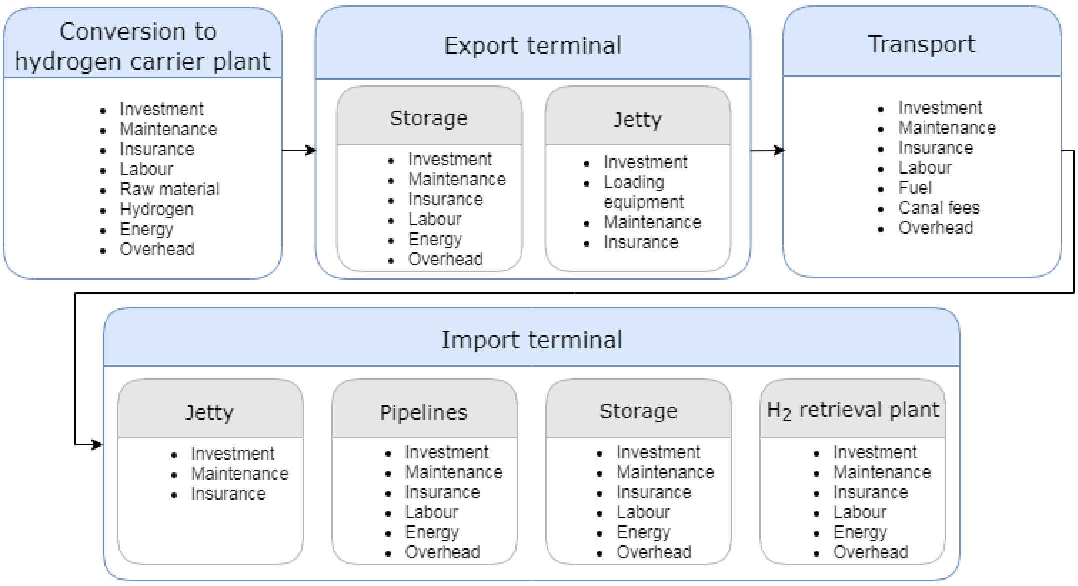


Figure 3.6: All possible supply chain elements from the model

As can be seen in Figure 3.6, the model contains four main elements of the supply chain. Determining the supply chain starts by defining the links of the different elements with the concerning costs. For this reason, the model has access to all the different elements with the corresponding costs before deciding which supply chain is preferred. The different element are connected since a certain volume is connected to the capacity of the different phases of the supply chain and the scale-up requirements.

Defining the possible import route starts with the first element, which is the conversion to hydrogen carrier. The hydrogen costs are an input value of this asset, therefore not treated separately. The volume will determine whether it can sustain with one conversion to hydrogen carrier plant or expansion is needed. It is assumed that the parameters of the conversion to hydrogen carrier plant are equivalent for all locations. The second element is the export terminal including storage and jetty. It is assumed that the storage and jetty investment costs do not fluctuate with time and place. The required static storage capacity is determined by the call size of vessels and cycles per year. Next is the determination of the capacity of the transportation mode, which varies for each supply chain. The import terminal is the last part of the supply chain, and comprises jetties, pipelines, storage, and dehydrogenation facilities. For gaseous hydrogen an import terminal is redundant. It is assumed that the jetty costs are similar for each hydrogen carrier, because they all contribute to a liquid bulk terminal. Only a temporary storage is included in the import terminal. Seasonal and large scale storage will take place in empty salt caverns, whereby all the commodities are converted back to hydrogen gas.

3.1.5 Cash flows & cost price

When the calculation structure of the elements are clear, financial characteristics of the supply chains can be generated. The financial characteristics can be converted to various cash flows, coherent to the supply chain design. The included cash flows are the capital expenditures and operational expenditures. The capital expenditures include the investment and reinvestment costs of the various assets. The operational expenditures contain the costs which assure that the function of the asset can be utilized (Collier, 2012). This category refers to the cost items such as maintenance, labour and energy costs. With these cash flows, the cost price per ton of the supply chain can be calculated. Only the operating and investing activities are covered in the model due to the preliminary feasibility study, financing activities related to non-current liabilities and owners' equity are excluded. Eventually, the discounted cash flow technique is used, with the real WACC as method for the discount rate.

3.2 Setup of the import terminal investment model

The second model is the import terminal investment model. In this section, first the modelling objective will be discussed. Subsequently, the model design and implementation are outlined, in which the layout of the model is given and the triggers and boundary conditions are discussed. Afterwards, the elements of the supply chain are elaborated in Section 3.2.4, whereby the input values and calculation structure can be found in Appendix B and Appendix C respectively. The validation of the model can be found in Appendix E. The model can be found at Github; github.com:TUDelft-CITG/Terminal-Optimization.git, with the tag v0.3.0 (see Appendix C for the QR code).

3.2.1 Model approach & objective

A second model in this research is developed for a more in-depth view of the import terminal. The import terminal investment model serves as a case study for the port of Rotterdam, where the input values of the supply chain model are used. For this research purpose, the input values will be used in a specific framework for the terminal in Rotterdam. The objective of this model is to financially valuate the terminal design and to make an explicit cost assessment with more in-depth knowledge on the investment decisions and cost price of a hydrogen import terminal. The port of Rotterdam has been chosen, due to the characteristic of largest port in Europe and due to their strategy to increasing emphasis on clean, renewable and sustainable (Castelein et al., 2019). This strategy does not only apply to, for example, the reuse of industrial heat and the capture and storage of CO_2, but also through the use of increasingly cleaner fuels. In addition to a reduction in CO_2 emissions, the port of Rotterdam also strives to increase the social dimension and economic added value of the port and its industry (Castelein et al., 2019).

This model translates fluctuations in hydrogen demand to corresponding expansions in the separate elements of the hydrogen import terminal to gain a terminal design. In other words, a terminal design means that the model ascertains the need to expand any of the elements of the import terminal, based on performance triggers. When demand increases, the residual capacity of the assets decreases and therefore the performance of the elements declines. An expansion of the component is thus mandatory. An example of a terminal design is given in Figure 3.7.

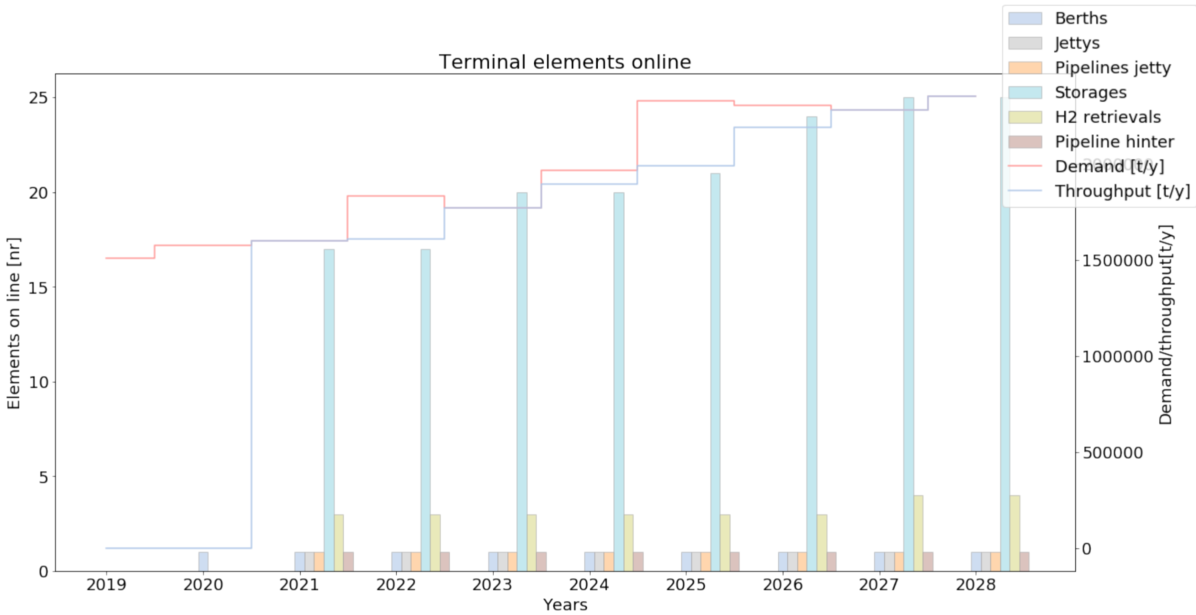


Figure 3.7: Terminal design

The terminal design is established based on a set of assumptions, referring to the various elements of the terminal. The expansion triggers are based on these design assumptions. When an asset is triggered, operational and investment expenses coherent to this asset are generated. The investment costs are expenses, which only occur in the construction years of the asset. The operational costs are amounts with a yearly returning occurrence. The cash flow statement is established by translating the various investment and operational expenses, with the corresponding capacities, into cash flows during the project period. The argumentation of the use of a cash flow model is given in Section 1.7.

The hydrogen cost price can be constructed with the discounted cash flows over the project's lifetime. The discounted cash flows express the present value of cash outflows over a project's lifetime (J. Chen, 2018). The discounted cash flow method is a powerful tool to analyze complex situations. Yet, the method is subject to an extensive assumption bias and even small changes in the underlying assumptions of an analysis can drastically change the valuation results (Steiger, 2010). These cash flows are discounted with WACC as discount method (see Section 3.1.1 for an explanation). For a more in-depth view a discount rate with nominal values and post-tax, without adjustment for inflation, is taken into account.

Eventually, with the cash flows a cost price per ton is generated. By evaluating the financial implications of various hydrogen import terminal, the model provides insight into the optimal cost structure of a hydrogen import terminal. To conclude, the model objective is to financially valuate the terminal design and to make an explicit cost assessment with more in-depth knowledge on the cost price and investment decisions of a hydrogen import terminal.

3.2.2 Model design & implementation

The model outline can be found in Figure 3.8. The model defines the various investment decisions, whereby a cost price of the imported hydrogen is generated. The expansions of the hydrogen import terminal model are based on triggers, boundary conditions and initial terminal setup. With the input values and the expansions a cost price per ton can be developed.

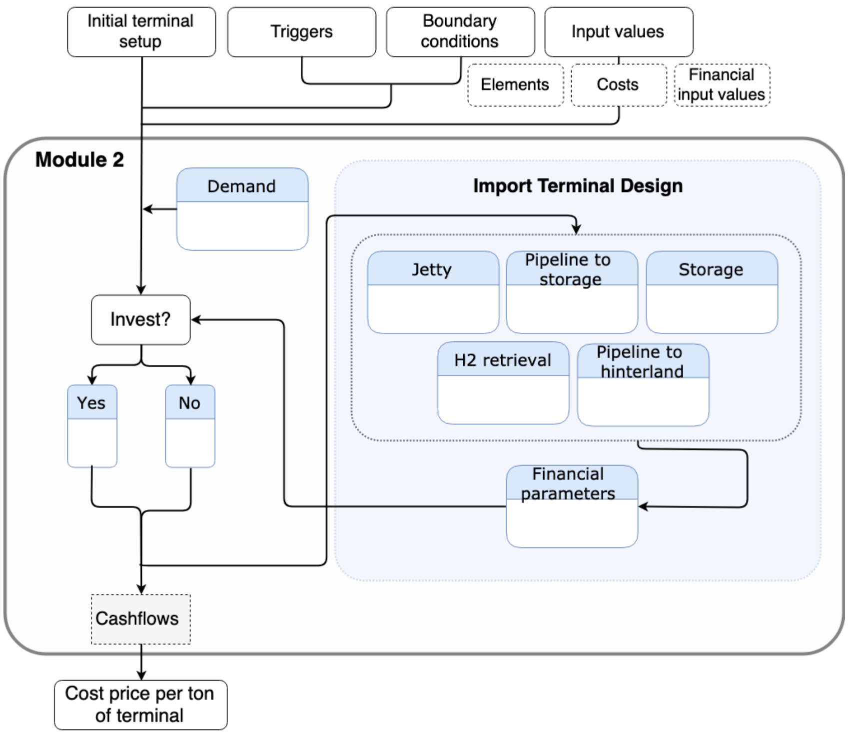


Figure 3.8: Overall outline of the import terminal investment model

Initial terminal setup
A project may use the existence of an older terminal, which already features certain terminal assets at the start of the development. In this case, the certain import terminal assets are accessible at the start of the development. These assets have influence on the reinvestment decisions. Therefore, it is required that the lifetime of the already existing assets are known.

On the other side, developing a project without the use of existing assets, all assets are built at the start of the project, is referred to greenfield deployment. In this model, the existing import terminal infrastructure (or the initial import terminal setup) is modeled as a greenfield, due to the fact that there is not yet a hydrogen import terminal in Rotterdam.

Triggers
With the help of design assumptions, in other words performance triggers, the acceptable occupancy rate of an asset is indicated. The acceptable occupancy rate is defined in Appendix E2.2.1. Whenever this acceptable occupancy rate is exceeded, an expansion will occur. The type of performance triggers used in the import terminal investment model is the reactive mode. When triggering the assets on reactive mode, the investment starts when the allowable trigger is exceeded. A benefit of the reactive mode is that investments are postponed, which is financially attractive looking at the financial concept of discounting future cash flows. Though, the demand with this performance trigger can not always be met. The capacity expansion is based on the real time demand in a given year. Therefore, the throughput is not always equivalent to the demand. This trigger is chosen due to the preliminary state of the project, given it a lot of uncertainties. The functioning of the various triggers of the elements can be found in the validation in Appendix E.

Boundary conditions
It is important to establish the same set of boundary conditions for each separate terminal, in order to be able to compare the different import terminals. The work method is therefore equivalent for all terminals. The adopted boundary conditions are:

- A design assumption implements that the expansion is based on the reactive mode. As the import demand increases over the years, the residual capacity of the different elements will decline. Therefore, whenever the capacity is not according to the requirement, an investment in that asset is triggered.
- The supply of hydrogen is assumed to have no boundaries, therefore there is no volume restriction on the export supply.
- The import terminal is assumed to be located in Rotterdam, the Netherlands. Therefore, the financial parameters such as inflation and tax rates are based on this given country.
- The implemented discount rate consist of a WACC with nominal values. This WACC is based on companies in the energy sector in the Netherlands. A more in detailed explanation of the WACC can be found in Appendix D. Yet, each company mostly preferred their own selected WACC, which presumable differs from the WACC's given in the model.

Input values
The input values of the import terminal investment model consist of the elements of the terminal, costs and financial input values. The financial input values are included for the terminal in the port of Rotterdam and consist of, among other things, cost of energy and WACC. The input value of the costs of hydrogen in the port of Rotterdam, is determined by the general supply chain model. This value, excluding the import terminal, is expressed as a cost price per ton and is added to the cost price per ton of the import terminal. The data is obtained from a literature study, interviews with experts and employees of companies, from the MTBS database and the model of Kalavasta. The input values are given in Appendix B, with the corresponding data sources.

3.2.3 Demand

The demand in the Netherlands is given in Section 3.1.3.

3.2.4 Import terminal elements

The terminal consists of various elements with their own characteristics (see Figure 3.9).

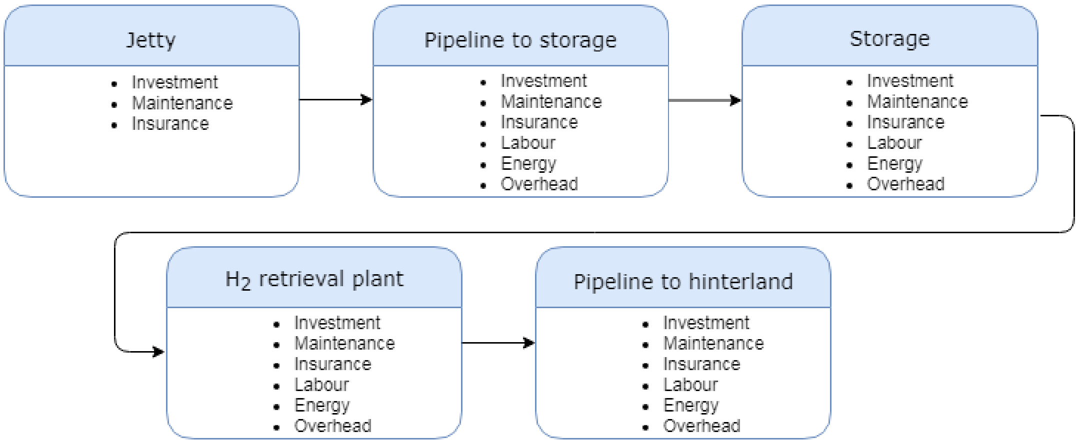


Figure 3.9: Terminal characteristics

As can be seen, the terminal contains five main elements; jetty, pipeline to storage, storage, H_2 retrieval and pipeline to hinterland. The different elements are connected as a certain volume is connected to the capacity of the different phases of the terminal and the scale-up possibilities. Also, the minimal capacity of an element determines the throughput through the whole system, resulting in a decrease of vessels arriving at the jetty. The vessel calls are therefore based on the throughput and they determine the volume at the start of the jetty. The pipeline capacity is based on the peak unloading capacity of the largest vessels. The storage and H_2 retrieval are based on the throughput, and their purchasing dates depend on each other. The last element, the pipeline to the hinterland, is calculated based on the peak production rate of the H_2 retrieval.

The terminal elements are based on two kind of parameters; input- and interactive components. Input components are a fixed number, which have static characteristics. These components can be adjusted and defined by the user to generate a different simulation. Examples of input components are energy use, the division of the share of investment and the salary of the operational staff. Input components are based on data gathered through a literature study, interviews with employees of various companies such as GasUnie, Vopak and Port of Rotterdam and meetings with professional engineers. Interactive components are based on the interaction of different elements. An example of this component is the number of mooring dolphins of a jetty. The number of mooring dolphins depends on the various vessels mooring at the jetty. Another example is the purchase date of an asset, which depends on the expansion trigger. The expansion of an asset is triggered by the demand and throughput. The throughput again depends on the capacity of all the elements. In the end, the system has a lot of interactive components and therefore considered to be nonlinear.

3.2.5 Cash flows & cost price

Financial characteristics of the import terminal can be generated, when the calculation structures of the elements are clear. The financial characteristics can be converted to various cash flows, corresponding to the import terminal design. The cash flows that are included, are the capital expenditures and operational expenditures. The investment, reinvestment and mobilization costs of the various assets are included in the capital expenditures.

Operational expenses contain cost items such as maintenance, labour and energy costs. With these cash flows, the cost price per ton of the supplied hydrogen can be calculated. Eventually, the discounted cash flow technique is used, with a WACC as discount rate with nominal values as discount rate.

3.3 Conclusion

In Figure 3.10, the structure of the models are shown, even as its collaboration. The cost value created by the supply chain model, excluding the import terminal, can be used as an input value for the import terminal investment model. When adding the costs of the import terminal, the costs of hydrogen in the port of Rotterdam can be calculated with a more in-depth analysis of the import terminal.

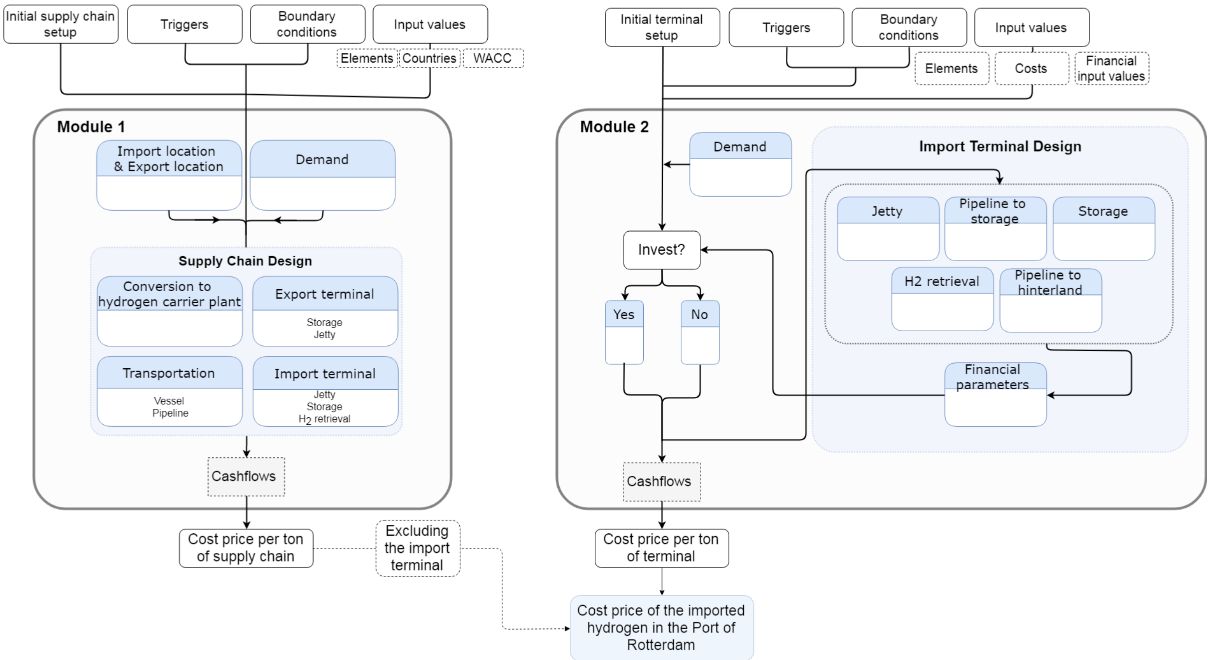


Figure 3.10: Model outline overview

The first model, the general supply chain, is conducted in Excel. The objective of this model is to assess the costs of the hydrogen supply chain for any selected set of preferred parameters. The model contains four main elements of the supply chain; conversion to hydrogen carrier plant, export terminal, transport and import terminal. The investment decisions are based on forward-looking decisions that do not take into account long-term future developments or consequences. The import location is a variable and can be any location within the predefined set and therefore also the demand is variable. The second model is the more in-depth analysis of the import terminal in Rotterdam, conducted in Python. The model objective is to financially valuate the terminal design and to make an explicit cost assessment providing more in-depth knowledge on the terminal decisions and cost price of the supplied hydrogen. The model contains five elements of the import terminal; jetty, pipeline to storage, storage, H_2 retrieval and pipeline to hinterland. The investment decisions are based on reactive mode, the investment starts when the allowable trigger is exceeded.

4 Costs of the general supply chains elements

In this chapter, an analysis is conducted regarding the general supply chain model. The general supply chain model is a model of the supply chain costs for different hydrogen carriers for each of the export/import locations, depending on a certain volume. In this chapter the cost price of the supplied hydrogen is given with a random example scenario; Brazil as the export country and the Netherlands as the import country. Secondly, the various cost prices for the supplied hydrogen are shown per country for the different hydrogen carrier supply chains for the import in Spain. Finally, a sensitivity analysis is conducted regarding to the demand volume, energy price and discount rate. In this chapter the following research question will be answered: *What is the impact of the selection of the export terminal and hydrogen carrier on the cost price of the imported hydrogen (on system level)?* The assumptions made in the models are found through solid reasoning. Altering them could result in a slight difference in the output. For all cases, these values have been kept the same.

4.1 Company costs of the supply chain elements

In this section, the company costs for the supply chain of importing hydrogen are discussed. In Appendix C, the various calculation structures per element are outlined and the input values can be found in Appendix B. A brief explanation about the build-up of the costs is given in each paragraph. At the end the question regarding what the contribution is of each element to the cost price per ton, can be answered. Investment, maintenance and insurance costs are three cost items that appear for each element. The sometimes occurring cost items are labour, raw materials, energy, overhead, fuel and canal fees. The gaseous hydrogen supply chain has a different element structure due to the fact that it only contains two elements, storage and transportation by pipeline. This section presents a case that considers Brazil as the export country and the Netherlands as the import country. In this case the real, pre-tax discount rate is included with WACC as method.

4.1.1 Conversion to hydrogen carrier plant

At the conversion to hydrogen carrier plant, the costs of the hydrogen carriers, ammonia, MCH and liquid hydrogen, are analyzed. Gaseous hydrogen is excluded, because no conversion is required for this commodity. Therefore, a conversion to hydrogen carrier plant in this case is irrelevant. The average costs of the project lifetime can be found in Figure 4.1, where they are mentioned as euro per ton [€/t] hydrogen. The production of hydrogen is excluded in this figure, therefore only the costs of the conversion plant have been taken into account. When the hydrogen demand is increased, the cost price per ton hydrogen is decreased, due to the declination in residual capacity. The largest share in the costs of the conversion to ammonia, are the energy costs. Studying the MCH costs, the high material (toluene) costs stands out immediately. The high costs of liquid hydrogen are derived through high investment and energy costs. The discrepancy in costs for the different hydrogen demands is mostly driven by the residual capacity. The conversion plant unit contains a fixed capacity, whereby at a hydrogen demand of 100,000 t/y, only a small part of this capacity is used. The small decline of MCH is derived through the small residual capacity for both demands.

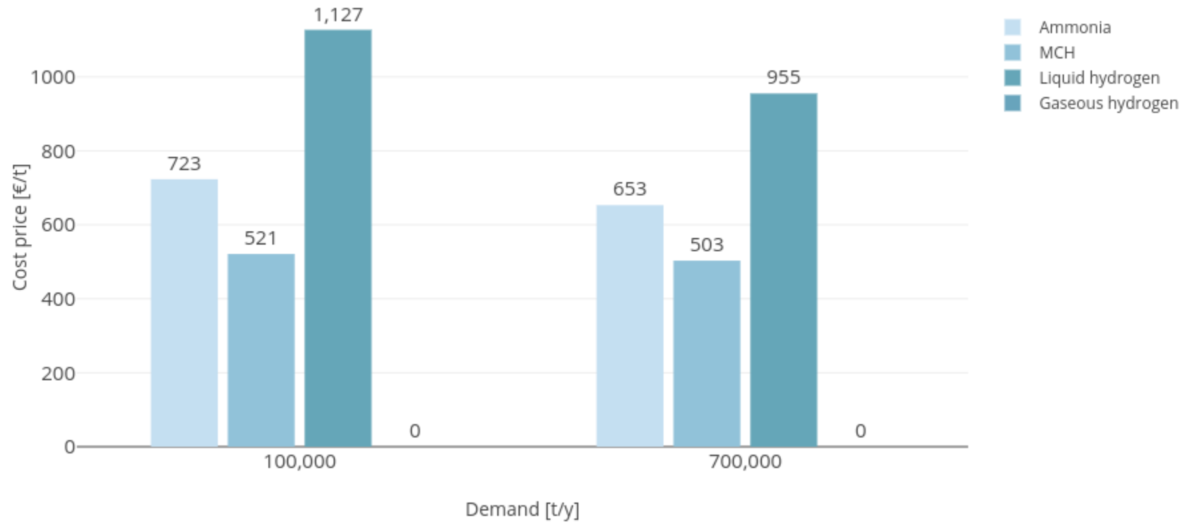


Figure 4.1: Cost price of the conversion plant per hydrogen carrier

4.1.2 Export terminal

At the export terminal, including a jetty and storage, the costs of ammonia, MCH, liquid- and gaseous hydrogen are analyzed. Gaseous hydrogen only contains the storage, hence, the jetty is excluded. The costs can be found in Figure 4.2, where the costs are mentioned as euro per ton [€/t] hydrogen. The costs of the jetty are equivalent for ammonia, MCH and liquid hydrogen and are almost negligible when looking at its share in the total costs (consisting of less than 5%). The storage costs for ammonia, MCH and gaseous hydrogen are low compared to liquid hydrogen, due to the high overhead and investment costs of liquid hydrogen storage. The high investment costs of the liquid hydrogen storage are driven by expensive material to store hydrogen at a temperature of -253°C. The investment costs are the main parameter for the cost cash flows for all hydrogen carrier storages. Thus, the export terminal costs for liquid hydrogen are the highest, because of the high investment costs of the storage and they are the lowest for MCH, due to low investment costs of the storage. When increasing the hydrogen demand, the cost price per ton hydrogen will decline. This decrease is most significant for liquid hydrogen. The discrepancy of the costs for the different hydrogen demands is mostly driven by the residual capacity. An export terminal unit contains a fixed capacity, whereby at a hydrogen demand of 100,000 t/y, only a small part of this capacity is used. When increasing the demand to 700,000 t/y, the available capacity is used more efficiently.

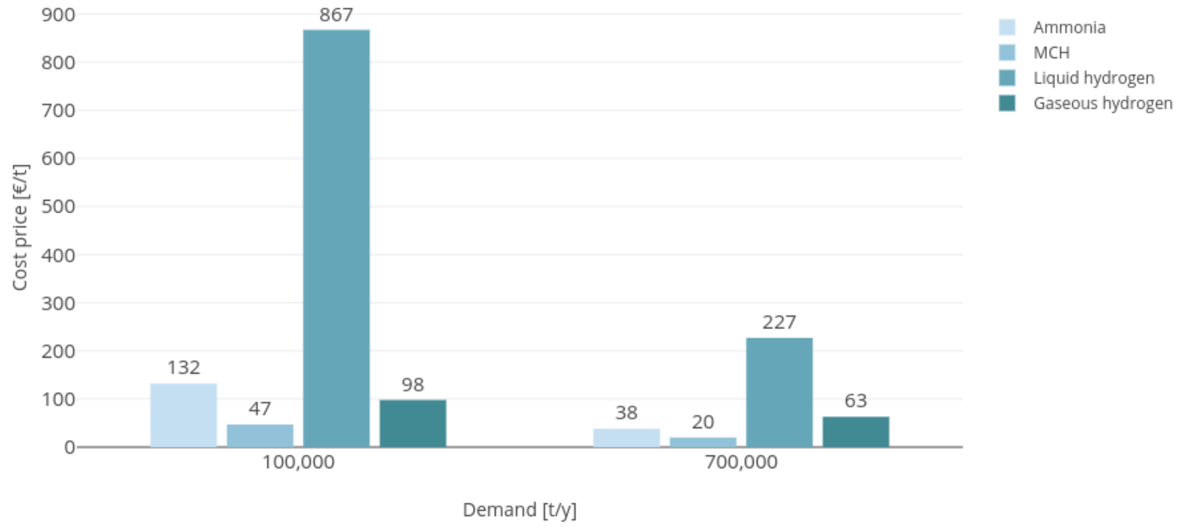


Figure 4.2: Cost price of the export terminal per hydrogen carrier

4.1.3 Transport

Before evaluating the transportation costs, it needs to be clarified that ammonia, MCH and liquid hydrogen are transported with vessels and gaseous hydrogen with pipelines. The costs of the transportation per ton of hydrogen for the various hydrogen carrier can be found in Figure 4.3. This sailing route, from Brazil to the Netherlands, does not include any canal fees. At this moment, liquid hydrogen vessels do not exist in common practice. However, Kawasaki is currently working on a liquid hydrogen vessel (Kawasaki Heavy Industries, 2018). The input values used in the model are based on LNG vessels, due to the similarities between liquid hydrogen- and LNG vessels (Kawasaki Heavy Industries, 2018). The transportation of hydrogen gas in this research is conducted with new pipelines, although existing pipelines can be used to transport hydrogen when they are present. Pipelines designed for the transport of natural gas are technically able to transport natural gas containing a certain amount of hydrogen (Timmerberg & Kaltschmitt, 2019). The transportation costs of hydrogen gas can, therefore, be significantly reduced.

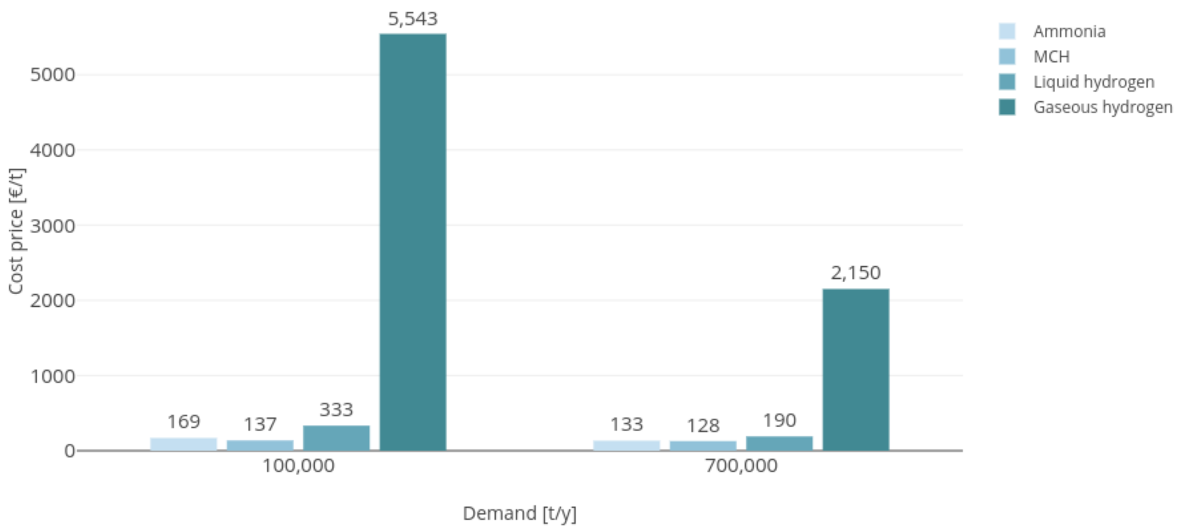


Figure 4.3: Cost price of the transportation per hydrogen carrier

The cost price of ammonia and MCH are small compared to liquid hydrogen, due to the high investment costs of liquid hydrogen vessels. Even though, ammonia and MCH vessels contain fuel costs and the liquid hydrogen vessel uses the boiled-off hydrogen as fuel. The transportation costs of gaseous hydrogen is the highest, due to the high investment costs of new pipelines and the long distance between Brazil and the Netherlands. For gaseous hydrogen, transport-related investment costs are highly dependent on distance. When the demand is small, the transportation cost of gaseous hydrogen is small due to the large investment and mobilization costs. When increasing the demand, these costs increase only a little bit, whereby the demand increases significantly. Therefore, the cost price per ton for the transportation of gaseous hydrogen contains a significantly declination. When increasing the demand, the cost price per ton hydrogen will decline. The discrepancy of costs for the different demand is mostly driven by the residual capacity, whereby a vessel unit contains a fixed capacity. Therefore, when increasing the demand to 700,000 t/y, the available capacity is used more efficiently.

4.1.4 Import terminal

The import terminal costs of hydrogen are analyzed for the various hydrogen carriers. The import terminal costs are more thoroughly analyzed in Chapter 5. When reviewing the import terminal costs, it needs to be clear that this cost item is only applicable for ammonia, MCH and liquid hydrogen. Gaseous hydrogen is imported directly into the Netherlands, therefore an import terminal is redundant. The costs can be found in Figure 4.4, where the costs are mentioned as euro per ton [€/t] hydrogen. The costs of the import terminal consists of the jetty, pipelines, storage and H_2 retrieval plant. The high costs of ammonia and MCH originate from the H_2 retrieval plant. The storage element is responsible for the high CAPEX of the liquid hydrogen import terminal. When increasing the demand, the cost price per ton hydrogen will decline. This decrease is most significant for liquid hydrogen. The discrepancy of the costs for the different demands is mostly driven by the residual capacity. An import terminal unit contains a fixed capacity, whereby at a demand of 100,000 t/y, only a small part of this capacity is used. When increasing the demand to 700,000 t/y, the available capacity is used more efficiently.

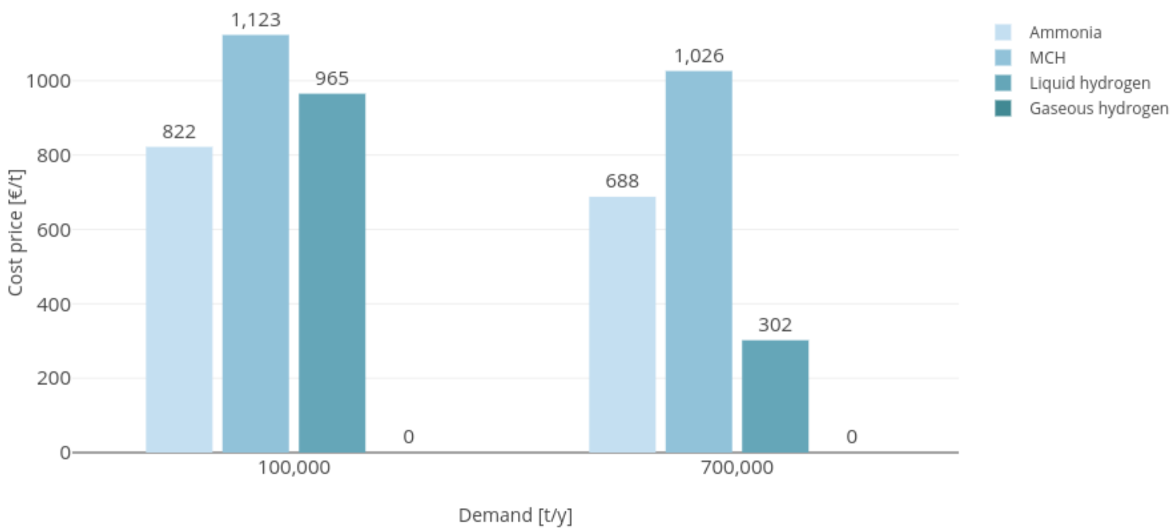


Figure 4.4: Cost price of the import terminal per hydrogen carrier

4.1.5 Comparison with a literature study

In the last month of this research, a study was published by the International Energy Agency containing the future of hydrogen (Birol, 2019). In this study the import costs of hydrogen in Japan from Australia were examined (see p.82 from Birol, 2019). A comparison has been made regarding the supply chain costs of this study. The production costs of hydrogen is different, because this study includes green hydrogen and in this research grey, blue and green hydrogen are considered. Additionally, the ammonia costs of that study is different compared to this research, because the study of IEA contains higher investment costs of the re-conversion (H_2 retrieval plant). The transport and terminal costs are in the same range. When comparing the costs of MCH and liquid hydrogen, all costs are in the same cost range. However, all elements consist of higher costs due to higher country specific input parameters. Also, the margin between the hydrogen carriers is more significant at the IEA report due to small deviations compared to the costs of this research.

4.1.6 Conclusion

Following the assessment of the separate supply chain elements, this paragraph assesses the aggregated supply chain costs on € per ton basis. The applicable cost price per hydrogen carrier for the entire lifetime of the project with the assumptions of the model can be found in Figure 4.5. The costs refer back to the elements of the supply chains.

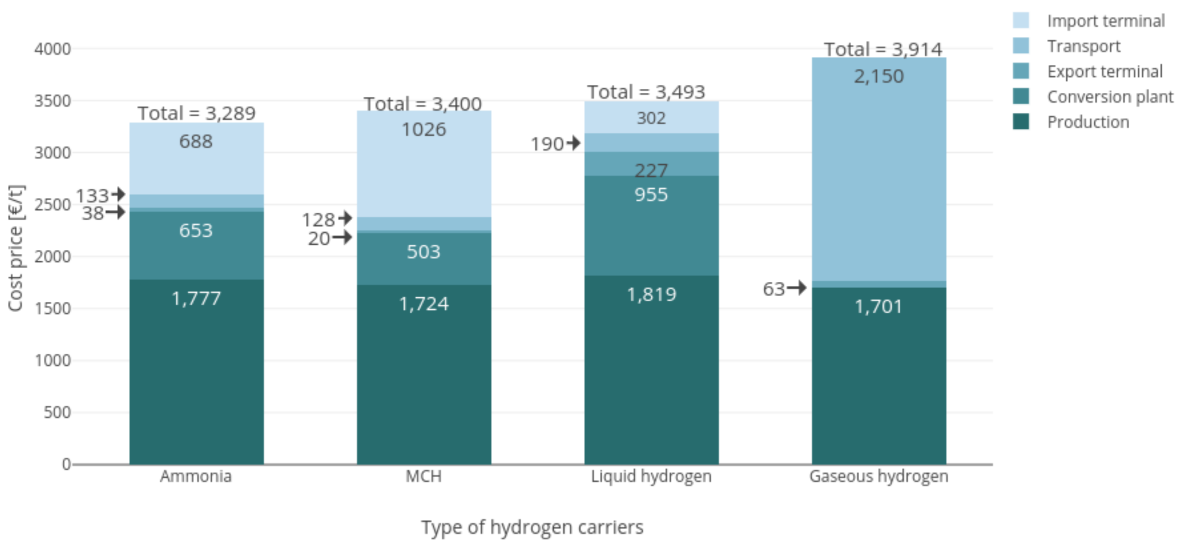


Figure 4.5: Cost price of the entire supply chain per hydrogen carrier with a demand of 700,000 ton, from Brazil to the Netherlands

With this figure, the element which is responsible for the largest contribution to the cost per ton can be found. In most cases, the production costs have the highest share of the total costs, except for gaseous hydrogen where the transportation costs dominate. The production costs differ for the various supply chains, due to the deviating amount in losses at each supply chain. Therefore, more or less production of hydrogen is needed. For ammonia, the import terminal is responsible for the largest share of the supply chain costs due to the high H_2 retrieval costs. The same applies for the supply chain of MCH. The largest costs of the supply chain of liquid hydrogen are related to the conversion plant; a process that causes high energy costs.

Overall costs per ton are the highest for gaseous hydrogen, despite the lack of investment costs related to investments in conversion plants and import terminals; this is mainly due to the high costs concerned with transport or gaseous hydrogen (the high investment costs of new pipelines and the large transportation distance). It is not common to transport gas in pipelines over such a long distance (5,286 nautical mile (nm) or 9,800 km). The largest distance in 2018 crossed by a natural gas pipeline is 8,707 km (Husseini, 2018).

4.2 Cost price regarding various export countries

In this section the various cost prices for different export locations are discussed. In this section, the following research question is answered: *"What is the impact of the selection of the export terminal and hydrogen carrier on the cost price of the imported hydrogen (on system level)?"* These cost prices include the production of hydrogen as well as the costs of the supply chain. The input parameters are randomly chosen:

- The import country is Spain;
- The demand consist of 700,000 t/y;
- The WACC for all export countries originates from gas companies in Spain.

4.2.1 Import in Spain

In Figure 4.6, the various cost prices for hydrogen supplied to Spain, for the different hydrogen carriers and various export countries are presented.

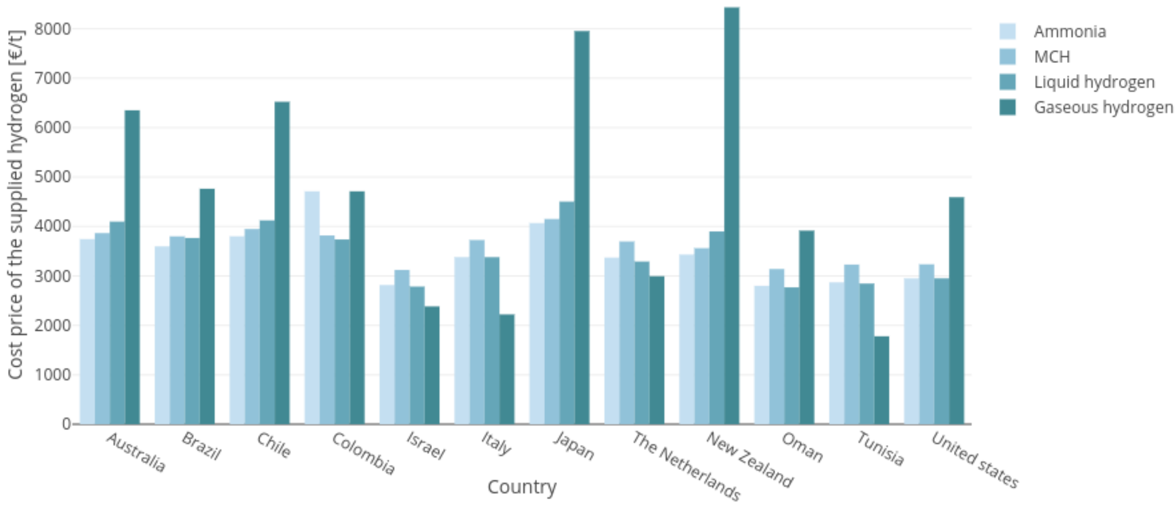


Figure 4.6: Cost price of hydrogen imported in Spain, with a demand of 700,000 t/y

The cost prices depend on the country specific parameters and the distance of transportation, which can have a significant influence on the cost price. Another notable parameter is the costs of the production of hydrogen, which can vary for the different export countries.

4.2.2 Cost prices in line with the distance

The different cost prices are plotted in line with the distance of the various export countries (see Figure 4.7). These cost prices are based on a discount rate with WACC as method and with real values. For short distances up to 3,500 nm, gaseous hydrogen is the preferable option. Hydrogen gas only contains transportation costs and storage at the export terminal. Due to the low transportation costs, gaseous hydrogen can compete with the other hydrogen carriers. Investigating liquid hydrogen, it appears that the investment costs are high compared to ammonia and MCH due to the high storage and vessel investments. Therefore, liquid hydrogen contains higher discounted costs. For short distances, less vessels are needed, compared to long distances, which results in a lower investments. These investments are still higher than for MCH, however due to low operational expenses of liquid hydrogen, the cost price is financially beneficial compared to MCH. Therefore, for short distances liquid hydrogen is financially more attractive than MCH. Whereby, the costs for liquid hydrogen are almost equal to ammonia. Ammonia is preferred above MCH, due to the low costs of the well-known technologies. However, ammonia is not a preferred commodity from an environmental perspective because of its greenhouse gas characteristic and indirect contribution to global warming (Lechtenböhmer et al., 2018). For long distances the costs of MCH are almost equal to ammonia, due to the fact that production and distribution of ammonia contains more hydrogen losses. The most cost effective way to import hydrogen in Spain is from Tunisia with gaseous hydrogen with a cost price of 1.8 €/kg (see Table 4.1). This analysis can be generated for all countries within the scope (see Appendix F).

€/ton	Ammonia	MCH	Liquid hydrogen	Gaseous hydrogen
Australia	3,744	3,866	4,098	8,058
Brazil	3,598	3,800	3,767	4,763
Chile	3,801	3,949	4,123	6,522
Colombia	3,616	3,818	3,737	4,711
Israel	2,816	3,121	2,784	2,383
Italy	3,380	3,726	3,380	2,221
Japan	4,068	4,151	4,503	7,953
The Netherlands	3,432	3,561	3,899	8,432
New Zealand	2,800	3,140	2,768	3,916
Oman	3,371	3,696	3,291	2,994
Tunisia	2,870	3,230	2,845	1,779
United states	2,950	3,235	2,951	4,592

Table 4.1: Cost price of the supplied hydrogen imported in Spain, with a demand of 700,000 t/y

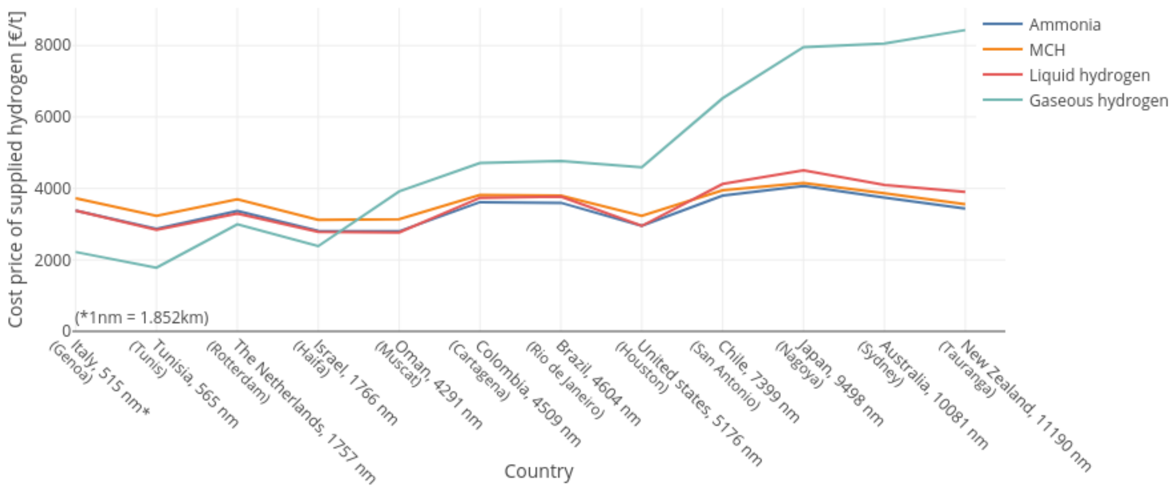


Figure 4.7: Cost price of the supplied hydrogen for the import in Spain varying with the countries, with a demand of 700,000 t/y

4.2.3 Conclusion

Every country that is included in the scope is analyzed regarding the cost price of the supplied hydrogen in line with the distance (see Appendix F). Combining all import location, it can be stated that in general for distances up to 3,500 nm gaseous hydrogen is preferred and for intermediate to long distance ammonia. There are exceptions on this statement for some countries, such as Brazil whereby ammonia is always preferred and Chile whereby first gaseous hydrogen, than liquid hydrogen and then ammonia is preferred. The discrepancy in costs between ammonia, MCH and liquid hydrogen is almost negligible. Therefore, it can be stated that it makes no difference when choosing one carrier, or the other for ammonia, MCH and liquid hydrogen. Combining the environmental and financial perspective, it can be preferred to import MCH, liquid- or gaseous hydrogen instead of ammonia. Hereby, the following research question is answered: *"What is the impact of the selection of the export terminal and hydrogen carrier on the cost price of the imported hydrogen (on system level)?"*

4.3 Sensitivity analysis of the cost price

In this section, a sensitivity analysis is performed for the demand, discount rate and energy price, to examine what the influence is on the cost price. The sensitivity analysis is performed to recognize the bandwidth of the cost price and outline the sensitiveness. At first, the demand is examined regarding the supply chain costs. Secondly, the energy costs of the import terminal are investigated. This component is active in almost every element of the supply chain. The last component that is discussed is the discount rate, which has an uncertain character. The cost prices given in this section are based on Brazil as export country and the Netherlands as import country. A demand of 700,000 t/y is considered. These countries and demand are equal to the considered values in Section 4.1, to investigated the sensitivity of that cost price. Therefore, a distance of 5,286 nm has been taken into account.

4.3.1 Demand volume

In Figure 4.8, the supplied hydrogen costs of the various hydrogen carriers are outlined.

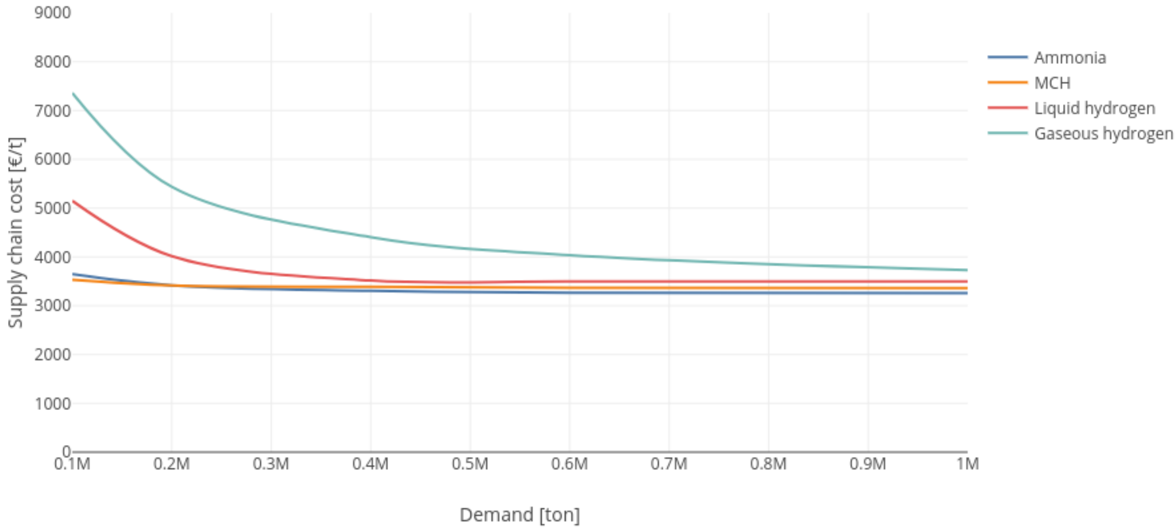


Figure 4.8: Cost price of the supplied hydrogen for the different hydrogen carriers

As can be seen, the supply chain costs of ammonia and MCH are always lower than the costs of liquid and gaseous hydrogen, due to lower investment costs (with the current assumptions of the model). As the demand increases, the supply chain costs decline. This decline holds till the demand reaches an amount of about 500,000 t/y for ammonia, MCH and liquid hydrogen, in which the capacity is fully utilized. For gaseous hydrogen, these declines will continue as well for values beyond 500,000 t/y. Ammonia is almost always preferred above MCH, due to the previous developed technologies and experience in the field. However, this might change with further innovation. Increasing the volume means that the supply chain costs decrease, whereby the supply chain costs of MCH decrease almost equally compared to the supply chain costs of ammonia. The discrepancy in costs, between MCH and ammonia, is negligible.

4.3.2 Energy prices

All supply chains contains elements at the export and import side of the supply chain. A choice has been made regarding this issue and therefore only the energy prices of the import country are examined, due to the conversion plant process that causes high energy costs for most hydrogen carriers. The applied energy price is from 0.08 to 0.14 €/kWh. The average energy price in the Netherlands during the project's lifetime is 0.09 €/kWh. It is assumed that the energy prices will increase (Birol, 2019). Therefore, only a small deviation downwards is taken into account and a large deviation upwards. This price is the average energy price in the project's lifetime. As can be seen in Figure 4.9, the influence of the energy prices on the cost price are linear. The influence on the costs of MCH is the largest due to the high energy consumption of the H_2 retrieval process at the import terminal. Also, ammonia contains a high energy consumption at the import terminal. Liquid hydrogen contains a low energy consumption at the import terminal and therefore the increase in energy price is almost negligible.

Gaseous hydrogen does not contain any energy consumption at the import terminal and therefore it remains a straight line. All in all, the effect of an increase energy price has a large influence on the cost price of MCH and ammonia and (almost) no effect on liquid- and gaseous hydrogen.

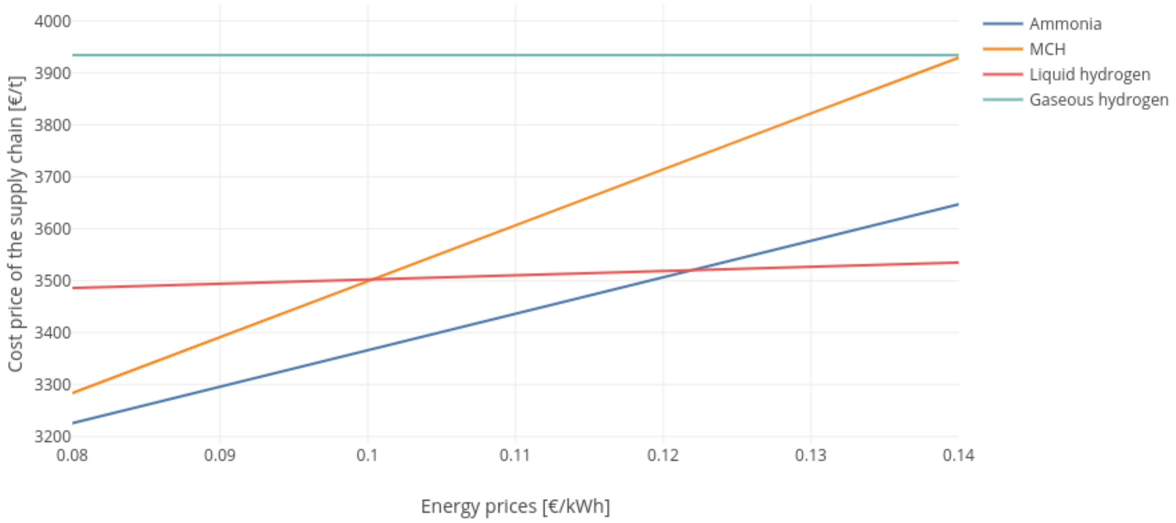


Figure 4.9: Cost price of the supplied hydrogen in combination with a varying energy price

4.3.3 Discount rate

The influences of the discount rate on the costs are compared with an assumed real discount rate of 1% to 15%, with WACC as method (see Figure 4.10).

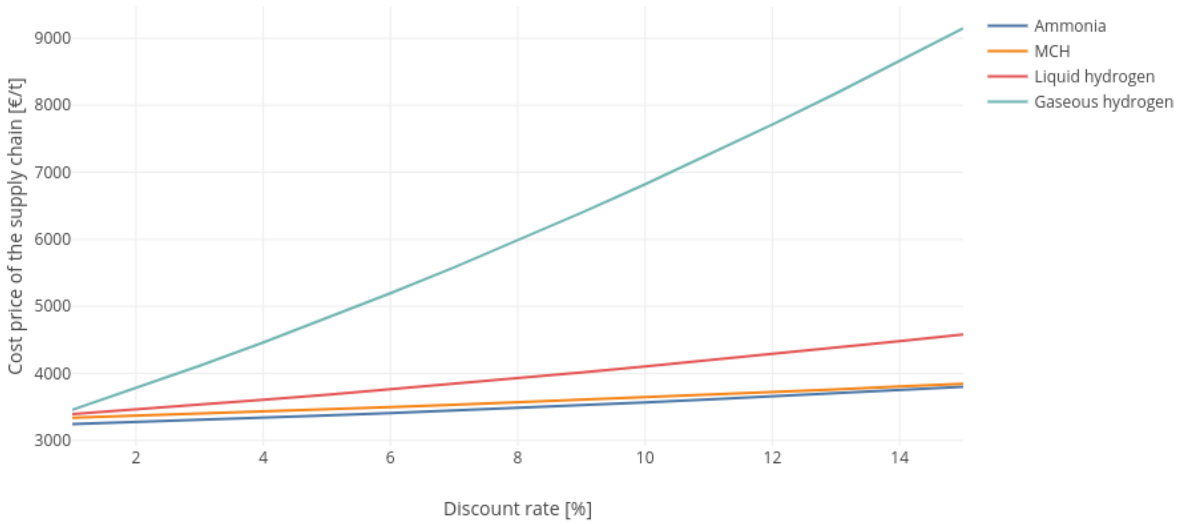


Figure 4.10: Cost price of the supplied hydrogen in combination with a varying discount rate

The implement discount rate of the Netherlands in this research is 2.47%, therefore a discount rate of 15% is very high. To investigate also the effect of very high discount rates this number is taking into account. A discount rate is mostly present and therefore a minimum discount rate of 1% is assumed. An optimal capital structure of a company includes the lowest possible WACC and the maximum market value of the company (Hayes, 2019).

Therefore, the mix of debt and equity that minimizes the WACC while maximizing its market value is seen as the optimal capital structure (Hayes, 2019). As can be noted, the lower the discount rate, the lower the preferred cost price of hydrogen. The influence of an increase discount rate is most noteworthy at gaseous hydrogen, due to the large investment costs. The increase in discount rate has also a large influence on the cost price of liquid hydrogen and it has a small effect on the supply chains of MCH and ammonia.

4.3.4 Conclusion

The parameter demand has a negative correlation with the cost price of the supply chain, in other words, when the demand increases the cost price of the supply chain decreases. This decline holds till the demand reaches an amount of around 500,000 t/y for ammonia, MCH and liquid hydrogen. For gaseous hydrogen, these declines will continue as well for values beyond 500,000 t/y. The effect of an increase energy price has a large influence on the cost price of MCH and ammonia and (almost) no effect on liquid- and gaseous hydrogen. On the other hand, the discount rate has a large influence on liquid- and gaseous hydrogen and less on MCH and ammonia. With this sensitivity analysis, error margins are identified. It can be seen, that the gaseous hydrogen cost price deviates more than the other hydrogen carriers. Next to the demand, discount rate and energy price, a lot of different parameters have an effect on the cost price of hydrogen. Therefore, a general error margin of 30% is applied. This is the average of the individual error margin obtained from this sensitivity analysis. This error margin can be seen in Figure 4.11. In conclusion, a lot of different parameters have an effect on the cost price of hydrogen and therefore the risk of using this theoretical price can be very high.

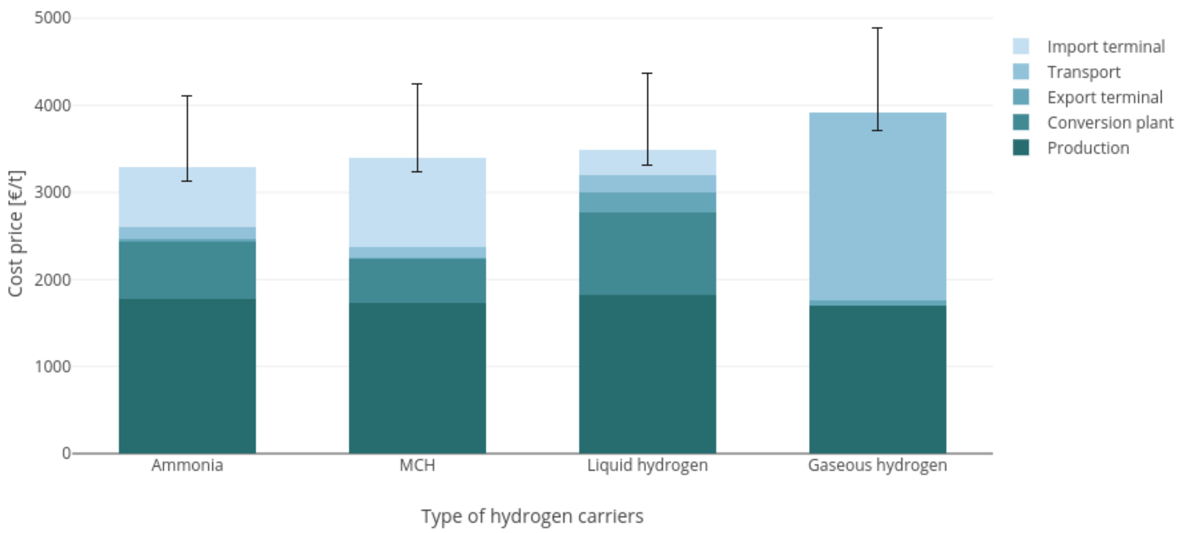


Figure 4.11: Cost price of the supplied hydrogen with a demand of 700,000 t/y, from Brazil to the Netherlands

4.4 Conclusion

The cost price, in this chapter, of the supplied hydrogen is given with a random example scenario; Brazil as the export country, the Netherlands as the import country and a demand of 700,000 t/y. In most cases, the production costs have the highest share of the total costs of the cost price. This is not the case for gaseous hydrogen where the transportation costs dominate. The overall costs per ton are the highest for gaseous hydrogen, despite the lack of investment costs related to investments in conversion plants and import terminals; this is mainly due to the high costs concerned with transport or gaseous hydrogen (the high investment costs of new pipelines and the large transportation distance). The answer on the research question, *"What is the impact of the selection of the export terminal and hydrogen carrier on the cost price of the imported hydrogen (on system level)?"*, is: For distances up to 3,500 nm, gaseous hydrogen is preferred and for intermediate to long distances ammonia is preferable. However, the discrepancy between ammonia, MCH and liquid hydrogen is almost negligible. Therefore, when combining the financial and environmental perspective it can be preferred to select MCH or liquid hydrogen instead of ammonia. The hydrogen costs for ammonia, MCH and liquid hydrogen decreases as long as the demand increases, up until an amount of 500,000 t/y, whereby for gaseous hydrogen this decline holds for values beyond this amount as well.

5 Import terminal costs in Rotterdam

The import terminal investment model uses the predefined costs for the import terminal for the case study in Rotterdam, which depends on a certain hydrogen carrier and volume. Gaseous hydrogen is directly transported through pipelines to the grid and to the seasonal storage, and therefore does not contain any import terminal costs. Consequently, the hydrogen carriers, which are considered in this chapter, are ammonia, MCH and liquid hydrogen. In this chapter, the various cost components of the import terminal in the port of Rotterdam are given. First, the contribution of the various elements to the total cost price is given. Secondly, the space requirements are elaborated. Finally, a conclusion is given regarding the optimal combination of export country and carrier for the terminal in the port of Rotterdam. In this chapter the sub-question and the main question will be answered and are stated below respectively:

- *What are the integrated costs for the import terminal in Rotterdam for different hydrogen carrier types (on terminal level)?*
- *What is the most cost effective way to import hydrogen into the port of Rotterdam to supply the future hydrogen demand in the Netherlands, given a selected set of hydrogen carriers and export locations?*

5.1 Company costs of the import terminal

In this section the company costs for the elements of the import terminal are outlined. The cost structure of the import terminal is divided into five components; a jetty, pipeline to the storage, storage, H_2 retrieval and pipeline to the hinterland. Hereby, the following question arises; What are the integrated costs of an import terminal? The given cost price from the terminal, without taking into account the production of hydrogen, is stated in Figure 5.1, which includes both OPEX and CAPEX. The included cost items for the CAPEX are the investment, mobilization and reinvestment costs. The included costs for the OPEX are maintenance, insurance, overhead, labour and energy costs. The considered hydrogen import demand is 700,000 t/y.

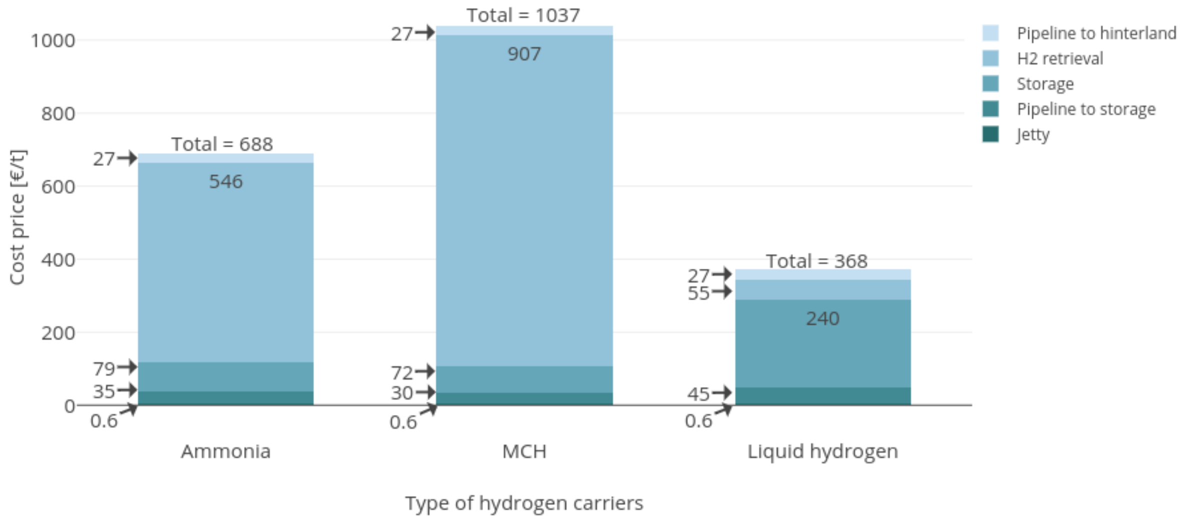


Figure 5.1: All the contributed costs (CAPEX and OPEX) of the elements of the import terminal, with a demand of 700,000 t/y

As can be seen, the dominating costs of the import terminal of ammonia are the H_2 retrieval costs. This is the same for the situation of the MCH terminal. For the liquid hydrogen terminal, the storage is the largest cost item. Each element has its own paragraph with an overview of a more in-depth study on the nominal value of the costs. If reduction of the cost price is desirable, it is useful to start with examining the dominating cost components.

5.1.1 Jetty

The jetty costs are divided into CAPEX and OPEX. The OPEX, include maintenance and insurance costs. The element does not contain any energy or labour costs. In the CAPEX, the investment and mobilization costs are included. At the end of the project, residual values of the assets occur. Inter alia, the jetty lifetime is 50 years and the project lifetime is 20 years, therefore the residual value is 60% of the investment costs. This amount is subtracted from the investment costs in this analysis to analyze the impact of the different cost components. This has been done because the residual cash flow originates from the investments, whereby in a business case this amount will be added as a cash inflow at the end of the project lifetime. In this analysis the revenues are not incorporated, therefore the residual cash flow is neglected. In Figure 5.2, the division of these cost components can be found. As can be seen, the largest cost item is the CAPEX. The maintenance and insurance costs are equal. All these costs combined only contribute slightly to the total costs of the import terminal.

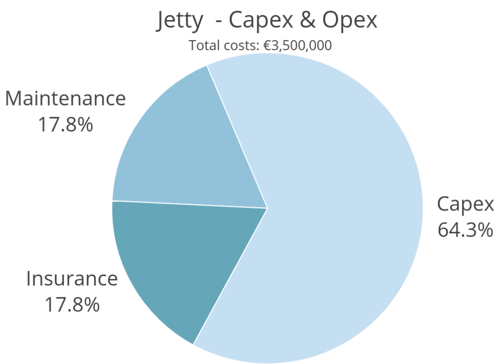
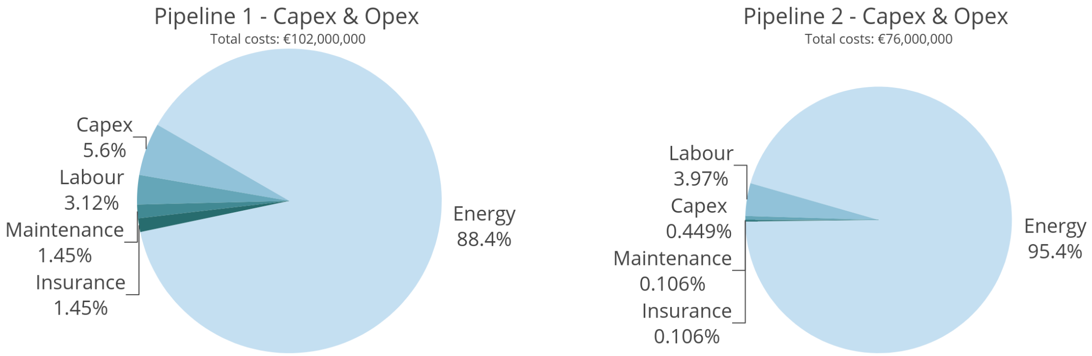


Figure 5.2: All the contributed costs of the jetty for all carriers

5.1.2 Pipelines

In this section, the pipeline from the jetty to the storage (pipeline 1) and the pipeline of the H_2 retrieval to the hinterland (pipeline 2) are discussed. The commodities are in different liquid phases at pipeline 1 and in gas phase at pipeline 2. The cost items of the pipelines are CAPEX and OPEX. The OPEX of the pipelines are divided into maintenance, insurance, labour and energy costs. The contribution of the different cost items to the total costs can be found in Figure 5.3. The leading cost component of pipeline 1 are the energy costs with 88.4 %, due to the high energy consumption. For pipeline 2, the pipeline to the hinterland, the main cost item is also the energy costs, which amounts to 95.4% of the total costs, also due to the high energy consumption.

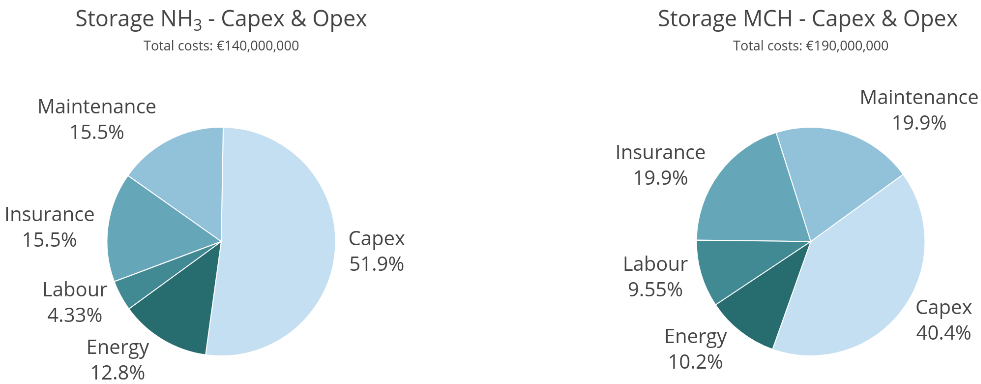


(a) Pipeline to storage **(b)** Pipeline to hinterland

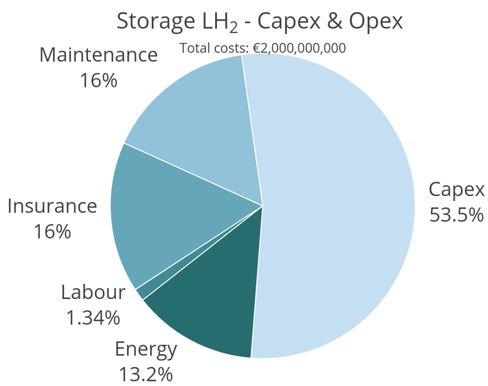
Figure 5.3: All the contributed costs of the pipelines for all carriers, based on the model output

5.1.3 Storage

The storage of the hydrogen carriers is in liquid phase. The cost items of the storage are CAPEX and OPEX, in which the OPEX of the storage are divided into maintenance, insurance, labour and energy costs. The CAPEX have the largest share in the total costs for all carriers, due to the high investment costs (see Figure 5.4).



(a) Storage - ammonia **(b)** Storage - MCH



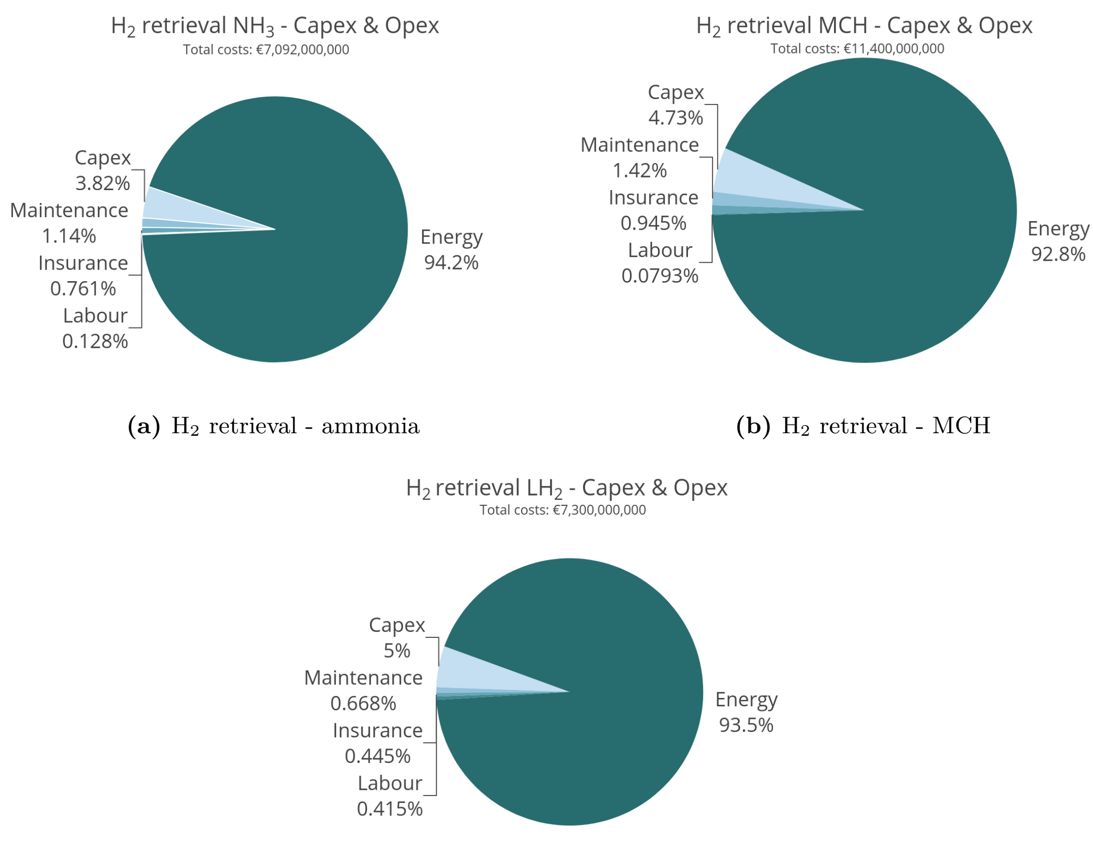
(c) Storage - liquid hydrogen

Figure 5.4: All the contributed costs of the storage for all carriers, based on the model output

The maintenance and insurance costs are equal in all cases, as annual maintenance and insurance costs are both assumed to be equal to 1% of total CAPEX. The energy and labour costs of the storage of the LH_2 contribute only to a small share of the total costs, even though the absolute energy costs of the LH_2 storage are the largest from all storages. This is because the LH_2 storage have high investment costs. The storage from ammonia contains two unit, liquid hydrogen contains nine units and MCH contains six units, due to the demand and the vessel size.

5.1.4 H_2 retrieval

The H_2 retrieval costs varies along the different hydrogen carriers. The cost items of the H_2 retrieval are CAPEX and OPEX, in which the OPEX of the H_2 retrieval are divided into maintenance, insurance, labour and energy costs. In Figure 5.5, the cost components of the H_2 retrieval for all hydrogen carriers can be found. As can be seen, the energy costs have the largest share of costs for all hydrogen carriers, due to the high energy consumption. The labour costs are almost negligible, even though there is always someone present at every unit. Ammonia and MCH contains three units and liquid hydrogen only one unit, due to the varying capacity and the hydrogen content in the hydrogen carriers.



(a) H_2 retrieval - ammonia

(b) H_2 retrieval - MCH

(c) H_2 retrieval - liquid hydrogen

Figure 5.5: All the contributed costs of the H_2 retrieval for all carriers, based on the model output

5.1.5 Conclusion

In this section, the conclusion regarding the integrated costs of an import terminal is elucidated. Whereby, the following sub-question is answered: *"What are the integrated costs for the import terminal in Rotterdam for different hydrogen carrier types (on terminal level)?"* The CAPEX contribute to the largest share of the costs at the jetty, due to the high investment costs. At the pipelines, the energy costs dominate due to a high energy consumption. The storage of liquid hydrogen is the most expensive compared to the other storages, due to the high investment costs. The energy costs of all H_2 retrievals are the largest cost component, due to the high energy consumption of this process. The H_2 retrieval of MCH is the most expensive, due to the highest energy consumption. The MCH import terminal has the highest costs due to the high energy costs of the H_2 retrieval plant. In the ammonia terminal, the largest costs originate from the energy costs of the H_2 retrieval as well. In the liquid hydrogen terminal the largest costs originate from the investment costs of the storage. To conclude, when reduction of the cost price from ammonia and MCH terminal is desirable, it is convenient to reduce the energy costs of the H_2 retrieval and the investment costs of the storage by liquid hydrogen.

5.2 Space requirements of the import terminal

In this section the space requirements for an ammonia, MCH and liquid hydrogen import terminal in the port of Rotterdam are outlined. Space may be a serious issue over the next 20 years, as existing and new markets will work side by side for a long period of time, while both requiring suitable sites (Castelein et al., 2019). Therefore, the question arises; what is the required space needed for a hydrogen import terminal? The transition of the port creates new spatial challenges, whereby the availability of physical space and environmental space is crucial. The energy transition will presumably not lead to less use of physical and/or environmental space. For example, a reduction in CO_2 emissions does not mean that there is less noise pollution.

The total area of the port of Rotterdam consists of 12,713 Hectare (ha), from which 7,903 ha of the area is land and 4,710 ha is water (Castelein et al., 2019). At this moment, around 548 ha is unused and therefore available for new developments. In this area, only temporary storage is included at the import terminal. Seasonal and large scale storage will take place in empty salt caverns, whereby all the commodities are converted back to hydrogen gas. The province of South Holland, in which Rotterdam is located, does not have access to any salt caverns. Therefore, the storage needs to take place in the Northern and Eastern part of the Netherlands. Veendam is an example of a location with multiple available salt caverns (Van Gessel et al., 2018). It is assumed that the import terminal contains a square layout, excluding general buildings such as offices and parking space.

5.2.1 Space requirements for an ammonia terminal

When looking at the demand for hydrogen in Rotterdam in 2030 (around 800,000 t/y, see Section 3.1.3), one jetty, one pipeline to storage, two storages, three H_2 retrievals and one pipeline to hinterland are needed. This is obtained from the import terminal investment model, see Chapter 3 for a more in-depth explanation. When assigning a space requirement to the assets, the total area can be calculated. The surface areas are calculated with the help of the terminal of the company Yara in the place Sluiskil.

Yara consist of two storage tanks with a tank size of 17,500 m^3, each consisting of 3,150 m^2, in Sluiskil. When converting it to units of 50,000 m^3, a 8,500 m^2 surface is needed per unit. In Table 5.1, the surface per asset is given as well as the possible terminal area in Rotterdam in 2030. As can be seen, the total area for the terminal will be 14 ha.

	Needed surface per unit [m^2]	**Number of units 2030** [#]	**Total surface 2030** [m^2]
Jetty	980	1	980
Storage	9,000	2	18,000
H_2 retrieval	30,000	3	90,000
General	150,000	-	27,000
Total	-	-	140,000

Table 5.1: Surface of the potential ammonia import terminal (MTBS, personal communication, June, 2019)

5.2.2 Space requirements for a MCH terminal

The MCH import terminal consists of one jetty, one pipeline to storage, six storages, three H_2 retrievals and one pipeline to hinterland in 2030. The surface areas are calculated with the help of the Vopak Terminal Laurenshaven in Rotterdam. The Laurenshaven terminal consists of 15 storage tanks with a tank size of 60,000 to 70,000 m^3, requiring a total area of 12.5 ha, in the port of Rotterdam. When converting it to units of 50,000 m^3, a 8,500 m^2 surface is needed per unit. In Table 5.2, the surface per asset is given as well as the possible terminal area in Rotterdam in 2030. As can be seen, the total area for the terminal will be 16 ha.

	Needed surface per unit [m^2]	**Number of units 2030** [#]	**Total surface 2030** [m^2]
Jetty	980	1	980
Storage	8,500	6	51,000
H_2 retrieval	30,000	3	90,000
General	75,000	-	21,000
Total	-	-	160,000

Table 5.2: Surface of the potential MCH import terminal (MTBS, personal communication, June, 2019)

5.2.3 Space requirements for a liquid hydrogen terminal

The liquid hydrogen terminal consists of one jetty, one pipeline to storage, nine storages, two H_2 retrievals and one pipeline to hinterland in 2030. The surface areas are calculated with the help of the LNG gate terminal in Rotterdam. The gate terminal is operational for 24 hours a day, 365 days a year and consists of three storage tanks, two jetty's and a process area where the LNG is regassified with an annual throughput capacity of 12 billion m3 of gas per year. This LNG gate requires 35 ha of space in the port of Rotterdam.

This LNG terminal includes three storage units, with a capacity of 180,000 m^3 and a surface of 26,500 m^2 each. When converting it to units of 50,000 m^3 and implementing an extra safety vector due to a more dangerous commodity, a 10,000 m^2 surface is needed. In Table 5.3, the surface per asset is given as well as the possible terminal area in Rotterdam in 2030. As can be seen, the total area for the terminal will be 20 ha. This space is smaller than the LNG terminal, due to the fact that it requires less storage space and better use of the area due to the layout.

	Needed surface per unit [m^2]	**Number of units 2030** [#]	**Total surface 2030** [m^2]
Jetty	980	1	980
Storage	10,000	9	89,000
H_2 retrieval	30,000	2	60,000
General	300,000	-	50,000
Total	-	-	200,000

Table 5.3: Surface of the potential liquid hydrogen import terminal (MTBS, personal communication, June, 2019)

5.2.4 Conclusion

The required area for an ammonia import terminal for the port of Rotterdam in 2030 with a demand of around 800,000 t/y is around 140,000 m^2, which is 14 ha. For a MCH import terminal the required area consists of 160,000 m^2, or 16 ha and for a liquid hydrogen import terminal it is 200,000 m^2, or 20 ha. All surfaces of the import terminals of the various hydrogen carriers are shown in Figure 5.6. As can be seen, all terminals only take a small share (between 2 to 3 %) regarding the indicated area (764 ha) for a hydrogen import, according to the article Meta trends (Van Dorsser, Taneja, & Vellinga, 2018). This is because only temporary storage is included in the terminal. Therefore, the indicated area, accordingly to the article Meta trends, is too large which makes it convenient to consider a possible relocation. To conclude, the import of hydrogen with ammonia, MCH and liquid hydrogen as carriers, does not require a lot of space in the port of Rotterdam, because the strategical storage can be done in salt caverns located in the hinterland.

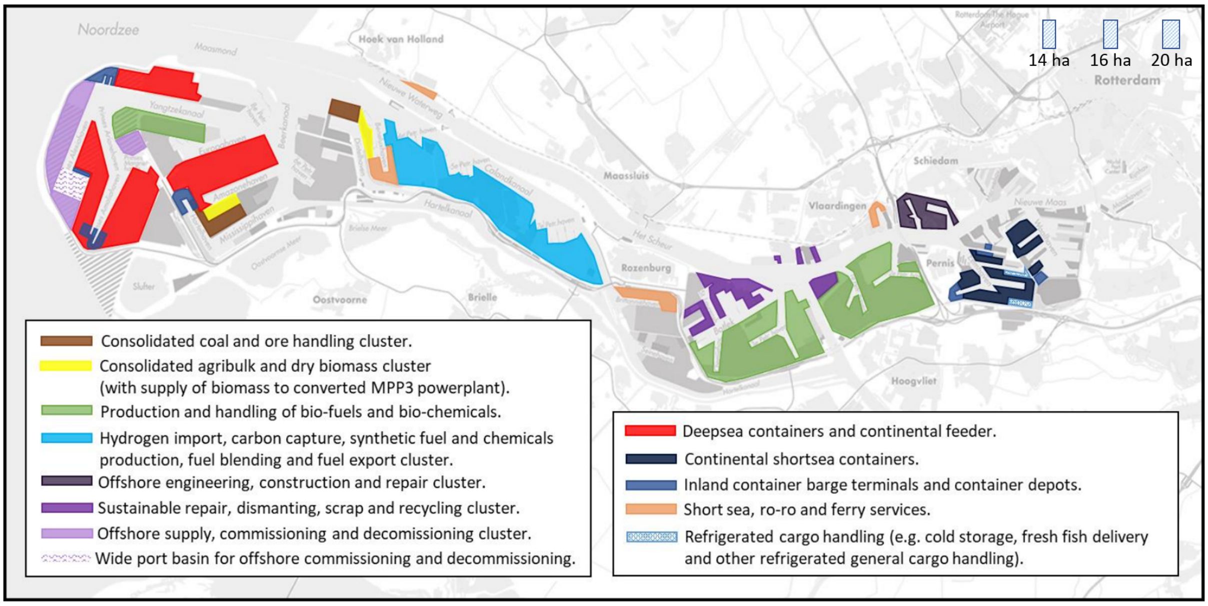


Figure 5.6: Outlined clustering of activities as suggested for the year 2040 with the indicated area for the import terminals (Van Dorsser, Taneja, & Vellinga, 2018)

5.3 Optimal cost price for the import of hydrogen in Rotterdam

In this section the optimal combination of export country and hydrogen carrier for the case study for the port of Rotterdam is discussed. This results in finding the hydrogen supply chain with the financially most beneficial cost price for the Netherlands. The possible export countries for Rotterdam are given in Figure 5.7. This set of countries are in the scope of the research (see Section 2.2). The future hydrogen demand in Rotterdam is estimated to be around 800,000 t/y in 2030, outlined in Section 3.1.3.

Figure 5.7: Scoped export location for the import of hydrogen in Rotterdam

5.3.1 Cost price of various export locations

The various cost prices for the hydrogen supply chain for the import in the Netherlands are shown for the different hydrogen carriers in Figure 5.8 and Table 5.4. These cost prices include the production of hydrogen as well as the costs of the supply chain.

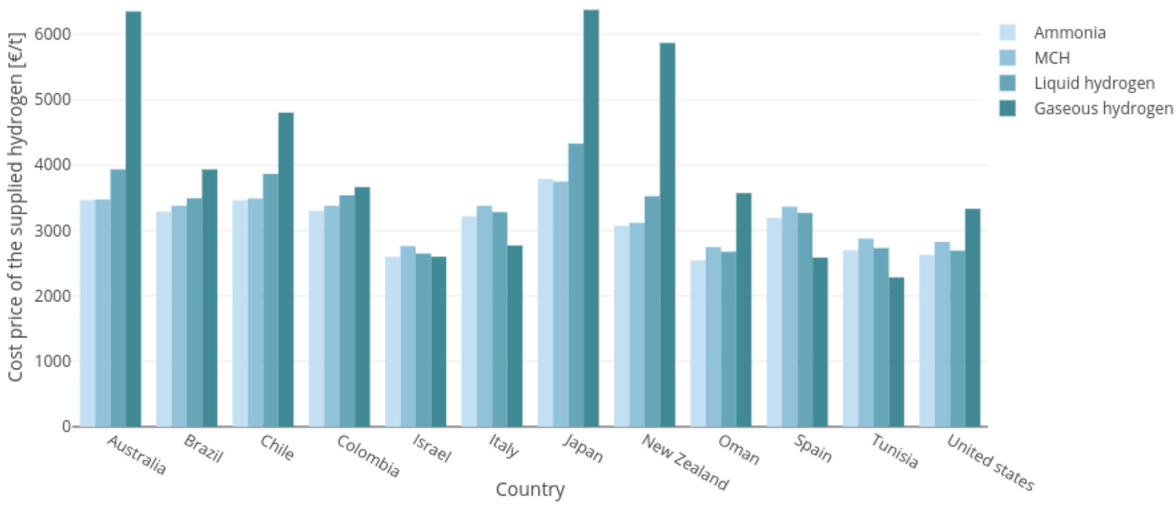


Figure 5.8: Cost price of the supplied hydrogen for the import in the Netherlands

€/ton	Ammonia	MCH	Liquid hydrogen	Gaseous hydrogen
Australia	3,465	3,474	3,935	6,350
Brazil	3,289	3,380	3,493	3,934
Chile	3,463	3,489	3,866	4,803
Colombia	3,301	3,378	3,538	3,664
Israel	2,599	2,760	2,648	2,599
Italy	3,219	3,379	3,282	2,771
Japan	3,788	3,749	4,328	6,374
New Zealand	3,074	3,118	3,524	5,868
Oman	2,545	2,747	2,675	3,572
Spain	3,195	3,365	3,269	2,586
Tunisia	2,696	2,876	2,732	2,283
United states	2,628	2,826	2,692	3,332

Table 5.4: Cost price of the supplied hydrogen for the import in the Netherlands

The prices depend on the country specific parameters and the transportation distance, which has a large influence on the cost price. Another notable parameter is the cost of the production of hydrogen, which varies for the different export countries. The different cost prices are plotted as a function of the distance corresponding to each export country in Figure 5.9.

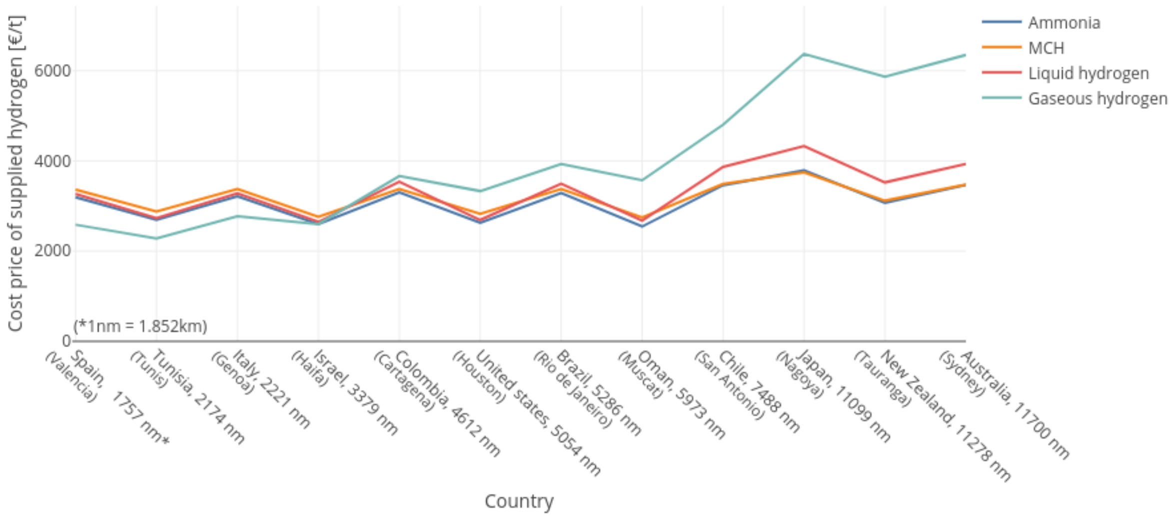


Figure 5.9: Cost price of the supplied hydrogen for importing in the Netherlands for the future hydrogen demand

For short distances hydrogen gas will be the most preferred option. Hydrogen gas only contains transportation and storage costs at the export terminal. When the transportation costs are low, it can compete with the other commodities. The investment costs of liquid hydrogen are high, compared to ammonia and MCH. Yet, the operational costs are lower than for ammonia and MCH. The nominal values of the costs of liquid hydrogen are mostly lower than for ammonia and MCH, however it contains higher discounted costs. For short distances, less vessels are needed which results in a smaller investment upfront. Therefore, for short distance liquid hydrogen is almost financially equal to ammonia. For the import in Rotterdam, the cost price of ammonia will always be lower than that of MCH. The cost price for MCH is comparable to the others, but due to the smaller amount of losses for MCH and from environmental perspective it can be considered as the most favourable carrier option for long distances.

5.3.2 Optimal cost prices

The lowest cost prices follow from export countries laying nearby, in which gaseous hydrogen will be financial the most beneficial option (see Figure 5.10). With the estimated demand of Rotterdam, the cost price of the delivered hydrogen will be 2,283 €/ton (2.3 €/kg). The most financially beneficial combination for ammonia is obtained from Oman, with a cost price of 2,545 €/ton. The lowest cost price regarding the hydrogen carrier MCH is derived from Oman with a cost price of 2,747 €/ton, which is the most expensive carrier for the terminal in Rotterdam. Liquid hydrogen has a cost price of 2,648 €/ton, collected from Israel. As can be seen, the cost prices of ammonia, MCH and liquid hydrogen are really similar to each other. When technical innovations occur, these cost prices can decline with different rates, which can result in larger or smaller deviations between these carriers.

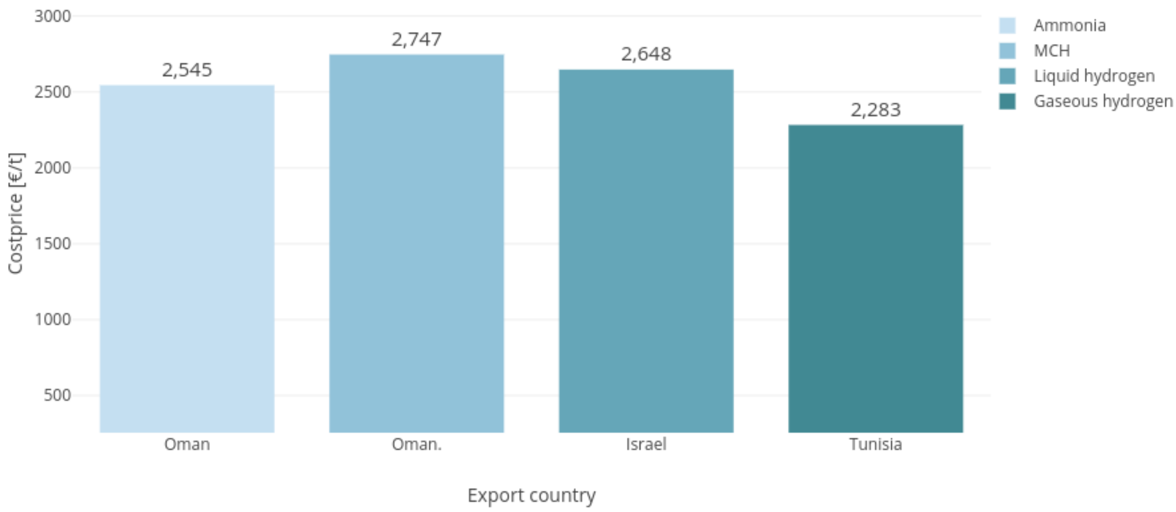


Figure 5.10: The optimal cost price of the hydrogen carriers combined with the export countries, for the import terminal in Rotterdam

5.3.3 Conclusion

The answer to the main-research question, "*What is the most cost effective way to import hydrogen into the port of Rotterdam to supply the future hydrogen demand in the Netherlands, given a selected set of hydrogen carriers and export locations?*", is that the optimal hydrogen import supply chain for the estimated demand of Rotterdam is obtained from gaseous hydrogen exported in Tunisia with a cost price of 2.3 €/kg, based on the current assumptions of the model (see Figure 5.9). This cost price is based on the construction of new pipelines. When using the existing pipelines from Tunisia to the Netherlands, this cost price can be significantly reduced. The domestic cost price of hydrogen in Tunisia is 1.3 €/kg. The domestic cost price of the hydrogen production in the Netherlands is 1.7 €/kg. This cost price does not include any transportation to the grid and can therefore increase. When the cost price of the imported hydrogen declines and the domestic cost price increases, the imported hydrogen can compete with domestic production. Also, import of sustainable energy is presumably necessary to fulfil the energy demand in 2030, in order to switch to a sustainable society (Van Wijk et al., 2019). Therefore, it is reasonable that the import of hydrogen can be established by gaseous hydrogen with pipelines from Tunisia in the port of Rotterdam.

5.4 Conclusion

In this chapter the sub-question, "*What are the integrated costs for the import terminal in Rotterdam for different hydrogen carrier types (on terminal level)?*", and the main-research question, "*What is the most cost effective way to import hydrogen into the port of Rotterdam to supply the future hydrogen demand in the Netherlands, given a selected set of hydrogen carriers and export locations?*", are answered. The MCH import terminal is the most expensive due to the high energy costs of the H_2 retrieval plant. In the ammonia terminal, the largest costs originate from the energy for the H_2 retrieval as well and in the liquid hydrogen terminal the investment costs of the storage are responsible for the largest expenses. The import of hydrogen with ammonia, MCH and liquid hydrogen as carriers, do not need a lot of space in the port of Rotterdam, because the strategical storage can be done in salt caverns located in the hinterland. Gaseous hydrogen is directly transported through pipelines to the grid and to the seasonal storage, and therefore does not contain any import terminal costs. The optimal hydrogen import supply chain for the estimated demand of Rotterdam is obtained from gaseous hydrogen exported in Tunisia with a cost price of 2.3 €/kg. With gaseous hydrogen as hydrogen carrier, an import terminal is redundant and therefore there will not be any space requirements in the port of Rotterdam. With this analysis, it is reasonable that the import of hydrogen can be established by gaseous hydrogen with pipelines from Tunisia in the port of Rotterdam, without the need of an import terminal.

6 Discussion & Conclusions

Energy distribution and storage in the form of hydrogen production is a potential candidate to accomplish the decrease of CO_2 emissions. However, to use hydrogen for distribution or storage, it must be compressed, liquefied or attached to a carrier due to its low volumetric energy density. At this moment, though, the most cost-effective method to import hydrogen is unknown (Li et al., 2019). In this chapter, the results of the research regarding the problem are given and the conclusion regarding the research questions are presented. At first, critical points are outlined to point out the limitations of this research. The research contributes to profound conclusions and gives a preliminary indication of which hydrogen supply chain would be beneficial. Therefore it is able to answer the research question. Afterwards, the three research questions will be answered in the main conclusion.

6.1 Discussion

This section will outline the limitations of the research. The first critical point is that the model assumed an unlimited supply of hydrogen. This assumption is however not realistic as the supply of (renewable) energy by hydrogen is in reality limited. In other words, the (sustainable) energy projects in countries consist of a maximum generation capacity, whereby it is not technically feasible to generate more than this capacity. When the import flow is no longer assumed to be unlimited, multiple import flows may be required to meet the demand.

The second critical point is that some input values of the supply chain elements are based on existing technologies. With technological innovation, the technology gets more advanced and the prices will decrease. It is however difficult to almost impossible to predict the precise level of declination. Another example is that at this moment, there are various trade offs regarding the vessels, in which technical innovation occurs. Therefore, the considered vessels in this research will develop in time and their volume and costs will change over time.

Lastly, a critical point is that some input parameters of the elements of the supply chain are not country based, in other words; they have the same value regardless the export/import country. For example, the investment cost of the conversion to hydrogen carrier plant is equal for every country. This is uncommon in daily basis and therefore is a point of discussion. These input parameters have an influence on the cost price and therefore a switch in the most financially beneficial supply chain flow can occur.

6.2 Conclusion

This research analyzed the cost parameters that are related to the different hydrogen supply chains for international import and assessed the feasibility for an individual import terminal in the port of Rotterdam. This analysis was done through the use of two computer models; the general supply chain model and the import terminal investment model. The input values of both models and the scope of this research (regarding the hydrogen carriers, import/export country and HSC) were based on a literature study, the model of Kalavasta, MTBS database and interviews with employees of various companies.

The general supply chain model was used to provide insight into the costs of each of the elements in the supply chain, given an annual demand and predefined import and export locations. The goal was to assess the costs of the hydrogen supply chain for any selected set of preferred parameters. The first sub question regarding the general supply chain reads:

What is the impact of the selection of the export terminal and hydrogen carrier on the cost price of the imported hydrogen (on system level)?

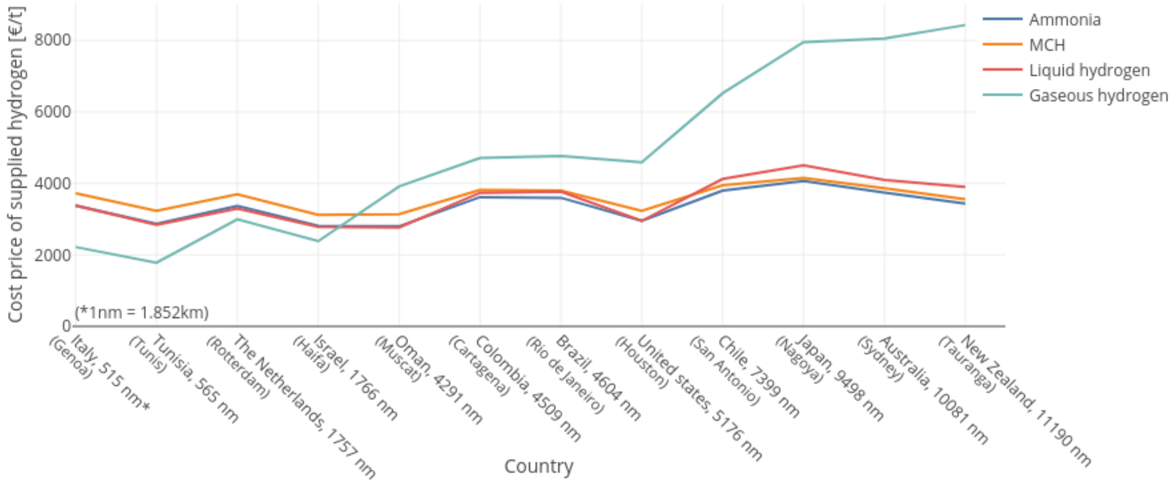


Figure 6.1: Cost price of the supplied hydrogen for the import in Spain with a demand of 700,000 t/y

In Figure 6.1, the various cost prices for the supplied hydrogen, including the production of hydrogen, are shown for the different hydrogen carriers per country for the import in Spain with a demand of 700,000 t/y. This combination was chosen for no specific reason, every other combination is possible within the model. At short distances, it can be seen that gaseous hydrogen is the preferable option. Due to the low transportation costs, gaseous hydrogen can compete with the other hydrogen carriers. Investigating liquid hydrogen, it appears that the investment costs are high compared to ammonia and MCH. Liquid hydrogen contains higher discounted costs and is therefore less favorable. For short distances the costs for liquid hydrogen are almost equal to ammonia, due to lower investment and operational expenses. Ammonia is preferred above MCH. However, ammonia is not a preferred commodity from an environmental perspective because of its indirect contribution to global warming (Lechtenböhmer et al., 2018). For long distances the costs of MCH are almost equal to ammonia, due to the fact that production and distribution of MCH results in less hydrogen losses. This analysis can be generated for all countries within the scope. To answer the first research question; for distances up to 3,500 nm gaseous hydrogen is preferred and for intermediate to long distances ammonia is preferred. Although, the discrepancy between ammonia, MCH and liquid hydrogen is almost negligible. When combining the financial and environmental perspective it can be preferred to select MCH or liquid hydrogen instead of ammonia.

The terminal investment model enables a more granular assessment of the hydrogen cost price for a specific case study; the selected case study concerns a hydrogen import terminal in the port of Rotterdam. A case study for the port of Rotterdam was performed to validate the operation of the general supply chain for a specific case, resulting in a more in-depth understanding of the import terminal. The objective was to financially valuate the terminal design based on an explicit cost assessment. The research question regarding the import terminal is:

What are the integrated costs for the import terminal in Rotterdam for different hydrogen carrier types (on terminal level)?

Zooming in on the import terminal in Rotterdam, a specific framework for the terminal is established. Hereby, the terminal design is financially valuated and an explicit cost assessment providing more in-depth knowledge on the terminal decisions and cost price of the supplied hydrogen is made. The MCH import terminal has the highest costs due to the high energy costs of the H_2 retrieval plant.

In the ammonia terminal, the highest costs also originate from the energy costs of the H_2 retrieval plant. In the liquid hydrogen terminal the highest costs originate from the investment costs of the storage. To answer the second research question, it can be concluded that the H_2 retrieval plant has the highest costs at the ammonia and MCH terminal and at the liquid hydrogen import terminal storage is the highest cost item.

The cost value created by the supply chain model, excluding the import terminal, is used as an input value for the import terminal investment model. When adding the costs of the import terminal, the costs of hydrogen in the port of Rotterdam were calculated with a more substantiated analysis of the import terminal. The main research question of the research is:

What is the most cost effective way to import hydrogen into the port of Rotterdam to supply the future hydrogen demand in the Netherlands, given a selected set of hydrogen carriers and export locations?

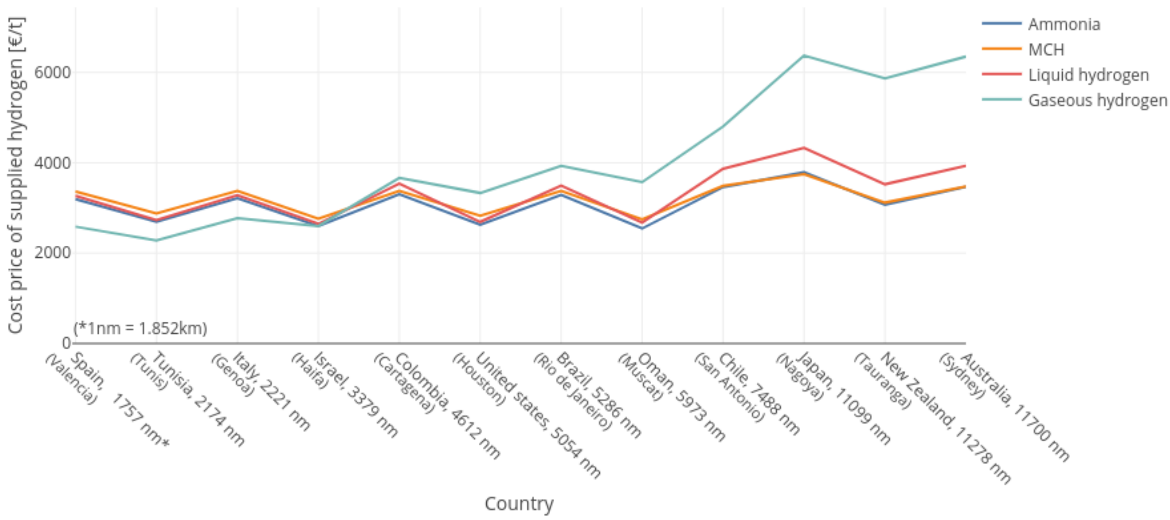


Figure 6.2: Cost prices of the supplied hydrogen for the import in the Netherlands

The optimal hydrogen import supply chain for the port of Rotterdam is obtained from gaseous hydrogen exported from Tunisia with a cost price of 2.3 €/kg, with the estimated demand in the Netherlands (see Figure 6.2). This cost price is based on new pipelines. When using the existing pipelines from Tunisia to the Netherlands, this cost price can be significantly reduced. The domestic cost price of hydrogen in Tunisia is 1.3 €/kg. With gaseous hydrogen as hydrogen carrier, an import terminal is redundant eliminating the need for terminal space at the port. The domestic cost price of the hydrogen production in the Netherlands is 1.7 €/kg. This cost price does not include any transportation to the grid and therefore the actual price can be higher. When the cost price of the import hydrogen declines and the domestic cost price increases, the imported hydrogen can compete with domestic production. Furthermore, the import of sustainable energy is required to fulfil the energy demand in 2030, in order to transform to a sustainable society (Van Wijk et al., 2019). To answer the main research question; the optimal way to import hydrogen into the port of Rotterdam is by transporting gaseous hydrogen with pipelines from Tunisia.

7 Recommendations

In this chapter the recommendations are outlined. The recommendations will cover aspects that could be included in future research to improve and build on the findings of this research.

- The first recommendation is related to improving the general applicability of the developed model by enlarging the list of hydrogen carriers that fall within the scope of this research. This research considers four hydrogen carriers (i.e. ammonia, MCH, liquid- and gaseous hydrogen). However, there are more hydrogen carriers such as methanol, ethanol, formic acid and sodium borohydride, which have been left out of scope. To receive an even better overview, these hydrogen carriers should be included in further studies.
- The second recommendation is to examine more countries, which can result in a more suitable model. The determination of the hydrogen export country can be improved, due to the fact that more combinations can be examined, which gives an even better overview. Another perspective regarding the countries is to implement more country dependent input parameters. Also, a recommendation in relation to the countries, is regarding the supply and demand aspects. To implement a better view on the actual hydrogen supply chain flows, the supply of hydrogen of every country needs to be examined. When the import flow is no longer assumed to be unlimited, multiple import flows may be required to meet the demand. This can happen when the most financially beneficial supply chain only can fulfil a small part of the demand of the import country and therefore a second supply chain is probable necessary.
- The third recommendation, is to implement forecasting for the input parameters, regarding the supply chain elements, such as energy and investment costs of the conversion plant. Hereby, a more accurate cost view can be created. In which, the various innovations are taken into account in relation to efficiency, costs and capacity.
- The last recommendation is to combine more project phases in the import terminal investment model. The model is than more representative for the actual process that leads up to a project's final cost price. Within terminal development, five design stages are presented (Van Dorsser, 2018). The model of this research only includes the first and second stage together with factors of the third stage. When more phases are included into the model, this may lead to a better and more streamlined design development. On the other side, it may be inefficient to try to combine all stages into a single assessment model, due to the integrative nature of the five stages. The five design stages are (Van Dorsser, 2018):

1. Cargo projections	Includes the forecast throughput volumes, tariff levels and revenues;
2. Terminal design	A design is generated, which is translated into CAPEX and OPEX;
3. Financial evaluation	The financial feasibility of the project is analyzed and inflation rates, finance structure and tax payments are given;
4. Economic evaluation	The project feasibility from an economic perspective is analyzed, which includes also the effects from the societal point of view, this includes non- and desirable effect. This is compulsory for subsidies and grants;
5. Project funding	Financial experts examined the options to fund the project by investigating conditions in which returns and risk levels of the project are sufficient to for example the bank.

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Annex

A Definitions of the supply chain

The global energy system must undergo a transformation to achieve lower CO_2 emissions in 2030. At this moment we are in the 6th Kondratieff wave, which started in 2010 till unknown (see Figure A0.1). Kondratieff waves are hypothesized cycle-like phenomena in the modern world economy, which are also called super cycles, great surges, long waves, K-waves or the long economic cycle (Allianz, 2010). The transition from the 5^{th} K-wave to the 6^{th} K-wave is mainly dominated by two drivers: a shift from globalization to sustainability and the hyper connectivity trend (Van Dorsser, Taneja, & Vellinga, 2018).

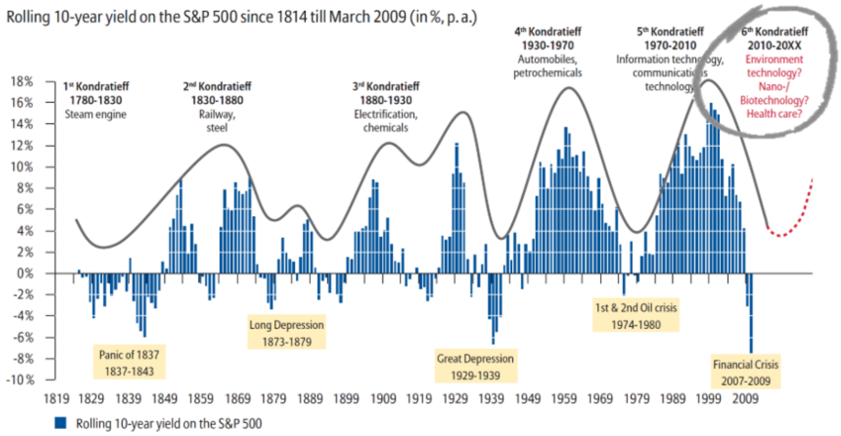

Figure A0.1: Kondratieff waves (Allianz, 2010)

The shift from globalization to sustainability includes the energy transition, which is for a part driven by the climate targets of the Paris Agreement (McKinsey & Company, 2017). The two main pillars of the energy transition are energy efficiency and renewable energy (IRENA, 2018a). This comprehensive, long-term energy transition will have additional costs of \$1.7 trillion annually in 2050, but this will be compensated by cost savings of \$6 trillion annually in 2050 in the fields of reduced air pollution, better health and lower environmental damage (IRENA, 2018a). The two main pillars can provide 94% of the required reduction of the energy-related CO_2 emission (IRENA, 2018b). The share of the renewable energy needs to grow from 15% of the total primary energy supply in 2015 to two-third of the total primary energy supply in 2050 to meet climate targets (IRENA, 2018a). This growth mostly originates from growth in solar- and wind power. At this moment, between early 2017 and early 2018, the global weighted average costs for onshore wind and solar PhotoVoltaics (PV) are \$0.06/kWh and \$0.10/kWh respectively (IRENA, 2018a). The energy intensity of the global economy needs to fall by about two-third in 2050, which means that the energy supply in 2050 will be slightly lower than the energy supply of 2015, despite the population and economic growth (IRENA, 2018a). This can be achieved through improving the energy efficiency.

Import of energy is therefore presumably necessary to fulfil the energy demand in 2030, in order to switch to a sustainable society (Van Wijk et al., 2019). However, renewable electricity consists of electrons that are hard to store and transport. Hydrogen can be the missing link in the energy transition, due to its characteristics, which moderate transportation and storage (Van Wijk et al., 2019). Even more, it can replace fossil fuels without the need to fully change end-use technologies (Council & of Engineering, 2004).

The hydrogen feedstock market had a total estimated value of \$115 billion in 2017 and is expected to grow significantly in the coming years, reaching \$155 billion by 2022 (Taibi et al., 2018). The production cost of green hydrogen by electrolysis will decline the coming years from 2020-2025 between €2.0-3.0/kg to 2025-2030 between €1.5-2.5/kg till > 2030 around €1/kg (see Figure A0.2 for the buildup of these costs) (Van Wijk, 2017). NASA is one of the largest users of hydrogen as a fuel and uses it already since 1950. The first supply chain of Kawasaki is based on brown coal with an estimation of cost regarding insurance and freight of \$3.73/kg for hydrogen and the possibility to generate electricity at \$0.18/kWh (Hinkley et al., 2016).

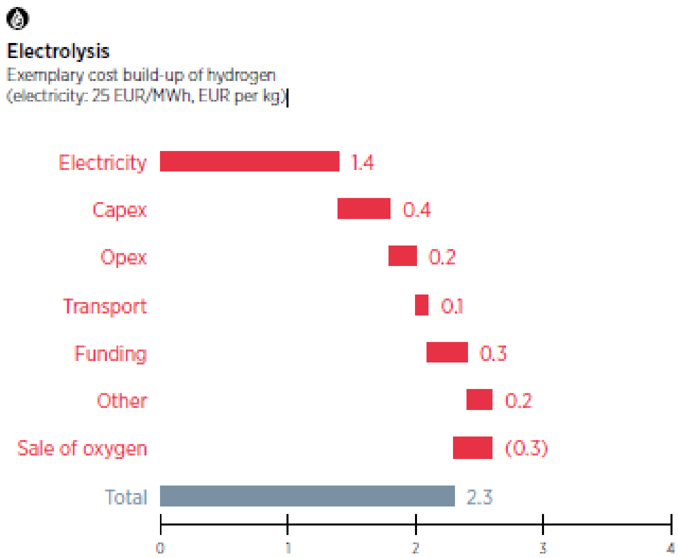

Figure A0.2: Exemplary cost build-up of hydrogen (Van Wijk, 2017)

A1 Hydrogen sources

There are a lot of different sources for the production of hydrogen, as can be seen in Figure A1.1, this includes fossil resources as well as renewable resources.

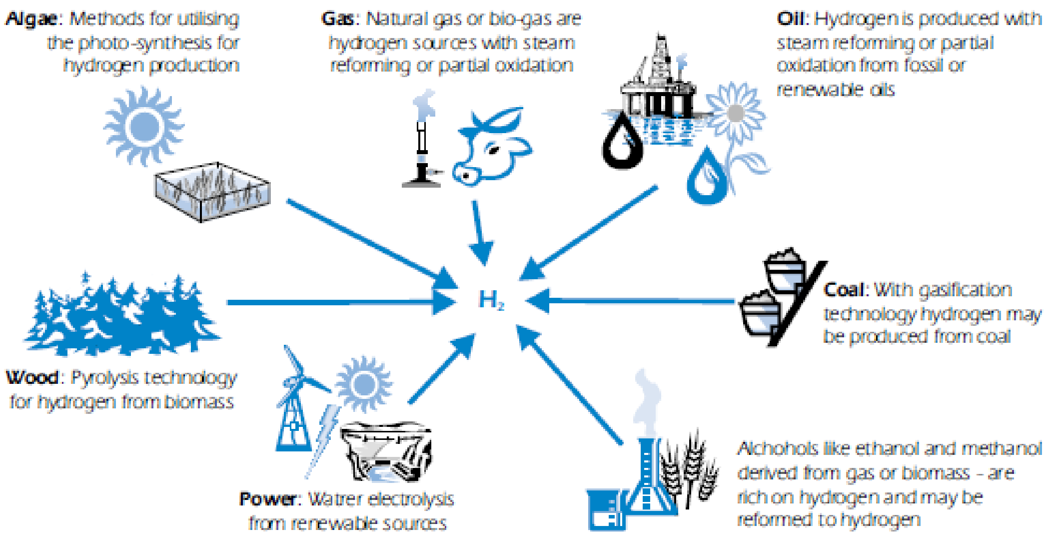

Figure A1.1: Different sources and process alternatives (IEA, 2006)

The prices of wind and solar power are declining and in 2017 the first offshore wind park project of 700 MW, which is conducted by Vattenfall, without subsidy took place (Weston, 2018). The global average costs of raw material prices in 2020 will be around \$0.06/kWh for solar power, \$0.05/kWh for wind energy onshore and \$0.06 à 0.10/kWh for wind offshore (IRENA, 2018b). However, the forecast for energy prices in specific area are lower. Solar energy may be produced for \$0.02 à 0.03/kWh in 2020 in the Middle-East, Brazil, Chili, Mexico, India, China, Australia and Africa (Van Wijk et al., 2017). Onshore wind energy may also be produced for \$0.02 à 0.03/kWh in 2020 in the Morocco, Mexico, Argentina, the United-States, China, India, parts of Africa, Mongolia and Kazakhstan (Van Wijk et al., 2017). For offshore wind the first tender offers in 2017 were less than €0.04/kWh in Germany and Denmark (Bloomberg, 2018a). The prediction is that the prices of wind and solar power will decline even further in 2040, with 66% for solar power, 47% for onshore wind and 71% for offshore wind (Bloomberg, 2018a).

There are already a couple of studies that have been done on the developments of the supply of hydrogen. In Table A1.1, the developments of offshore wind in the Netherlands from the Ministry of Economics and Climate can be found.

	2018	**2024**	**2030**	**2050**
Offshore wind (GW)	1	3.5	11.5	12-75

Table A1.1: A study of the developments of offshore wind in the Netherlands (Wiebes, 2018)

A selection of developments of renewable energy around the world are (Bloomberg, 2018b; Asian renewable energy hub, 2018; Climate Action, 2018):

- Solar power project in Tunisia called TuNur, will generate about four gigawatts of power around 2020;
- Wind power project in China called Jiuquan Wind Power Base, will generate about 20 gigawatts of power around 2020;
- Solar power and wind project in Australia called Asian Renewable Energy Hub, will generate about 11 gigawatts of power around 2024;
- Solar power project in Saudi Arabia, will generate about 200 gigawatts of power by 2030 (currently on hold).

A2 Conversion to hydrogen

For the production of hydrogen, different conversion types can be applied, see Figure A2.1. Each technology is in a different stage of development and each offers unique opportunities, benefits and challenges (Gigler & Weeda, 2018a). In this section the hydrogenation process with electrolysis and the thermochemical conversion are discussed.

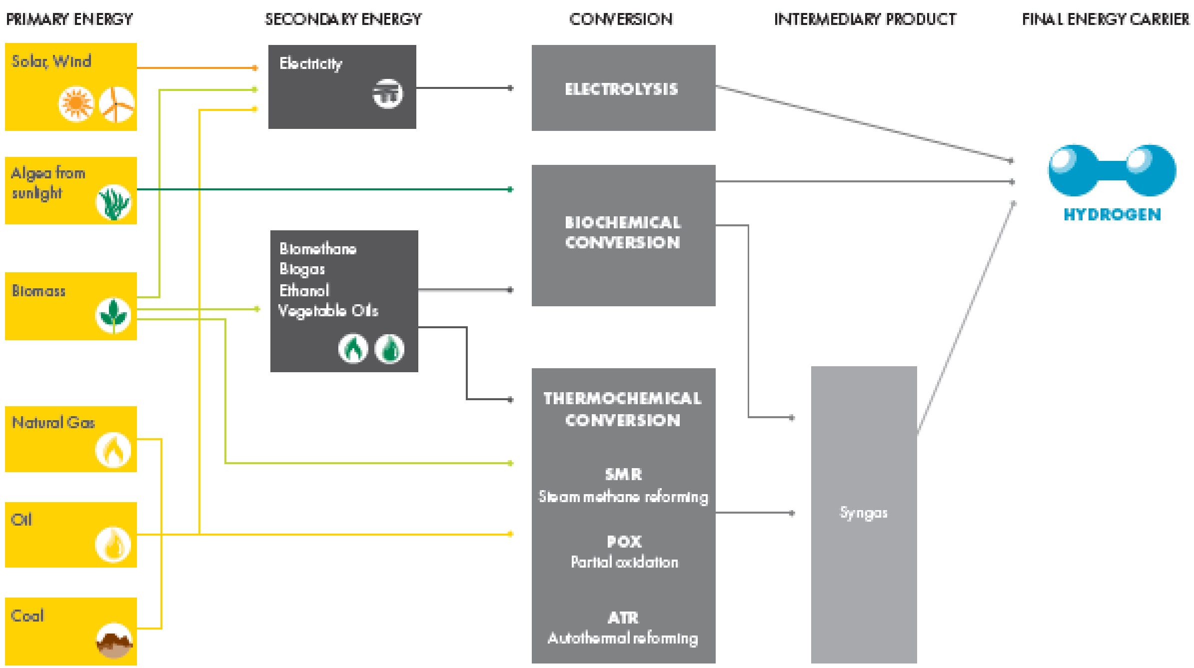

Figure A2.1: Processes for producing hydrogen (Shell Deutschland Oil GmbH, 2017)

A2.1 Electrolysis

The production of hydrogen can be generated with electrolysis, which is a device that splits water into hydrogen and oxygen with the help of electricity (see Equation A.1).

$$H_2O + electricity \rightarrow H_2 + \frac{1}{2}O_2 \tag{A.1}$$

There are different variants of electrolysis, each in a different stage of development. A couple of variants are discussed in this section. In Table A2.1, the unique benefits and challenges for the different methods can be found.

- The first variant which is discussed is the PEM electrolysis. It contains a membrane, which ensures the conductance of the protons, the separation of the gases and the electrical isolation of the electrodes (anode and cathode) (Saba et al., 2018). The efficiency of the PEM is rapidly increasing from 65% in 2010 to 80% in 2017 and with a prognosis of 86% in 2050 (Van Wijk et al., 2017).
- The second variant is the alkaline systems or AEC, which is already widely used for largescale industrial applications since 1920 (Schmidt et al., 2017). Alkaline electrolysers use an aqueous KOH solution (caustic) as an electrolyte that usually circulates through the electrolytic cells (IEA, 2006).
- The last variant is the Solid Oxide Electrolysis Cells (SOEC), which has an efficiency of 85% nowadays, but this is only demonstrated at a laboratory and on a small demonstration scale. The key components are a dense ionic conducting electrolyte and two porous electrodes. Steam is fed to the porous cathode. When required electrical potential is applied to the SOEC, water molecules diffuse to the reaction sites and are dissociated to form hydrogen gas and oxygen ions at the cathode–electrolyte interface (Ni et al., 2008).

	Alkaline systems	PEM	Solid Oxide Electrolysis
Benefits	Commercially-available	Gas purity	Low material cost
	Low capital cost	Compact system design	High stack lifetime
	Readily available	Dynamic operation	High electrical efficiency
		High efficiency	High efficiency
Challenges	Low current densities	R&D stage	High operating temperature
	Low partial load range	High investment costs	Low system response

Table A2.1: Unique benefits and challenges for the different methods

In Table A2.2, the different characteristic features of the various electrolysis methods can be found. This information has been used to define the scope of the research and can be used for further literature review.

	Alkaline systems		**PEM**		**Solid Oxide Electrolysis**	
	2018	**2030**	**2018**	**2030**	**2018**	**2030**
Temperature C	60 - 80		60 - 80		700 - 900	
Electrolyte	Potassiumhydroxid		Solid state membrane		Oxide ceramic	
Plant size Nm3 H_2/h	0.25 - 760		0.01 - 240		Until now at experimental	
[MW]	1.1 – 5.3	4.9 – 8.6	0.1 – 1.2	2.1 - 90	0.5 – 50	0.5 – 50
Efficiency	65	66 (50 - 74)	62 (40 - 69)	69 (62 - 79)	77	81
Minimum part load [% of capacity]	30 (20 - 40)	10 - 20	9 (5 - 10)	0 - 5	3	3
Purity H_2	99.5 % – 99.9998 %		99.9 % – 99.9999 %		N/A	
Investment costs [€ 2015/kW]	600 – 2,600	400 - 900	1900 - 3700	300 - 1300	400 - 1000	400 -1000
O & M cost [%]	2 -5	2 -5	2 -5	2 -5	2 - 3	2 - 3
Stack Lifespan [1000 h]	60 - 90 h	90 - 100	20 - 90	60 - 90		
System life span [years]	20 - 30	30	10 - 30	30	10 - 20	10 - 20
Stack replacement cost	50% of investment cost		60% of investment cost		Included in O& M cost	
Maturity level	Commercially used in industry for the last 100 years					

Table A2.2: Different characteristic features of the various electrolysis methods (Shell Deutschland Oil GmbH, 2017; Bertuccioli et al., 2014; Ni et al., 2008)

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A2.2 Steam methane reforming

The hydrogenation of natural gas is mostly done with the SMR, it separates hydrogen atoms from carbon atoms in methane (Gigler & Weeda, 2018a). The capacity of a standard factory is around nine-ton hydrogen per hour. The process can be split in two parts, the first part is reforming the natural gas with steam by temperatures of 800 till 1000 °C (Gigler & Weeda, 2018a). The product of this part is syngas, which consist of carbon monoxide and hydrogen.

The second part is the water-gas-shift-step, which consist of the carbon monoxide reacting with steam creating CO_2 and more hydrogen (Gigler & Weeda, 2018a). With this technique it is hard to completely capture all the CO_2 due to the flue gases with low CO_2 emissions. The average capture percentages are around 50- 60 % and the production cost in the future will be around €1.0 - 1.5/kg H_2 (Gigler & Weeda, 2018a). Two other variants to create hydrogen from natural gas are ATR and POX. By these two variants, high-temperature-process-heat is produced by burning the natural gas in the reactor with pure oxygen. The benefits and challenges of these methods are discussed in Table A2.3.

	SMR	**ATR or POX**
Benefits	High efficiency	Smaller size
	Low investment costs	Simple system
		Fully capture of emissions possible
Challenges	Emissions	Lower efficiency
	Costs for large units	H2 purification
	Complex system	High investment costs
	Sensitive to natural gas qualities	

Table A2.3: Overview of the benefits and challenges of SMR, ATR or POX (Gigler & Weeda, 2018a)

A3 Hydrogen carriers

In Table A3.1 the different properties of the hydrogen carriers can be found.

	Ammonia	**MCH**	**LH_2**	**H_2**
Physical properties for transport				
Pressure [bar(a)]	Ambient	Ambient	Ambient	700
Temperature [C]	-33	Ambient	-253	Ambient
State of matter	Liquid	Liquid	Liquid	Gas
Boiling point [°C]	-33	101	-253	-253
Melting point [°C]	-78	-127	-259	-259
Atom	NH_3	C_7H_{14}	H_2	H_2
Molar mass [g/mol]	17.03	98.19	2.02	2.02
Volumetric storage efficiency [g H_2/L]	89	43	71	39
Density [t/m^3]	0.6826	0.77	0.0708	0.0057
Energy density (LHV) [g/mol]	5.178	12	33	33
Hydrogen content [%]	17.7	14.37	100	100

Table A3.1: Overview of the most important feedstocks (ISPT, 2017; IEA, 2006; Peschka, 2014)

A4 Storage - Salt caverns

Hydrogen gas can be stored in salt caverns. Salt caves storage concern a series of caves leached from the deep, thick layers of rock salt (Engie, 2018). Leaching is a process whereby minerals are extracted from a solid substance by means of dissolution in a liquid (Engie, 2018). These caves are therefore made by injecting water, whereby the salt is dissolved. This salt is then removed, creating empty spaces and room for hydrogen gas. Storage of hydrogen in salt caverns is an established practice and the advantages and disadvantages of salt caverns can be found in Table A4.1 (Crotogino, 2016).

Advantages	Disadvantages
High safety due to only one well per storage cavern	Need for exploration phase
Low geological risk	Several years construction time
High flexibility, maximum 10–12 turnovers per annum	Need to dispose large quantities of salt brine
High deliverability and injectivity/high rates	
Low percentage of cushion gas	
No reactions between storage gas and rock salt	

Table A4.1: Advantages and disadvantages of gas storage in salt caverns (Crotogino, 2016)

A5 Dry bulk terminals

Dry bulk terminals are mostly designed for one-way traffic only and therefore are the import and export (unloading and loading) terminals different in character (Ligteringen & Velsink, 2012). The main unloading systems are grabs, pneumatic systems, vertical conveyors, bucket elevator, slurry systems and self-discharging vessels (Ligteringen & Velsink, 2012). The effective capacity of the unloading systems is defined as the average hourly rate attained during the unloading of the entire cargo of a ship. When multiplied this by the annual operational availability of the berth times the permissible occupancy rate, gives the annual berth capacity (Ligteringen & Velsink, 2012). The annual berth capacity is the main parameter for a port planner (Ligteringen & Velsink, 2012). The unloading systems have a typical rated capacity from 75 to 10,000 t/hour, with the lowest capacity originated from the spiral conveyor and the highest from self-unloading vessels (Ligteringen & Velsink, 2012). The storage of a dry bulk terminal can be done in a stockpile. Each stockpile must be able to accommodate at least a full shipload from each source. Sodium borohydride can also be stored in a sealed container. An estimate of the total length and width required for the stockpiles can be made with the equation (Ligteringen & Velsink, 2012):

$$V = b * 1/2 * h * l * m_b \tag{A.2}$$

In which:

- V = Maximum volume of cargo in storage [m3]
- b = Width of stockpile [m]
- h = Height of stockpile [m]
- l = Total length of stockpile [m]
- mb = Utilization rate [-]

A dry bulk hydrogen carrier is sodium borohydride. Sodium borohydride is a solid powder which is stable at room temperature and atmospheric pressure. In comparison with pressurized hydrogen the safety issues for transportation are significantly reduced (Rivarolo et al., 2018). However, sodium borohydride is limited by high costs, low efficiency of recycling the by-product and a lack of effective gravimetric storage methods(Rivarolo et al., 2018). The endothermic reaction of sodium borohydride with a heterogeneous catalyst, makes the release of hydrogen easy to control (Muir & Yao, 2011). The dehydrogenation reaction of sodium borohydride is (W. Chen et al., 2017):

$$NaBH_4 + 2H_2O \leftrightarrow 4H_2 + NaBO_2[\Delta H = 217kJ/mol] \tag{A.3}$$

B Input values concerning the countries and supply chain elements

In this appendix, the input values regarding the import/export countries and elements of the supply chain are discussed. An exchange rate of 1.16 is applied when the input values were in USD.

B1 Countries

In this section the various input values regarding the import and export countries are given. The different countries are included in the supply chain model as export or import locations. For each country different aspects are included such as wages, fuel costs and WACC. The countries which are included in this research are Australia, Brazil, Chile, Colombia, Israel, Italy, Japan, The Netherlands, New Zealand, Oman, Spain, Tunisia, United States (see Section 2.2 and Table B1.1). The data is obtained from a literature study and from the MTBS database.

Country	**Continent**	**Potential hydrogen country**	**Assess to a port**	**Possible renewable energy price**	**Natural gas access**	**Included**
Chad	Africa			1.40	No	No
Spain	Europe	✓	✓	1.50	Yes	Check
United States	North America	✓	✓	1.55	Yes	Check
Switzerland	Europe	✓		1.55	No	No
Italy	Europe	✓	✓	1.58	Yes	Check
Puerto Rico	North America		✓	1.63	No	No
Japan	Asia	✓	✓	1.70	Yes	Check
Israel	Asia	✓	✓	1.72	Yes	Check
Oman	Asia	✓	✓	1.79	Yes	Check
China	Asia	✓	✓	1.74	Yes	No
Libya	Africa	✓	✓	1.74	Yes	Check
....	....	....	....	....	....	....

Table B1.1: Overview of the different criteria for selecting the countries (Terwel & Kerkhoven, 2018)

The potential of each country is checked with the announcements and developments related to hydrogen. A few announcements and developments, since early 2018, of the countries within the scope, are given below (Birol, 2019):

- *Australia*: "Announced more than AUD 100 million to support hydrogen research and pilot projects. Published a technical road map for hydrogen in Australia produced by the Commonwealth Scientific and Industrial Research Organisation. Has set up a government working group to develop a national hydrogen strategy for completion by the end of 2019."
- *Brazil*: "Included hydrogen in the science, technology and innovation plan for renewable and biofuels. Hosted and supported the 22^{nd} world hydrogen energy conference in 2018."
- *Italy*: "Issued regulations to overcome barriers to the deployment of hydrogen refuelling stations by raising the allowable pressure for hydrogen distribution and enhancing safety, economic and social aspects."

- *Japan*: "Hosted the first hydrogen energy ministerial meeting of representatives from 21 countries, plus companies, resulting in a joint Tokyo Statement on international co-ordination. Updated its strategic road map to implement the basic hydrogen strategy, including new targets for hydrogen and fuel cell costs and deployment, and firing hydrogen carriers in power plants. The development bank of Japan joined a consortium of companies to launch Japan H_2 mobility with a target to build 80 hydrogen refuelling stations by 2021 under the guidance of the Japanese central government's ministerial council on renewable energy, hydrogen and related Issues."
- *The Netherlands*: "Published a hydrogen road map and included a chapter on hydrogen in the Dutch Climate Agreement. Spearheaded the first meetings of the Pentalateral Energy Forum of Belgium, the Netherlands, Luxembourg, France, Germany and Austria in support of cooperation on hydrogen in north-west Europe."
- *New Zealand*: "Signed a memorandum of co-operation with Japan to work on joint hydrogen projects. Began preparing a New Zealand Green Hydrogen Paper and hydrogen strategy. Set up a green investment fund to invest in businesses, including those commercialising hydrogen."
- *United States*: "Extended and enhanced the 45Q tax credit that rewards the storage of CO_2 in geological storage sites, and added provisions to reward the conversion of CO_2 to other products, including through combination with hydrogen. California amended the low carbon fuel standard to require a more stringent reduction in carbon intensity by 2030, incentive development of refuelling stations and enable CCS operators to participate in generating credits from low-carbon hydrogen. California fuel cell partnership outlined targets for 1,000 hydrogen refuelling stations and 1,000,000 Fuel Cell Electric Vehicle (FCEV) by 2030, matching China's targets."

The WACC given in Table B1.2 is obtained from the calculation and input values given in Appendix D.

Countries	**Port place**	**Wages** [€/y]	IFO 380 [€/t]	**Real, pre-tax discount rate** [%]
Australia	Sydney	44,276	478	4.8
Brazil	Rio de Janeiro	7,397	341	9.3
Chile	San Antonio	11,733	439	4.9
Colombia	Cartagena	5,026	401	6.7
Israel	Haifa	32,129	292	5.1
Italy	Genoa	26,741	299	6.0
Japan	Nagoya	33,233	307	5.2
The Netherlands	Rotterdam	39,810	274	2.5
New Zealand	Tauranga	33,595	372	5.0
Oman	Muscat	12,448	384	6.6
Spain	Valencia	23,431	324	6.0
Tunisia	Tunis	3,017	412	7.1
United States	Houston	50,233	277	4.1

Table B1.2: Various characteristics of the scoped countries (World data, World bank group, 2018; IHS, 2019)

B1.1 Energy prices

The energy prices are given in Table B1.3. It is assumed that the energy prices will increase and that this increase will be linear. This assumption is based on the report of "*The future of hydrogen by IEA*" (Birol, 2019).

Energy prices [€/kWh]	2019	2030	2040
Australia	0.07	0.13	0.14
Brazil	0.11	0.13	0.14
Chile	0.12	0.14	0.15
Colombia	0.12	0.14	0.15
Israel	0.09	0.11	0.12
Italy	0.10	0.12	0.13
Japan	0.13	0.15	0.14
The Netherlands	0.07	0.09	0.10
New Zealand	0.10	0.12	0.13
Oman	0.06	0.09	0.09
Spain	0.10	0.12	0.13
Tunisia	0.09	0.11	0.12
United States	0.06	0.09	0.09

Table B1.3: Energy prices in €/kWh of each country (Birol, 2019)

B2 Hydrogen costs

The hydrogen costs are based on grey, blue and green hydrogen. The hydrogen costs are based on a literature study and interviews with experts. The calculation of the costs of hydrogen per country is performed outside the model and is therefore taken as an input parameter. This parameter has a varying character in time and place, since the cost of hydrogen decreases with time and the cost of sources depends on the production country.

All countries within the scope, have access to their own natural gas or import natural gas and therefore can produce grey and blue hydrogen. It is assumed that in 2030 a CO_2 tax will be implemented, therefore the cost of grey hydrogen will increase (see Table B2.1). It is also assumed that an improvement in technique will decrease the cost of blue hydrogen. The cost of grey and blue hydrogen for the various region for 2018 can be found in Figure B2.1.

Region	Today	2030	Long term
Advanced economies	5-16	100	160
Emerging economies	0-5	75	145

Table B2.1: CO_2 price [\$/t CO_2] (Birol, 2019)

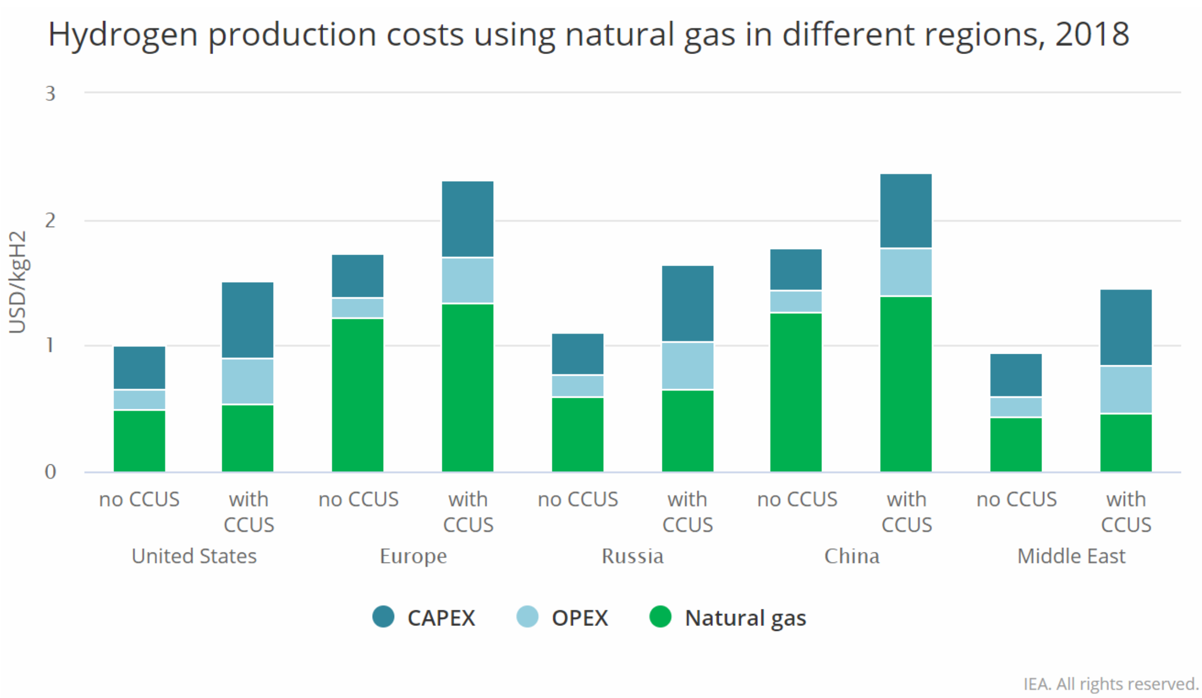

Figure B2.1: Hydrogen production costs using natural gas in different regions, 2018 (Birol, 2019)

The green hydrogen costs depends on the sun- and wind power in a country. The countries are divided into large potential for renewable energy to small potential (see Table B2.2). An improvement in technique will eventually decreases the costs.

Sun/wind	**Sun solar [kWh/kWp]**	**Range**	**Wind capacity [W/m2]**	**Range**
Australia	1880	High	465	Low
Brazil	1601	Medium	241	Low
Chile	1987	High	3694	High
Colombia	1206	Low	351	Low
Israel	1728	Medium	336	Low
Italy	1418	Low	614	Medium
Japan	1258	Low	797	Medium
The Netherlands	985	Low	518	Medium
New Zealand	1306	Low	2156	High
Oman	1849	High	684	Medium
Spain	1660	Medium	678	Medium
Tunisia	1731	Medium	615	Medium
United States	1602	Medium	808	High

Table B2.2: Sun and wind power per country (Global Solar Atlas, 2018; Global Wind Atlas, 2018)

In the price of the green hydrogen it is taken into account the available area for renewable energy per country. This has influence on the price and volume of renewable energy. When the available area is bigger, the installed capacity will be higher and therefore the price will be lower. Also, it takes into account which policy the country contains on renewable energy. When a country obtains renewable energy as focus point, the investment in this category will rise and therefore the price of the energy will decline (see Figure B2.2).

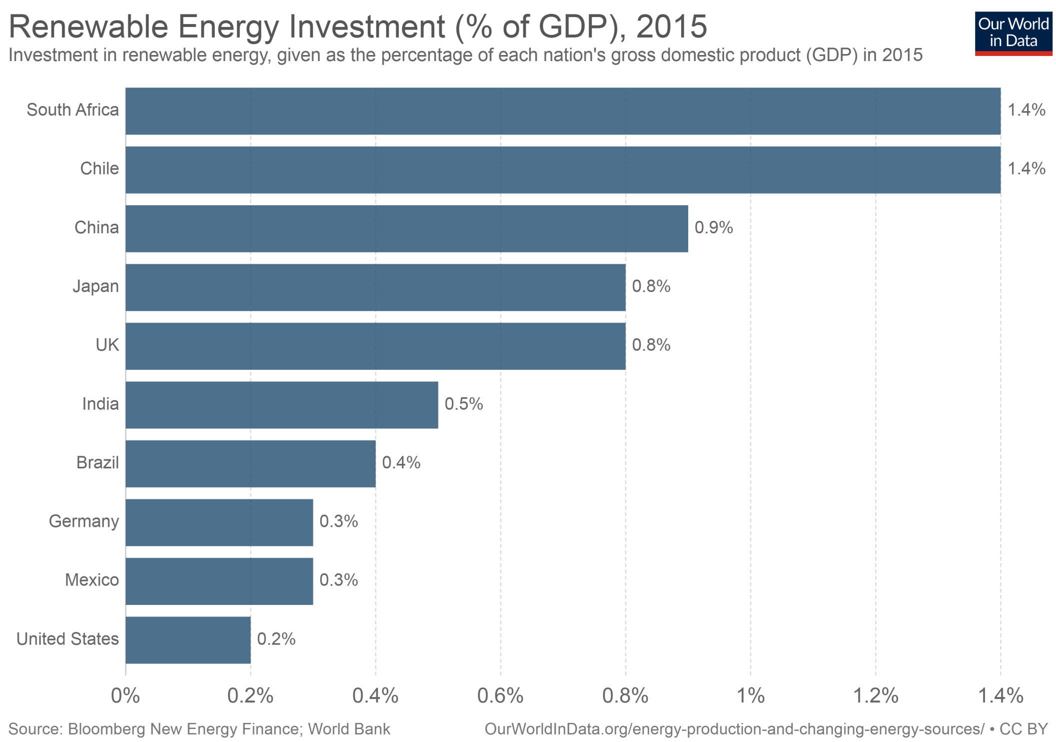

Figure B2.2: Renewable energy investment per country (IEA, 2006)

The global hydrogen costs from hybrid solar PV and onshore wind systems in the long term can be found in Figure B2.3. This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area (Birol, 2019). The included costs are (Birol, 2019):

- Electrolyser CAPEX = 450 $/kW_e$;
- Efficiency (LHV) = 74%;
- Solar PV CAPEX and onshore wind CAPEX = between 400–1,000 $/kW and 900–2,500$/kW depending on the region;
- Discount rate = 8%.

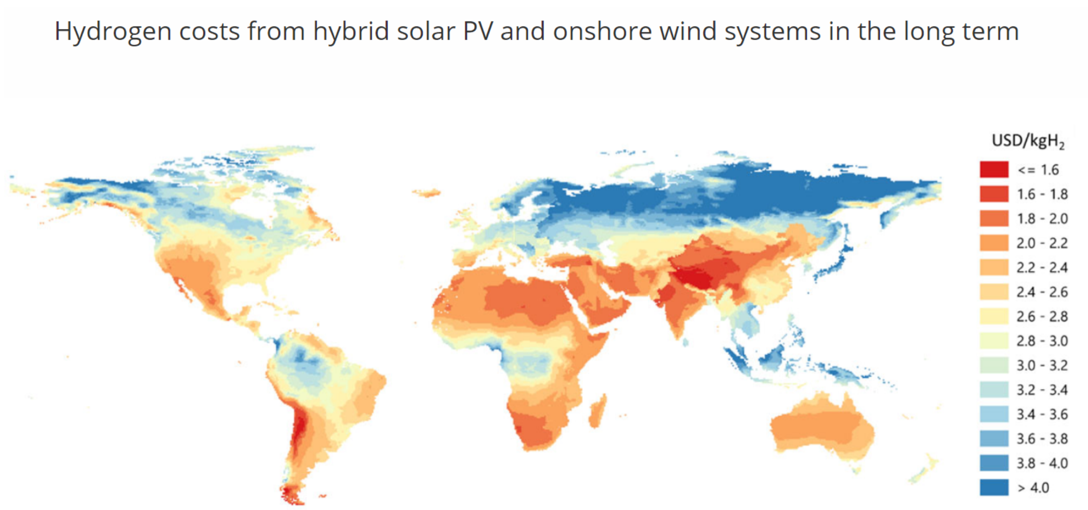

Figure B2.3: Hydrogen costs from hybrid solar PV and onshore wind systems in the long term (Birol, 2019)

As can be seen from Figure B2.3, promising areas are Patagonia, New Zealand, Northern Africa, the Middle East, Mongolia, most of Australia, and parts of China and the United States.

All this together lead to various hydrogen prices for grey, blue and green hydrogen. These prices are stated in Table B2.3. The most favorable price of hydrogen per year is taking into account, which can therefore vary from grey to blue or green hydrogen.

Hydrogen [€/kg]		**2020**	**2030**	**2040**
Australia	Grey	1.29	1.72	2.07
	Blue	1.72	1.64	1.55
	Green	3.28	3.10	2.07
Brazil	Grey	1.55	1.98	2.24
	Blue	1.90	1.72	1.64
	Green	2.76	2.33	1.81
Chile	Grey	1.55	1.98	2.24
	Blue	1.90	1.72	1.64
	Green	2.59	2.16	1.55
Colombia	Grey	1.55	1.98	2.24
	Blue	1.90	1.72	1.64
	Green	3.02	2.59	2.41
Israel	Grey	0.86	1.21	1.55
	Blue	1.25	1.25	1.21
	Green	3.71	2.76	1.72
Italy	Grey	1.49	1.72	2.16
	Blue	2.00	2.00	1.98
	Green	3.62	3.02	2.67
Japan	Grey	1.72	1.81	1.90
	Blue	2.24	2.16	2.07
	Green	5.34	4.48	3.45
The Netherlands	Grey	1.49	1.72	2.16
	Blue	2.00	2.00	1.98
	Green	3.62	3.02	2.67
New Zealand	Grey	0.86	1.55	2.07
	Blue	1.31	1.29	1.29
	Green	4.14	3.02	2.24
Oman	Grey	0.81	1.21	1.55
	Blue	1.25	1.16	1.12
	Green	3.62	2.59	1.55
Spain	Grey	1.49	1.72	2.16
	Blue	2.00	2.00	1.98
	Green	3.62	3.62	2.67
Tunisia	Grey	0.81	1.47	1.90
	Blue	1.25	1.38	1.51
	Green	2.76	1.98	1.47
United States	Grey	0.86	1.29	1.72
	Blue	1.38	1.34	1.29
	Green	3.02	2.59	1.90

Table B2.3: Hydrogen cost per country for grey, blue and green hydrogen (Birol, 2019)

B3 Conversions to hydrogen carrier

The possible carriers for transporting hydrogen have been identified during a literature study. The carriers are cross-checked with experts, for the potential of the carrier. The carrier conversion costs are based on the model of Kalavasta and personal contact with Vopak and Fertilizers Europe. This is cross-checked with a literature study.

Carrier plant	**Ammonia**	**MCH**	**Liquid hydrogen**
Investment [M€]	250	20	300
Construction period [years]	3	3	3
Lifetime [years]	20	20	20
Overhead OPEX rate, excl. labour [%]	2.5	2.5	2.5
Nr of personnel per unit [#]	3	3	3
Electricity costs [kWh/kg]	0.64	0.3	6.1
Material cost [€/ton]	27	350	-
Recycle rate of material [%]	-	97	-
Capacity [ton/year]	1,000,000	333,333	250,000

Table B3.1: Conversion to hydrogen carrier costs (Birol, 2019), (Vopak, personal communication, January, 2019), (Fertilizer Europe, personal communication, February, 2019)

B4 Export terminal

The export terminal contains two elements, the storage and the jetty. The loading of the vessel is done with shore-based pumps, this amount is included in the jetty costs.

B4.1 Storage

The storage cost per carrier are defined with several interviews with expert and employees of companies and with a literature study. The cost for ammonia, MCH and liquid hydrogen storage are mostly originating from an interview with Vopak and crossed checked with a literature study (Birol, 2019; Kamiya et al., 2015). The salt cavern cost and capacity calculation are obtained from a literature study (Oldenbroek et al., 2019).

Export terminal – Storage	**Ammonia**	**MCH**	**Liquid hydrogen**	**Gaseous hydrogen**
Investment [M€/tank]	60	35	200	107
Construction period [years]	1	1	1	1
Lifetime [years]	30	50	30	50
Overhead OPEX rate [%]	2	2	2	0.5
Nr of personnel per unit [#]	1	1	1	1
Electricity costs [kWh/kg]	0.01	0.01	0.61	-
Capacity [m3]	50,000	50,000	50,000	500,000
Capacity [ton]	34,130	38,500	3,540	3733
Vector for buffer capacity	1.3	1.3	1.3	-
Cycles per annum	26	26	26	26
Losses [% per annum]	11	-	13	0.5

Table B4.1: Storage cost from the export terminal, obtained from interview with Vopak and a literature study (Birol, 2019; Oldenbroek et al., 2019)

The cost of the salt cavern consist of the total installed capital cost for the entire seasonal hydrogen storage (SHS) plant, which consists of the underground cavern, cushion gas, piping, cooler, gas dryer and pressure reduction unit, tube trailer filling station, but excluding tube trailer and SHS filling compressors (Oldenbroek et al., 2019).

B4.2 Jetty

The jetty costs are defined in collaboration with an expert from the TU Delft. The equipment costs are defined with the help of a literature study.

Export terminal – Jetty	
Investment [€/jetty]	2,960,480
Equipment [€/jetty]	1,000,000
Construction period [years]	1
Lifetime [years]	30
Overhead OPEX rate [%]	2
Capacity (depending on hydrogen carrier) [t/y]	4,000,000

Table B4.2: Jetty costs (Dr. ir. De Gijt and Ir. Quist, personal communication, April, 2019)

The number of mooring dolphins is depending on the vessel size, whereby it in general can vary from four to six mooring dolphins with two breasting dolphins. For the mooring dolphins six steel piles are needed with the dimensions of (Ir. Quist, personal communication, April, 2019):

- Length: 45 m
- Width: 1219 mm
- Wall thickness: 25 mm
- Density: 7850 kg/m^3
- Price: 1100 €/t

The concrete on the mooring dolphins contains the following dimensions:

- Length: 4m
- Width: 4 m
- Height: 1.5 m
- Price: 275 €/m^3

The jetty head and catwalk contains the following dimensions and Gijt constants (Dr. ir. De Gijt and Ir. Quist, personal communication, April, 2019):

- Catwalk length: 100 m
- Catwalk width: 5 m
- Gijt constant catwalk: 1000 €/m^2
- Jetty head length: 30 m
- Jetty head width: 16 m
- Gijt constant jetty head: 2000 €/m^2

B5 Transportation

The transportation modes consist of vessels and a pipeline. Ammonia, MCH and liquid hydrogen are transported with a vessel and gaseous hydrogen with a pipeline. The data of the vessels is gained by the model of Kalavasta and cross-checked with the MTBS database. The total cost per kg hydrogen from the liquid hydrogen vessel are validated with a presentation of Kawasaki (Kawasaki Heavy Industries, 2018).

Transportation (vessel)	Ammonia	MCH	Liquid hydrogen
Investment [M€/vessel]	64	44	175
Construction period [years]	3	3	3
Lifetime [years]	30	30	30
Overhead OPEX rate [%]	4	4	4
Nr of personnel per unit [#]	10	10	10
Panama fee [€/trip]	155,000	150,000	320,000
Suez fee [€/trip]	160,000	178,000	270,000
Capacity [ton]	44,000	40,500	10,300
Average speed [knots]	13.20	14.5	13.1
boiled of losses [%]	0.2	-	0.32

Table B5.1: Transportation costs of the various vessels obtained from MTBS database and a literature study (Terwel & Kerkhoven, 2018; Kawasaki Heavy Industries, 2018)

The boiled-off losses of the liquid hydrogen are higher than in reality, because they need to be large enough to fulfil the fuel demand of the vessel. Therefore, more losses are taking into account, which is used as fuel, than when fuel is calculated separately. The fuel consumption of a LNG carrier is 100 ton/day (HSVA, 2013). Hydrogen has energy content which is three times as high as LNG, therefore 33 ton/day of hydrogen is needed as fuel (HSVA, 2013).

The data of the pipeline is gained and cross-checked with the help of Gasunie, IRM smart pipeline data and Internation Energy Agency (IEA) Report "the future of hydrogen"(Birol, 2019). The data of the compression is gained from Ad van Wijk. The investment cost are based on Ad van wijk in combination with GasUnie. These numbers are crossed-checked with IRM, which indicated a rough number of 4 - 4.5 M€/km for a offshore concrete coated pipeline with a diameter 1.2m taking into account the weather conditions, water depth and Engineering, procurement and construction (EPC) contracts. GasUnie indicated a rough number of 3 - 3.5 M€/km for a offshore pipeline with a diameter 1.2m. A in-between number is taking into account in relation to the diameter, which vary with the demand.

Transportation (pipeline)	Gaseous hydrogen
Investment [M€/km]	2
Construction period [years]	3
Lifetime [years]	40
Overhead OPEX rate [%]	1
Nr of personnel [#]	2
Diameter [m]	0.5
Hydrogen spreed [m/s]	15
Losses [%]	0.5

Table B5.2: Pipeline cost based on the interviews with GasUnie

Compressors (equipment pipeline)	Gaseous hydrogen
Investment [€]	50,000,000
Construction period [years]	1
Lifetime [years]	20
Overhead OPEX rate [%]	2
Electricity costs [kWh/kg]	0.24
Pressure [bar]	100
Capacity [nm]	150
Losses [%]	0.5

Table B5.3: Compression of the hydrogen gas at pipeline (Oldenbroek et al., 2019; Van Wijk, 2018)

B6 Import terminal

The data where this parametric model of the terminal is based on is obtained from different sources. At first the jetty cost are based on the experience of Dr.ir. J.G. de Gijt and Ir. P. Quist. The pipelines cost data is gathered from Gasunie and the MTBS Database. The data from the storage element is received from the company Vopak. Subsequently, the data of the H_2 retrieval is also obtained from Vopak and is cross-checked with the company Kalavasta.

B6.1 Jetty

The jetty costs are defined in collaboration with an expert from the TU Delft. In Appendix B4.2 a more in-detailed design and cost parameters are discussed.

Import terminal – Jetty	
Investment [€/jetty]	2,960,480
Construction period [years]	1
Lifetime [years]	30
Overhead OPEX rate [%]	2
Capacity (depending on hydrogen carrier) [t/y]	4,000,000

Table B6.1: Jetty costs (Dr. ir. De Gijt and Ir. Quist, personal communication, April, 2019)

B6.2 Pipelines

The pipeline cost are based on the MTBS database, which are given in Table B6.3.

Import terminal - pipeline 1	Ammonia/MCH/Liquid hydrogen
Investment [€/m]	13,000
Construction period [years]	1
Lifetime [years]	26
Overhead OPEX rate [%]	2.5
Nr of personnel per unit [#]	2
Electricity costs [kWh/kg]	0.1
Capacity [t/y]	4,000,000

Table B6.2: Cryogenic pipeline cost of the import terminal based on the MTBS database

Import terminal - pipeline 2	Ammonia/MCH/Liquid hydrogen
Investment [€/m]	1,500
Construction period [years]	1
Lifetime [years]	26
Overhead OPEX rate [%]	2.5
Nr of personnel per unit [#]	2
Electricity costs [kWh/kg]	0.08
Capacity [t/y]	4,000,000

Table B6.3: Pipeline cost of the import terminal based on the MTBS database

B6.3 Storage

The storage cost per carrier are defined with several interviews with expert and employees of companies and with a literature study. The cost for ammonia, MCH and liquid hydrogen storage are mostly originating from an interview with Vopak and crossed checked with a literature study (Birol, 2019; Kamiya et al., 2015).

Import terminal – Storage	Ammonia	MCH	Liquid hydrogen
Investment [M€/tank]	60	35	200
Construction period [years]	1	1	1
Lifetime [years]	30	50	30
Overhead OPEX rate [%]	2	2	2
Nr of personnel per unit [#]	1	1	1
Electricity costs [kWh/kg]	0.1	0.01	0.61
Capacity [m3]	50,000	50,000	50,000
Capacity [ton]	34,130	38,500	3540
Vector for buffer capacity	1.3	1.3	1.3
Cycles per annum	26	26	26
Losses [% per annum]	10,96	-	13

Table B6.4: Storage cost from the export terminal (Birol, 2019; Oldenbroek et al., 2019)

B6.4 Hydrogen retrieval plant

The data of the H_2 retrieval is obtained from Vopak and is cross-checked with the company Kalavasta.

Hydrogen retrieval	Ammonia	MCH	Liquid hydrogen
Investment [M€/unit]	100	200	18
Construction period [years]	2	2	2
Lifetime [years]	20	20	20
Overhead OPEX rate [%]	2.5	2.5	2.5
Nr of personnel per unit [#]	1	1	1
Electricity costs [kWh/kg]	5.89	9.36	0.6
Capacity [ton hydrogen/year]	320,000	333,333	1,000,000

Table B6.5: Hydrogen retrieval costs (Terwel & Kerkhoven, 2018; Birol, 2019)

C Calculation structure of the supply chain elements

In this chapter the calculation structure of the general supply chain model and import terminal investment model are outlined. The elements of the supply chain are discussed; conversion to hydrogen carrier plant, export terminal, transport and import terminal. The import terminal model can be found at Github, see Figure C0.1.

Figure C0.1: QR code for the import terminal investment model

C1 Conversion to hydrogen carrier plant

The conversion plant is the first asset of the supply chain, because the hydrogen costs are considered as a material input in the conversion process. Gaseous hydrogen does not need to convert, so there is no need for a conversion plant. Liquid hydrogen on the other hand, is liquefied from gaseous hydrogen. This means that a liquefaction plant has to be taken into account when dealing with liquid hydrogen. Ammonia and MCH are produced with a conversion plant. The costs for the conversion plant for ammonia, MCH and liquid hydrogen are outlined in this section.

The investment cost has the largest share in the total cost flow. Compared to the other two hydrogen carriers, the investment cost is the largest. nonetheless, the capacity of the plant is also the largest. Considering the relationship between the capacity and investment costs, the conversion to hydrogen carrier plant of ammonia is considered as the mean of all the hydrogen carriers. When looking at the operational expenses, the largest share originates from the nitrogen costs which has a value of 27 €/t. Studying the MCH costs, the high toluene costs stands out immediately with a value of 350 €/t. The investment costs compared to the capacity are the lowest costs of all hydrogen carriers. The overhead costs are the most significant regarding the liquid hydrogen plant. This conversion to hydrogen carrier plant, liquefaction plan, does not include any raw materials such as nitrogen and toluene.

CAPEX - Investment costs

The CAPEX of the conversion plant includes the unit investment costs (I), which are fixed costs per plant correlated to a specific capacity. These costs are divided over the construction years of the unit, with a distribution percentage. The share of investment (p), for example, can be divided over a construction period of three years, as 50% in the first construction year, 35% in the second year and 15% in the last year. An equal coherent lifetime is allocated to every unit, therefore reinvestments are included. With this lifetime, a depreciation balance can be generated, on which the OPEX depend. The investments are triggered by perfect forecasting, which is stated in the previous Paragraph 3.1.2. The investment costs (C) are expressed in Equation C.1 (with n as year).

$$C(n) = p(n) * I \tag{C.1}$$

CAPEX - Reinvestment
Capital assets depreciate in their utility and efficiency over time due to wear and tear. The capital asset has a higher frequency in repairs and maintenance. All conversion to hydrogen carrier plants have a lifetime ($t_{lifetime}$) of 20 years. This is equal to the timeframe used in the model, therefore reinvestments are unnecessary in this case. If an asset is constructed over the years, the remaining lifetime of the asset is larger than 1 year at the end of the life cycle of the model. When an asset contains a remaining lifetime at the end of the model's timeframe, it still contains a value. This value is indicated with linearly depreciation of the asset, whereby the value of the asset reduces linearly with time. The remaining value (V) of all assets are expressed as revenues at the end of the model's timeframe, taking into account the age of an asset (t_{age}).

$$V = C * (1 - \frac{t_{age}}{t_{lifespan}}) \tag{C.2}$$

Capacity
The capacity of the conversion plant is a fixed capacity per unit, in ton per year.

OPEX - Maintenance/Insurance costs
The purpose of maintenance is to ensure an optimal working condition and to conserve the life span of an asset. Whereby, insurance contributes to the general economic growth of the society by providing stability to the functioning of process. The maintenance and insurance costs are items of the OPEX. These costs are expressed in a percentage of the CAPEX (ζ).

$$Insurance/maintenance\ costs = \sum_{n=operation\ period} I * \zeta \tag{C.3}$$

OPEX - Labour costs
Labour represents all of the people that are available to transform resources into goods or services that can be purchased. It's important that a labour force is well educated and well trained to ensure that they can produce goods at peak efficiency and quality. The labour costs are calculated with the number of people of an asset, multiplied with the annual working hours.

$$Labour = \frac{(operational\ hours * nr\ of\ units)}{(shift\ length * annual\ shifts)} * nr\ of\ crew\ per\ unit * salary \tag{C.4}$$

OPEX - Energy costs
For the operation of the conversion plant, consumption of energy is required. The energy consumption (E_c) is expressed in kWh/ton. Therefore, the total energy costs (E_t) are a direct result of the demand (D), when combining it with the unit price of the energy (U_e) expressed as € per kWh. The unit price of the energy has varies regarding time and place, since the cost of energy decreases with time and depends on the export country (see Appendix B).

$$E_t = E_c * D * U_e \tag{C.5}$$

OPEX - Raw material costs
Raw material expenses refer to the cost of the components that go into a final manufactured product. The operational costs of the conversion plant consist of raw material costs. All the included conversion plants generate costs concerning the hydrogen material costs. The hydrogen costs are based on material and production costs, which are used as an input value for the model. This parameter has a varying character in time and place, since the cost of hydrogen decreases with time and the cost of sources depends on the production country (see Appendix B). The ammonia plant obtains costs of nitrogen and the MCH of Toluene. All these costs are expressed as € per ton and therefore a direct result of the demand. Toluene is a product that can be recycled, therefore only 3% of the demand access toluene after year 1.

C2 Export terminal - Storage

One asset of the export terminal includes the storage of the commodities. The calculation structure of this asset contains parameters which have a similar calculation structure as the first asset, the conversion plant. The storage of ammonia, MCH and liquid hydrogen are developed in the export terminal. An export terminal is excluded for the gaseous hydrogen case, because the storage exists in salt caverns in the hinterland. The calculation structure of this storage is also included in this section. A salt cavern with geometric volume of 500,000 m3 is used with a net use-able hydrogen storage of approximately 3733 ton hydrogen at 180 bar. All the various CAPEX and OPEX of the storage are mentioned in this section, however some of the calculation structure is already described in Section C1.

The storage costs for ammonia and MCH are low compared to liquid hydrogen. The investment costs are the main parameter for the cost cash flows for all hydrogen carrier storages. The investment costs of ammonia and MCH storage are low compared to the storage of liquid hydrogen. To reduce the storage cost for liquid hydrogen the amount of annual cycles can be reduced, whereby the necessary capacity decreases or a low-priced option can be examined, whereby the price decreases.

CAPEX - Investment costs
Calculation structure according the same method as the conversion plant (see Section C1).

CAPEX - Reinvestment
Calculation structure according the same method as the conversion plant (see Section C1).

Capacity
The needed storage capacity includes two triggers: the cycles per annum and the vessel call size. At a large demand, the storage capacity is strongly dependent on the cycles per annum of the commodity; the number of times the liquid bulk volumes can theoretically be turned over each storage year. The cycles per annum cannot be set in line with benchmark projects, therefore an assumption for this number has been made. It is assumed that the cycles per annum will remain constant over time and every two weeks be turned over. It takes a number of days to fill the storage, as the commodity is transported from the hinterland. Once the storage volume is sufficiently high, a vessel will call the jetty to load the commodity.

After this loading process, a new cycle begins (database MTBS). The second trigger is the vessel call size. This implies that the storage needs to store at least one vessel call size of the largest vessel. This trigger is mostly active in the beginning of the project, when the throughput is small. Both needed storage capacities required a buffer capacity. This buffer capacity is set on 10% of the initially needed storage capacity.

$$Storage\ capacity = max(\frac{demand}{cycle\ rates\ per\ annum}, vessel\ call\ size) * buffer \tag{C.6}$$

OPEX - Maintenance/Insurance costs
Calculation structure according the same method as the conversion plant (see Section C1).

OPEX - Labour costs
Calculation structure according the same method as the conversion plant (see Section C1).

OPEX - Energy costs
Calculation structure according the same method as the conversion plant (see Section C1).

C3 Export terminal - Jetty

This includes the jetty and the loading equipment. Gaseous hydrogen is exported through a pipeline, whereby the export terminal is excluded. The loading pipelines and pump are included in the jetty.

The jetty costs are equal for all hydrogen carriers, consisting of ammonia, MCH and liquid hydrogen. They are around 5 €/ton at a demand of 700,000 exported from Brazil. These jetty costs includes the investment, maintenance, insurance and equipment costs. The capacity of the jetty is high, therefore the cost price of the jetty per hydrogen carrier is low.

CAPEX - Investment costs
This cost item briefly outlines the design of the jetty. The detailed design approach of the jetty can be found in Appendix B. The jetty design consists of the jetty-head, catwalk, mooring dolphins and loading equipment. A Gijt constant is adopted for the jetty-head (α_1) and catwalk (α_2). The draft of the jetty needs to be larger than the draft of the largest vessel, executed by dredging.

$$Jetty\ structure = \alpha_1 * L_{jettyhead} * B_{jettyhead} + \alpha_2 * L_{catwalk} * B_{catwalk} \tag{C.7}$$

The number of mooring dolphins is calculated with the length of the vessel (LOA).

$$\begin{aligned} LOA < 200m &\longrightarrow 6\ mooring\ dolphins \\ LOA > 200m &\longrightarrow 8\ mooring\ dolphins \end{aligned} \tag{C.8}$$

The loading system is calculated as one dedicated pipeline including a pump system per jetty, which is included in the jetty. The pipeline costs are expressed in € per m (β), calculated with the needed length. Subsequent, a pump price is included.

$$Pipelinecosts = (L_{catwalk} + B_{jettyhead} + L_{terminal}) * \beta + pump\ price \tag{C.9}$$

CAPEX - Reinvestment
Calculation structure according the same method as the conversion plant (see Section C1).

Capacity
The capacity of the jetty depends on the turnaround time (t_t) of a vessel. The turnaround time of a vessel is defined as the time it takes for the vessel to be loaded (t_l) together with the mooring and de-mooring time of a vessel (t_m). Whereby, the service time is governed by the call size of the vessel (W_{call}) and the loading productivity of the equipment (P_{load}).

$$\begin{aligned} t_t &= t_l + t_m \\ with\ t_l &= \frac{W_{call}}{P_{load}} \end{aligned} \tag{C.10}$$

With this turnaround time combined with the operational hours, the number of vessel calls per year can be determined. When combining this with the call size of the vessel, the capacity in ton per year is generated.

$$Capacity\ jetty = \frac{operationalhours}{t_t} * W_{call} \tag{C.11}$$

It is not desirable to use this entire capacity, due to the decline in operational functioning.

Therefore, the eligible capacity is the capacity multiplied with the acceptable berth occupancy (ρ_1). When this acceptable capacity is too low, an expansion of this asset will be triggered.

$$Desirable\ capacity = \rho_1 * Capacity\ jetty \tag{C.12}$$

OPEX - Maintenance/Insurance costs
Calculation structure according the same method as the conversion plant (see Section C1).

C4 Transport - Vessels

The transportation is included in the model as an asset, with expansion triggers. Ammonia, MCH and liquid hydrogen are transported with vessels and gaseous hydrogen with pipelines. The vessels are considered as assets as well, so charter rates are not included. Three vessel types are presented: the LPG tanker, the chemical tanker and the LNG tanker.

The liquid hydrogen transportation costs are low compared to the other elements of the supply chain. At this moment, liquid hydrogen vessels do not exist in common practice. Kawasaki is currently working on a liquid hydrogen vessel (awasaki Heavy IndustriesKAWASAKI HEAVY INDUSTRIES, 2018). The values used in the model are based on LNG vessels.

CAPEX - Investment costs
Calculation structure according the same method as the conversion plant (see Section C1).

CAPEX - Reinvestment
Calculation structure according the same method as the conversion plant (see Section C1).

Capacity
The carry mass of the vessels are determined by the available share (γ) of the Deadweight Tonnage (DWT) and the carry volume (V_{vessel}). A vessel contains a space for the commodity with a maximum volume. The vessel also contains restrictions regarding its weight. Therefore, it depends on the density of the commodity (ρ_d), which parameter is limited.

$$Carry\ mass = min(\gamma * DWT, V_{vessel} * \rho_d) \tag{C.13}$$

The annual capacity is derived from the annual trips of a vessel (T_a) combined with the carry mass of the vessel (C_a). To generate the annual trips, the duration of one single trip (T_s) needs to be derived, which is found when combining the distance (D), average speed (ν_a), hours per day (hrs) and port days (D_p). Subsequently, the annual trips can be derived with the availability rate (η) multiplied with number of days in a year (D_y)

$$\begin{aligned} T_s &= \frac{\frac{D}{\nu_a}}{hrs} * 2 + D_p \\ T_a &= \frac{\eta * D_y}{T_s} \\ Annual\ capacity &= T_a * C_a \end{aligned} \tag{C.14}$$

OPEX - Maintenance/Insurance costs
Calculation structure according the same method as the conversion plant (see Section C1).

OPEX - Labour costs
Calculation structure according the same method as the conversion plant (see Section C1).

OPEX - Fuel costs

The fuel costs are based on the fuel consumption of the vessel per day. The weight of the vessel is derived using the carry mass, the remain part of the DWT and the ship weight (M) when loaded (Barrass, 2004). The unloaded weight of the vessel is without taking into account the carry mass.

$$\begin{aligned} W_l &= (1-\gamma) * DWT + Carry\ mass + M \\ W_u &= (1-\gamma) * DWT + M \end{aligned} \tag{C.15}$$

When sailing, the fuel consumption per day is calculated with weight of the vessel (W), the type of engine (F_c) and the average speed (ν_a) (Barrass, 2004). Whereby, the F_c is 110,000 for steam turbine machinery and 120,000 for diesel machinery (Barrass, 2004).

$$\begin{aligned} S_l &= \frac{W_l^{2/3} * \nu_a^3}{F_c} \\ S_u &= \frac{W_u^{2/3} * \nu_a^3}{F_c} \end{aligned} \tag{C.16}$$

The fuel consumption in the port is computed with a port fuel usage factor (σ) combined with the loaded and unloaded fuel consumption when sailing (S_l and S_u). In a port, half of the time the vessel is unloaded and the other half it is loaded. These processes balance each other out, therefore it is assumed that the vessel is unloaded in the export port and loaded in the import port. The fuel consumption per day in the port for a loaded and unloaded vessel are mentioned as P_l and P_u respectively.

$$\begin{aligned} P_l &= S_l * \sigma \\ P_u &= S_u * \sigma \end{aligned} \tag{C.17}$$

The summation of all these fuel consumption times the amount of days for each aspect will contribute to the total fuel consumption. When multiplying this number with the cost of fuel (C_f), the fuel costs can be derived. Whereby, the port days in the import and export terminal are equivalent and mentioned as d_1 containing the days of one port. It also assumed that the days of the outward and return trip are equivalent and mentioned as d_2 containing half of the days of the trip.

$$Fuel\ cost = ((S_l + S_u) * d_1 + (P_l + P_u) * d_2) * C_f \tag{C.18}$$

OPEX - Canal fees

The fee costs are calculated based on the vessels characteristics, with the help of a toll calculator. This is a fixed amount per time crossing the canal. The fees differ when the vessel is loaded or unloaded, unloaded has a fee of 90 % of the loaded vessel fee. The fees for the Suez canal and Panama canal are taken into account.

C5 Transport - Pipelines

Ammonia, MCH and liquid hydrogen are transported with vessels and gaseous hydrogen with pipelines. The pipeline is calculated for the case of building new pipelines, assuming there exists no pipeline infrastructure at the moment. Naturally, when including the option to use the existing infrastructure there could be a possibility to lower the cost. Pipelines designed for the transport of natural gas are technically able to transport natural gas containing an certain amount of hydrogen (Timmerberg & Kaltschmitt, 2019). The compressor cost for the pipeline are included in this section.

CAPEX - Investment costs
The investment costs are divided into the pipeline costs and the compressor costs. The pipeline investment costs (I_p) are defined based on the distance (D) between the export and import country and the investment cost per km ($U_k m$).

$$I_p = D * U_k m \tag{C.19}$$

The investment cost of the compressor (I_c) are also based on the distance (D) between export and import country, the distance capacity (D_c) of one compressor and the unit rate (U_c).

$$I_c = \frac{D}{D_c} * U_c \tag{C.20}$$

CAPEX - Reinvestment
Calculation structure according the same method as the conversion plant (see Section C1). This parameter appears for the pipeline as well as for the compressor.

Capacity
The capacity of the pipeline is determined with the diameter. The needed pipeline capacity is equal to the highest demand ($D-H$) during the lifetime of the project. The diameter is derived from the volumetric flow rate and cross section. The volumetric flow rate is determined by the demand, the capacity multiplier (C_m), the density (ρ), hours per year (hrs_{year} and the seconds per hour (s_h). The cross section is determined by the volumetric flow rate and hydrogen speed (H_s).

$$\begin{aligned} volumetricflowrate &= \frac{D_H * C_m}{\rho * hrs_{year} * s_h} \\ Crosssectionpipeline &= \frac{volumetricflowrate}{H_s} \\ Diameter &= \sqrt{\frac{crosssectionpipeline * 4}{\pi}} \end{aligned} \tag{C.21}$$

OPEX - Maintenance/Insurance costs
Calculation structure according the same method as the conversion plant (see Section C1). This parameter occurs at the pipeline as well as the compressor.

OPEX - Labour costs
Calculation structure corresponds with the conversion plant (see Section C1). This parameter occurs at the pipeline as well as the compressor.

OPEX - Energy costs
Calculation structure corresponds with the conversion plant (see Section C1). This parameter occurs only at the compressor.

C6 Import terminal - Jetty

The jetty consists of a berth, which is the area of the jetty where a vessel is moored. Berths provide a vertical front which allows safe and secure mooring, facilitating the unloading or loading of the cargo of the vessel. The cost of the jetty is mostly originating from the investment costs. The jetty only contains maintenance and insurance as operational costs. Every jetty contains a pipeline with the capacity of the peak unloading capacity of the vessel or higher.

CAPEX - Investment
The detailed design approach of the jetty can be found in Appendix B. The jetty design consists of the jetty-head, catwalk and mooring dolphins. A Gijt constant is adopted for the jetty-head (α_1) and catwalk (α_2). The draft of the jetty needs to be larger than the draft of the largest vessel, executed by dredging. The jetty is designed to function for all types of vessels, containing only a divergence in the mooring dolphins.

$$Jetty\ investment = \alpha_1 * L_{jettyhead} * B_{jettyhead} + \alpha_2 * L_{catwalk} * B_{catwalk} \tag{C.22}$$

The number of mooring dolphins is calculated using the difference in length of the mooring vessels (LOA), because of the fact that various vessels should be able to moor at the jetty.

$$\begin{aligned} LOA_{max} - LOA_{min} > 100m \longrightarrow 8\ mooring\ dolphins \\ LOA_{max} - LOA_{min} < 100m \longrightarrow 6\ mooring\ dolphins \end{aligned} \tag{C.23}$$

$$Jetty\ CAPEX = jettyinvestment + mooringdolphins * unitrate \tag{C.24}$$

These costs are divided over the construction years of the unit, with a distribution percentage. The share of investment (p), for example, can be divided over a construction period of three years, as 50% in the first construction year, 35% in the second year and 15% in the last year. An equal coherent lifetime is allocated to every unit, therefore reinvestments are included. With this lifetime, a depreciation balance can be generated, on which the OPEX depend. The investments are triggered by the reactive mode, which is stated in the previous Section 3.2.2. The investment costs (C) are expressed in Equation C.35 (with n as year).

$$C(n) = p(n) * Jetty\ CAPEX \tag{C.25}$$

CAPEX - mobilization costs
Mobilization costs consist of preparation work and operations, those required for moving personnel, equipment, supplies and incidental parts belonging to the project location, the creation of all offices, buildings and other facilities needed for work, for the project and for all other work and operations that must be performed. But also the costs incurred prior to commencement of work on the various items on the project site. The mobilization costs are derived with a share (θ) from the CAPEX or from a fixed amount, whereby the maximum of these values is taken into account as mobilization costs.

$$mobilization = max((JettyCAPEX * \theta), mobilizationminimum) \tag{C.26}$$

CAPEX - Reinvestment
Capital assets depreciate in their utility and efficiency over time due to wear and tear. This results in the capital asset having a higher frequency in repairs and maintenance. When an asset has a remaining lifetime at the end of the model's timeframe, it still contains a value.

This value is indicated with a linearly depreciation of the asset, whereby the value of the asset reduces linearly with time. The remaining value (V) of all assets is expressed as a revenue at the end of model's timeframe, taking into account the age of the asset (t_{age}).

$$V = C * (1 - \frac{t_{age}}{t_{lifespan}}) \tag{C.27}$$

Capacity

This part explains the capacity of a jetty, with MCH as example. All vessels that appear at a given commodity, in this case MCH, are used to determine the operational productivity at the berth. Even though, it is not likely that the largest vessel will be used in the starting years of operations. It is more efficient to use small and 'common' vessels at the beginning. These vessel types have been bench marked against the liquid bulk vessels that are currently used in Western Europe.

	Handy size	Panamax	Very Large Crude Carriers (VLCC)
Call size [ton]	35,000	65,000	200,000
LOA [m]	130	220	300
Draft [m]	10	13	18.5
Beam [m]	24	32.2	55
Mooring time [hrs]	3	3	3
Vessel shares [%]	30	40	30

Table C6.1: Vessel characteristics of MCH as commodity (Clarkson research, 2019)

The capacity of the jetty depends on the turnaround time (t_t) of a vessel. The turnaround time of a vessel is defined as the time it takes for the vessel to be unloaded (t_u) together with the mooring and de-mooring time of the vessels (t_m). Whereby, the service time is governed by the call size of the vessel (W_{call}) and the unloading productivity of the equipment (P_{unload}). The mooring and de-mooring time is the same for all vessels. The service time is different, depending on the unloading productivity of the vessels equipment and the vessels call size.

$$\begin{aligned} t_t &= t_u + t_m \\ with\ t_u &= \frac{W_{call}}{P_{unload}} \end{aligned} \tag{C.28}$$

With this turnaround time combined with the operational hours and the vessel shares (δ), the various number of vessel calls per year can be determined. When combining this with the call sizes of the vessels, the capacity in ton per year is generated. In Equation C.29, the capacity of a jetty with three shares in vessel is given.

$$\begin{aligned} Capacity\ jetty = &\frac{operationalhours}{t_{t1} * \delta_1 + t_{t2} * \delta_2 + t_{t3} * \delta_3} * \delta_1 * W_{call1} \\ +&\frac{operationalhours}{t_{t1} * \delta_1 + t_{t2} * \delta_2 + t_{t3} * \delta_3} * \delta_2 * W_{call2} \\ +&\frac{operationalhours}{t_{t1} * \delta_1 + t_{t2} * \delta_2 + t_{t3} * \delta_3} * \delta_3 * W_{call3} \end{aligned} \tag{C.29}$$

It is not desirable to use this entire capacity, due to the decline in operational functioning. Therefore, the eligible capacity is the capacity multiplied with the acceptable berth occupancy (ρ_1). When this acceptable capacity is exceeded, an expansion of this asset is triggered.

$$Desirable\ capacity = \rho_1 * Capacity\ jetty \tag{C.30}$$

The berth occupancy ratios are calculated using the probabilistic queuing theory. This theory calculates the berth occupancy based on the arrival rate divided by the average service rate. The formulation of the arrival rate (λ, Equation E.3), the average service rate (μ, Equation E.4) and the berth occupancy (ρ, Equation E.5) are given below.

$$\lambda = \frac{numberofcalls}{operationalhours} \tag{C.31}$$

$$\mu = \frac{1}{\frac{W_{call}}{P_{unload}} + t_m} \tag{C.32}$$

$$\rho = \frac{\lambda}{\mu} \tag{C.33}$$

The acceptable berth occupancy factor depends on the number of berths and the allowable average waiting time. For a liquid bulk terminal, a reasonable value for the allowable berth occupancy of one berth is around 0.5 (Monfort et al., 2011). The probabilistic queuing theory can be denoted by the Kendall notation, which is "interarrival time distribution/service time distribution/number of berths" (Monfort et al., 2011). The distribution for the interarrival time can vary from a random value to a value that is less random. When the arrival of vessels is totally random, a negative exponential interarrival time can be assumed, denoted by M. If the interarrival is less random, an Erlang-K distribution can be used, denoted by E_k with a shape factor of K = 2.

For common users of the liquid bulk terminal a realistic queue is M/E_2/n and for a dedicated shipping line is E_2/E_2/n (Monfort et al., 2011). An overview of the acceptable berth occupancy can be found in Table E2.1.

Number of berths n_b	**Acceptable berth occupancy factor** m_b [%]	
	Common-user M/E_2/n	Dedicated E_2/E_2/n
1	41	55
2	64	73
3	73	81
4	78	84
6 or more	84	89

Table C6.2: Acceptable berth occupancy factor (Monfort et al., 2011)

OPEX - Maintenance/Insurance costs

The purpose of maintenance is to ensure an optimal working condition and conserves the life span of an asset. Whereby, insurance contributes to the general economic growth of the society by providing stability to the functioning of process. The maintenance and insurance costs are items of the OPEX. These costs are expressed in a percentage of the CAPEX (ζ).

$$Insurance/maintenance\ costs = \sum_{n=operation\ period} I * \zeta \tag{C.34}$$

C7 Import terminal - Pipelines

In this section the pipeline from the jetty to the storage and the pipeline from the H_2 retrieval to the hinterland are elaborated. The loading system is calculated as one dedicated pipeline per jetty. And one dedicated pipeline from the H_2 retrieval to the hinterland.

CAPEX - Investment costs
The pipeline costs are expressed in € per m (β), calculated with the necessary length. These costs are divided over the construction years of the unit, with a distribution percentage (see Section C6 for a more in-depth explanation).

$$C(n) = p(n) * Jetty\ CAPEX \tag{C.35}$$

$$Pipelinecosts = (L_{catwalk} + B_{jettyhead} + L_{terminal}) * \beta \tag{C.36}$$

CAPEX - Mobilization cost
Calculation structure according the same method as the jetty (see Section C6).

CAPEX - Reinvestment
Calculation structure according the same method as the jetty (see Section C6).

Capacity
The loading system is calculated as one dedicated pipeline per jetty. And one dedicated pipeline from the H_2 retrieval to the hinterland. Therefore, the capacity is equal to the capacity of the jetty for the pipeline of the jetty to the storage and to the H_2 retrieval for the pipeline from the H_2 retrieval to the hinterland.

OPEX - Maintenance/Insurance costs
Calculation structure according the same method as the jetty (see Section C6).

OPEX - Labour costs
Labour represents all of the people that are available to transform resources into goods or services that can be purchased. It is important that a labour force is well educated and well trained to ensure that they can produce goods at peak efficiency and quality. The labour costs are calculated with the necessary number of employees at an asset combined with the annual working hours.

$$Labour = \frac{(operational\ hours * nr\ of\ units)}{(shift\ length * annual\ shifts)} * nr\ of\ crew\ per\ unit * salary \tag{C.37}$$

OPEX - Energy costs
For the operation of the pipelines, consumption of energy is required. The energy consumption (E_c) is expressed in kWh/ton. Therefore, the total energy costs (E_t) are a direct result of the demand (D), when combining it with the unit price of the energy (U_e) expressed as € per kWh. The unit price of the energy has a varying character in time and place, since the cost of energy decreases with time and depends on the export country (see Appendix B).

$$E_t = E_c * D * U_e \tag{C.38}$$

C8 Import terminal - Storage

One asset of the import terminal includes the storage of the commodities. The calculation structure of this asset contains parameters which have a similar calculation structure as the first asset and second asset, the jetty and pipelines. All the various CAPEX and OPEX of the storage are mentioned in this section, however, some of the calculation structure is already described in Section C6 and Section C7.

The largest cost item in the investment cash flow of the import terminal is derived from the storage element. This element is responsible for most of the added value of the liquid hydrogen import terminal. The storage in the liquid hydrogen terminal is 14 times as high as in the ammonia terminal and even 47 times as high as in the MCH terminal. The other three cost items in the liquid hydrogen terminal are almost negligible, due to the small share compared to the investment and operational costs.

CAPEX - Investment costs
The CAPEX of the storage includes the unit investment costs, which are fixed costs per plant correlated to a specific capacity. These costs are divided over the construction years of the unit, with a distribution percentage (see Section C6 for a more in-depth explanation).

CAPEX - Mobilization cost
Calculation structure according the same method as the jetty (see Section C6).

CAPEX - Reinvestment
Calculation structure according the same method as the jetty (see Section C6).

Capacity
The necessary storage capacity can be triggered by two things: the cycles per annum and the vessel call size. The storage capacity is strongly dependent on the cycles per annum of the commodity; the number of times the liquid bulk volumes can theoretically be turned over each storage year. The cycles per annum have been set in line with benchmark projects (MTBS). It is assumed that the cycles per annum will remain constant over time. It takes a number of days to fill the storage, as the commodity is transported from the hinterland. Once the storage volume is sufficiently high, a vessel will call the jetty to load the commodity. After this loading process, a new cycle begins. (Terwel & Kerkhoven, 2018). The second trigger is the vessel call size. This implies that the storage is stored at least one vessel call size of the largest vessel. This trigger is mostly active in the beginning of the project, when the throughput is small. Both storage capacities require a buffer capacity. This buffer capacity is set on 10% of the initial necessary storage capacity.

$$Storage\ capacity = max(\frac{demand}{cycle\ rates\ per\ annum}, vessel\ call\ size) * buffer \tag{C.39}$$

OPEX - Maintenance/Insurance costs
Calculation structure according the same method as the jetty (see Section C6).

OPEX - Labour costs
Calculation structure according the same method as the pipeline (see Section C7).

OPEX - Energy costs
Calculation structure according the same method as the pipeline (see Section C7).

C9 Import terminal - H_2 retrieval

After the commodities are stored, the regasification/subtraction of hydrogen will take place. Regasification will take place by liquid hydrogen. Regasification is a process of converting LH_2 at 253 °C back to hydrogen gas at atmospheric temperature. For the other commodities (NH_3 and MCH) subtracting of hydrogen will occur. The conversion to H_2 occurs in different plants for the different commodities, with different input values. All the various CAPEX and OPEX of the storage are mentioned in this section, yet some of the calculation structure is already described in the previous sections.

CAPEX - Investment costs
Calculation structure according the same method as the storage (see Section C9).

CAPEX - Mobilization cost Calculation structure according the same method as the jetty (see Section C6).

CAPEX - Reinvestment
Calculation structure according the same method as the jetty (see Section C6).

Capacity
The capacity is a fixed number, noted by ton per years. Nonetheless, it is not desirable to use its entire capacity, due to an asset's performance. The expansion trigger of the H_2 retrieval is based on the occupancy of the plant. The plant occupancy ratios are calculated using the arrival rate divided by the service rate. The formulation of the arrival rate (λ_1, Equation E.7), the average service rate (μ_1, Equation E.8) and the berth occupancy (ρ_1, Equation E.9) are given below.

$$\lambda_1 = \frac{Throughput}{operationalhours} \tag{C.40}$$

$$\mu_1 = Productionrate \tag{C.41}$$

$$\rho_1 = \frac{\lambda}{\mu} \tag{C.42}$$

OPEX - Maintenance/Insurance costs
Calculation structure according the same method as the jetty (see Section C6).

OPEX - Labour costs
Calculation structure according the same method as the pipeline (see Section C7).

OPEX - Energy costs
Calculation structure according the same method as the pipeline (see Section C7).

D Calculation of the discount rate (WACC)

The elements of the supply chain generally have extensive investments at the start of a project before developing revenues. The time that money is received or spend is a important factor from a financial perspective. The time value of money is an approach, that implies that capital available at present time is worth more than the exact sum in the future due to its potential earning space (J. Chen, 2018). This assumption means that if money can earn interest, each amount is worth more the sooner it is received (J. Chen, 2018). Accordingly, future amounts are worth less than amounts earned at the present time. Therefore, the future amounts are discounted. This discounting is executed with a discount rate, which translating cashflows into their respective present values. These cashflows are mentioned as discounted cash flow.

D1 Discount rate

The discounted cash flows express the present value of cash outflows over a project's lifetime (J. Chen, 2018), and are generated with a discount rate, which is based on different approaches such as a WACC, risk free interest rate plus a certain risk premium with a required profit margin or rate prescribed by the government or a development bank (Van Dorsser, 2018). WACC represents the investor's opportunity costs when taking the risk of investing in a company (J. Chen, 2018). The WACC is adopted as a discount rate, which is suitable for large companies in which a relative small investment does not change its financing structure. The risk free interest rate plus a certain risk premium can provide a more favorable observation, although more specific information is often requested. Therefore, in order to generate a high level view, the WACC is used. The best capital structure for a company includes the lowest possible WACC and the maximum value of the company (Hayes, 2019). Therefore, the mix of debt and equity that minimizes the WACC while maximizing its market value is seen as the optimal capital structure (Hayes, 2019). The cost of capital is the rate of return recommended to assure an investor to make an investment in a given project. This is identified with the risk premium.

For the import terminal in Rotterdam, it is assumed that the project has a gearing of 60%, implying that 60% of the needed funds are present through a loan from a bank and 40% of the needed funds are present in the form of equity. Another input value is that the Netherlands has a corporate tax rate of 25%.

The WACC in this research is based on values found within comparable energy projects in western Europe. The nominal WACC is used in the import investment model and the real WACC is used in the general supply chain model. The general supply chain model contains various WACC of different export and import location. The import terminal is a case study for the port of Rotterdam and therefore only this WACC is included in the model. Therefore, only the WACC for the port of Rotterdam is outlined in this appendix. All thing considerd, these assumptions lead to a nominal WACC of 3.7 % and a real WACC of 2.47 %.

D2 Calculation of the discount rate

The pre-tax, nominal discount rate is calculated with the equation (MTBS database):

$$WACC_{nominal} = D_{\%} * (1 - T_c) * D_c + E_{\%} * E_C = 3.70\% \tag{D.1}$$

D %	60%	Assumed percentage of total project costs derived from debt, also known as gearing.
T_c	25%	This value is assigned as the tax shield. The corporate tax in the Netherlands is assumed to be 25%, when the taxable amount is higher than €200,000 (IJzerman & de Meerendonk, 2018).
D_C	1.5 %	The cost of debt is based on the risk premium and the risk-free rate within Europe. The risk premium is specific for a project and is based on a project's risk and the project's sponsor. The risk-free rate can be seen as the return rate on investments that carry negligible risk. The cost of debt is based on Shell. This is based on the bonds from 2016 with a 12-year maturity bonds, whereby a longer maturity a higher yield contains. The two 12-year maturity bonds contains a 0.75% and 1.25 % bonds (Shell, 2019). This is also in line with the bonds of GasUnie.
E %	40 %	Assumed percentage of total project costs derived from equity. Equity refers to a loan that mostly holds more risk than debt. This risk is derived from that debt investors have a higher claim to the project's assets than equity investors, when a project turns out to go bankrupt. On the other side, equity loans are associated with higher interest rates than debt loans.
E_C	7.56 %	The cost of equity is in line with the article "Market Risk Premium and Risk-Free Rate used for 69 countries in 2019: a survey" and can be determined as follows (Fernandez et al., 2019):

$$E_C = r_{f,local} + \beta * r_{m,local}$$

$r_{f,local}$	0.11 %	The risk-free rate within Europe. This is the return rate on investments that holds risk. This risk-free rate is based on Germany 20 year maturity government bond (MarketWatch, 2019)
$r_{m,local}$	5.96 %	The market risk premium. This premium is country specific and is primarily based on a country's stability, financial institutions and liquidity . This market risk premium of the Netherlands is based on Stern (Stern, 2019).
β	1.25	The industry's beta. This is a sector-specific risk factor. When a sector contains high risk, such as tech companies, the beta contains high values and when they have a low risk the beta contains the low values (Stern, 2019).

The pre-tax, real discount rate is adjusted for inflation and tax. The inflation in the Netherlands is, at this moment (June 2019) 2.4%.

$$WACC_{real} = \frac{(D_{\%} * D_c + \frac{1}{(1-T_c)} * E_{\%} * E_C) + 1}{i_{TheNetherlands} + 1} - 1 = 2.47\% \tag{D.2}$$

The input values for the pre-tax, real discount rate of all countries are given in Table D2.1. The WACC of each country can be found in Appendix B.

	D% [%]	D_C [%]	T_C [%]	E% [%]	$R_{f,local}$ [%]	$R_{m,local}$ [%]	Beta [-]	Inflatie [%]
Australia	60	1.5	30	40	1.70	5.96	1.25	1.30
Brazil	60	1.5	34	40	7.20	10.13	1.25	3.37
Chile	60	1.5	26	40	3.26	6.94	1.25	2.30
Colombia	60	1.5	33	40	5.89	8.06	1.25	3.43
Israel	60	1.5	23	40	1.44	6.64	1.25	0.80
Italy	60	1.5	24	40	0.11	9.02	1.25	0.80
Japan	60	1.5	31	40	0.10	6.94	1.25	0.70
The Netherlands	60	1.5	25	40	0.11	5.96	1.25	2.40
New Zealand	60	1.5	28	40	2.81	5.96	1.25	1.50
Oman	60	1.5	15	40	1.28	9.02	1.25	0.22
Spain	60	1.5	25	40	0.11	8.18	1.25	0.40
Tunisia	60	1.5	25	40	8.25	13.60	1.25	6.80
United States	60	1.5	25	40	1.58	5.96	1.25	1.60

Table D2.1: Input parameters for the discount calculation, based on (Stern, 2019; MarketWatch, 2019)

E Validation of the two models

In this chapter the model of the general supply chain and import terminal, are outlined. At first, the general supply chain will be validated. This parametric model is conducted in Excel. Subsequently, the import terminal model is validated, which is a parametric model conducted in Python.

E1 General supply chain validation

This section contains the validation of the supply chain model. The validation is based on element level, divided into the different carriers. The validation is based on the ammonia supply chain. The demand and capacity at the conversion to hydrogen carrier plant, export terminal and transport is based on ammonia as commodity, whereas the import terminal is based on hydrogen as commodity.

E1.1 Conversion to hydrogen carrier Plant

The first validation of the model is the expansion progress of the ammonia plant. An assumed demand of ammonia will be at first 500,000 ton per year and will increase to a volume of 1,500,000 ton per year, with a between step of 1,000,000 ton per year. These demands are fictive and chosen only for the validation.

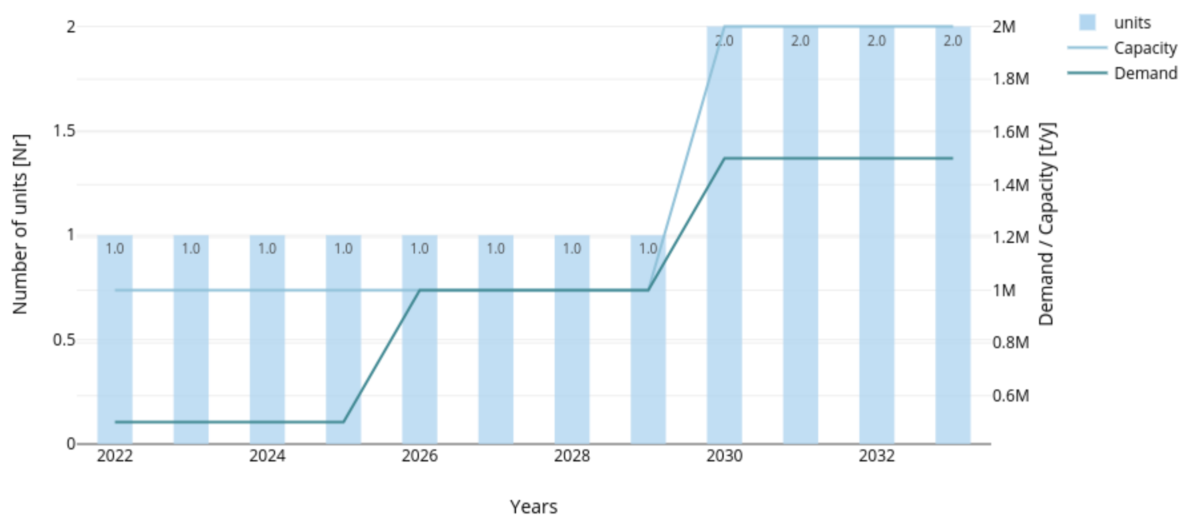

Figure E1.1: The development of the capacity of the carrier plant

In Figure E1.1, the development of the carrier plant units and the coherent capacity are graphed. The capacity of the units is larger than the demand, therefore the throughput is always equal to the demand. In the capacity of the carrier plant, the losses are taken into account in the prices and therefore the capacity can be equal to the demand in 2026-2029.

E1.2 Export terminal

The next validation is the storage element in the export terminal of ammonia, whereby the expansion will be evaluated. The storage volume is based on the carry mass of vessels and annual cycles. The annual cycles is assumed to be 26, with a storage multiplier of 1.1. The desired storage volume is (Terwel & Kerkhoven, 2018):

$$Storage\,volume = multiplier * max(1/26 * demand, carrymass * vector) \tag{E.1}$$

When calculating the storage capacity input, the losses are taken into consideration. The losses are calculated over the storage demand (storage output) and together with the storage demand amounts for the storage input (storage capacity). Therefore, the storage capacity is higher than the storage demand, as the losses are included. The losses are calculated as (Terwel & Kerkhoven, 2018):

$$Losses\,[ton\,ammonia\,per\,annum] = \frac{max(0.2 * nr\,of\,vessels, 1) * 2 * carrymass}{1 - losses\,percentage} - max(0.2 * nr\,of\,vessels, 1) * 2 * carrymass \tag{E.2}$$

Validation of the element 'Storage'	2022-2025	2026-2029
Traffic volume [t/y]	500,000	4,000,000
Ammonia vessel call size [ton]	44,000	44,000
Annual cycles [-]	26	26
Number of elements, call size (based on theory) [nr]	3	3
Number of elements, throughput (based on theory) [nr]	1	6
Number of elements (model result) [nr]	3	6

Table E1.1: Validation of the model of the element 'Storage' with the literature

The demand in the figure ranges from 2,000,000 t/y to 4,000,000 t/y, with an in-between step of 3,000,000 t/y. This demand deviates from the demand used in the table. This is done because a demand of 1,724,696 t/y is the turning point of when the volume is based on annual cycles instead of the vessel carrying mass.

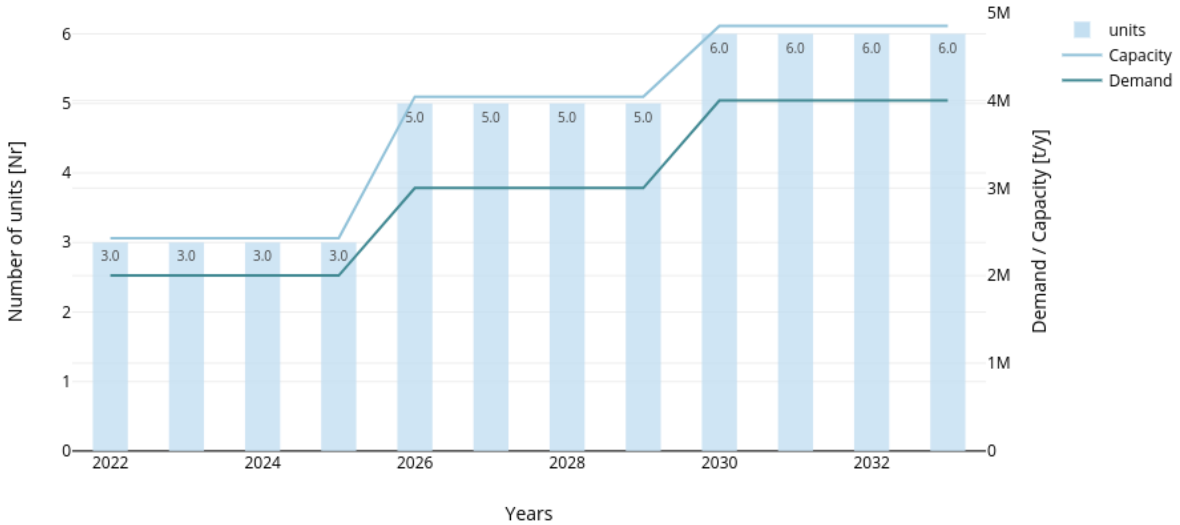

Figure E1.2: The development of the capacity of the storage

As can be seen in Figure E1.2, the storage capacity increases with almost the same factor as the demand does. The capacity of the storage is higher than the demand, because losses will take place when storing ammonia. When there is a demand of 4,000,000 t/y, the number of needed vessels is 11 units with a carry mass of 44,102 ton and 9 trips a year. The losses will be therefore 23,886 t/y (see Equation E.2). The needed storage capacity excluding losses will be 168,767 t/y, which is 192,653 (168,767 + 23,886) t/y including losses.

E1.3 Transport

The pipeline is excluded from this validation, because only one pipeline is always present. The needed number of vessels depends on the sailing distance. This validation is defined from Brazil (export) to the Netherlands (import), these countries are randomly chosen. The sailing distance concerns 5,286 nautical meters between the import and export countries. The demand of ammonia will be first 500,000 t/y and will increase to a volume of 1,500,000 t/y, with a between step of 1,000,000 t/y.

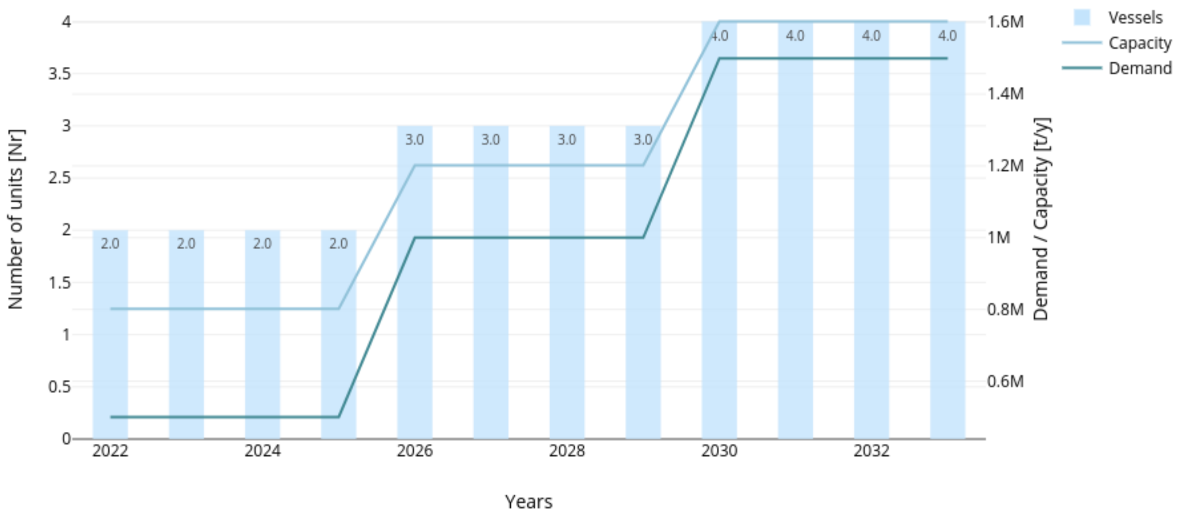

Figure E1.3: The development of the capacity of the transport mode

As can be seen in Figure E1.3, the capacity is higher than the demand because there is residual capacity and losses are taken into account. When looking at a demand of 1,000,000 t/y (with an annual capacity of a vessel of 400,681 t/y and losses of 3.6 % a year), the theoretical number of units for the vessels are 2.59 units. This theoretical number is identical to the number of the model, see Figure E1.3.

E1.4 Import terminal

The import terminal consists of four elements, labelled as jetty, pipeline, storage and H_2 retrieval. The capacity of the entire import terminal is the minimal capacity of the various elements including in the terminal. The end product of the import terminal is hydrogen and therefore the configuration capacities are calculated in hydrogen. The occurrence of losses is only applicable to the storage element. The number of the various elements are shown in Figure E1.4.

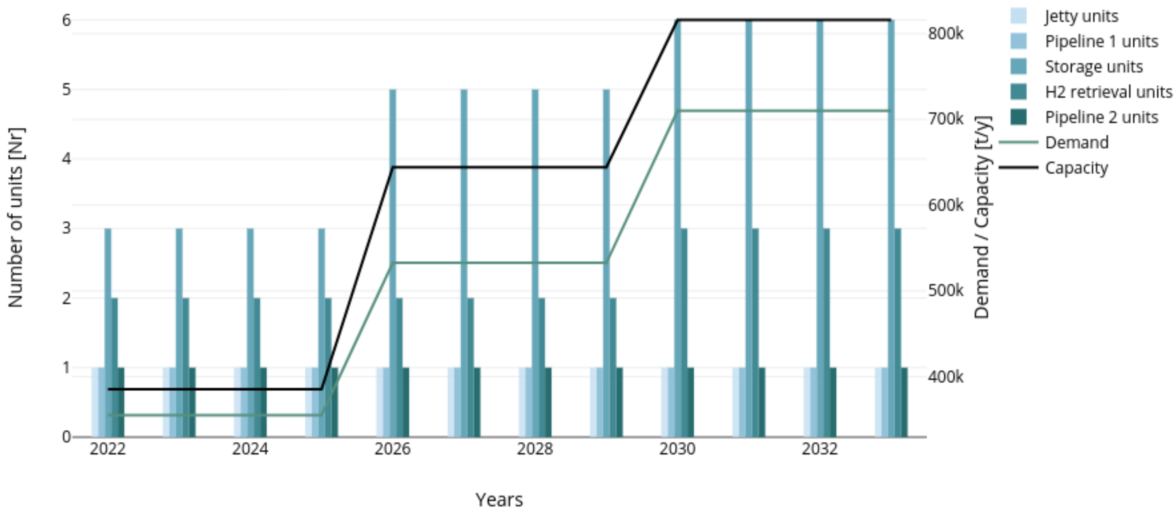

Figure E1.4: The development of the capacity of the import terminal

As can be seen in the graph, the number of jetties and pipelines has a constant value of one. Looking at the capacity of the jetties and pipelines, which consist of 4,000,000 t/y, this number is equivalent to the theory. The other elements, storage and H_2 retrieval, are expanding with the increasing demand. The storages will handle the in between product, in this case, ammonia. Therefore, the hydrogen demand is converted back to ammonia which has a value of 2,000,000 t/y in 2022-2025, 3,000,000 t/y in 2026-2029 and 4,000,000 t/y from 2030 and further going. As explained in Paragraph E1.2, the number of storage units are based on annual cycles with a demand of 1,724,696 t/y. The demand in 2022 is already higher than this turning point and therefore all storage units are based on annual cycles. Due to this fact the storages increase when the demand increase. The H_2 retrieval plant has a capacity of 332,043 ton hydrogen per annum. The hydrogen demand has the values of 17.75 % of the ammonia demand, considering the H_2 mass of ammonia. Therefore, the hydrogen demand is 355,096, 532,644 and 710,192 hydrogen t/y respectively. As can be seen (Figure E1.4), in the first and second phase only two H_2 retrieval plants are necessary. In phase three, the unit numbers are evolved to three due to crossing of the available capacity.

E2 Import terminal validation

Before conclusions can be drawn about the models output, the model is validated. In this chapter the different parts of the model for a liquid hydrogen import terminal will be validated with the help of the theory, obtained from a literature study. A fictional demand is plotted and the results are generated with the help of this demand. The results are shown in graphs, which display the expansions of the different elements. The outcomes are cross-checked with the literature study. The validated elements of the import terminal and throughput are summarized below.

- Throughput: the throughput is based on the minimum of all the capacities of the elements combined with the demand. This section explains how the throughput is defined and how the throughput has been triggered.
- Jetty: jetty is a structure that is designed from the land out into water, which is a connection between the port and unloading vessels. Vessels unload with their own unloading equipment. Therefore, every vessel has a different service time at the berth. The berth occupancy [%] is calculated by the summation of the service rate and the mooring time of all the vessels.

In this section the validation of the berth occupancy and number of jetties will be shown.

- Pipeline jetty-storage: the pipeline capacity is equal to the highest unloading rate of the vessels. In case of more than one jetty, the capacity is equal to the number of jetties multiplied with the highest unloading rate. Due to this formulation, there won't be any clogging at the pipeline and therefore it is not a bottleneck. In this section the capacity of the pipeline is validated.
- Storage: the required storage capacity is based on the annual cycles and the largest vessel capacity. The capacity and expansions are validated in this section.
- H_2 retrieval: the required capacity of the H_2 retrieval depends on the demand with constrains of the achievable throughput. This element is also validated on the expansion process.
- Pipeline H_2-retrieval: the pipeline capacity is equal to the production rate of the H_2 retrieval. In case of more than one H_2 retrieval, the capacity is equal to the number of H_2 retrievals multiplied with the production rate. This process has been verified in Section E2.6.

The validation of the different elements is done with a demand step in 2024 from 1,000,000 t/y to 5,000,000 t/y. The years are divided in phases. Phase 1 from 2018-2023, where the demand is 1,000,000 t/y. Phase 2 is the period where the expansion is triggered, but not yet accessible. Therefore the total demand is not yet reached. The length of this period is two years, because the longest construction period of an element is two years. Phase 3 is the period where the terminal has completed its expansion, which starts in 2026. The expansion from all elements triggered by the demand and throughput can be found in Figure E2.1.

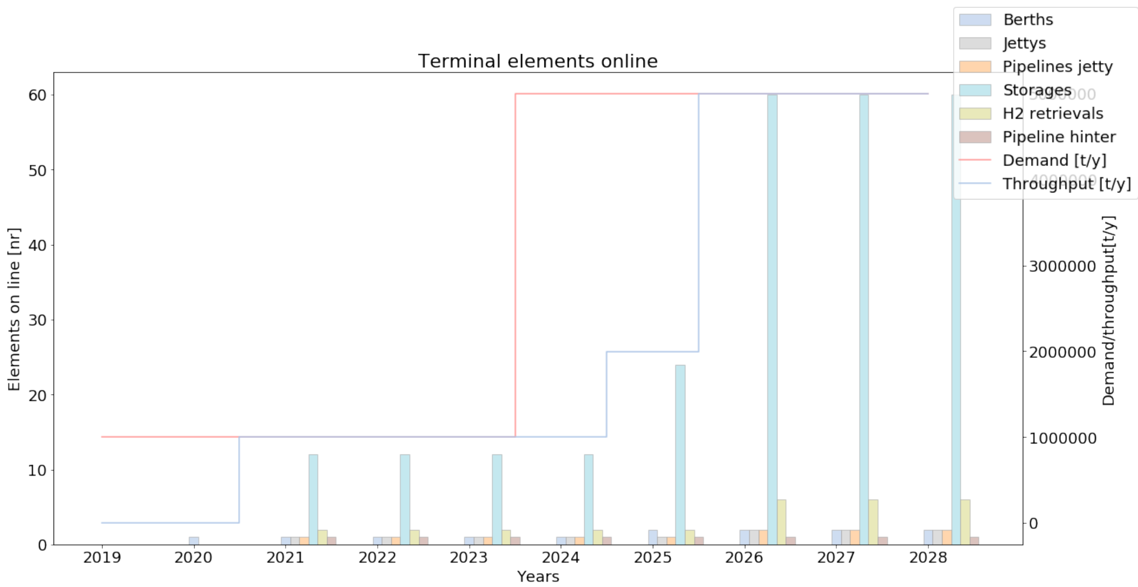

Figure E2.1: The elements of the terminal

E2.1 Throughput

The throughput depends on the capacities of all the elements. At first, all those capacities of the current year are recognized. Next to this, the demand is mapped. The minimum from all these values is the current throughput. The investment decisions of an element depends on the planned throughput, without taking into account its own capacity, of the supply chain.

If the element is the bottleneck, the capacity of the element is lower than the planned throughput and therefore is expanded. In Figure E2.2, two blockages (the element storage and H_2 retrieval) are shown. As can be seen, that in 2024 the throughput is only a bit higher than the throughput in 2023 even though the demand increased. This can be explained by the limiting available capacity of the storages. The storages are triggered to expand in 2025, because they have a construction period of one year. The storages are triggered by the throughput and not by the demand. Not all storage elements are available to meet the demand in 2025, as a result of the bottleneck of the capacity of the H_2 retrieval. The H_2 retrieval has a construction period of two years. Therefore, the throughput in 2025 is increased but does not yet meet the demand. In 2026, all elements are accessible and therefore the throughput is equal to the demand.

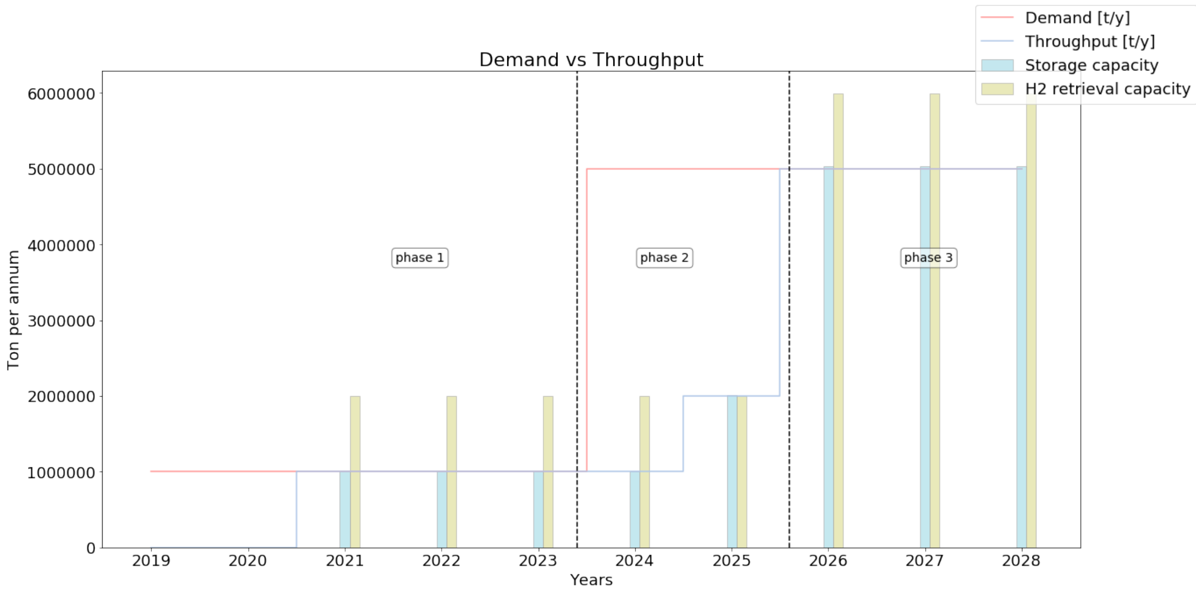

Figure E2.2: Throughput with bottleneck elements

Storage is mostly the bottleneck due to its small capacity per unit, which is included in the model, and therefore more expansion is required. The second most common bottleneck is the H_2 retrieval, this is also a result of low capacity compared to the other assets. The number of pipelines from the jetty to the storage is always equal to the number of jetties. Yet, the construction period is only one year, compared to two years for the jetty. Therefore, the jetty is the bottleneck if it comes down to these two assets.

E2.2 Jetty

In this section the berth occupancy and waiting time are explained.

E2.2.1 Berth occupancy

The berth occupancy ratios are calculated using the probabilistic queuing theory. This theory calculates the berth occupancy based on the arrival rate divided by the average service rate. The formulation of the arrival rate (λ, Equation E.3), the average service rate (μ, Equation E.4) and the berth occupancy (ρ, Equation E.5) are given below.

$$\lambda = \frac{number of calls}{operational hours} \tag{E.3}$$

$$\mu = \frac{1}{\frac{callsize}{unloadingrate} + mooringtime} \tag{E.4}$$

$$\rho = \frac{\lambda}{\mu} \tag{E.5}$$

The berth occupancy is calculated in the model with the unloading rate of each vessel, because the unloading equipment is based on the kind of ship, that have different unloading rates. With this the service time per vessel can be calculated and can be added to the mooring time. With the number of calls, the total time at the berth can be formulated and when dividing this number by the number of operational hours, the berth occupancy is defined. The acceptable berth occupancy factor depends on the number of berths and the allowable average waiting time. For a liquid bulk terminal, a reasonable value for the allowable berth occupancy is around 0.5 (Monfort et al., 2011). The probabilistic queuing theory can be denoted by the Kendall notation, which is "interarrival time distribution/service time distribution/number of berths" (Monfort et al., 2011). The distribution for the interarrival time distribution can vary from random to less random. When the arrival of vessels is totally random, a negative exponential interarrival time can be assumed, denoted by M. If the interarrival is less random, an Erlang-K distribution can be used, denoted by E_k with a shape factor of K = 2.

For common users of the liquid bulk terminal a realistic queue is M/E_2/n and for a dedicated shipping line is E_2/E_2/n (Monfort et al., 2011). An overview of the acceptable berth occupancy can be found in Table E2.1.

Number of berths n_b	**Acceptable berth occupancy factor m_b [%]** Common-user M/E_2/n	Dedicated E_2/E_2/n
1	41	55
2	64	73
3	73	81
4	78	84
6 or more	84	89

Table E2.1: Acceptable berth occupancy factor (Monfort et al., 2011)

E2.2.2 Validation Jetty

The validation of the jetty is based on the berth occupancy and the number of elements. This can be found in Figure E2.3 and Figure E2.4. The commodity taken into account is only liquid hydrogen and therefore, only the vessel coherent to liquid hydrogen is mooring at the jetty. Three different phases are assumed, phase one where a demand of 1,000,000 t/y is assumed in 2019-2023, phase two where there is a demand of 5,000,000 t/y assumed and no extra element is yet available in 2024 and 2025 and phase three where an extra element is added from 2026. An extra element is added because the capacity was not sufficient to serve a demand of 5,000,000 t/y. The berth occupancy is based on the throughput and not on the demand. In the first phase the first jetty element is added. The jetty is triggered in 2019, when the demand is bigger than zero. The construction period of a jetty is assumed to be two years, so the jetty will be online in 2021. In 2021 the demand can be unloaded at the jetty and the throughput is present in the terminal. The capacity of one jetty is sufficient to process the total demand. In 2024, phase 2, the demand is increased to a demand of 5,000,000 t/y. At this moment the capacity of the jetty is still sufficient to process the demand.

Though, the capacity of the total supply chain of the terminal is not sufficient and therefore the throughput cannot be equal to the demand. The berth occupancy in phase 2 is never higher than the allowable berth occupancy, due to the limited throughput. The expansion of the jetty is triggered when looking at the planned throughput which is equal to the demand. If no expansion will appear, the berth occupancy will be higher than the allowable berth occupancy when the throughput is equal to the demand. Therefore, the jetty is triggered to add an element to decrease the berth occupancy. The second jetty is online in 2026, due to the construction period. In this phase, phase 3, the berth occupancy has a reasonable level and two jetties are online.

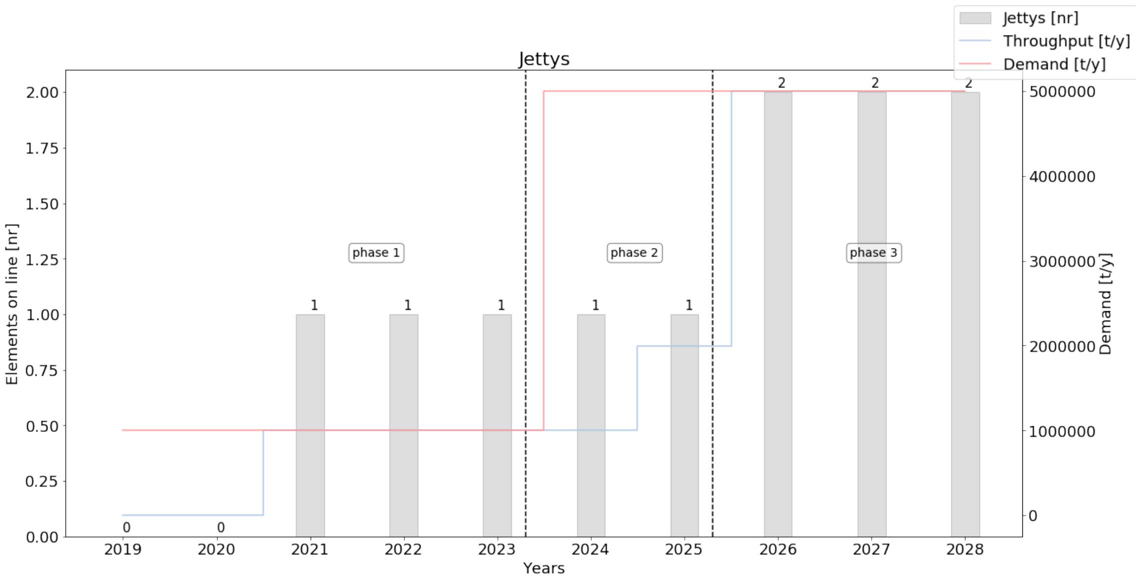

Figure E2.3: Number of jetties

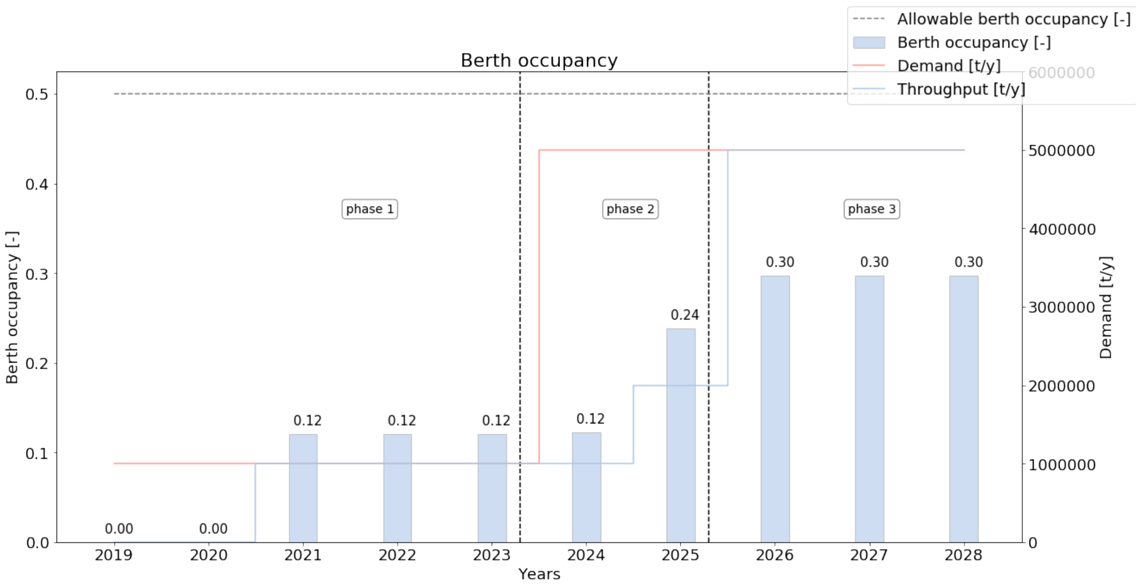

Figure E2.4: Berth occupancy

Validation of the element 'jetty'	Phase 1 [2021-2023]	Phase 2 [2024]	Phase 2 [2025]	Phase 3 [2026-2028]
Demand [t/y]	1,000,000	5,000,000	5,000,000	5,000,000
Throughput [t/y]	1,000,000	1,022,857	2,090,000	5,000,000
Number of total calls per year [-]	54	57	118	267
Small hydrogen vessel calls per year [-]	30	31	65	150
Large hydrogen vessel calls per year [-]	24	25	52	117
Total berth time per berth [hrs]	702	717	1417	1735.5
Berth occupancy (model result) [%]	12.02	12.28	24.27	29.72
Berth occupancy (based on theory) [%]	12.02	12.28	24.27	29.72
Berth occupancy, demand (theory) [%]	12.02	59.43	59.43	29.72

Table E2.2: Validation of the model of the element 'jetty' with the literature

In Table E2.2, the validation of the jetty and the associated parameters can be found. The berth occupancy is calculated with the unloading time of all vessel calls. The throughput does not exactly match the total carry volume of all calls. The throughput is 1,000,000 t/y in 2021 and the total carry volume of all calls is $30 * 10,000 + 24 * 30,000 = 1,020,000$ ton. There is a deviation of 20,000 ton, which is included in the berth time. Yet, this volume of 20,000 t/y is not present at the berth because the demand is lower. Therefore, the exact berth occupancy is a fraction smaller than formulated in the model.

E2.3 Pipeline (Jetty-Storage)

In the terminal a distinction is made between different parts of the pipeline. Part one is from the jetty to the storage and part two from the H_2 retrieval to the hinterland connection. In this section the pipeline from the jetty to the storage is outlined.

The capacity of the pipeline of the jetty to the storage is equal to the highest unloading rate of a vessel times the number of jetties. The highest unloading rate originates from the large hydrogen vessel with an unloading rate of 3,000 t/h. In Figure E2.5, the capacity development of the pipeline from the jetty to the storage can be found. The pipeline is accessible from 2021, which is the same accessibility year as the jetty. This is due to the fact that the throughput depends on the availability of the jetty and since the construction year of the jetty is two years, the jetty is not available in 2020 yet. For financial reasons the pipeline needs to be usable at the same time the construction period of the jetty ends and not sooner even though the construction period of the pipeline is only one year.

As can be seen, the capacity of the pipeline always follows the capacity of the jetty in all phases. In phase 1, the capacity of the jetty is 3,000 t/h, which can already be fulfilled with one unit of pipeline. In phase 2, the amount of jetties will expand to two units, which increases the capacity of the jetties with 3,000 t/h. Therefore, the pipeline capacity also needs to increase. Due to the construction period of two years of a jetty, the element will be accessible in phase 3.

Figure E2.5: Capacity of the jetty to storage pipeline

E2.4 Storage

In this section the storage of the commodities will be validated. The storage of the three commodities will be in three different kind of tanks. The investment decisions regarding the storage are the same for the three commodities. The expansion of the capacity of the tanks are conform to the steps of the capacity. These capacity steps are varying for the different commodities.

The storage expansion includes two triggers: the annual cycles and the vessel call size. The annual cycles is a relevance parameter that refers to the time a commodity spends in the storage. The annual cycles, which is an input value (can be adjusted by the user), is set on 26 times in a year (van Niekerk, 2018). On top of this required storage capacity, a buffer capacity is needed. This buffer capacity is set on 10% of the cycle storage (Terwel & Kerkhoven, 2018). The storage capacity regarding the annual cycles is calculated as follows:

$$\begin{aligned} StorageCapacity = (Throughput * 1/(annualcycles)) * Buffer = \\ (Throughput * 14/365) * 1.1 \end{aligned} \tag{E.6}$$

The second trigger is the vessel call size. This implies that the storage is stored at least one vessel call size of the largest vessel. This trigger is mostly active in the beginning of the project, when the throughput is small.

For this validation only liquid hydrogen is included for the commodity. Liquid hydrogen can be transported in two different vessels, a small liquid hydrogen vessel and an average liquid hydrogen vessel. The largest call size is originated from the average liquid hydrogen vessel with a call size of 30,000 DWT. With a storage capacity of 4,000 ton, eight storages are needed. When there is a throughput of 1,000,000 t/y, annual cycles of 26 and a buffer capacity of 10%, 11 storages are needed. In Table E2.3 and Figure E2.6, the validation of this two triggers can be found. In phase 1 and 2 (2019-2025) the trigger is based on the call size and in phase 3 (2026-2028) on the throughput, therefore phase 1 and 2 are taken together in the table.

Validation of the element 'Storage'	Phase 1 and 2 [2021-2023]	Phase 3 [2024-2028]
Traffic volume [t/y]	500,000	1,000,000
Large hydrogen vessel call size [ton]	30,000	30,000
Annual cycles [-]	26	26
Number of elements, call size (based on theory) [nr]	9	9
Number of elements, throughput (based on theory) [nr]	6	12
Number of elements (model result) [nr]	9	12

Table E2.3: Validation of the model of the element 'Storage' with the literature

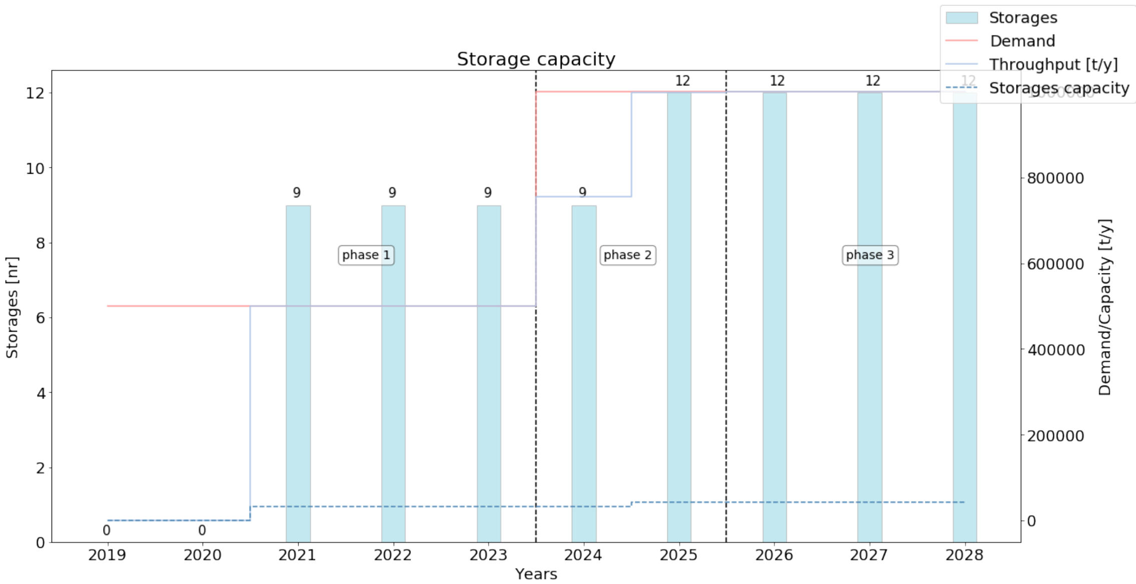

Figure E2.6: Number of storages with the two triggers

In phase 1 (see Figure E2.7), there is a throughput of 1,000,000 t/y, therefore 12 storages are needed. In phase 2, the expansion is triggered based on the throughput. In 2025 the number of storages is increased with 12 units, to a total of 24 storages. The throughput is not equal to the demand and therefore not all 60 units will be online in 2025. In phase 3, the demand is equivalent to the throughput.

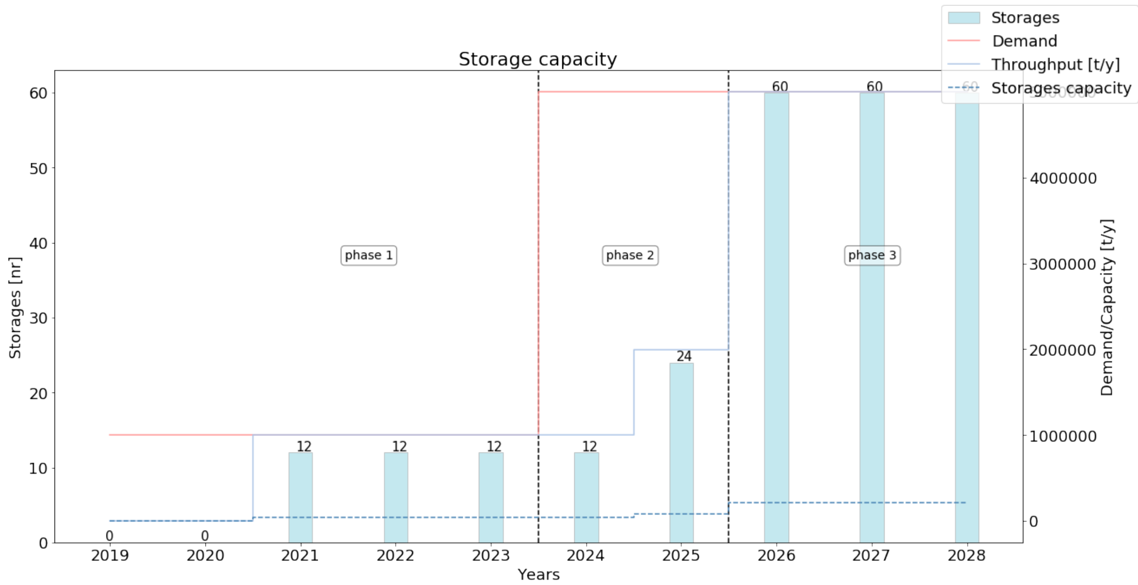

Figure E2.7: Number of storages with throughput

E2.5 H_2 retrieval

After the commodities are stored the regasification/subtracting of hydrogen will take place. Regasification will take place by liquid hydrogen. Regasification is a process of converting LH_2 at 253 °C back to hydrogen gas at atmospheric temperature. For the other commodities (NH_3 and MCH) subtracting of hydrogen will occur. The conversion to H_2 occurs in different plants for the different commodities, with different input values. In this section the validation of H_2 retrieval for liquid hydrogen will be discussed including the general expansion triggers and the capacity.

The expansion trigger of the H_2 retrieval is based on the occupancy of the plant. The plant occupancy ratios are calculated with the arrival rate divided by the service rate. The formulation of the arrival rate (λ_1, Equation E.7), the average service rate (μ_1, Equation E.8) and the berth occupancy (ρ_1, Equation E.9) are given below.

$$\lambda_1 = \frac{Throughput}{operationalhours} \tag{E.7}$$

$$\mu_1 = Productionrate \tag{E.8}$$

$$\rho_1 = \frac{\lambda}{\mu} \tag{E.9}$$

It is assumed that for all commodities the trigger is equivalent. In Figure E2.8, the expansion of the H_2 retrieval for liquid hydrogen can be found. As can be seen, if the demand rises the throughput will be higher and this will trigger the expansion of the H_2 retrieval plant. In phase 1, the retrieval capacity is a lot higher than the demand, due to the fact that the occupancy trigger is set on 1. In phase 2, the demand increases. Due to a construction period of two years the capacity will not be available straight away. The occupancy is at this moment one (see Figure E2.9), due to the fact that the demand is higher than the total capacity. The throughput in this period will not meet the demand quantity. In phase 3, all the plants are operative and the throughput will meet the demand again.

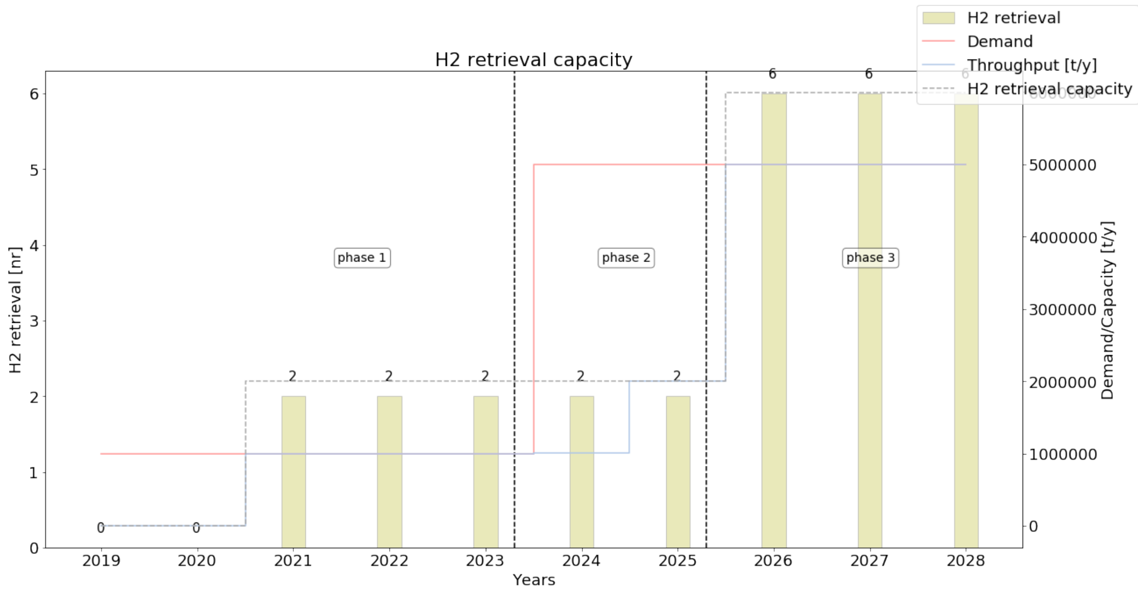

Figure E2.8: Number of H_2 retrieval's with coherent capacity

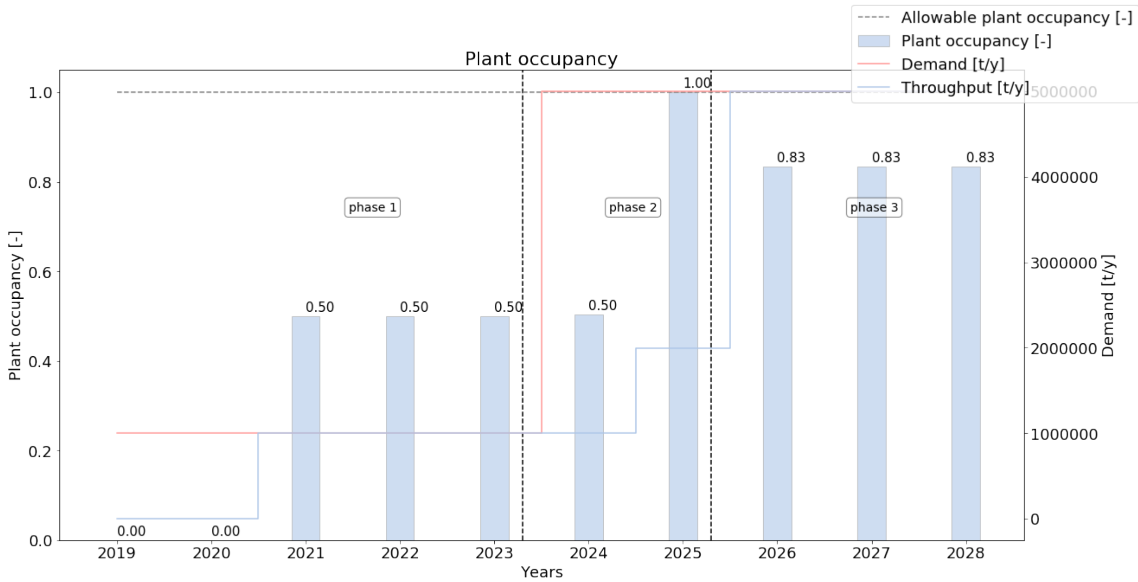

Figure E2.9: H_2 retrieval occupancy

E2.6 Pipeline (H_2 retrieval-Hinterland)

It is assumed that the pipeline capacity is equal or higher than the capacity of the H_2 retrieval plant. One H_2 retrieval plant has a production rate of around 125 t/h, where one pipeline has a service rate of 4,000 t/h. In phase 1, there are two H_2 retrieval plants and therefore one pipeline unit is sufficient. In phase 2 the demand increases from 1,000,000 to 5,000,000 t/y, which triggers the expansion of the H_2 retrieval plant to 6 units in phase 3. The total capacity of all H_2 retrieval plant is still lower than the capacity of one pipeline. Therefore, in phase 3, still one unit of pipeline is sufficient (see Figure E2.10).

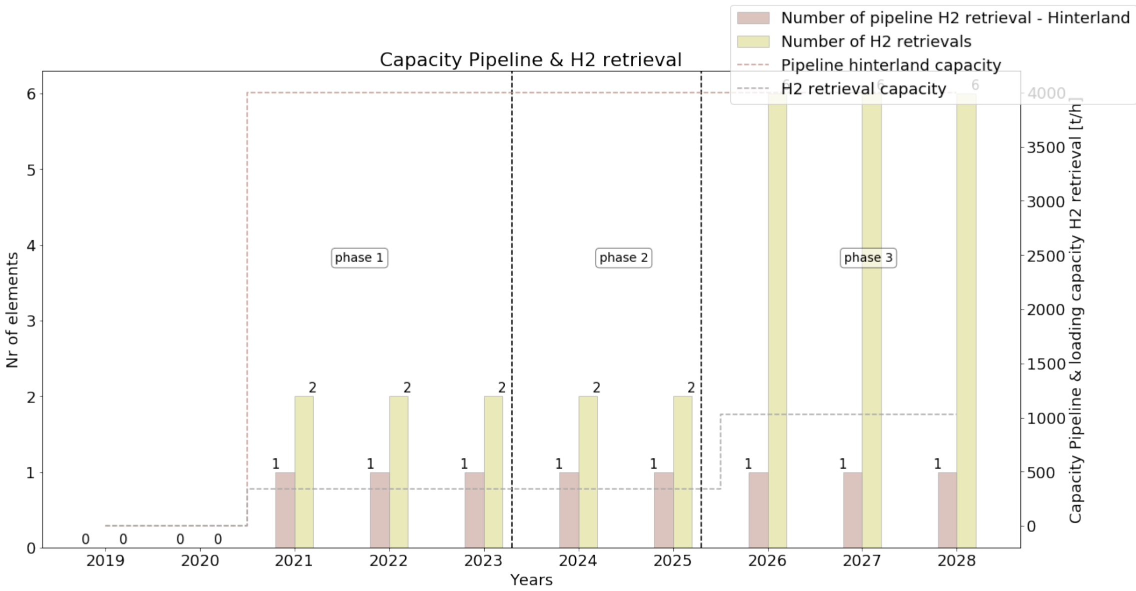

Figure E2.10: Number of pipelines [H_2 retrieval-Hinterland] with coherent capacity

F Cost price of supplied hydrogen regarding all countries within the scope

In this appendix, all graphs of the various import country are shown.

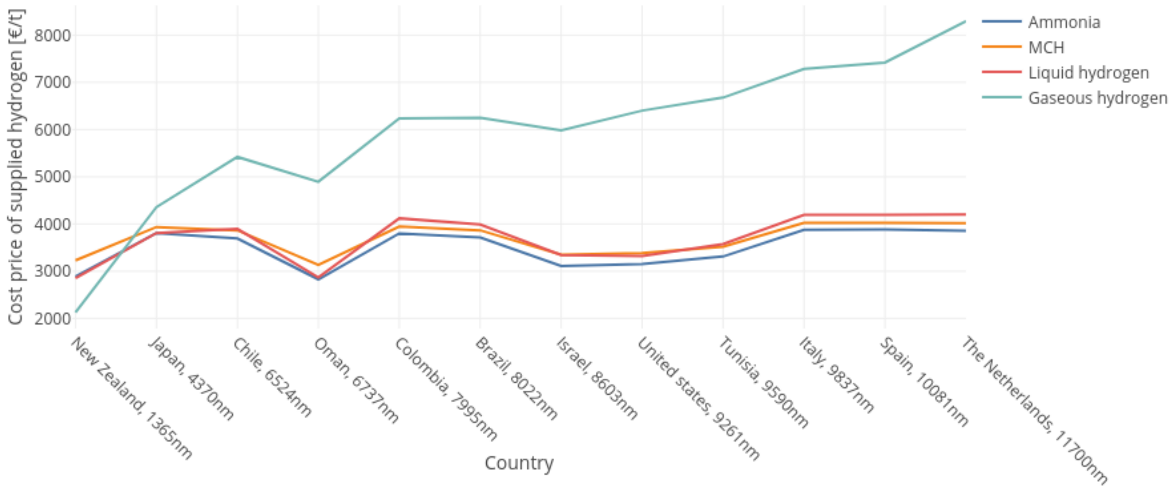

Figure F0.1: Cost price of the supplied hydrogen for the import in Australia varying with the countries, with a demand of 700,000 t/y

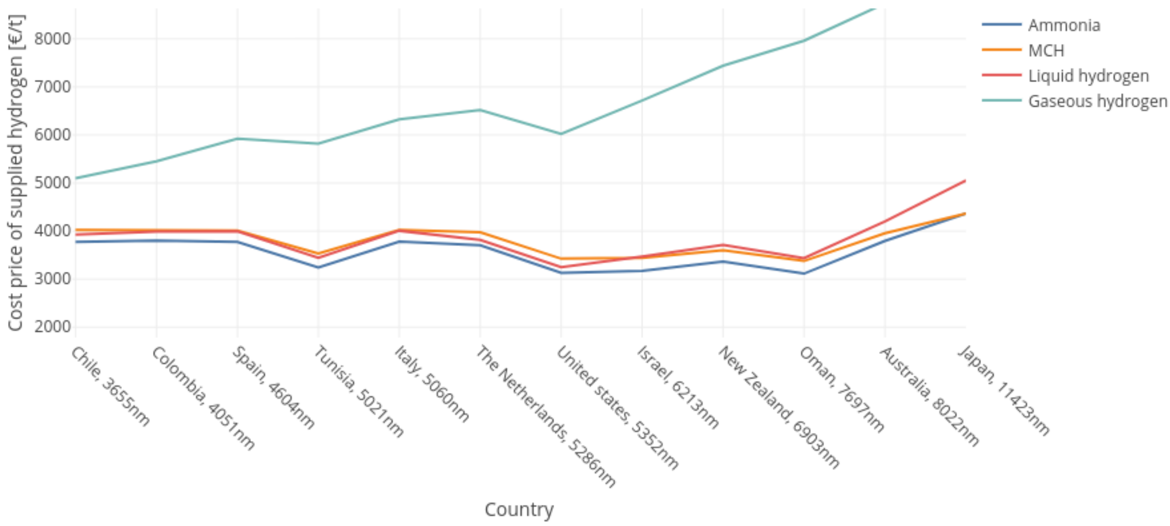

Figure F0.2: Cost price of the supplied hydrogen for the import in Brazil varying with the countries, with a demand of 700,000 t/y

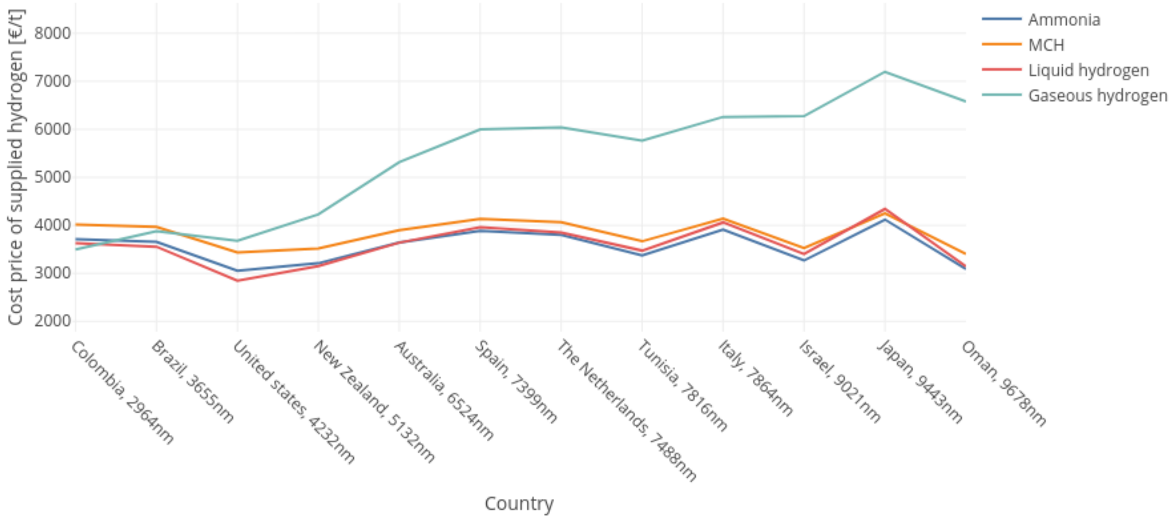

Figure F0.3: Cost price of the supplied hydrogen for the import in Chile varying with the countries, with a demand of 700,000 t/y

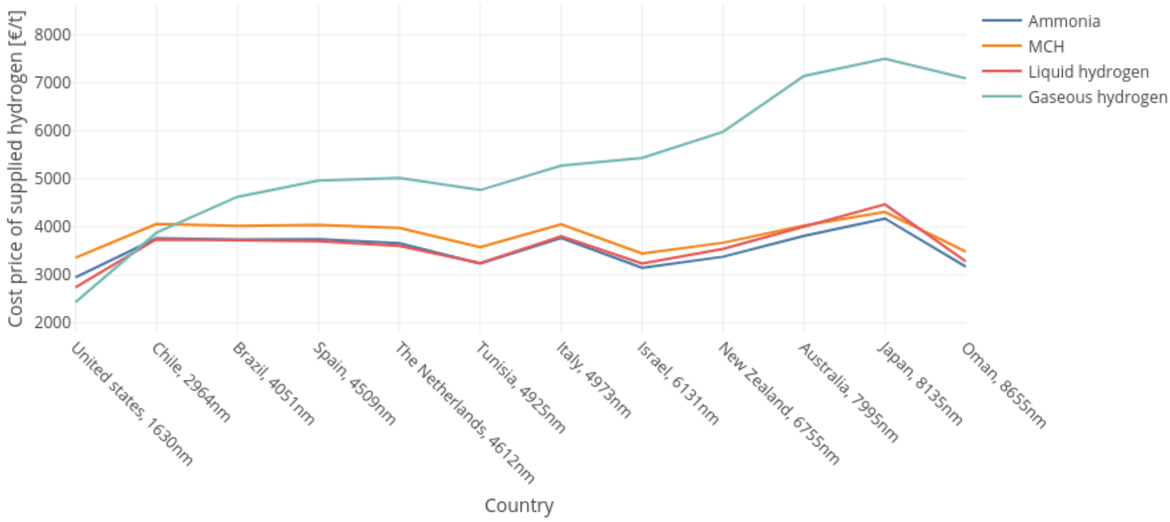

Figure F0.4: Cost price of the supplied hydrogen for the import in Colombia varying with the countries, with a demand of 700,000 t/y

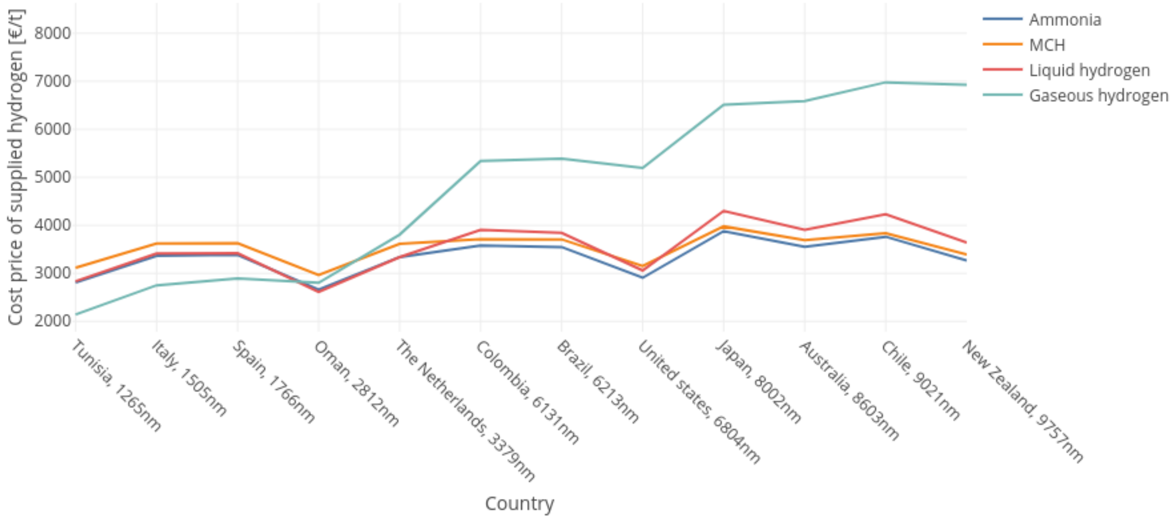

Figure F0.5: Cost price of the supplied hydrogen for the import in Israel varying with the countries, with a demand of 700,000 t/y

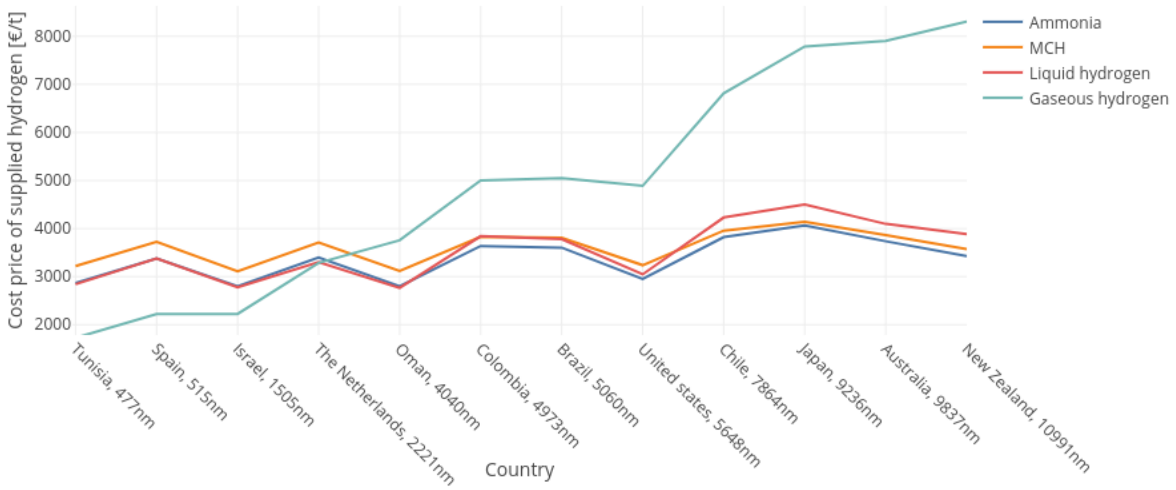

Figure F0.6: Cost price of the supplied hydrogen for the import in Italy varying with the countries, with a demand of 700,000 t/y

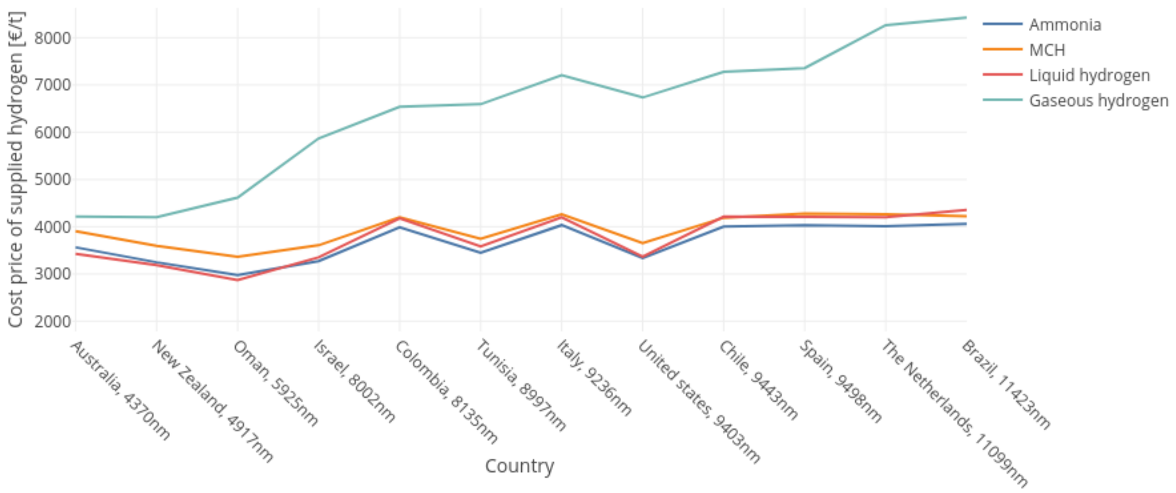

Figure F0.7: Cost price of the supplied hydrogen for the import in Japan varying with the countries, with a demand of 700,000 t/y

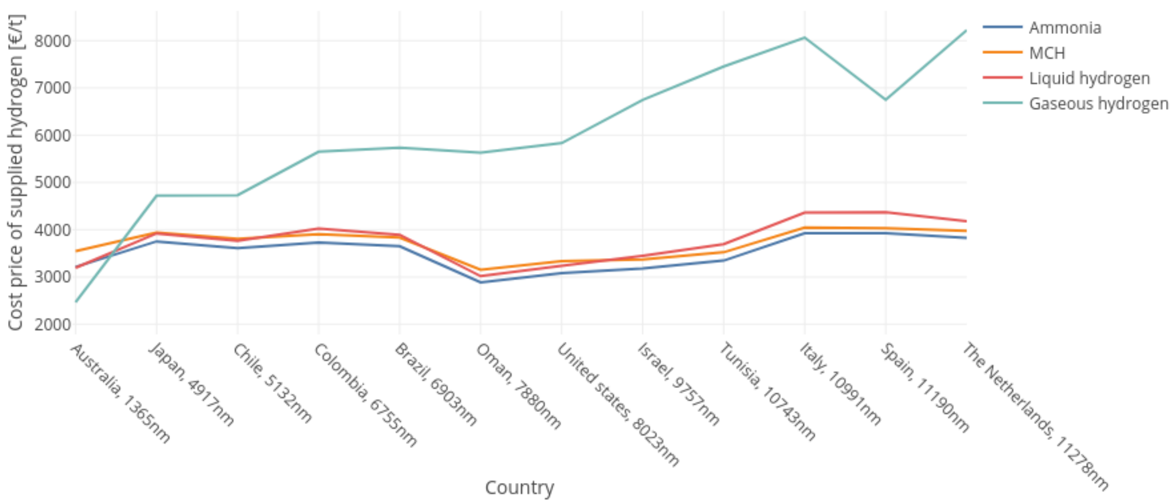

Figure F0.8: Cost price of the supplied hydrogen for the import in New Zealand varying with the countries, with a demand of 700,000 t/y

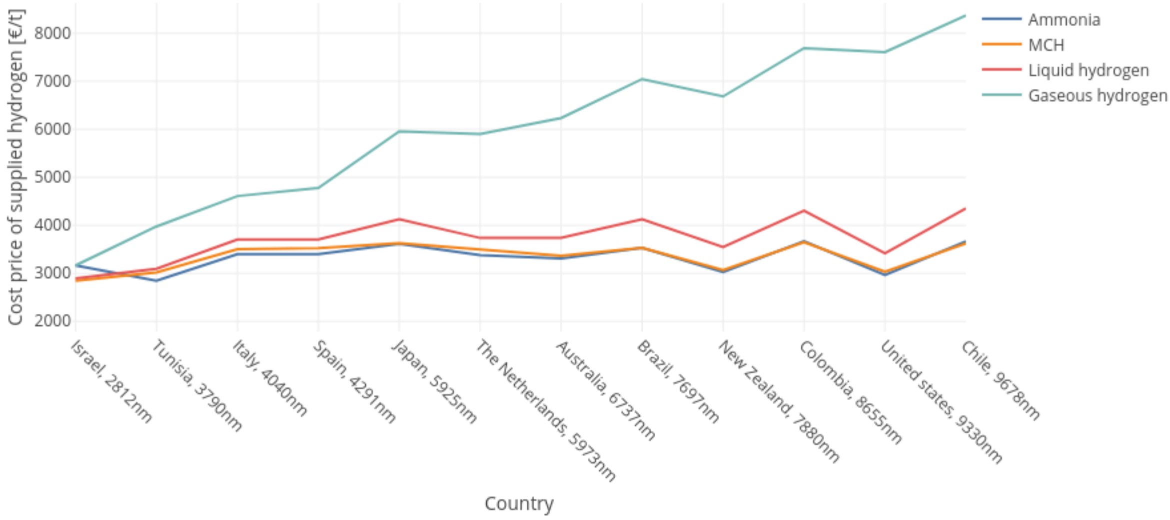

Figure F0.9: Cost price of the supplied hydrogen for the import in Oman varying with the countries, with a demand of 700,000 t/y

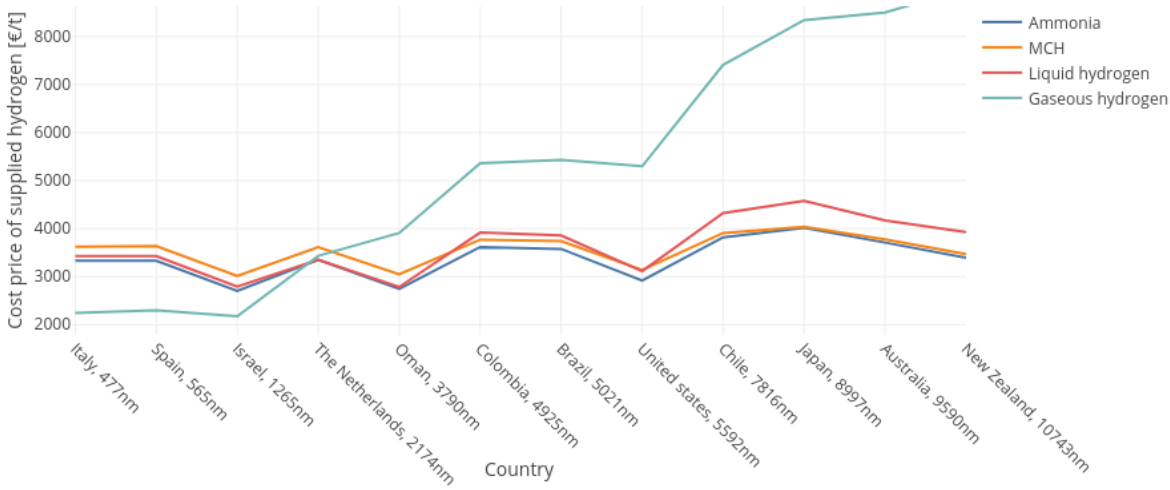

Figure F0.10: Cost price of the supplied hydrogen for the import in Tunisia varying with the countries, with a demand of 700,000 t/y

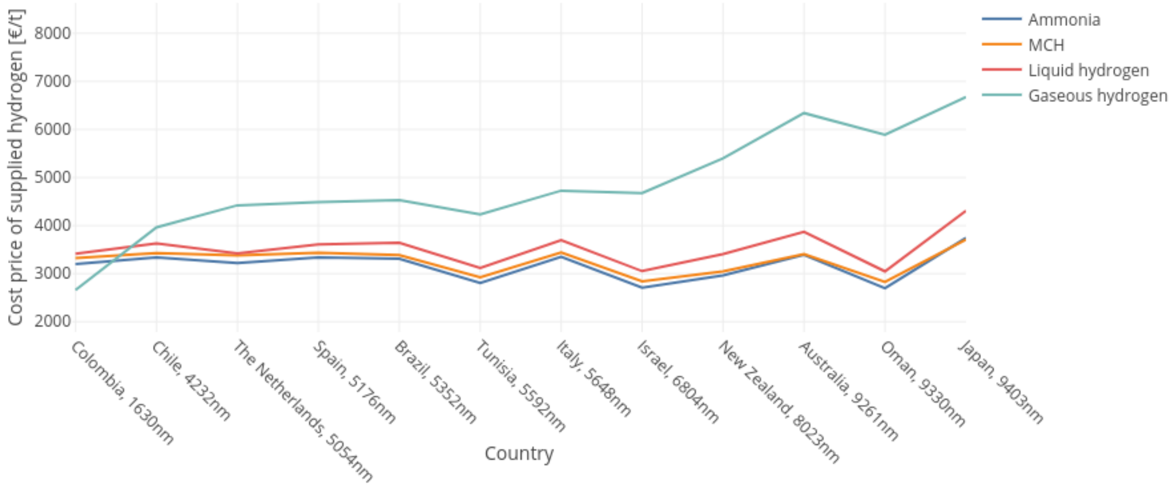

Figure F0.11: Cost price of the supplied hydrogen for the import in United States varying with the countries, with a demand of 700,000 t/y