# HyDelta

## WP7B Technical analysis

D7B.3 – Cost analysis and comparison of different hydrogen carrier import chains and expected cost development

Status: Final

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# Document summary

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## Executive summary

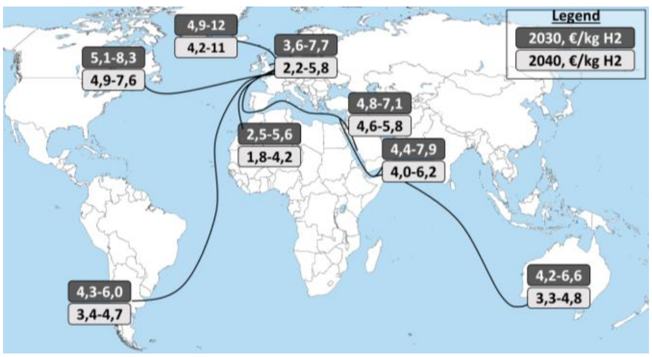
One of the central transitions that is part of our global efforts to transition to at least net zero, are the energy transition and the raw material transition. The energy transition describes the change in the global primary energy supply and demand from fossil-based energy to renewable energy. The raw material transition, or the transition towards a circular use of materials and fuels, aims to change our linear take-make-waste economy into an economy that does not deplete our planet earth. Both these transitions are essential, and as the focus of this research encompasses hydrogen, ammonia and methanol, both the energy transition and the transition to a decarbonized (chemical) commodities industry are at the heart of the study that lies in front of you.

The Netherlands, Germany and Belgium are three befriended spiders in the web of the current global energy market. Primary energy and raw material sources are imported and partially sourced from regional resources in the form of coal, crude oil and natural gas. These fossil molecules act as building blocks that naturally combine hydrogen ($H_2$), carbon (C), nitrogen ($N_2$) and oxygen ($O_2$) molecules. From these molecular building blocks, many products are manufactured and services are provided to meet our societal needs. In fully sustainable future energy and material value chains we may trade these individual hydrogen, carbon, nitrogen and oxygen molecules separately, or in an intermediate form (e.g. ammonia ($NH_3$) or methanol ($CH_3OH$)) and build more complex molecules, such as ethylene ($C_2H_4$) or jet fuel (e.g. $C_9$ to $C_{16}$) from the ground up ourselves. This study focusses on the import of hydrogen, ammonia and methanol from locations with abundant renewable energy potential to the Netherlands.

Given the variety of hydrogen import supply chains that can be developed towards the Netherlands and NW Europe, it is of importance to have a thorough understanding of the technological and economic performance of these import chains to be able to make informed strategic, policy and investment decisions. Materialization of scalable hydrogen import supply chains is a challenge as the upstream, midstream and downstream processes of the future are yet to be developed. Uncertainties remain regarding (1) the process and technology mixes involved, the (2) demanded hydrogen volumes-over-time, and the (3) dependencies between each of the hydrogen carrier import supply chain element that need to be aligned to safe-guard an efficient global supply chain.

The objective of this study is to identify and compare import supply chains to the Netherlands from a technical and logistical perspective, and to increase the insight into the expected cost development from 2030 to 2040 of imported hydrogen, ammonia or methanol via five hydrogen carrier options: synthetic ammonia, synthetic methanol, liquid hydrogen, compressed hydrogen and the liquid organic hydrogen carrier methylcyclohexane.

**Insight 1: The cost ranges of the selected hydrogen carrier import countries is too large to distinguish the single most cost-effective import routes.**




There is no clear consistency in the lowest cost estimates for country-carriers combinations.

Domestic production of $H_2$ without carrier conversion has lower costs than importing hydrogen carriers with ships or hydrogen pipelines.

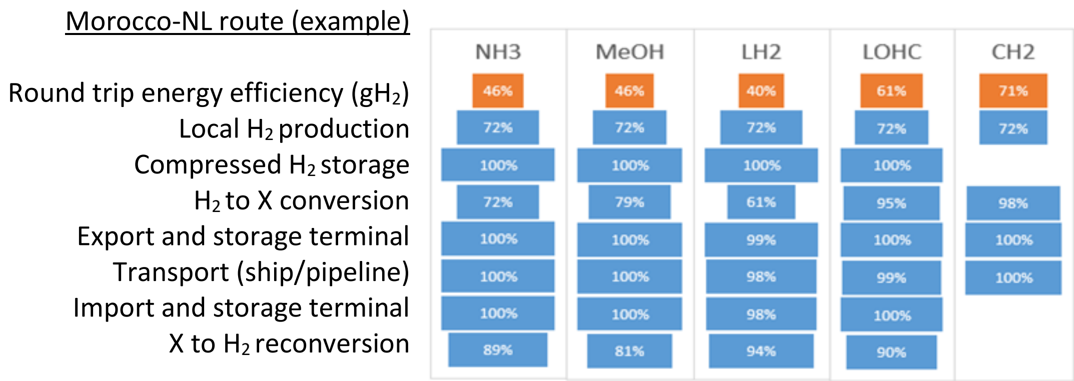
$NH_3$ and MeOH import, without the aim to reconvert to $H_2$, have a smaller cost spread.

**Insight 2: Technology-related costs and geographical factors are both dominant cost drivers of the levelized cost of imported hydrogen.**

*Technological cost drivers:*
> **Hydrogen production**. This dominant cost driver accounting for an average cost of 50% in LH2 and LOHC chains, 70% in $NH_3$ and MeOH chains and up to 90% in cH2 chain. In addition to the **cost of power, the specific investment costs and efficiency** (losses) are main cost drivers.
> The specific **investment costs** as well as the **economies of scale factor** of **industrial process plants** (carrier production and reconversion).

*Geographical cost drivers*:
> The **local cost of renewable electricity**. The LCoE is the main cost driver in all chains.
> The **full load hours**. The annual utilization of RES, PtH2 and H2tX assets determine the mass flow of the import chain. The larger this mass flow, the lower the LCoH2.
> **Distance of country of import is only relevant for shipping LOHC and $LH_2$** when the cargo consumed as a shipping fuel. $NH_3$ and MeOH are more effective fuels.

**Insight 3: Supply chain efficiencies and load-following hydrogen production volumes illustrate the importance of maximizing the mass flows of molecules.**



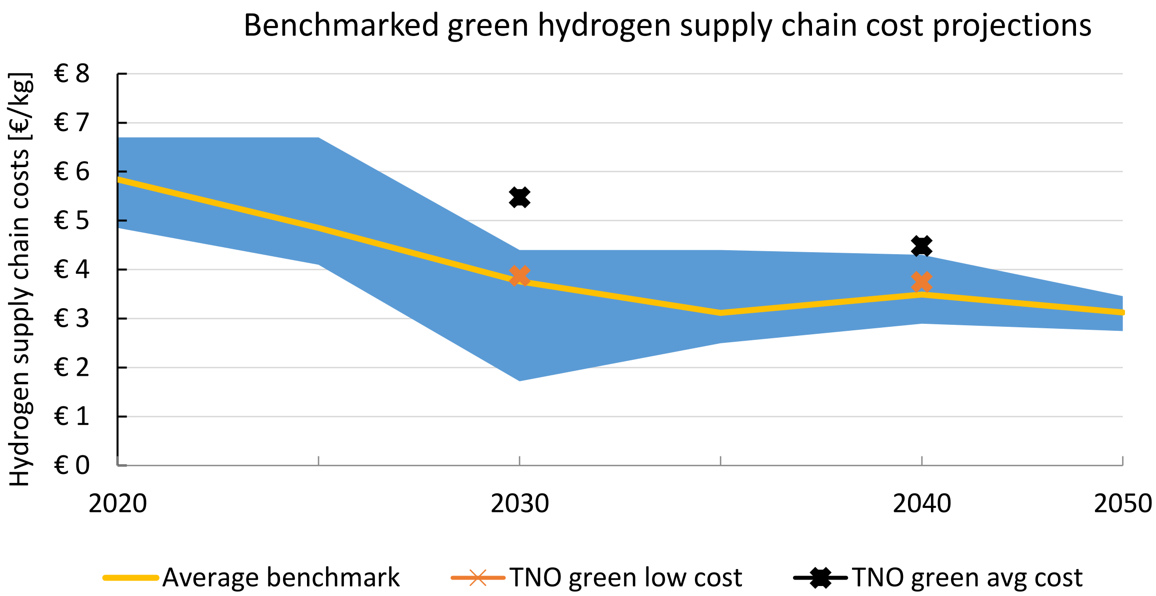

Improvement of the process efficiency in the power-to-hydrogen, hydrogen-to-X and X-to-hydrogen steps would lead to savings in cost and energy. Improvements in these processes may, however, be thermodynamically challenging and/or costly. Maximization of the full load hours of each asset along the supply chain is also of major importance. The higher the utilization rate of the power-to-hydrogen process, the more constant the hydrogen production annually. And consequentially, the larger the mass flow of hydrogen carriers towards the Netherlands, which drives down the $LCoH_2$.

**Insight 4: Current uncertainties in technology-specific costs lead to large spreads of cost estimates.**

Current uncertainties in the techno-economic input parameters of many assets in the supply chains lead to large spreads of cost estimates.

Results in this study are on the expensive end of the cost ranges compared to benchmark studies.

The aggressive uncertainty analysis shows that imported $LCoH_2$ estimations with optimal site specific conditions and optimized and integrated assets can be lower.




**Recommendations**

Future research is recommended to focus on four topics that are deepening or broadening the analysis conducted in this study:

1. **Strive for a maximization of asset utilization** in future cost assessments by maximizing the full load hours of assets up to the carrier production assets, optimize the dimensions of assets in the logistics network and incorporate end-user demands in dimensioning the reconversion assets.
2. To assess the value of storage and investments that are required to guarantee a secured supply of hydrogen by shifting the perspective to **supply network analysis** and increase the level of detail of the **time-scale relevant to the security of supply**-topic (e.g. days, hours).
3. Adding **more types of molecules** (e.g. fuels and feedstock) can enrich the comparison, and by making deliberate decisions on the **location of each supply chain element**, the costs of more complex supply chains can be compared.
4. By **adding the imported hydrogen purity levels** to the cost comparison, the levelized cost of hydrogen can more accurately represent the quality of each product that is imported.

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# 1. Introduction

The transition of our society to net zero, or even negative greenhouse gas emissions is ongoing to safeguard a sustainable future for our children. And while this transition is unfolding, our society is demanding that we also keep meeting our current needs. These current needs are already out of balance with the natural ecosystem, making this transition to a sustainable future an unprecedented challenge. To top off this challenging task, both global population growth as well as increased welfare levels are expected to put even higher stresses on the planetary boundaries of our natural ecosystem.

On the other hand, human actions still could have the potential to determine the future course of our natural ecosystem. The Paris Agreement acts as a cornerstone and urges us to act. In addition to the Paris Agreement, the Fit for 55 programme of the European Parliament refers to the EU's short-term target of reducing net greenhouse gas emissions by at least 55% by 2030.

One of the central transitions that is part of our global efforts to transition to at least net zero, are the energy transition and the raw material transition. The energy transition describes the change in the global primary energy supply and demand from fossil-based energy to renewable energy. The raw material transition, or the transition towards a circular use of materials and fuels, aims to change our linear take-make-waste economy into an economy that does not deplete our planet earth. Both these transitions are essential, and as the focus of this research encompasses hydrogen, ammonia and methanol, both the energy transition and the transition to a decarbonized (chemical) commodities industry are at the heart of the study that lies in front of you.

## 1.1 The global energy and raw material trade is changing

While the majority of the attention in the conversations about energy the transition goes to electrical energy, the majority of the energy that passes through the Netherlands, Germany and Belgium is oil and gas related. Figure 1 illustrate how the different energy types relate to each other in 2019 in The Netherlands, which shows us how far we still have to go to achieve our sustainability goals.

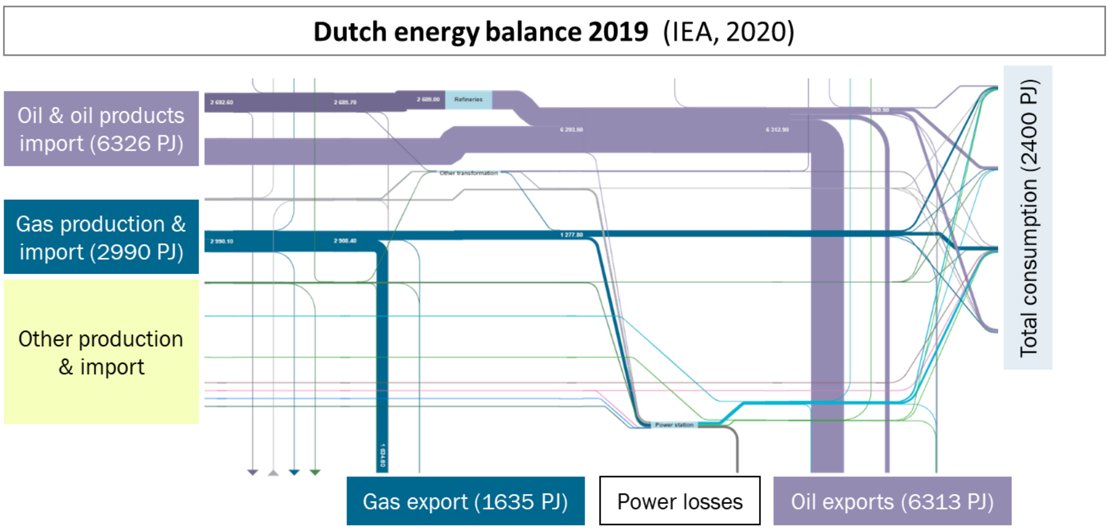



*Figure 1 Dutch energy balance of input, consumption and throughput in 2019*

In Europe, the trilateral region of North Rhine-Westphalia (Germany), Flanders (Belgium) and parts of the Netherlands, the so called ARRRA[1] cluster, is home to one of the most energy-intensive and emission-intensive industrial clusters in the world. The cluster holds 40% of the petrochemical industry of the European Union. The Dutch petrochemical and chemical industry is a global player in the production of bulk chemicals and has a large share (17%) in total Dutch exports. Different well-established value chains are served via integrated infrastructures and ecosystems of suppliers and consumers. The ARRRA cluster claims an annual turnover of 180 billion euros and provides jobs for over 350.000 persons[2]. However, the chemical and oil industry in the ARRRA cluster is also a large contributor of greenhouse gas (GHG) emissions.

The Netherlands, Germany and Belgium are three befriended spiders in the web of the current global energy market. Primary energy and raw material sources are imported and partially sourced from regional resources in the form of coal, crude oil and natural gas. These fossil molecules act as building blocks that naturally combine hydrogen ($H_2$), carbon (C), nitrogen ($N_2$) and oxygen ($O_2$) molecules. From these molecular building blocks, many products are manufactured and services are provided to meet our societal needs. In fully sustainable future energy and material value chains we may trade these individual hydrogen, carbon, nitrogen and oxygen molecules separately and build our own more complex molecules, such as ethylene ($C_2H_4$ ) or jet fuel (e.g. $C_9$ to $C_{16}$) from the ground up. Or replace current fossil forms of energy and raw material altogether by a (more) sustainable alternative, such as synthetic methanol, bio-diesel or green hydrogen. Circular use of raw materials would imply continuous utilization of hydrocarbons, aiming to minimizing environmental impact and scarcity of materials.

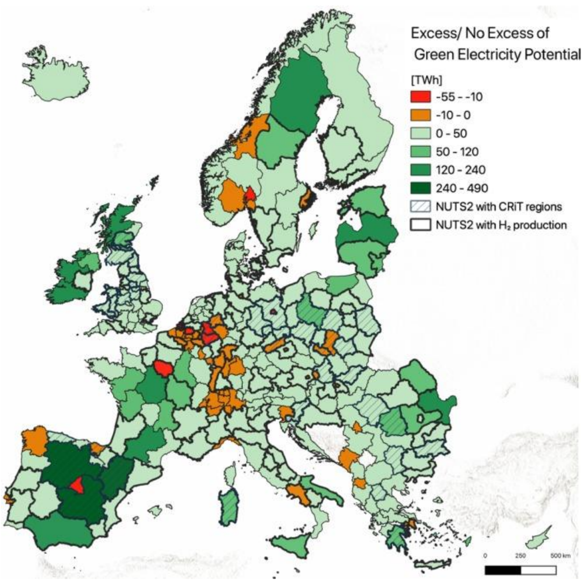



*Figure 2 Regions with an excess or deficit of technical potential for green electricity after subtracting the current consumption for all sectors and that needed for moving from existing hydrogen production from grey to green.*[3]

[1] ARRRA cluster: Antwerpen-Rotterdam-Rijn-Ruhr-Area

[2] https://www.trilateral-chemical-region.eu/

[3] Kakoulaki et al (2021) Green hydrogen in Europe – A regional assessment: Substituting existing production with electrolysis powered by renewables

Increasingly, hydrogen is regarded as a crucial element for the energy transition. While it is not the only decarbonization option, it provides an essential lever to a set of other technologies due to its variety of potential applications. Potential uses of hydrogen in the (near) future are:

- Enable the large-scale **integration of renewable electrical energy** generation through conversion, buffering and storage of the energy as a renewable gas, and transportation and distribution of that gas amongst sectors and regions.
- **Fuel** for short-haul fuel cells electric vehicles (cars, busses, trucks, trains) and **hydrogen-derivative synthetic and bio-fuel** for long-haul transport (trucks, ships, airplanes). The emphasis is on replacement of heavy fuels such as diesel, as this is typically the fuel used in heavy duty applications for which hydrogen and fuel cells are generally considered to be a better option than batteries. Batteries appear perfectly suitable for light duty transport applications.
- **High temperature heating** for industrial applications. This application is about replacement of fossil fuels, in particular natural gas, as a source for production of high temperature process heat in industrial processes.
- **Low temperature heating** of houses and buildings. This option also replaces fossil fuels for heating, in particular natural gas. Depending on the characteristics of the houses and buildings, hydrogen has to compete with other alternatives like replacement of boilers by heat pumps.
- **Electricity generation** in gas-fired (combined cycle) power plants. Despite the round-trip efficiency of the power-to-hydrogen-to-power cycle, hydrogen-fired CCPPs can fulfill a role in the energy system of the future. Electricity markets are regionally organized, and electricity has to be produced if the demand requires, which allow room to accept higher fuel cost if no alternative cost-competitive power production is available.
- **Replacement of current fossil-based feedstock** for production of fertilizers and complex chemical products. This use case considers replacement current natural gas-based hydrogen production and expansion of current industrial hydrogen applications.
- Use as a feedstock in **new industrial processes** such as DRI steel-making, synthetic and bio-fuel production and synthesis of complex non-fuel chemical products:
    - DRI steel-making: Iron ore is reduced with hydrogen while in a solid state, hence the name direct reduction, to produce direct reduced iron (DRI) called sponge iron. Sponge iron is then fed into an EAF, where electrodes generate a current to melt the sponge iron to produce steel. Some carbon is needed so that steel can be produced. This carbon can come from pulverized coal, biomethane or other biogenic carbon sources.
    - Syn-fuels and bio-fuels: Replacement of oil-based kerosene and fuel oil by fuels produced from hydrogen and a sustainable carbon source. This can be carbon from sustainable biomass, circular carbon from waste processing, and carbon or $CO_2$ from direct air capture (DAC).
    - Non-fuel chemicals: This applications is about replacement of oil and oil-based base chemicals as feedstock for chemical industry for the production of all kinds of chemical products, materials and plastics. This option also requires carbon sources on top of renewable hydrogen.

It is due to these large amounts of hydrogen that are envisioned that we focus on hydrogen supply in this study.

## 1.2 Sustainable molecule import to North-West Europe is crucial but challenging

In the years to come, the energy and feedstock market will change considerably due to the transition from fossil sources to renewable sources. Figure 2 shows that the Netherlands and its hinterland will benefit greatly in the future from importing renewable molecules that can be produced elsewhere in the world at lower costs, where renewable electricity is (super)abundant (Figure 3[4]):

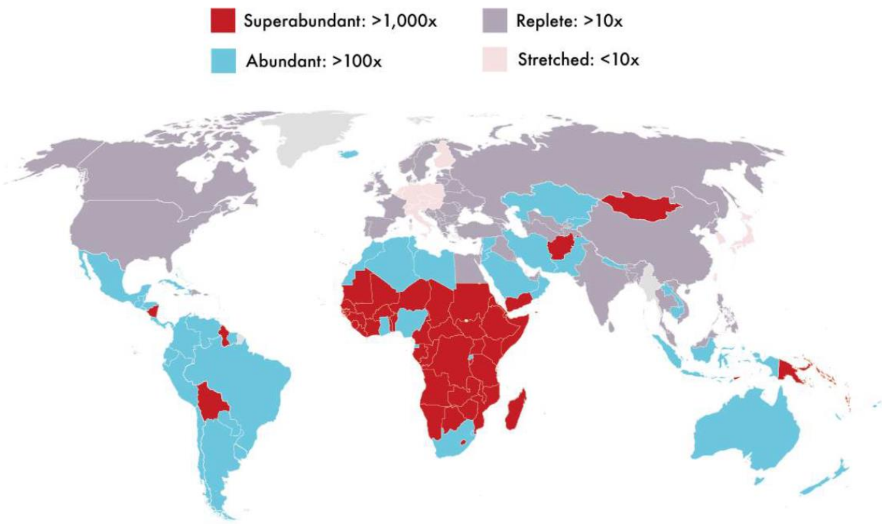



*Figure 3: Solar and wind energy potential as a multiple of energy demand*

In the ARRRA cluster, the intermittent electricity production is expected to characterize the local production of local green hydrogen; which will therefore also have a varying supply profile that will deviate from the market demand for hydrogen in terms of volume, place and time. Besides the local production, import will be a major source of hydrogen, hydrogen carriers and renewable fuel supply for the Netherlands and NW Europe. A better understanding of this potential energy supply route of the future will help to develop effective and multi-year policies at the corporate, regional, national and international levels.

In this study, five supply chain alternatives for importing hydrogen are considered. The hydrogen is assumed to be transported as **liquid hydrogen** ($LH_2$), as a **compressed gaseous hydrogen** ($cH_2$), or bound to three types of molecules to become a hydrogen carrier:

- **ammonia** ($NH_3$) by adding nitrogen to hydrogen
- **methanol** ($CH_3OH$, or MeOH) by adding carbon dioxide to hydrogen
- **methylcyclohexane** ($C_7H_{14}$), a liquid organic hydrogen carrier (LOHC), by adding toluene ($C_7H_8$) to hydrogen

Each of the alternatives has their own pros and cons[5] that ultimately lead to an import cost for one unit of gaseous hydrogen, ready to be used by an end-consumer.

*__The relevance:__* Given the variety of hydrogen import supply chains that can be developed towards the Netherlands and NW Europe, it is of importance to have a thorough understanding of the technological and economic performance of these import chains to be able to make informed strategic, policy and investment decisions.

[4] Carbon tracker initiative (2021) The sky's the limit

[5] An holistic comparison of those pros and cons is considered useful in order to make informed decisions from an integrated systems perspective, but kept out of scope in this study.

*<u>The challenge:</u>* The decisions to be made by each actor in the hydrogen import supply chain that lead to the materialization of scalable hydrogen import supply chains is not yet clear as the upstream, midstream and downstream processes of the future are yet to be developed. Uncertainties remain regarding (1) the process and technology mixes involved, the (2) demanded hydrogen volumes-over-time, and the (3) dependencies between each of the hydrogen carrier import supply chain element that need to be aligned to safe-guard an efficient global supply chain.

## 1.3 The objective of this study: Estimating future hydrogen import cost ranges

On the supply side different technologies to produce hydrogen lead to different costs per quantity of hydrogen. The cost of renewable electricity based hydrogen production via electrolysis is heavily depending on the cost of that electricity. In the Netherlands, this renewable electricity-based hydrogen has been more expensive compared to grey hydrogen production from natural gas using SMR. But when produced in countries with an (expected) low renewable electricity cost, renewable hydrogen import may be able to compete with domestically produced grey, blue or green hydrogen and serve as a complementary hydrogen supply option to contribute to the (inter)national sustainability goals. The hydrogen-supply merit order (right) will change over time depending on the costs of production per technology in the future.

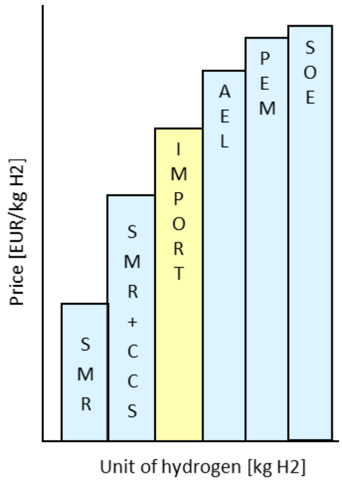


*Figure 4 Fictive supply merit order*

*<u>The objectives of this study are:</u>* Identify and compare import supply chains to the Netherlands from a technical and logistical perspective, and to gain insight into the expected cost development of these various import chains, as a result of technical innovations.

In line with this objective, the following research questions were defined and answered during the execution of the study:

1. What are the **import costs (EUR/kg)** of green hydrogen, synthetic ammonia and synthetic methanol, for different arche-type production locations globally towards the Netherlands?
2. How do the import cost of $H_2$/$NH_3$/MeOH **compare** with the cost of a locally produced equivalent in NL?
3. Which supply chain elements are **dominant cost drivers** (%) in the import cost breakdown per carrier?
4. Which import chain has the highest (energy-based) **round trip efficiency**?
5. What is the **uncertainty range** of the import cost per carrier import supply chain?

## 1.4 Report and connection to other HyDelta deliverables

This report answers the research questions by means of four key insight paragraphs in Chapter 2. Subsequently, the detailed results are discussed in Chapter 3. The **MS Excel dashboard** to navigate through the import analysis results is accompanying this third chapter as an appendix. In chapter 4 and 5, the uncertainty analysis and the comparison with relevant *benchmark* studies are presented. The recommendations for future research in Chapter 6 conclude this report. The cost modelling methodology and the supply chain specific assumptions and configuration logic is extensively discussed in the appendix of this report.

The HyDelta import cost analysis study is embedded within the HyDelta programme and uses multiple outputs of the other work packages of the programme as its inputs; mainly the techno-economic datasheets (D7B.1[6] and D7B.2[7]) and the domestic green and blue cost estimates that are part of the domestic value chain analysis (D7A.2). And the domestic value chain analysis (D7A.2) uses the import costs as input for specific value chains using import as source The insights from this cost analysis are an input to the innovation roadmap (D7B.4).

[6] HyDelta D7B.1: https://doi.org/10.5281/zenodo.6469569
[7] HyDelta D7B.2: https://doi.org/10.5281/zenodo.6469593

# 2. Four key insights

The result of the quantitative analysis of hydrogen import supply chains to the Netherlands is compressed into four key insights. The insights are described in the subsequent sections and encompass various levels of aggregation as is illustrated in Figure 5 below. The commonality between the key insights is the aim to identify trends that inform decision-makers, policy analysts and (applied) researchers regarding cost estimates on hydrogen import.

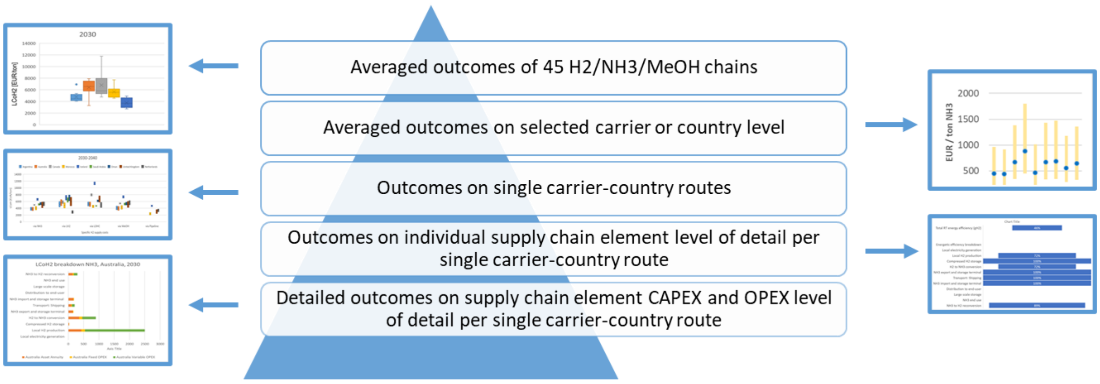



*Figure 5 Visualisation of the information and insights in this report which are generated on multiple levels of detail*

The four key insights of this study are:

1. The cost ranges of the selected hydrogen import chains is too large to distinguish the single most cost-effective export country.
2. Technology-related costs and geographical factors are both dominant cost drivers of the levelized cost of imported hydrogen.
3. Supply chain efficiencies and load-following hydrogen production volumes illustrate the importance of maximizing the mass flows of molecules
4. Current uncertainties in technology-specific costs lead to large spreads of cost estimates.

## Key insight 1: The cost ranges of the selected hydrogen import chains is too large to distinguish the single cost-effective export country.

One of the primary objectives of this project is to determine the most (cost-)effective route (combination of carrier and location of $H_2$ production) for importing hydrogen to the Netherlands. **This study shows that it is not possible to plainly rank the chains based on their economic viability, due to overlapping of the large cost ranges.**

The results of this study indicate that:

- There is no clear consistency in the lowest cost estimates for countries and carriers.
- Domestic production of $H_2$ without carrier conversion has lower costs than importing hydrogen carriers with ships and is competitive to low-cost pipeline import from specific countries.
- $CH_2$ via pipeline is the most cost-effective option for import. This option is restricted to countries close to the Netherlands and costs are highly uncertain.
- In 2030, the $NH_3$ chain is the most cost-efficient solution when $H_2$ transport cannot be conducted via pipeline. In 2040 or later, $LH_2$ , LOHC and MeOH become competitive.
- $NH_3$ and MeOH import, without the aim to reconvert to $H_2$ , have a smaller cost spread and follow the same cost reduction trend as the other hydrogen carriers.

The chains under consideration are: the import of $H_2$ (via $NH_3$, MeOH, $LH_2$, LOHC and compressed $H_2$) and import of $NH_3$ and of MeOH. The following graphs show how the import costs vary based on $H_2$ production location in all chains. Hence, it shows the range of levelized costs of hydrogen/ammonia/methanol (LCoH$_2$/NH$_3$/MeOH) for all possible routes for 2030 and 2040. The domestic LCoH$_2$ 7A NEC Green and Blue hydrogen estimates are also shown in 2030. The range in Blue hydrogen, is for 25-100 €/MWh gas price.

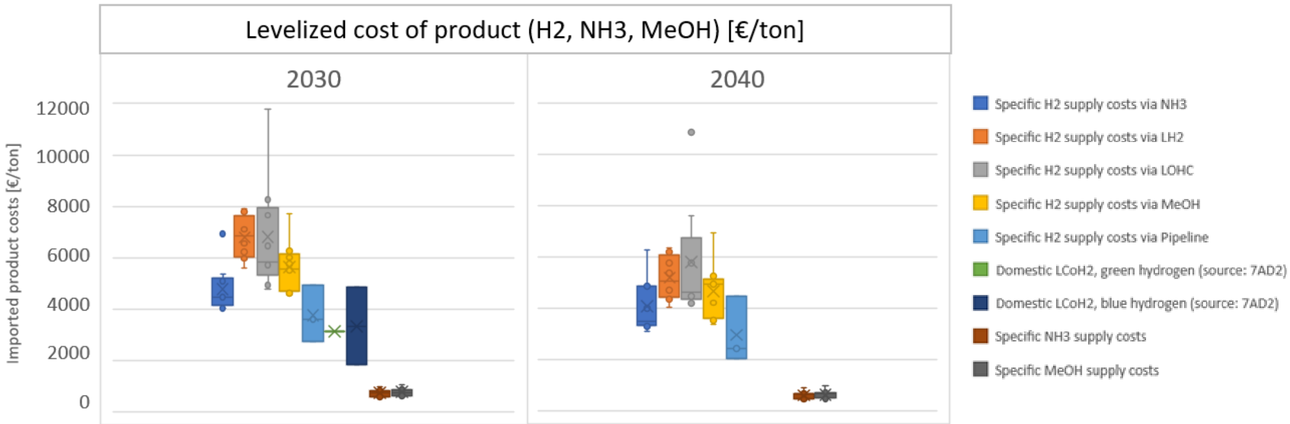


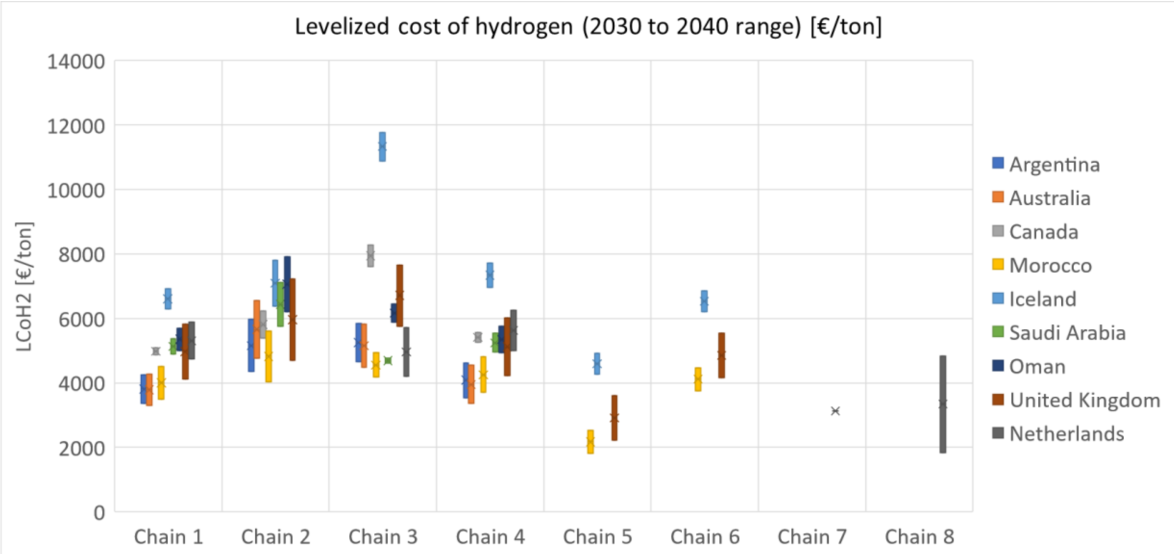

*Figure 6: Range of levelized cost of $NH_2$, $NH_3$ and MeOH for all chains and all the locations in 2030 and 2040. The domestically produced hydrogen costs from HyDelta deliverable 7AD2 is included for 2030. The range in Blue hydrogen, is for 25-100 €/MWh gas price.*

According to Figure 6, in 2030, $cH_2$ pipeline import, followed by shipped $NH_3$ are generally the most cost-effective options. However, the based on NEC production of blue or green hydrogen in the Netherlands (resp. 1839-4839 and 3131 €/ton[8]) is lower than all the possible routes of $NH_3$ and cost-competitive to $cH_2$ routes. The LCoH$_2$ via $LH_2$ greatly overlaps with LOHC routes, whereas MeOH chains are slightly cheaper. In 2040, the LCoH$_2$ of $LH_2$, LOHC and MeOH is lower than in 2030. Figure 6 shows

[8] See HyDelta D7A.2 for more detailed elaboration of the results.

increased overlapping between all the chains in 2040, with $cH_2$ with a lowest import costs. The $LH_2$ and MeOH chains are improved the most over the decade, due to technological advancements, and they are competing with the $NH_3$ chain for the most cost-efficient shipping solution. The levelized cost for imported $NH_3$ and MeOH is also presented in Figure 8.

The comparison of import routes versus $H_2$ production in the Netherlands can be seen in Figure 7, for both 2030 (top value of each bar) and 2040 (bottom value of each bar). The local $H_2$ production is the most economical route, whereas it lies on the expensive routes in $NH_3$ and MeOH chains. Additionally, it is important to notice that the ranking of countries for each supply chain is different for 2030 and 2040, as some routes show greater cost reduction than others.




1 = H2 via NH3
2 = H2 via LH2
3 = H2 via LOHC
4 = H2 via MeOH
5 = H2 via Pipeline (low)
6 = H2 via Pipeline (high)
7 = Domestic LCoH2, green hydrogen (source: 7AD2)
8 = Domestic LCoH2, blue hydrogen (source: 7AD2)

*Figure 7: Levelized cost of $H_2$ of all chains for all routes in 2030 and 2040. The value for 2030 is shown at the top of each country bracket and the value for 2040 is shown at the bottom. The value of LCoH 7A NEC Green and Blue hydrogen is for 2030. The range in Blue hydrogen is for 25-100 €/MWh gas price.*

$H_2$ import via pipeline could become the most cost-effective chain for most routes in 2030 and 2040.

Due to challenges of large-scale pipeline network development, which are beyond the scope of this import analysis, import via shipping may be preferred. The $LCoH_2$ cost spread is therefore categorized in pipeline and shipping transportation methods, and the results can be seen in Figure 8.

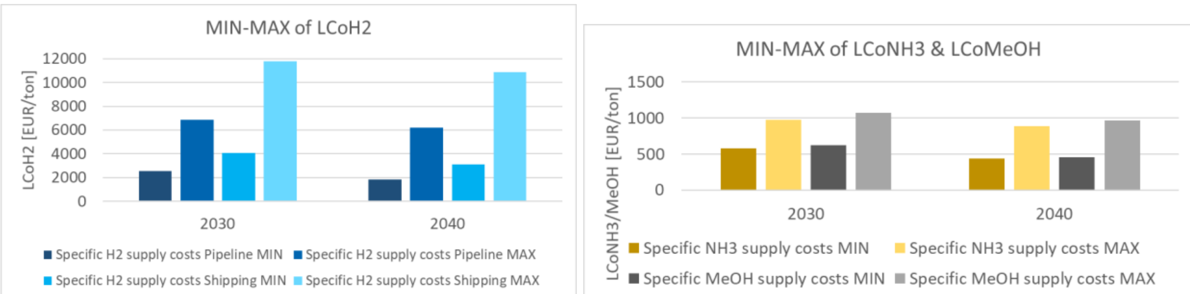



*Figure 8: Minimum and maximum value for Levelized cost of $H_2$ for transportation via pipeline and shipping, $NH_3$ and MeOH. The cost ranges summarize the different routes of transport for 8 exporting countries.*

## Key insight 2: Technology-related costs and geographical factors are both dominant cost drivers of the levelized cost of imported hydrogen

A cost driver is a key parameter that causes a large change in the cost of hydrogen import when that parameter changes. The cost drivers can change for different chains or for different countries of import. As the levelized cost of hydrogen is defined as the cost per mass of hydrogen, this $LCoH_2$ can be reduced either by reducing the cost of the production activities or by increasing the amount of product. Knowing which supply chain elements contribute the most to the $LCoH_2$ is the first step to driving down hydrogen costs effectively.

Summarized, the dominant technological cost drivers are:

- The $H_2$ production step. This dominant cost driver accounting for an average cost of 50% in $LH_2$ and LOHC chains, 70% in $NH_3$ and MeOH chains and up to 90% in $cH_2$ chain. In addition to the cost of power, the specific investment costs and efficiency losses are main cost drivers.
- The specific investment costs as well as the economies of scale factor of industrial process plants (carrier production and reconversion).

The dominant geographical cost drivers are:

- The local cost of renewable electricity. The combined LCoE is the main cost driver in all chains. The lower the LCoE, the lower the $LCoH_2$.
- The full load hours. The operational hours, and thus the utilization of capital, of the RES, $PtH_2$ and $H_2tX$ determine the mass flow of the import chain. More mass flow is a lower the $LCoH_2$.
- Distance of country of import is relevant for shipping LOHC and $LH_2$ when the cargo is consumed as a shipping fuel as $NH_3$ and MeOH are more effective fuels.

The cost-drivers can be divided in four different categories:

| | **Geographical (location-specific characteristics)** | **Technological (asset-specific characteristics)** |
|---|---|---|
| **CAPEX** | *e.g. full-load hours of renewable electricity supply technologies (FLH RES), Transportation distance, local interest rate* | *e.g. FLH RES, specific investment costs of assets* |
| **Variable OPEX** | *e.g. Levelized cost of electricity (LCoE), transportation distance, Feedstock costs* | *e.g. LCoE, Process efficiency* |

Geographical characteristics may change a little over time, depending on the local weather systems. Technological advancements over the years can however lead to larger cost reductions in every chain, based on the specific equipment and processes that are used. However, even in cases where the same equipment is used, the cost reduction will not necessarily be similar because of geographical characteristics (e.g. the different FLH RES-dependent hydrogen volumes produced scale the subsequent asset capacities).

The following graphs show a division of each chain's cost in annualized CAPEX, fixed OPEX and variable OPEX for Morocco as an example to identify which factors are the cost drivers in the $LCoH_2$ per chain.

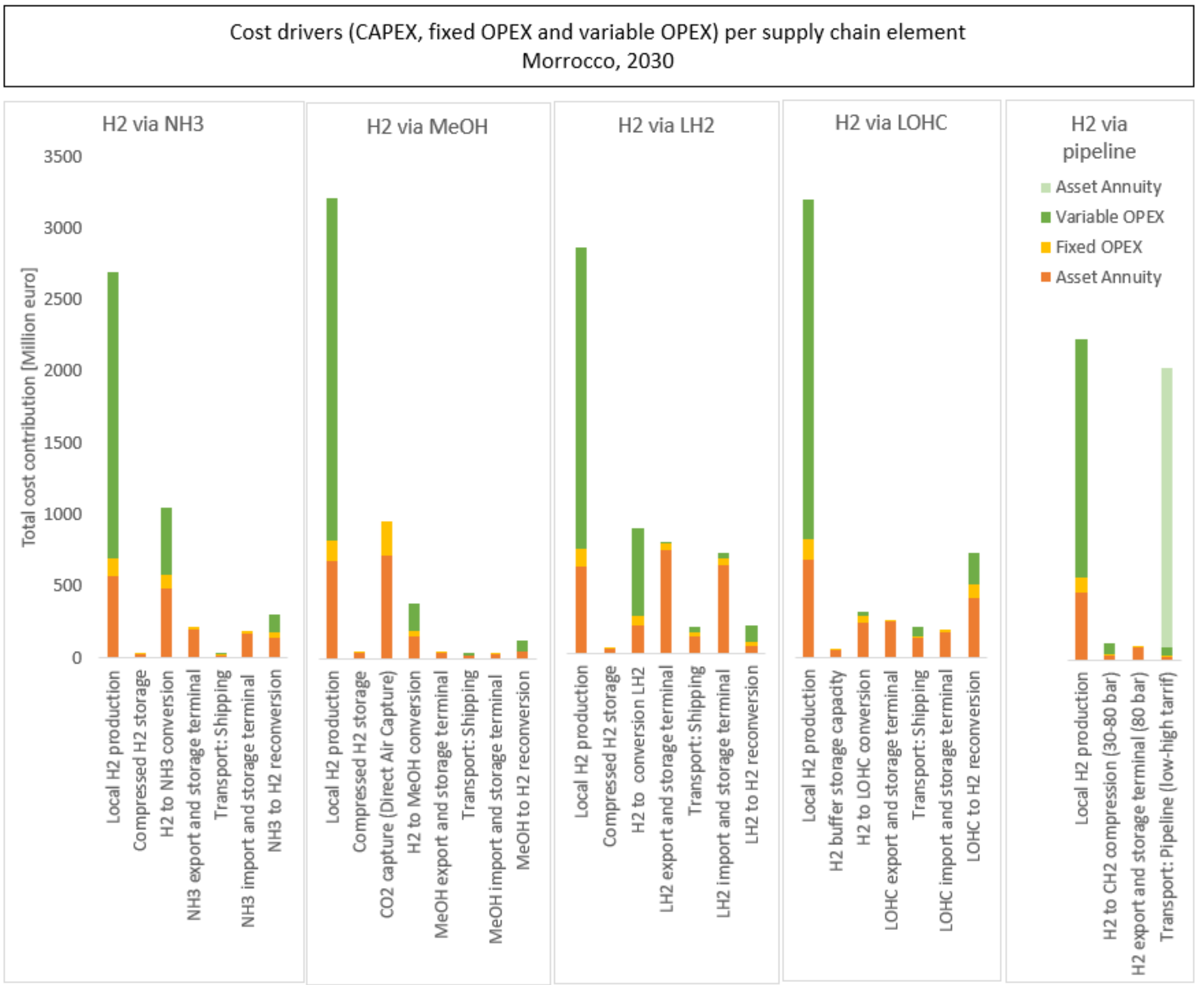



*Figure 9 High-level visualisation of cost drivers. Annualized CAPEX, fixed and variable OPEX per supply chain element.*

All costs shown are levelized costs which implies that the costs per unit of mass are directly related to the total amount of end-product delivered in the Netherlands. The higher the annual mass delivered, via for example a high round trip efficiency or a continuous hydrogen production instead of a RES-load-following approach, the lower the levelized costs. Continuous hydrogen production is not included in the scope of this research.

The variable OPEX accounts for the largest cost share within the total $H_2$ production step cost. That cost comes from electricity and it is predominantly dependent on LCoE. Additionally, variable OPEX accounts for 20% in MeOH, 40% in LOHC and 50% in $NH_3$ conversion steps, while it reaches up to 85% in $LH_2$ and $cH_2$ conversion. Again, this cost is mainly electricity that is dependent on LCoE and FLH. In shipping, the variable OPEX is usually around 50%, which comes energy supplied using the cargo as fuel. This cost can be improved by technological engine advancements. Variable OPEX in $cH_2$ transportation is based on a large spread of potential costs of high capacity pipeline network utilisation (60-2000 EUR/t $H_2$). This large spread of pipeline utilization costs is due to major uncertainties in the development of this infrastructure[9]. Finally, the variable OPEX of reconversion step is approximately 50% of the total reconversion step cost, and it is mainly heat supplied using the $H_2$ product, which

[9] Energy Transition Commission (2021) Making the hydrogen economy possible: accelerating clean hydrogen in an electrified economy, April 2021, V1.2

thereby reduces the efficiency of the step by 'cannibalizing' the end-product,  and a small amount of electricity.

CAPEX has a noticeable cost contribution in the $H_2$ production step of all chains, accounting for almost 20%. Technological improvements of the electrolysers can bring down this cost in the future. In the $NH_3$ chain, CAPEX accounts for 40% of the conversion and 50% of the reconversion step, but that corresponds to a small share of the total cost. In MeOH chain, the conversion step is highly CAPEX-dependent due to $CO_2$ capture facility that accounts for 70% of the conversion cost. In the $LH_2$ chain, the CAPEX is higher than the other chains for shipping and import/export terminals. The CAPEX of the chain accounts for more than 30% of the total chain cost, because of the special cryogenic equipment required for $LH_2$ storage and transport. The same increase in CAPEX of reconversion and shipping applies for the LOHC chain, due to the large LOHC volumes that need to be processed, whereas the CAPEX is minimal in the $cH_2$ chain, accounting for less than 15% of the total chain costs.

The lower OPEX cost contribution in the $LH_2$ and LOHC chains is compensated for by the increased share of CAPEX for handling $LH_2$ and LOHC, as discussed in the previous paragraphs. The increased contribution in $cH_2$ chain accounts to the lack of capital and operating cost requirements after production and the minimal costs of conversion and transportation. Shipping makes a worth mentioning impact only in the $LH_2$ and the LOHC chains, by increasing the CAPEX and less energetically favourable carrier consumption as a shipping fuel. Finally, FLH affects the total $H_2$ produced, which impacts all steps. The distance of the import country only has an impact in the LOHC chain, where the fuel requirements are more sensitive, because of the larger transport volume and the subsequently higher number of round trips.

Expressing the costs in terms of *levelized cost of hydrogen* is beneficial for comparisons. However, when investments in technologies are to be made, insights in the total installed costs and the yearly costs provides are more practical. In the example chain of $H_2$ via LOHC from Argentina in 2030 in the Table 1, the amount of assets required, their total installed costs and the yearly costs clearly show that large investments are required during the development process of a hydrogen import chain.

The investment costs for each asset that will need to be developed depend on four factors:
1) The technology-dependent purchase cost of equipment
2) The economy of scale effects for that specific technology
3) The installation costs, also commonly referred to as engineering, purchasing, construction and management (EPCm) costs, per asset
4) The interest rate

Coordination and alignment of design and development decisions between supply chain asset owners can bring down the upfront investment costs as well as the variable costs, based on these four factors: The optimization of the performance (OPEX) and designed capacity (CAPEX) of each individual supply chain element in relation to the characteristics of its neighboring chain elements (and externalities) is expected to improve the technological (e.g. efficiencies, mass flows) and economic performance (CAPEX, OPEX and interest rate due to lower investment risk) of supply chains as a whole.

*Table 0-1 Example of asset capacities, amounts of assets and annualized costs*

| *Chain: $H_2$ via LOHC, Argentina, 2030* | *No. of units* | *Designed capacity per unit* | *Total installed cost [M€]* | *Yearly costs [M€/y]* |
|---|---|---|---|---|
| *Local electricity generation plant: onshore wind+PV* | *1* | *2 GWe* | *n/a* | *n/a* |
| *Local $H_2$ production: Alkaline electrolyser plant* | *1* | *1.8 GWe* | *795* | *332* |
| *$H_2$ buffer storage* | *260* | *0.45 t H2 (g)* | *66* | *0.7* |
| *H2 to LOHC conversion plant* | *2* | *2579 ktpa MCH* | *280* | *11* |
| *LOHC export and storage terminal: MCH tank* | *4* | *38.5 kt MCH* | *152* | *1.2* |
| *LOHC export and storage terminal: TOL tank* | *3* | *43.4 kt TOL* | *122* | *1* |
| *LOHC export and storage terminal: Jetty* | *1* | *3000 ktpa* | *4* | *0.1* |
| *LOHC export and storage terminal: Loading facilities* | *1* | *3000 ktpa* | *13* | *0.3* |
| *Transport: MCH bulk carrier vessel* | *4* | *101 kt MCH* | *460* | *35.6* |
| *LOHC import and storage terminal: MCH tank* | *4* | *38.5 kt MCH* | *152* | *1.2* |
| *LOHC import and storage terminal: TOL tank* | *3* | *43.4 kt TOL* | *122* | *1* |
| *LOHC import and storage terminal: Jetty* | *1* | *3000 ktpa* | *4* | *0.1* |
| *LOHC import and storage terminal: Loading facilities* | *1* | *3000 ktpa* | *13* | *0.3* |
| *LOHC to $H_2$ reconversion: dehydrogenation plant* | *1* | *3131 ktpa MCH* | *490* | *28* |
| *LOHC to $H_2$ reconversion: hydrogen compressor* | *2* | *29 MWe* | *63* | *15.5* |

## Key insight 3: Supply chain efficiencies and load-following hydrogen production volumes illustrate the importance of maximizing the mass flows of molecules

The levelized cost of $H_2$ is the hydrogen cost per mass of hydrogen. Key insight 1 and 2 focussed on the economic perspective of hydrogen import. By adding insights on the total amount of hydrogen that becomes available for end-users per supply chain, a more complete view is established regarding the import chains.

Improvement of the process efficiency in the power-to-hydrogen, hydrogen-to-X and X-to-hydrogen steps would lead to savings in cost and energy. Improvements in these processes may, however, be thermodynamically challenging and/or costly.

Maximization of the full load hours of each asset along the supply chain is also of major importance. The higher the utilization rate of the power-to-hydrogen process, the more constant the hydrogen production annually. And consequentially, the larger the mass flow of hydrogen carriers towards the Netherlands, which drives down the $LCoH_2$.

The supply chain configuration in this study is a forward-moving flow of energy carriers: starting with electrons, followed by hydrogen and different types of hydrogen carriers, and ultimately converted back to hydrogen (or remaining in their carrier form). Figure 10 illustrates this chain.

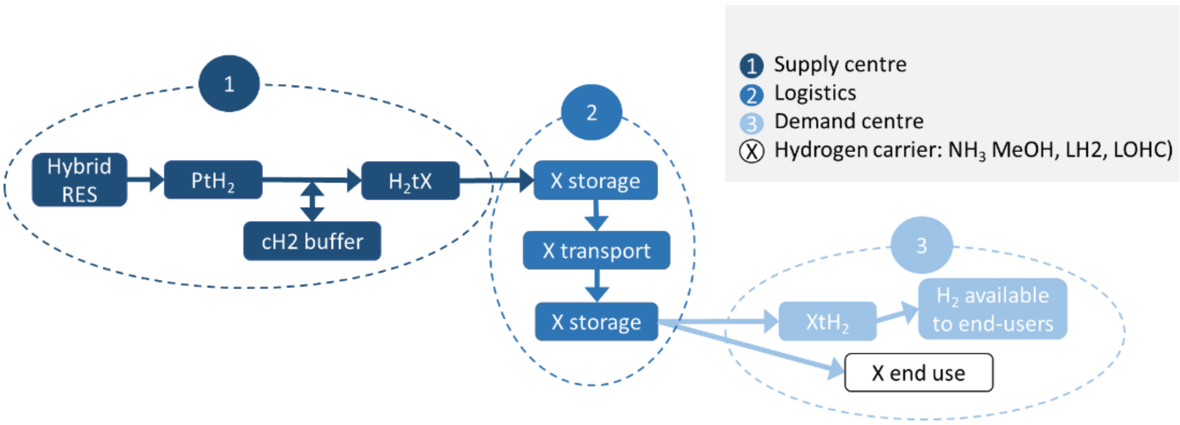



*Figure 10 Visualisation of the supply chain under consideration in the project scope*

As already introduced in the previous section, the overall energy efficiency is a valuable perspective to evaluate the performance of each chain. The higher the round-trip efficiencies[10], the larger the amount of energy (mass of hydrogen) that will be available to end-users in the Netherlands. In each supply chain element, losses are to be expected. Figure 11 shows the efficiency losses for each supply chain step for the five chains (taking Morocco as an example). $CH_2$ shows the highest energy efficiency followed by LOHC. $NH_3$ and MeOH are ranked third due to higher losses in conversion and reconversion steps. Finally, $LH_2$ chain shows the lowest energy efficiency due to the high power consumption in the $H_2$ to $LH_2$ conversion step. This graph can help identify the steps that can benefit from technological advancements. As we can see, $H_2$ production and $H_2$-to-X conversion are the most energy inefficient steps, while also the most cost intensive, as presented in key insight 2. Hence, improvement of the

[10] The round-trip efficiency is the efficiency of all individual supply chain steps combined by multiplying each individual efficiency.

process efficiency in these steps would lead to savings in cost and energy. Improvements in certain processes may, however, be thermodynamically challenging and/or costly.

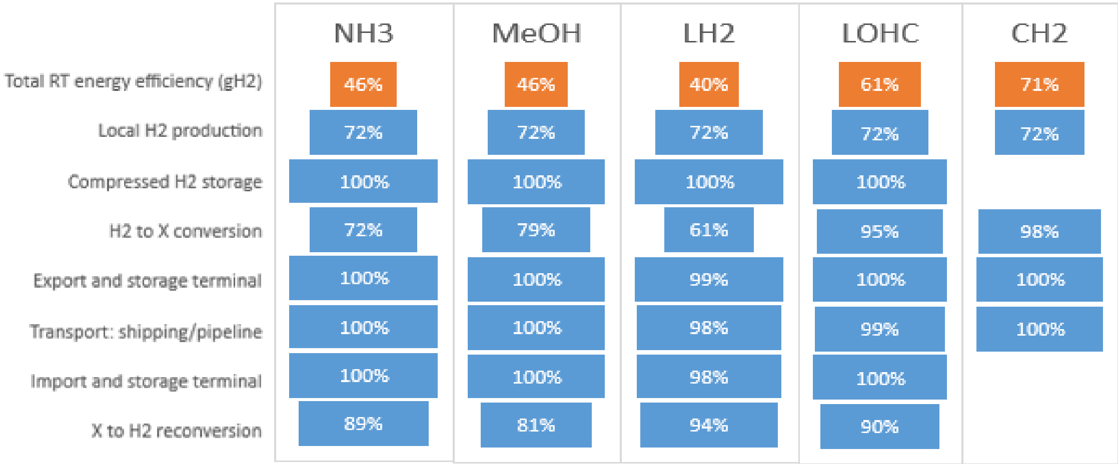



*Figure 11: Breakdown of overall efficiency for every chain for the reference country of Morocco*

Imported hydrogen, ammonia or methanol can have many end-use purposes[11]. For the envisioned end-users the price of the product is important, but other factors are of importance as well: e.g. the *quality* of the product, *how much* mass is imported, and *how consistent* (or secured) this imported flow of the product is.

[11] See D7A.2 appendix E market dynamics

## Key insight 4: Current uncertainties in technology-specific costs lead to large spreads of cost estimates

Cost estimates for hydrogen depend on many elements, amongst which CAPEX, efficiencies and the cost of electricity. The future values of these elements are uncertain. Developments, innovation and scale-up is taking place or expected for most technologies within the hydrogen value chain. As such, CAPEX is expected to decrease and efficiency is expected to increase. The subsequent question that is often raised is: how low may costs go? And how uncertain are current elements that, together, determine the cost of hydrogen? Taking into account these uncertainties gives us a range of plausible future costs of hydrogen.

Current uncertainties in the techno-economic input parameters of many assets in the supply chains lead to large spreads of cost estimates.

Results in this study are on the expensive end of the cost ranges in benchmark studies.

The aggressive uncertainty analysis shows that imported $LCoH_2$ estimations with optimal site specific conditions and optimized and integrated assets can be lower.

In our study, we distinguish two types of uncertainties: technical and fundamental. Technical uncertainties can be influenced, e.g. by stimulating innovation the efficiency can be improved, or mass production can lower the CAPEX of assets. Fundamental uncertainties cannot be influenced, e.g. the number of Full Load Hours (FLHs) for a wind farm asset can be higher or lower than predicted throughout a year and the wind yield may change in the decades to come due to the consequences of climate change.
The price of hydrogen will become less uncertain once we get closer to the point in time where investment decisions are made. Uncertainties may decrease over time. (Most of the) technical uncertainties are not uncertain anymore once the investment is made. In the year 2021, the CAPEX of an electrolyzer in 2030 is uncertain but it becomes less uncertain up to the point where it's actual value is known in 2030. However, there always remains some fundamental uncertainty as the actual FLHs of wind for the entire year of 2030 are still relatively unknown at January 1$^{st}$ of 2030.

To provide insight in the current uncertainty range of our cost estimates, the five figures below shows the effect of the CAPEX (technical), LCoE and FLH (fundamental) uncertainties on the cost of hydrogen per carrier ($H_2$ via $NH_3$; MeOH; L $H_2$; LOHC and pipe). The left blue bar represents the average cost of hydrogen without sensitivity range: the base value. The CAPEX, LCoE and FLH can have a **positive** effect and a **negative** effect on the cost of hydrogen, displayed by the green and red bars. Lastly, summing these uncertainties results in the minimum and maximum costs of hydrogen.

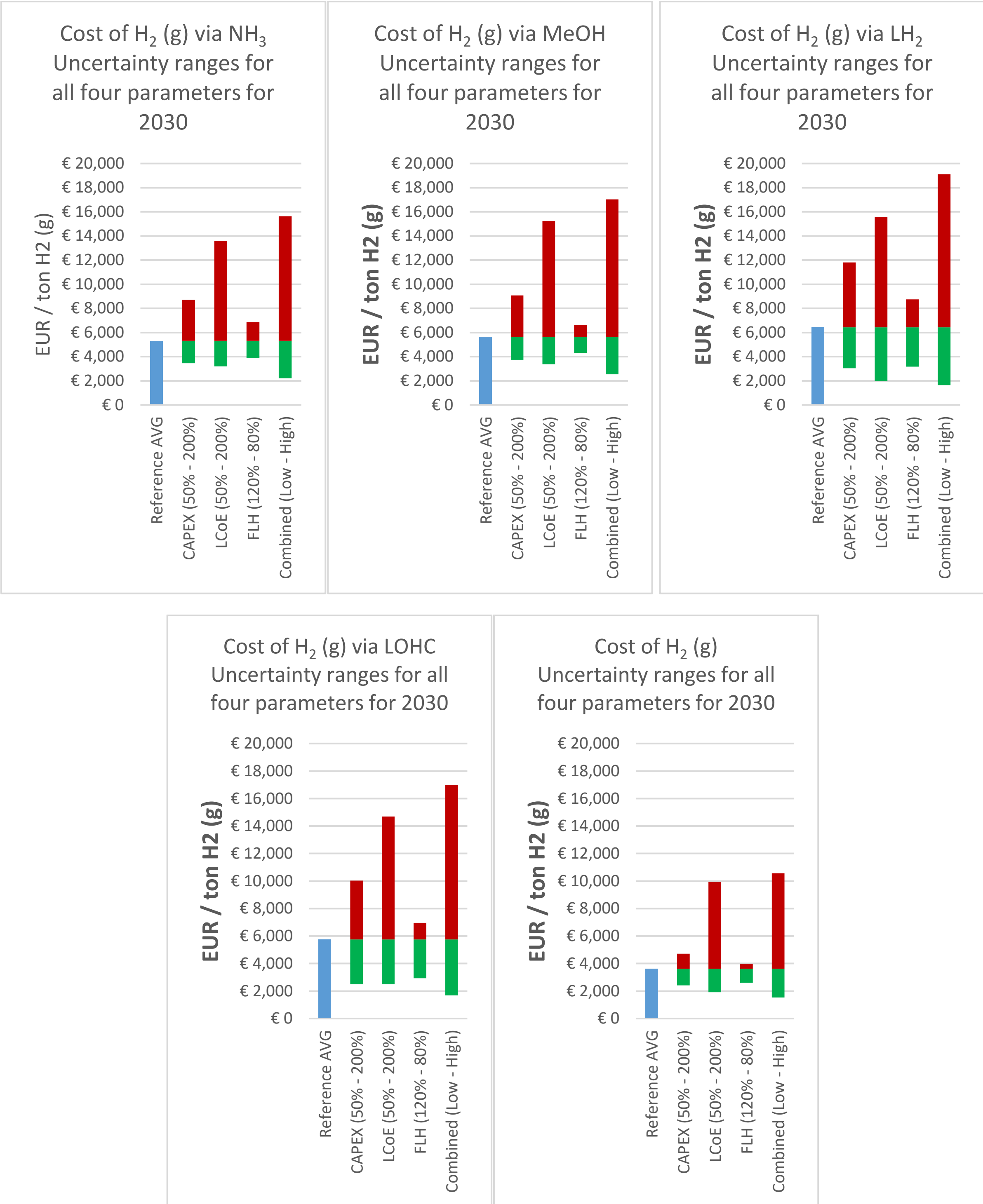



*Figure 12 – Uncertainty ranges per carrier type for all countries. Blue represents the average value for all countries, green the lowest cost estimate for all countries, and red the highest cost estimate for all countries*

It can be concluded that for all carriers, changing the LCoE input data results in the largest uncertainty. In all cases the 50% LCoE value approximately halves the $H_2$ import cost, whereas the 200% LCoE value sometimes almost triples it. Secondly, CAPEX plays a large role in especially the $H_2$import cost via $LH_2$ and LOHC. Lastly, the FLH have a minimal effect on the $H_2$import cost for all carriers.

To put this uncertainty range into perspective we performed a benchmark study where we compared our $H_2$ import cost results with comparable studies from other research and consultancy organizations. This benchmark exercise was done on two levels: looking solely at the cost of hydrogen production as well as looking at the complete landed cost of hydrogen.

Figure 13 below shows the benchmark results of green hydrogen production. The graph shows that our SCM results are on the higher end of the spectrum. For both 2030 and 2040 our low and average cost estimate are above the average benchmark value, showing that our results are a little less optimistic than what we find in comparable studies.

Secondly, Figure 14 shows the benchmark results of the full supply chain costs; hydrogen production as well as the conversion, import, storage, export and reconversion steps. In this figure we see a similar trend, with our low cost estimate close to the average value. However, now our average cost estimate is significantly higher than the benchmark studies, and falls without the range.

From these two graphs it can be concluded that our results are on the expensive end, compared to other studies. An extensive comparison of the underlying assumptions and modeling logic is required to explain the differences in outcomes. Such a comparison was out of the scope of this study.

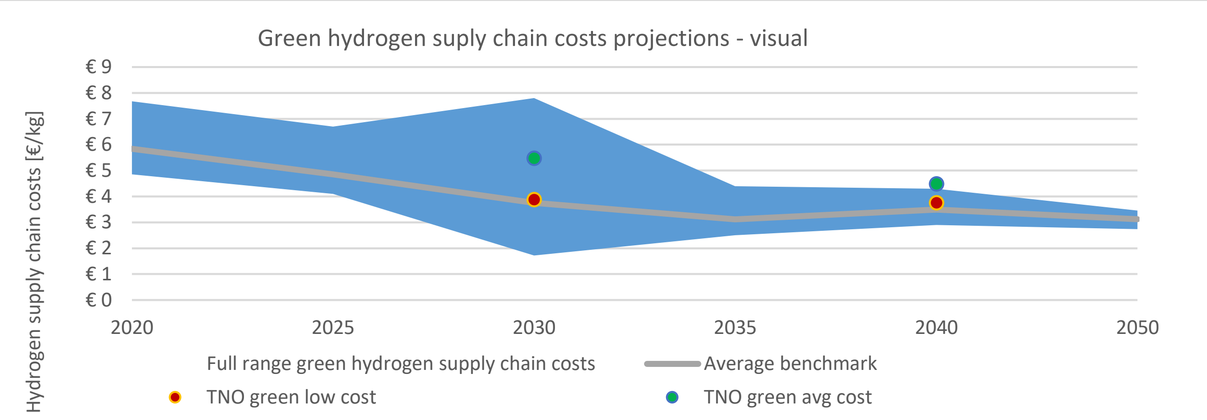



*Figure 13 – Benchmark of hydrogen supply chain costs including production. The blue area is an area plot of all benchmark studies, the yellow line shows the average of all benchmark studies, the orange and the green dot show the minimum and average cost estimation from our analysis respectively.*

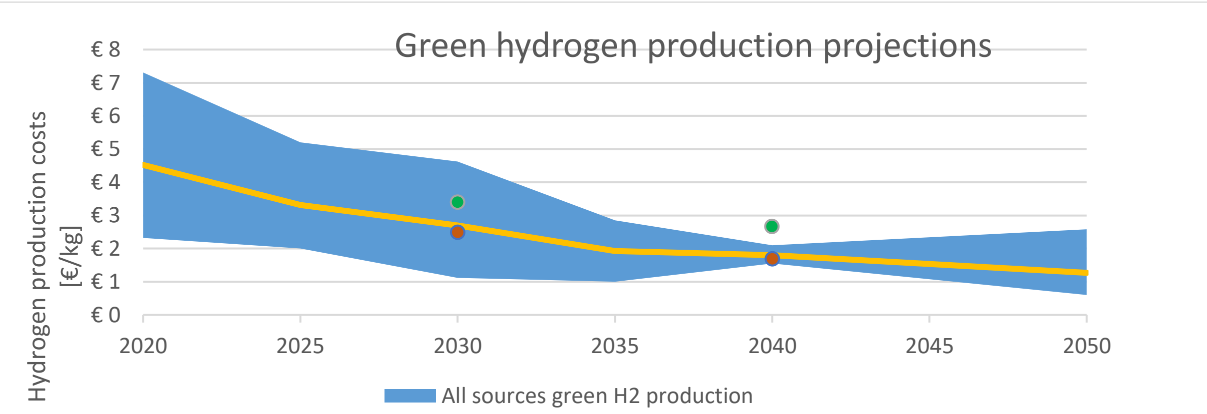



*Figure 14 Benchmark of hydrogen productions costs. The blue area is an area plot of all benchmark studies, the yellow line shows the average of all benchmark studies, the orange and the green dot show the minimum and average cost estimation from our analysis respectively.*

# 3. Extensive presentation of results

In this chapter the economic analysis of importing various hydrogen carriers from countries around the world to the Netherlands is presented. E-ammonia ($NH_3$), e-methanol (MeOH), liquid hydrogen ( $LH_2$), a liquid organic hydrogen carrier (LOHC) via bulk vessel transport, and compressed hydrogen via pipeline transport are incorporated in the analysis. The costs of importing e-ammonia and e-methanol for feedstock purposes as well as hydrogen carrier purposes is included in the analysis. When hydrogen as an end-product is considered, it is assumed to be gaseous hydrogen of 70 bar in the Port of Rotterdam as a reference location.

A levelized cost of hydrogen ($LCoH_2$) was determined for each hydrogen carrier import chain. This $LCoH_2$ is determined by dividing the annual chain cost by the annual amount of gaseous 70 bar hydrogen landed in Rotterdam. The levelized cost of hydrogen is found through:

$$LCoH_2\left[\frac{€}{ton}\right] = \frac{\sum\frac{annual\ cost\ of\ capital + fixed\ OPEX + variable\ OPEX}{(1+i)^n}}{\sum\frac{hydrogen\ produced}{(1+i)^n}}.$$

A similar approach leads us to the cost of one ton of ammonia or methanol when this commodity is not reconverted to hydrogen.

## 3.1 Overview of the $LCoH_2$ and supply chain cost breakdowns

For each hydrogen, ammonia or methanol import route we calculated the cost per imported kilogram or ton of hydrogen gas (70 bar), ammonia or methanol. The graphs below illustrate the range of these costs for the imported products from 9 different arche-type countries for 2030 and 2040 respectively.

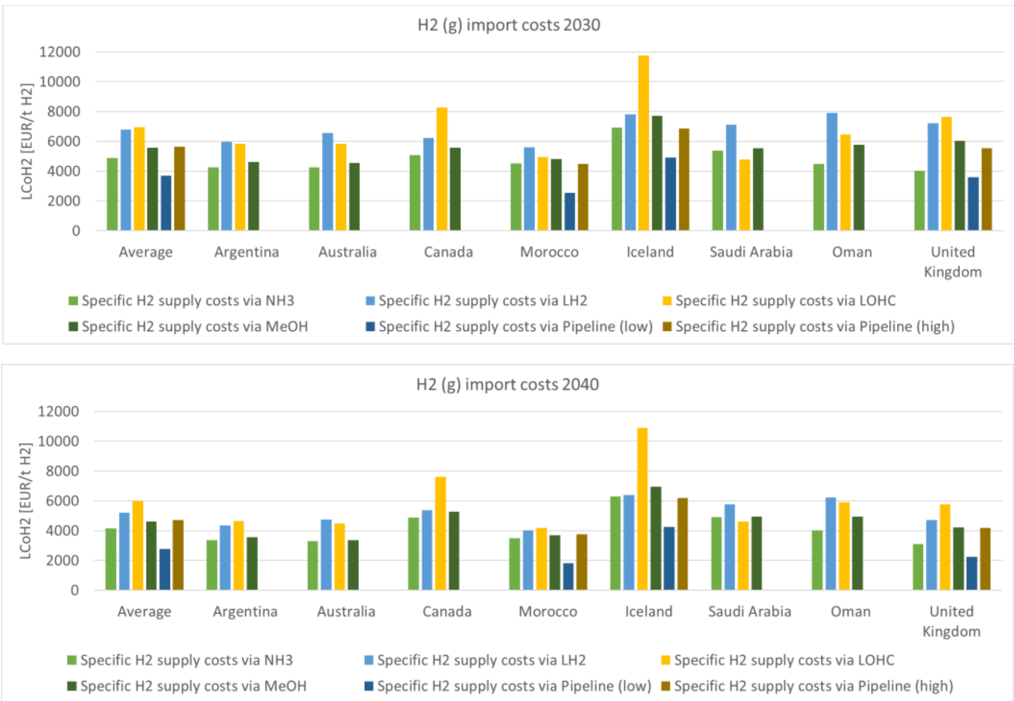



*Figure 15 - Costs ranges for the imported products from 9 different arche-type countries for 2030 (top) and 2040 (bottom)*

By zooming in on the individual supply chain cost estimates, one can gain insight in the prominent cost driving supply chain elements. The Figure 16 below illustrates the supply chain cost breakdown of the ammonia route from Argentina (134 ktpa $H_2$), Iceland (255 ktpa $H_2$) and the United Kingdom (144 ktpa ($H_2$) to the Netherlands in 2030, assuming an extrapolated identical operation of the supply chain for 20 years.

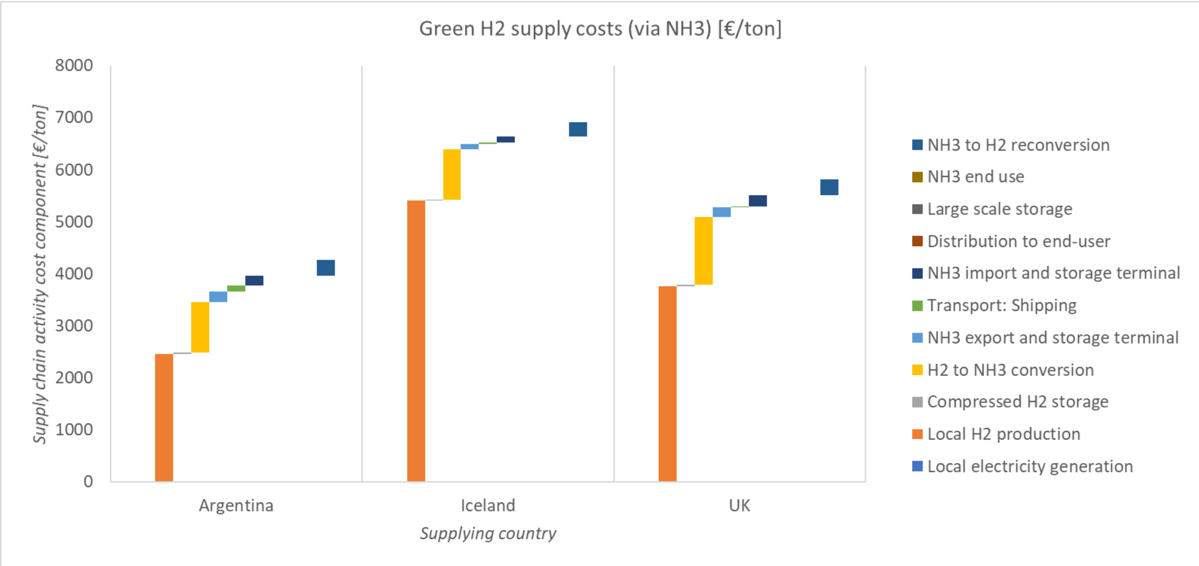



*Figure 16 - the supply chain cost breakdown of the $H_2$ from $NH_3$ route from Argentina, Iceland and UK in 2030*

From this figure it can be concluded that in all three cases the local $H_2$ production has by far the largest cost contribution to the supply chain cost breakdown followed by hydrogen to ammonia conversion and subsequently ammonia to hydrogen reconversion.

We are able to dig one level of detail deeper and thereby identify the cost components for each supply chain element. As discussed in the chapter introduction, the chain costs consist of three components:

- the *asset annuity*, which describes the part of the investment cost which is discounted over the entire operational lifetime
- the *fixed operational expenses* (OPEX), which holds the annual fixed maintenance cost per chain element
- the *variable OPEX* of assets, which represents the consumption costs of, for example, electricity or fuel to deliver a required function of the supply chain step.

The Figure 17 below shows the cost components for each supply chain element in more detail for the same ammonia route from the United Kingdom to the Netherlands in 2030. The figure shows that within the local hydrogen production cost element, the variable OPEX contribute the most. A similar observation can be made for the hydrogen to ammonia reconversion cost element. Lastly, the fixed operational expenses contribute little to the overall costs.

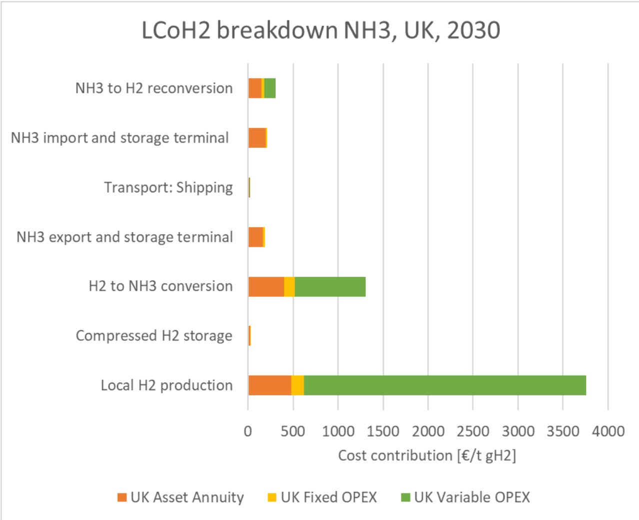



*Figure 17- Cost components for each supply chain element of the $NH_3$ route from UK to Rotterdam in 2030*

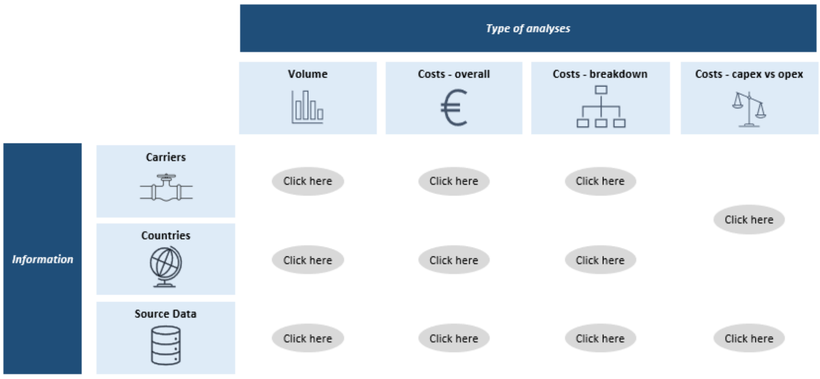
## 3.2 Results of the cost calculation of imported ammonia, methanol and hydrogen

For the sake of clarity we decided not to present the results for all cost calculations in this report, as this would result in an enormous amount of graphs. A detailed overview of the cost calculation results for all supply chain variations can be generated with the available *HyDelta Import Analysis Result dashboard*, containing an interactive drop down menu that enables the user to generate results for every possible supply chain, carrier and reference year combination that has been studied.

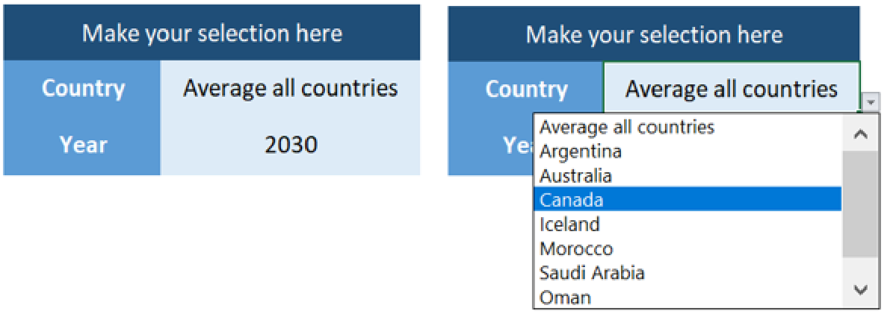
The *HyDelta Import Analysis Result dashboard* is built to present results of all different countries and hydrogen carriers. The tool consist of six sheets:

1. Overall cost of landed commodity per carrier
2. Overall cost of landed commodity per country
3. Volumes landed commodity per carrier
4. Volumes landed  commodity per country
5. Overall cost of landed commodity per carrier
6. Overall cost of landed commodity per country
7. Overall cost of landed commodity per cost type

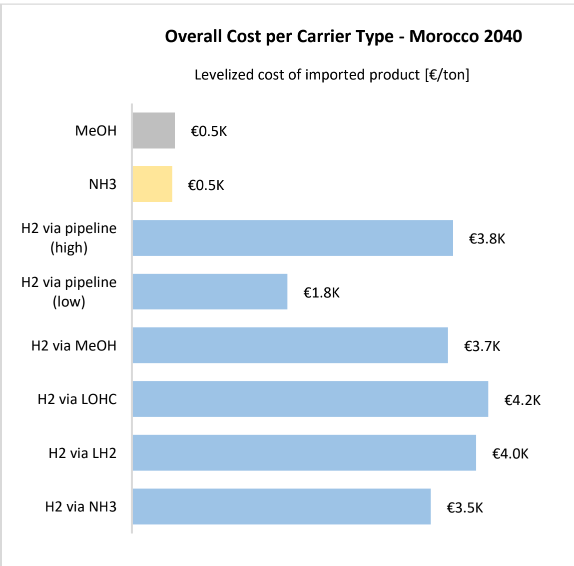
Using the interactive cover page one can easily walk through the different graphs, choosing for carriers, countries or source data under **Information** on the left side or volume, costs-overall, costs-breakdown or costs-capex vs opex under **Type of analyses** at the top. Clicking the desired match directly takes you to the correct sheet and graphs.

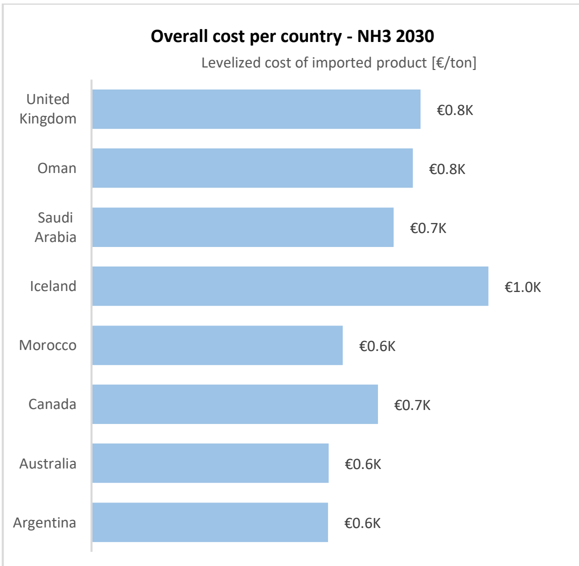



Every sheet has user friendly dropdown menu where a carrier, country and/or year can be selected to generate the corresponding graph. Below a quick run trough of all the graphs is explained.

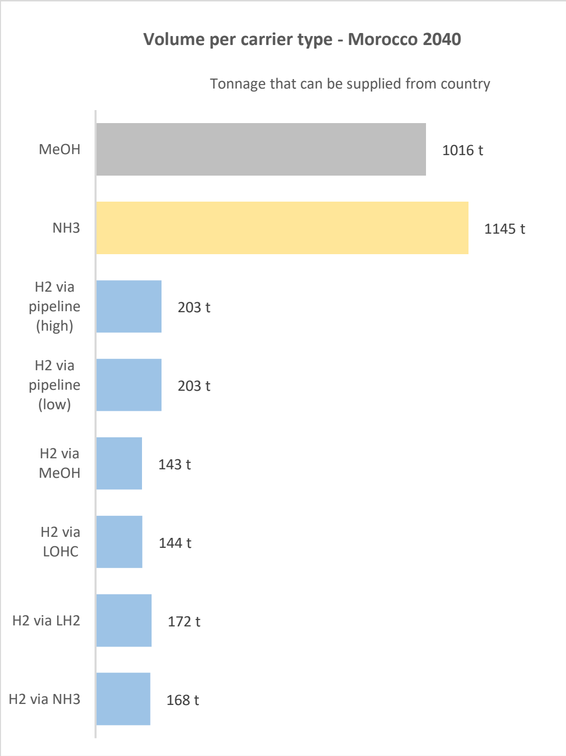


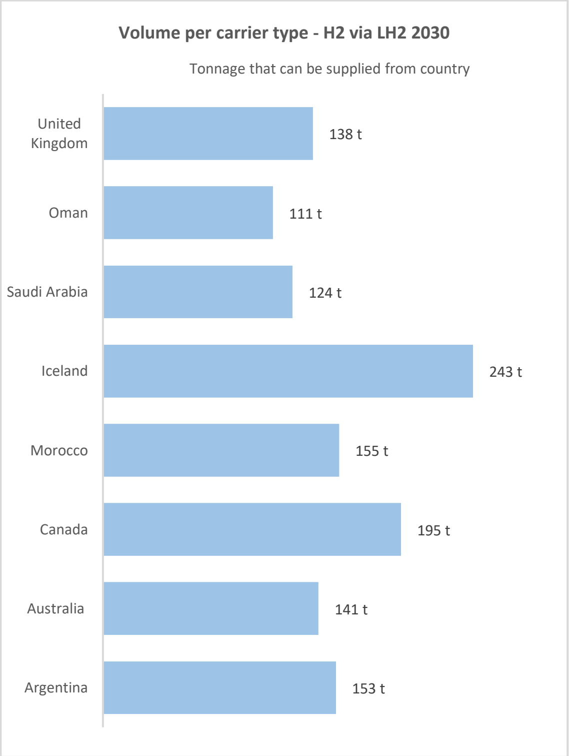

**Graph 1 and 2: Overall cost of landed commodity per carrier and country.** The overall cost graphs present the overall landed costs of hydrogen, ammonia or methanol depending on the carrier or import route.



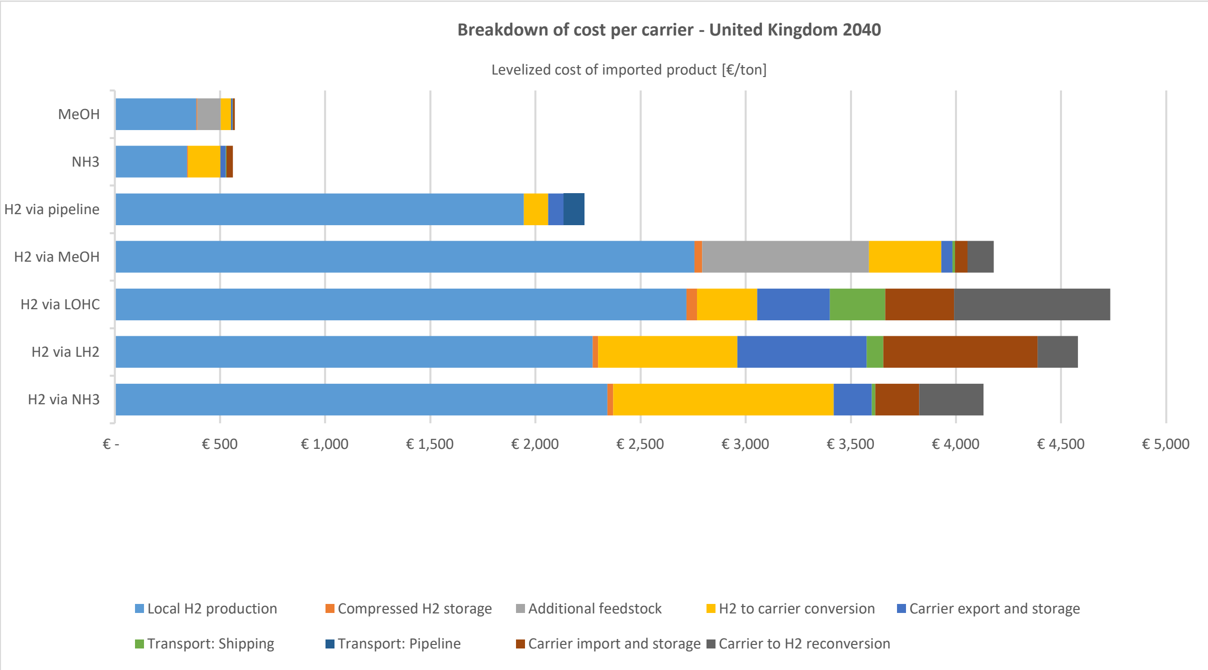



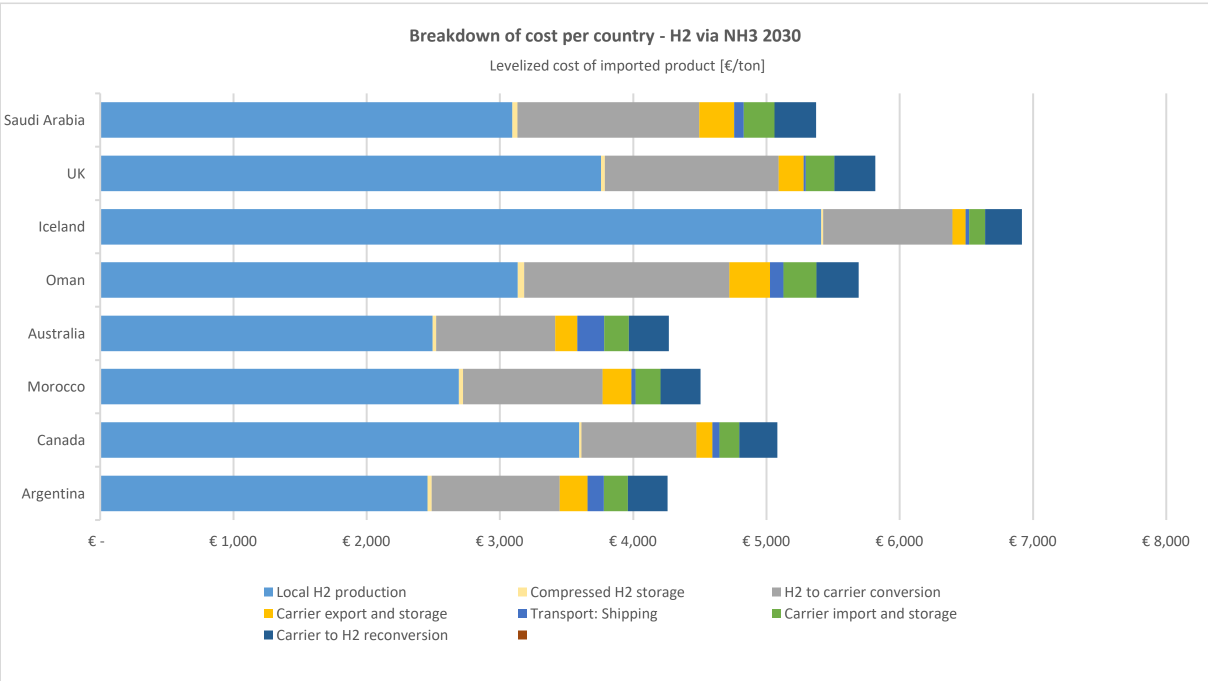

**Graph 3 and 4: Volumes landed commodity per carrier & country.** These volumes graphs provide insight in how much hydrogen, ammonia or methanol arrives in Rotterdam, giving insight in the overall energy efficiency to evaluate the performance of each chain and import route.


Volume per carrier type - Morocco 2040
Tonnage that can be supplied from country
MeOH
1016 t
NH3
1145 t
H2 via pipeline (high)
203 t
H2 via pipeline (low)
203 t
H2 via MeOH
143 t
H2 via LOHC
144 t
H2 via LH2
172 t
H2 via NH3
168 t

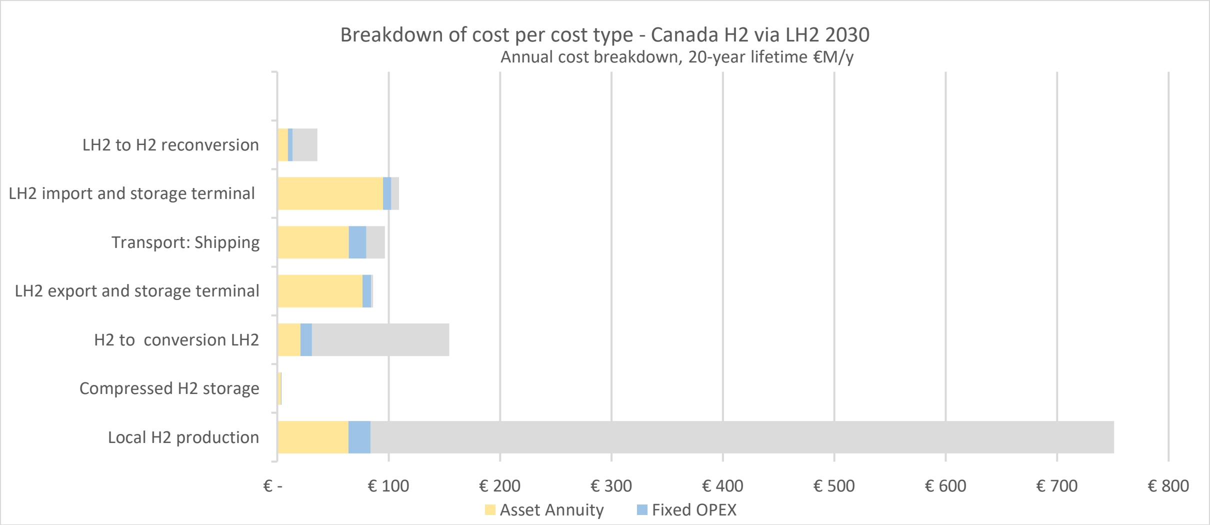

Volume per carrier type - H2 via LH2 2030
Tonnage that can be supplied from country
United Kingdom
138 t
Oman
111 t
Saudi Arabia
124 t
Iceland
243 t
Morocco
155 t
Canada
195 t
Australia
141 t
Argentina
153 t

**Graph 5 and 6: Levelized and annual cost breakdown per supply chain element per carrier per country.** The levelized and annual cost breakdown graph show the cost contribution for every supply chain element. The tool enables users to select different carriers and/or countries to compare what are the most important cost contributions per carrier and country.



**Graph 7: Cost breakdown per supply chain element per cost type.** This graph highlights the different cost types for every supply chain element. The three cost types presented are asset annuity, fixed and variable operational expenses. The graph shows the annual cost breakdown in million euros per year, assuming a 20 year lifetime.




## 3.3 Analysis and interpretation of the LCoH₂ results

Overall, we find that there is no clear consistency in the lowest cost estimates for country-carriers combinations. To clarify this, the two sections below give an overview of all results per carrier type and subsequently per country.

Note that all these levelized cost ranges largely ignore required demand profiles, safety, regulation and maturity and availability of the technology, as these requirements might justify higher import prices.

**$LCoH_2$ per carrier type:** Grouping all the levelized cost results for all countries in a boxplot shows that – on average – hydrogen transport using a pipeline is the cheapest option. For import routes that rely on shipping ammonia seems to be the cheapest carrier, followed by methanol, LOHC and liquid hydrogen. It is important to note that the cost ranges caused by the various import countries overlap, which makes it complex to draw hard conclusions. For example: importing hydrogen through LOHC *can* be cheaper than ammonia, but it is more likely that import through ammonia will be the cheaper option.

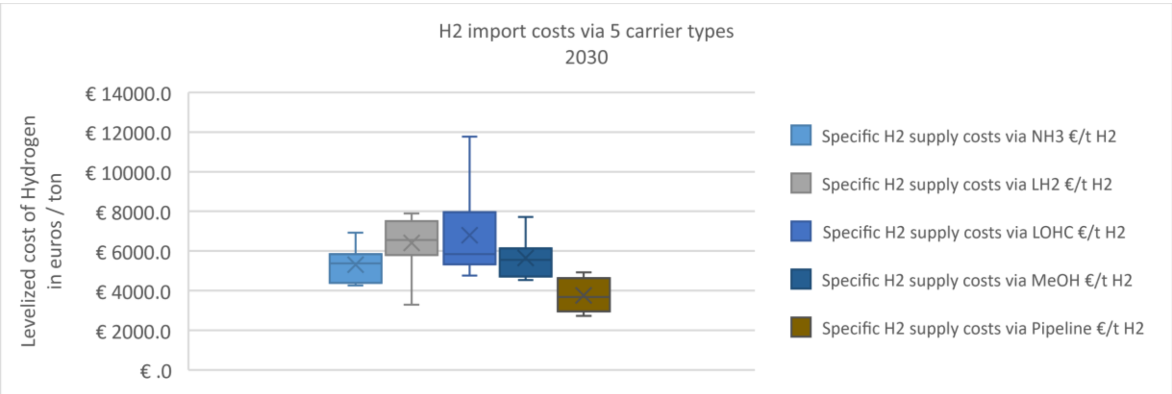



*Figure 18– levelized cost of hydrogen via 5 carrier types*

Without the aim to reconvert ammonia and methanol to $H_2$, we see a smaller cost spread that follows the same cost reduction trend as the other hydrogen carriers.

**$LCoH_2$ per country:** Visualizing the levelized cost results for all eight import routes on a global map gives the following overview. The figure shows that for 2030 the $LCoH_2$ is expected to be within 3.60 – 12 € per kg, and for 2040 between 2.20 – 11 € per kg. Again, there is a large overlap between the $LCoH_2$ from the eight import routes, which makes it difficult to favour one over the other. The figure also shows that – on average – domestic production of $H_2$ without carrier conversion has lower costs than importing hydrogen carriers with ships or hydrogen pipelines.

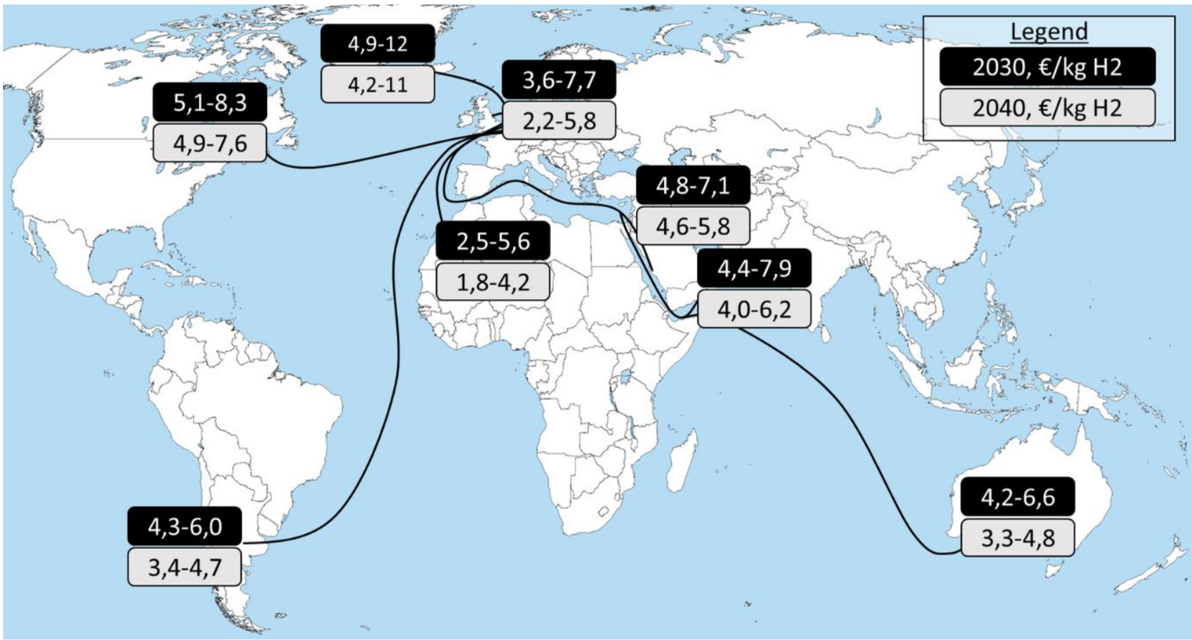



*Figure 19– Visualization of cost ranges per import route for 2030 (black box) and 2040 (grey box)*

As explained in paragraph 3.2 the *HyDelta Import Analysis Result dashboard* enables users to generate detailed comparative results for every cross-cut of the datset.

# 4. Sensitivity and uncertainty analysis of the estimated costs

Although all input data is collected with great care and detail, data uncertainty remains an issue. In order to highlight this, we assess the sensitivity of the supply chain model on the input data (4.1 and 4.2) and the uncertainty of the model inputs (4.3).

## 4.1 Methodology of the sensitivity analysis

The cost of hydrogen depends on many elements, e.g. CAPEX, efficiencies and the cost of electricity. For most technologies, developments and innovation is taking place. As such, CAPEX is expected to decrease and efficiency is expected to increase, but the question arises: by how much? For many of these elements we can make a fair prediction, but especially future values are uncertain. To enable us to analyse which parameter affects the end result – being the cost of hydrogen production and import – the most, we perform a sensitivity analysis. This analysis shows how which factors affect the output and gives a range of possible costs.

For this sensitivity analysis, we distinguish two types of uncertainties: technical and fundamental. Examples of technical uncertainties are CAPEX and efficiency. Whereas an example of fundamental uncertainties are the number of Full Load Hours (FLHs) for an asset. Technical uncertainties can be influenced, e.g. by stimulating innovation the efficiency can be improved. Fundamental uncertainties cannot be influenced, e.g. the FLHs of wind can be higher or lower in a year. Furthermore, (most of) the technical uncertainties are not uncertain anymore once the investment is made. In 2020 the CAPEX of an electrolyser in 2030 is uncertain, it becomes less uncertain in 2025 and is known in 2030. However, the FLHs of wind in 2030 is still unknown in 2030. Consequently the price of hydrogen will become less uncertain once we get closer to the investment decision, however, always some uncertainty remains.

For the sake of readability, not all countries and parameters are included in the sensitivity analysis, as this would simply result in a too complex assessment. We analyse a total of 336 scenarios:

- Seven import chains;
- Two points in time: 2030 and 2040;
- Six countries: Argentina, Australia, Canada, Iceland, Morocco and Saudi Arabia representing a diverse mix of input RES, transport modalities and distances.

And by varying the following parameters:

- LCoE of the RES (50%, 100% and 200%), [fundamental]
- The combined FLH of the RES (80%, 100% and 120%), [fundamental]
- The combined CAPEX of all investments (50%, 100% and 200%), [technical]
- The combined effect of all three previous parameters to identify the combined uncertainties.

## 4.2 Results of the sensitivity analysis

Instead of plotting numerous graphs showing the sensitivity of a single parameter on a single case, this analysis aims to highlight the overall uncertainty range combined with the sensitivity of the three parameters. Therefore, the results are accumulated in one graph, highlighting the total sensitivity effect of each parameter. In the figure below the left bar represents the average cost of hydrogen without sensitivity range (the average of all seven import chains): the base value. From there we add the technical uncertainties, by varying the CAPEX parameter. The green bar shows the sensitivity result for 50% CAPEX and the red bar for 200% CAPEX, which results in costs with technical uncertainties. The same is done for the LCoE and FLH, resulting in the costs with the fundamental uncertainties. Finally, the combined effect is presented in the right most bar, displaying the overall minimum and maximum costs of hydrogen.

Figure 20 below shows the uncertainty ranges for the cost of hydrogen import for 2030 (left) and 2040 (right). For both years it can be noted that a change in LCoE input data affects the cost of hydrogen import the most, followed by CAPEX and then FLH (ignoring the different sensitivity percentage for FLH, which is chosen to prevent FLH scenarios > 8760h).

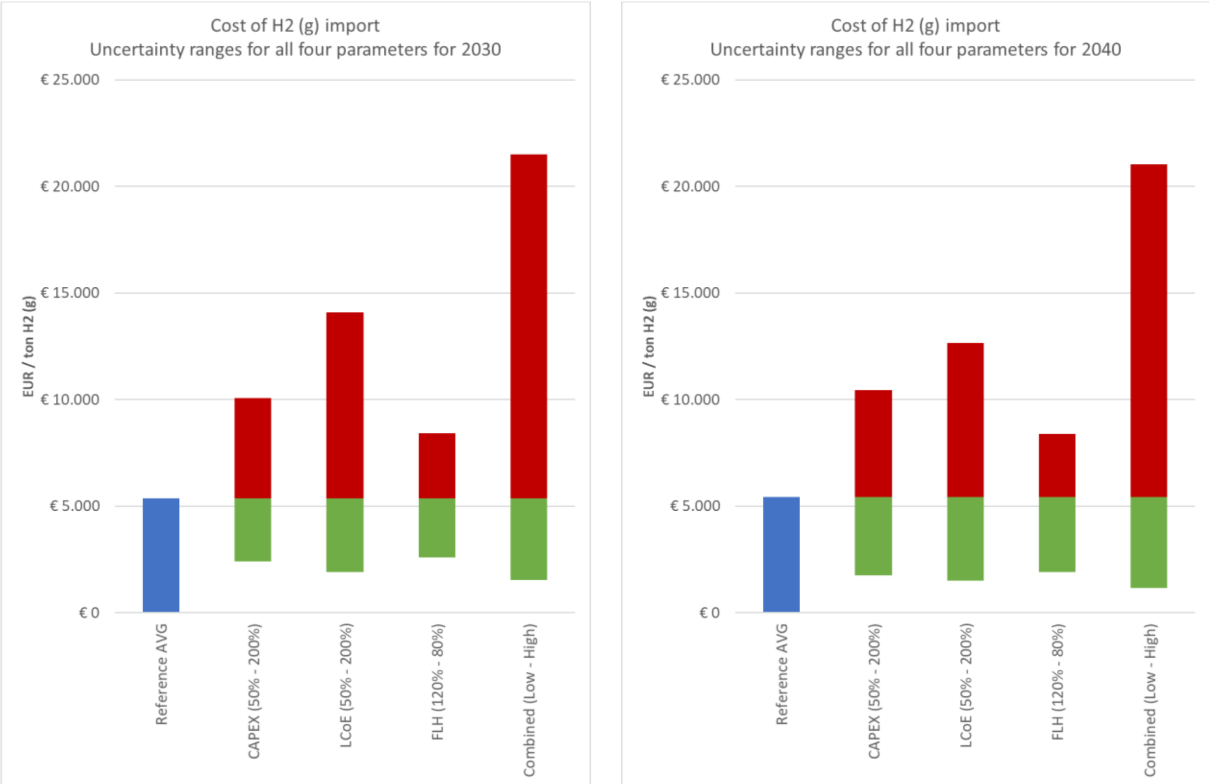



*Figure 20 uncertainty ranges for the LCoH$_2$ 2030 and 2040*

Since the results in Figure 20 include mixed results from hydrogen import through shipping and pipeline, two separate graphs are presented in Figure 21; showing the cost of hydrogen via ship (left) and via pipeline (middle). Also, a single scenario showing import of hydrogen through $NH_3$ from Marocco is presented, to highlight that the sensitivity ranges on a country level fluctuate significantly less.

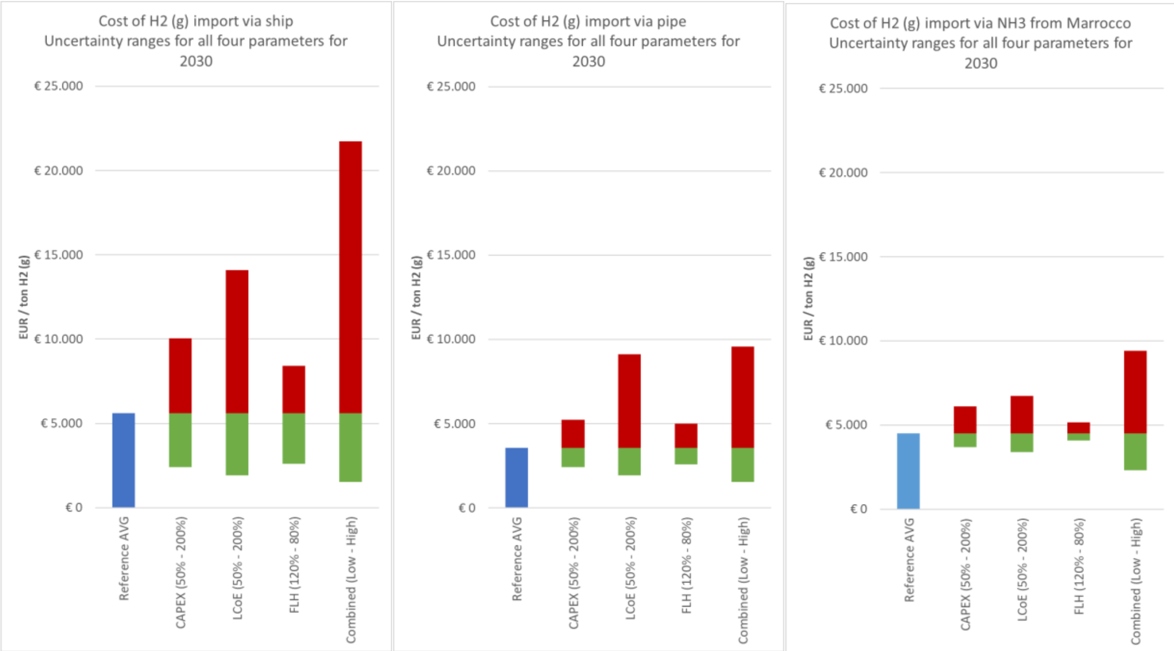



*Figure 21 2030 uncertainty ranges for the LCoH for all ship import routes, all pipe import routes and one single scenario example of hydrogen import through $NH_3$ from Morocco*

## 4.3 Anticipating on the uncertainty of input data availability

For some technologies the currently available input data is limited. In these cases, import nuances such as e.g. improvement over time is not included in the data sheets. Future cost projections are therefore anticipated to be less accurate. In order to highlight this shortcoming of the current study, we have analyzed for which technologies we i) currently have no data available and ii) anticipate a cost reduction in the future. In the table below, an overview is given for all technology data sheets: the column *Data available* indicates whether there is future data available and the column *Cost reduction* lists whether we anticipate a significant cost reduction in the near future. Future research should focus on obtaining more detailed and practice-based data on these technologies, which can partially reduce uncertainties.

# 5. Extensive presentation of validation with comparable studies

In this chapter, the outcomes of the study are compared to other reputable studies with similar objectives.

## 5.1 Validation of green hydrogen production cost estimates

For the validation of green hydrogen production cost estimates, various comparable studies have been assessed. In graph Figure 22 below an overview of the estimated production costs between 2020 and 2050 are presented, with a single data point in time per study. The studies included can vary in scope (e.g. RES technology, electrolysis process, etc.) and their identification is not part of this comparison exercise. In the benchmark sources such as IEA, Aurora Energy Research, McKinsey Hydrogen Council, Guidehouse, IRENA, Roland Berger, Fraunhofer, EWI, ETC, KBR Argus, CE Delft as well as previous TNO studies are included. To compare, the blue and yellow bars show the final average results of the current TNO and NEC study respectively.

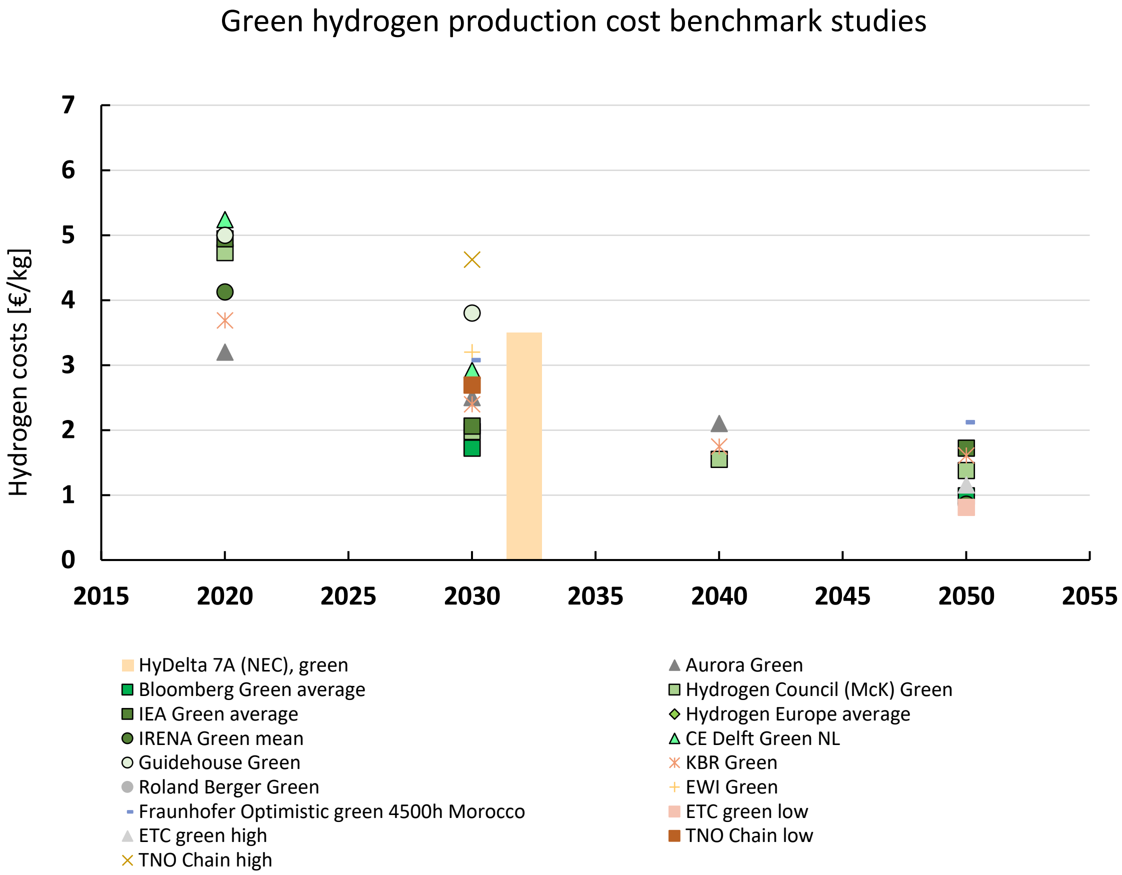



*Figure 22 Benchmark of hydrogen productions costs showing individual studies*

For the sake of readability this graph has been modified to the one below, where the blue area shows the range of benchmark datapoints, with the bottom line representing the lowest value, and the top line the highest. From this, it can be concluded that the TNO study shows results comparable to the range of benchmark cost projections; the average cost of green hydrogen produced we are at the higher part of the spectrum, and for the lowest green hydrogen production option we are a little below the average.

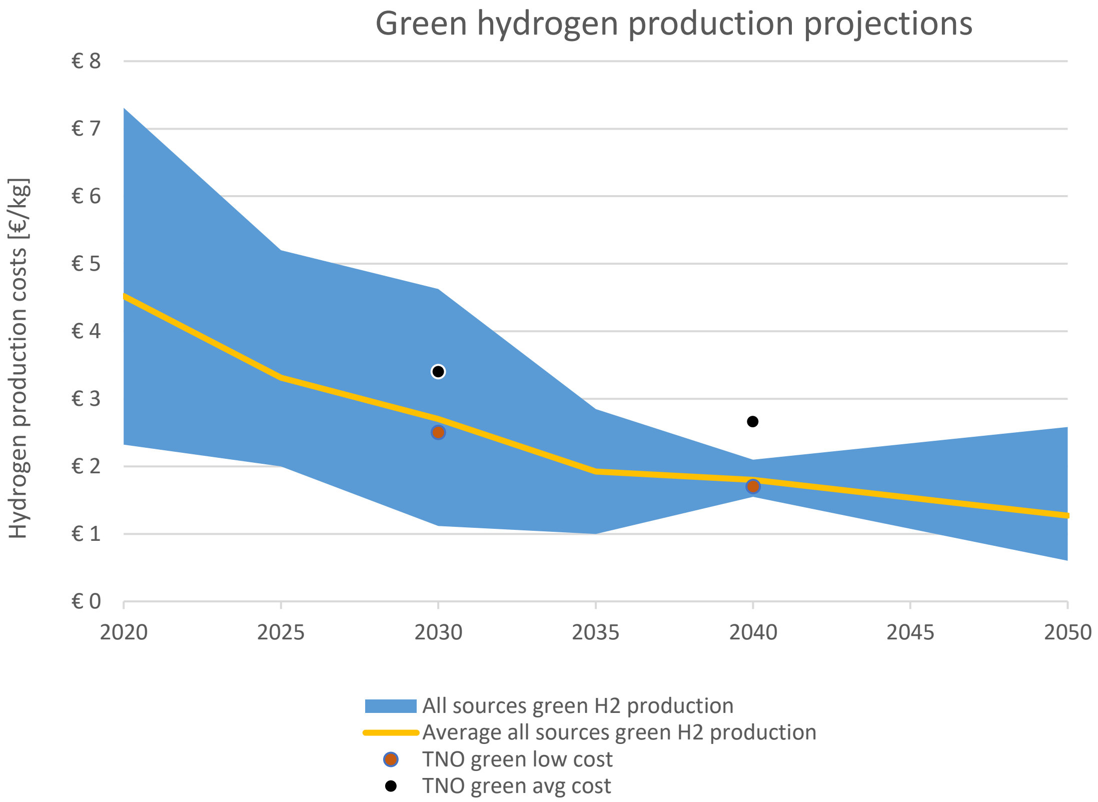



*Figure 23– Benchmark of hydrogen productions costs. The blue area is an area plot of all benchmark studies, the yellow line shows the average of all benchmark studies, the orange and the green dot show the minimum and average cost estimation from our analysis respectively.*

## 5.2 Cross-validation with green hydrogen, e-ammonia and e-methanol import cost estimate studies

A similar assessment as in Chapter 5.1 has been performed, but now for the total of import costs of hydrogen via 5 different routes. The study that comes closest to the subject of this report is the Master's thesis work of Stephanie Lanphen (2019, TU Delft). She developed a cost model for scale import chains to various countries, assuming a fixed annual capacity of 700kt $H_2$. This research shows the cost prices depend on the country specific parameters, the distance of transportation, and the local costs of the production of hydrogen. In the figure below the cost prices are plotted in line with the distance of the various export countries, assuming. Here, it can be seen that transport distance greatly influences the cost of transporting gaseous $H_2$ by pipeline (to be expected) but appears not to have much influence for the $LH_2$, LOHC and $NH_3$ cases.

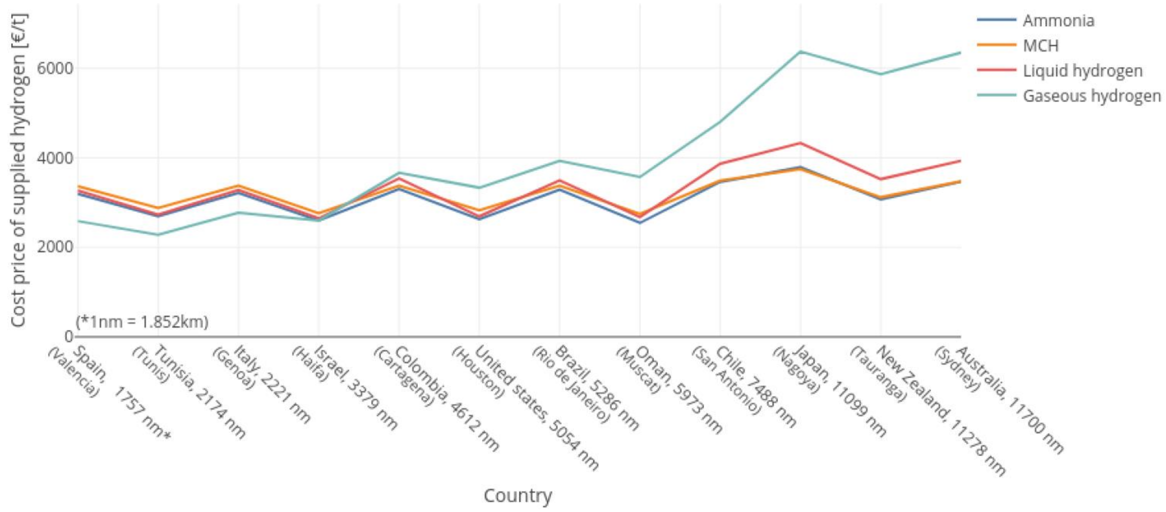



*Figure 24 Cost price of supplying green $H_2$ to the Netherlands from various countries (Lanphen, 2019)*

Her work shows strong clustering of the three options, with total supply chain costs estimated to be roughly €3,000 – 4,000 per ton. The cost of transporting liquid $H_2$ gradually increase with distance, because her model takes boil-off losses into account.

In the CHAIN study (2021), a previous study by TNO, cost projections for E-ammonia ($NH_3$), e-methanol (MeOH), liquid hydrogen (L $H_2$) and a liquid organic hydrogen carrier (LOHC) are calculated. The two figures below show the cost breakdowns in € per ton for liquid $H_2$ and $H_2$ from LOHC for various countries. Also the reference case of gaseous hydrogen production in the Netherlands is shown (left bar). Comparing this with our current results, where we find minimum and average values of € 3,295 and € 6,409 per ton $H_2$ via L $H_2$; and € 4,766 and € 6,802 per ton $H_2$ via LOHC, we can conclude that we are somewhat below these earlier cost predictions.

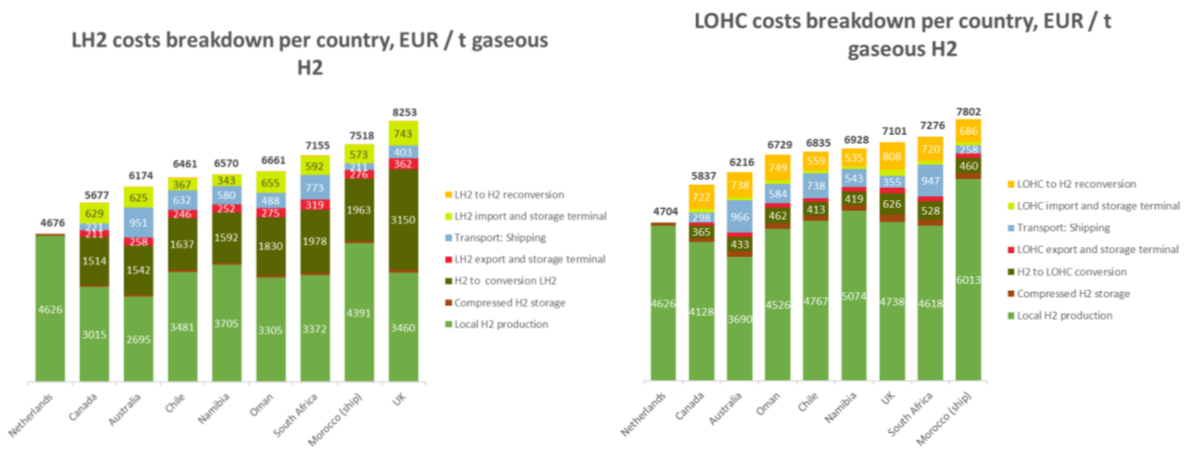



*Figure 25 Hydrogen import cost results from a previous TNO study[12]*

Gathering these findings combined with results from other previous work from e.g. CE Delft, KBR Argus, Roland Berger, Energy Transition Commission, EWI and McKinsey Hydrogen Council, results in the following cost range represented by the blue area. In this comparison we included the following

[12] TNO (2021) R12635 Transition to e-fuels: a strategy for the Harbour Industrial Cluster Rotterdam

cost elements: hydrogen production through electrolysis, conversion from $H_2$ to carrier (in all cases but $cH_2$), storage (import and export), transport, and reconversion.

This gives the following overview, showing a wide range of cost data points for $NH_3$ in lime, methanol in purple, LOHC in yellow, liquid hydrogen in blue and compressed hydrogen in orange. Overall it can be seen that the supply chain costs for liquid hydrogen and LOHC are anticipated to be the most expensive. $NH_3$ is somewhere in the middle, and compressed hydrogen and MeOH (limited benchmark studies found) are on the lower end on the graph.

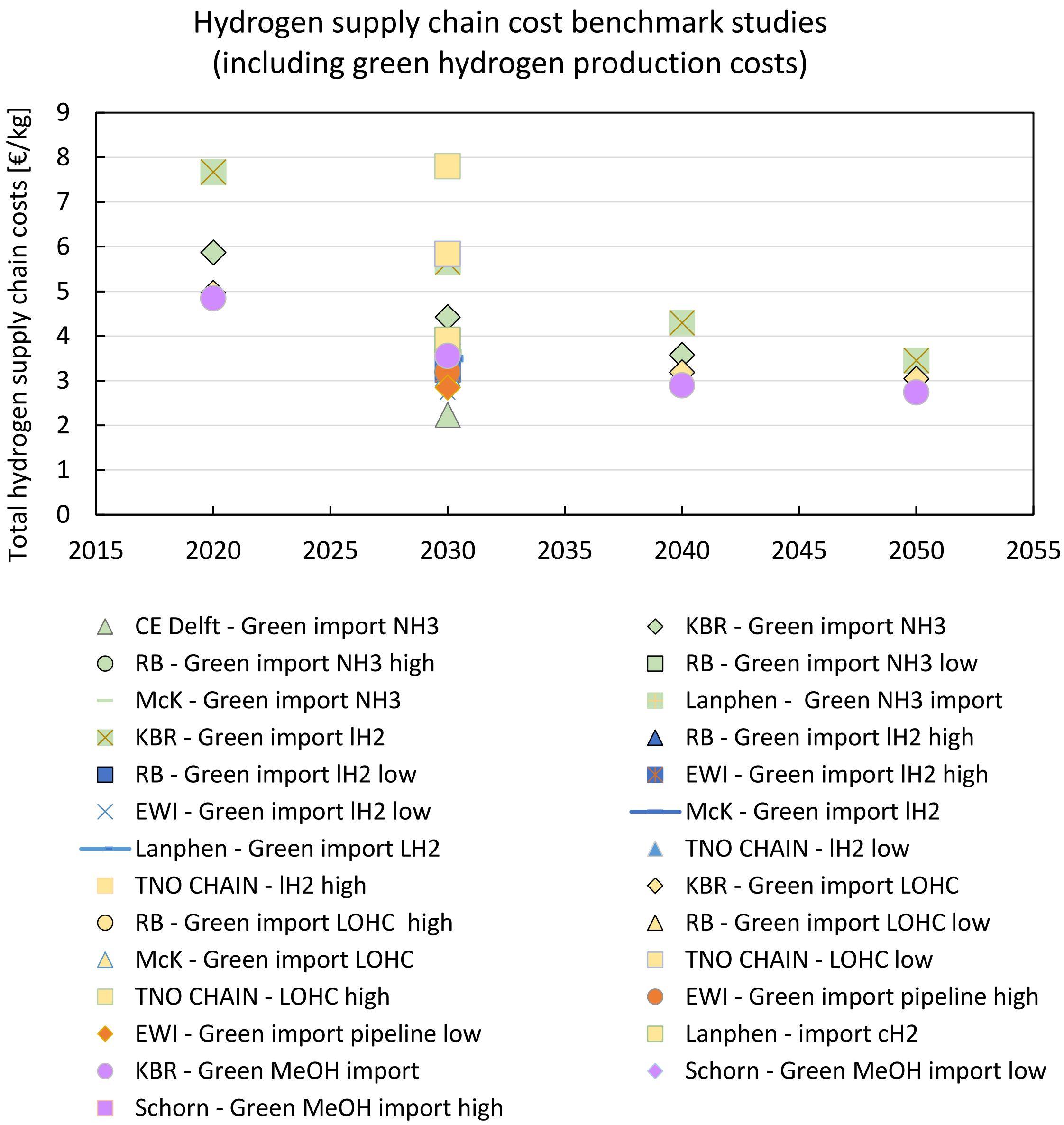



*Figure 26 Benchmark of hydrogen supply chain costs including production. Every dot represents a study. Ammonia = lime, methanol = purple, LOHC = yellow, liquid hydrogen = blue and compressed hydrogen = orange.*

Combining all these points in a data range and comparing this to the HyDelta study shows that we are on the higher end, with our average being higher than all benchmark studies and our lowest estimate just above the average benchmark.

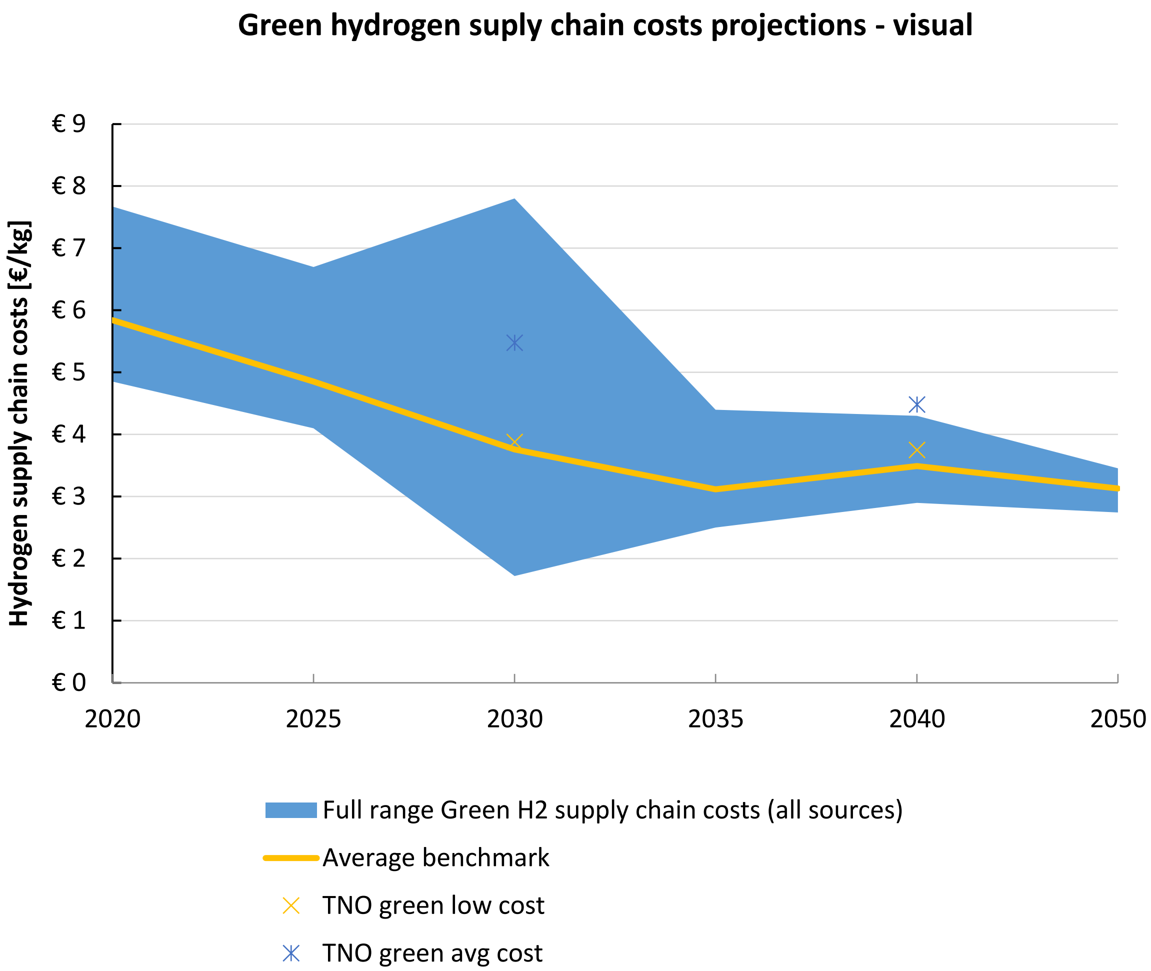



*Figure 27 Benchmark of hydrogen supply chain costs including production. The blue area is an area plot of all benchmark studies, the yellow line shows the average of all benchmark studies, the orange and the green dot show the minimum and average cost estimation from our analysis respectively.*

It is important to note that this benchmark study neglects differences in scope and assumptions. Most studies overlap largely in supply chain scope and analysis assumptions, however, the production site and destination do vary and can play a critical role in the final cost estimate.

# 6. Recommended directions for future research

The following four recommendations for future research topics are believed to focus on critical elements of renewable hydrogen-based value chains. This selection of topics is expected to yield an increased level of detail to the insight gained in this study, which benefit the public debate on renewable hydrogen import towards the ARRRA cluster, and the Netherlands in particular.

1. Strive for a maximization of asset utilization is the first recommended next step in assessing the range of import costs per country-carrier combination. Three focus areas are recommended to focus on: the supply cluster, the logistics network and the end-use cluster.

    - Firstly, maximizing chain mass flow outputs by changing the renewable electricity production 'load-following' assumption of the power-to-hydrogen asset to a base-load operation, and consequentially also a high utilization of the carrier production assets, is expected to lead to lower $LCoH_2$. When intermittent RES is complemented by fossil electricity sources or a electricity grid mix, the introduction of a guarantees of origin or certification approach is suggested to make sustainability-scores of hydrogen production transparent.
    - Secondly, a more detailed study of the harmonized dimensioning of large-scale storage (import and export terminals) and the carrier vessels, is expected to yield more detailed insights regarding the need for redundancy of assets and optimal storage and vessel dimensions, including the related costs.
    - Lastly, the end-users perspective can be added to the study to scale the carrier reconversion supply chain element according to the end-user needs. The need for ammonia and methanol as a commodity, the buffer-role of LOHC to complement intermittent domestic hydrogen production, or the residual high temperature heat available to reconvert carriers back to hydrogen can for example be leading dimensioning factors in the reconversion supply chain step.

2. To assess the value of storage and investments required to guarantee a secured supply of hydrogen, a change in perspective and modeling approach is recommended: shifting from analyzing single supply chains to supply networks. In networks, multiple stakeholders per chain element (e.g. suppliers, consumers, storage operators) participate and can complement the role of one another. The time granularity to be considered should correspond with the envisioned characteristics of the security of supply and security of demand.

3. The addition of more sustainable fuels and feedstock molecules, or intermediates, can enrich the comparison of carriers currently under consideration. And by making deliberate decisions on the location of each supply chain element, the costs of more complex supply chains can be compared (e.g. importing synthetic kerosine after production in a foreign country vs. importing syngas and producing kerosine locally).

4. The current imported hydrogen purities are not addressed in this study while different purity levels of the end-products in this study are evident (e.g. $LH_2$ will have a much higher level of purity than $H_2$ from dehydrogenated LOHC carriers). By expanding the analysis of this study with more detailed product quality characteristics, the levelized cost of hydrogen can more accurately represent the quality of each product that is imported. This recommended expansion can be accompanied by an additional supply chain element, hydrogen purification, to level out all the imported hydrogen purity levels which leads to a 'fair' comparison of $LCoH_2$ estimations.

# Appendix A: Supply chain model scope, logic and assumptions

## A1. The modelling approach explained

This section describes the modeling approach chosen to calculate the techno-economic performance of hydrogen import chains in the TNO Supply Chain Model.

TNO developed the hydrogen carrier import Supply Chain Model (SCM V1.4) to perform systematic comparisons of hydrogen carrier import supply chain alternatives. This model evaluates the cost of hydrogen or hydrogen carriers with the Netherlands as the importing country and archetype-level exporting countries globally. The model calculates the import costs at single project-scale supply chain sizes: all investments in the technologies required for the functioning of the supply chain are made for the sole purpose of that single supply chain to function between the exporting country, and the Netherlands.

The import chain of hydrogen can be described as a sequence of chain elements. Figure 28 shows these chain elements schematically. The logic that is modelled per chain element is described in detail in the subsequent paragraphs.

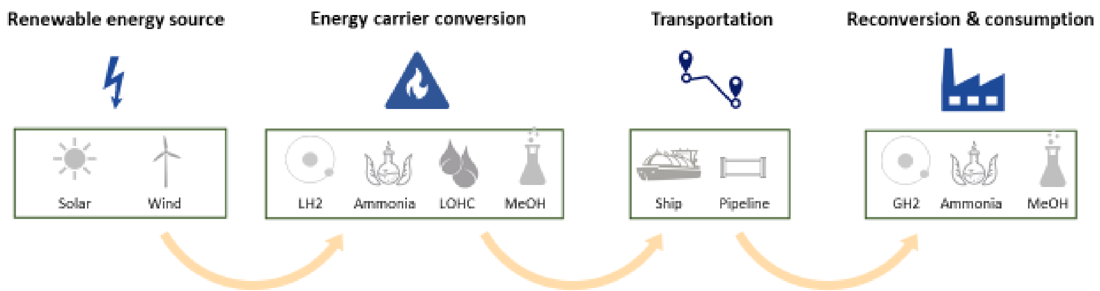



*Figure 28 Schematic illustration of the supply chain under consideration*

The Supply Chain Model is developed in MS Excel and has a modular design. Four key model elements are connected as such that repetitive calculations can be done effectively while maintaining a transparent view on the calculations: Generic input and chain specific input are directed to the various **supply chain calculation sheets.** And the outcomes of the calculation sheets are collected in the **dashboard** (Figure 29).

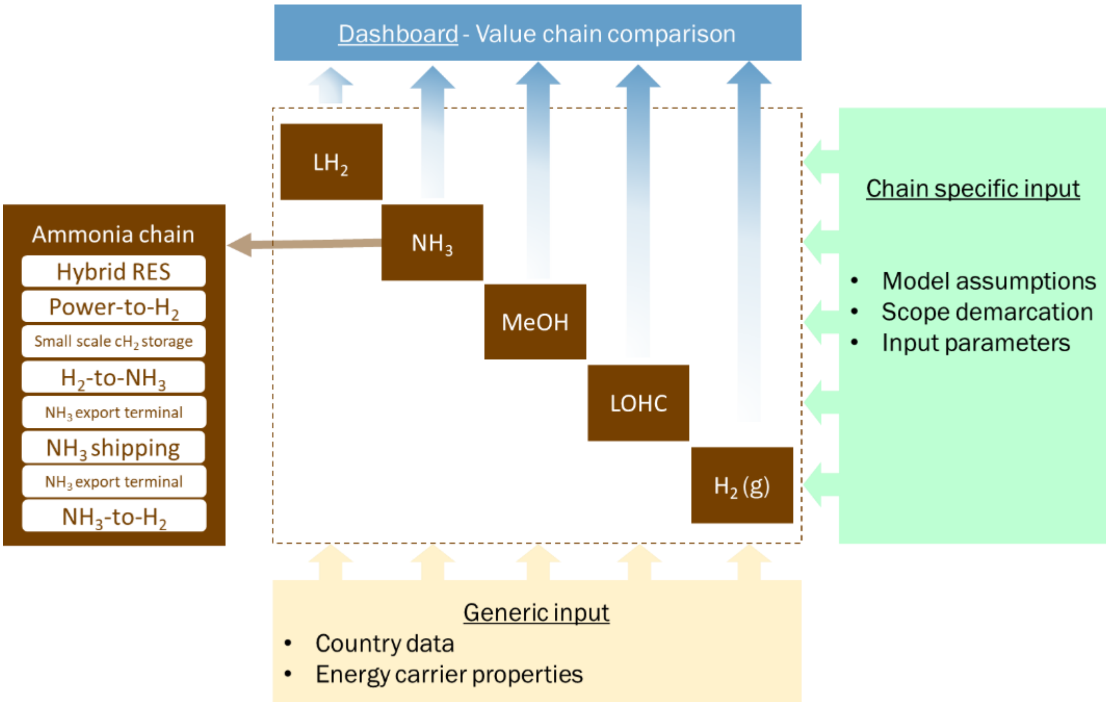



*Figure 29 Simplified architecture of the TNO Supply Chain Model V1.4*

## A2. Selection of the hydrogen carrier import supply chains

The four ship-based import chains have the same supply chain element configuration as is shown in the figure below. The Pipeline import chain differs slightly: the terminals, transportation and reconversion elements are replaced by a pipeline network supply chain element. The Chain configurations indicate the boundaries of the SCM.

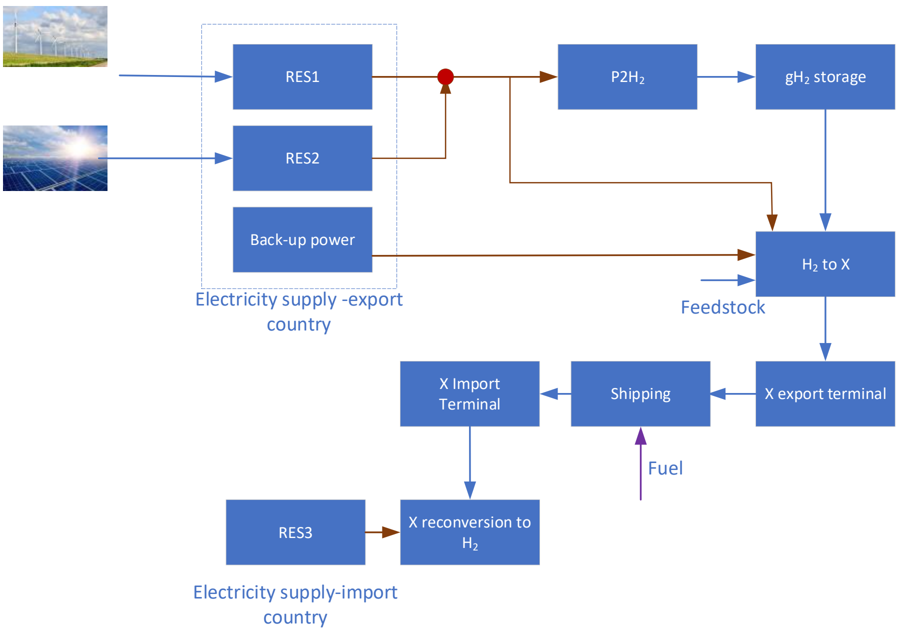



*Figure 30 Block diagram of the supply chains under consideration*

## A3. Selection of the export country archetypes

All around the world, countries are developing hydrogen-related strategies to explore their role in what may lead to be a global renewable hydrogen trade in the future. In this study, seven archetype export countries were chosen to give an impression of the import costs per carrier from these countries. The selected countries provide insight into the different influences that the difference in characteristics per country (e.g. type of renewable electricity generation with associated FLHs and LCoE, distance to be travelled per ship and interest rate) have on the import costs of hydrogen carriers. The following archetypes were chosen:

*Table 0-1 Archetype hydrogen export countries selected in this study*

| RES technology | Distance & modes of transport | Representative country |
|---|---|---|
| Utility PV & onshore wind | Short distance, ship and pipeline | Morocco |
| Utility PV & onshore wind | Medium distance, ship | Saudi Arabia |
| Utility PV & onshore wind | Medium distance, ship | Oman |
| Onshore wind & utility PV | Long distance, ship | Argentina |
| Offshore wind & utility PV | Short distance, ship and pipeline | United Kingdom |
| Geothermal & pumped hydro | Medium distance, ship and pipeline | Iceland |
| Pumped hydro & onshore wind | Medium distance, ship | Canada |

**Utility PV & onshore wind-based archetype countries:** The combination of utility-scale solar PV and onshore wind is widely considered as an attractive hybrid source of renewable electricity. Therefore, multiple archetype countries are selected with this combination of RES potential. Morocco, as a case with short transport distances, offers the plausible option to import via both vessel and pipeline, while Saudi Arabia and Oman are considered to be an option for vessel transport only. By selecting both Saudi Arabia and Oman, this study is able to show the consequences of smaller differences in supply chain characteristics (e.g. slightly different FLHs and LCoEs, as well as travel distance differences).

**Onshore wind/offshore wind & utility PV-based archetype countries:** To gain insight in costs of hydrogen from wind-rich regions, one onshore wind-dominant country (Argentina) and one offshore wind-dominant country is selected. Both onshore and offshore wind technologies are complemented by utility PV despite the relatively low amount of solar power expected in these regions.

**Geothermal & pumped hydro, and pumped hydro & onshore wind:** While wind and solar are intermittent renewable energy sources, geothermal and pumped hydro are less dependent on weather patterns. This on-demand property can be considered beneficial when high utility rates of electrolysers assets are desirable. Two archetype countries are selected to illustrate the advantages and disadvantages of this type of renewable energy supply: Iceland (due to their existing geothermal and hydropower RES) and Canada with large shares of hydropower in their current electricity grid mix, complemented by onshore wind power production.

For each country archetype, an interest rate is assumed which is used to annualize the CAPEX over the asset lifetime (see asset annuity method in the subsequent section). As interest rates can be expected to be project specific, the values below are for indicative purposes only. The lower the investment risk profile in a specific country, the lower the interest rate assumed:

*Table 0-2 Estimated interest rates for archetype countries*

| REPRESENTATIVE COUNTRY | ASSUMED INTEREST RATE (ASSUMED EQUAL TO WACC) |
|---|---|
| NETHERLANDS | 8% |
| MOROCCO | 10% |
| SAUDI ARABIA | 10% |
| OMAN | 11% |
| ARGENTINA | 10% |
| UNITED KINGDOM | 6% |
| ICELAND | 5% |
| CANADA | 5% |
| AUSTRALIA | 6% |

## A4. Generic modelling considerations that apply to all supply chain elements

*"All models are wrong, but some are useful."*

This famous saying of statistician George Box articulates the challenges that we face when creating an accurate representation of our world. To create a useful hydrogen carrier import supply chain model, many assumptions are made in the modelling process to mimic those supply chains from a techno-economic perspective. The considerations that were made that apply to all the different supply chains within the scope of this study are transparently discussed in this paragraph. Firstly, the topics are briefly introduced and subsequently, their implications and mutual relations are described in more detail.

A. Arguably the most important factor is **time.** The time stamp of the study affects forecasted (specific) cost estimates for the most costly chain elements, for example the LCoE for renewable power, CAPEX for $H_2$ and carrier conversion plants. We use the time stamps of 2020, 2030 and 2040 in this analysis.

B. The second most important factor for the cost estimates is the **scale** of the technologies utilized in each chain element, influencing production costs as well as logistics (shipping and export/import terminal costs). The supply chain scales are based on one single point of reference: the installed renewable electricity supply capacity. The minimal scale of the supply chain analysis that yields acceptable results based on underlying logic and input parameters is 600 $MW_e$. The maximal scale is 4 $GW_e$. For this study, we assume 2 $GW_e$ installed renewable electricity supply capacity. An appropriate scaling factor is used for each technology to benefit from economies-of-scale effects that reduces the specific cost of assets once deployed on a larger scale.

C. The number of **full-load hours (FLH) per year** for the $H_2$ production and the conversion plants has an impact on production volume, and thus the cost per unit produced. Hydrogen is only produced from renewable power, and thus the FLH depends on the region and the capacity factor of the selected power producing technology.

D. The **operating flexibility of the conversion plants** is also an important factor. Typically, such processes would need to keep running, or be maintained in hot stand-by when there is no renewable power or hydrogen available to operate. Following from (C), we assume that hydrogen carriers are only produced when hydrogen is available. Intermediate small-scale hydrogen storage to facilitate operational flexibility is discussed in more detail below.

E. Related to the previous two considerations C and D, carrier production plants are assumed to be stand-alone, or 'islanded' plants that are **not connected to a local power grid**. This implies that back-up power generation is needed to keep the show (partially) running when there is no wind or sunshine. While this power could be generated from the locally produced hydrogen, we assume an independent source of electricity as this would eat away some of the freshly produced $H_2$. The use of back-up power for the hot stand-by mode is discussed in more detail below.

F. The decision is made to evade large-scale $H_2$ (g) storage and simplify the modelling logic by **over-dimensioning the $H_2$-to-X assets**. All hydrogen-to-X conversion thus happens during the hours in which that hydrogen is produced from renewable power.

G. In the analysis, either a RES-project based lifetime (e.g. 40 years for solar PV utility scale) could be chosen, or the lifetime equal to the Hydrogen-to-X conversions plant (i.e. 20 years) could be taken. We decided to use **20 years** as the operational lifetime of the entire supply chains. Potential exploitation beyond this time horizon is thus excluded from the analysis.

H. In this analysis we assume that the investment comes from a bank loan and the **discount rate (DR) is set to the interest rate** of the country under consideration.

I. The **asset annuity method** is applied to integrate investment costs in the levelized cost of hydrogen.

J. **No taxes, levies, profit margins, raw material or equipment market dynamics and commodity market dynamics** are included in cost calculations. Economic results are thus bare technical costs with discounted investment costs (H) over the lifetime of the project (G), and not the estimates of end-user *prices* of hydrogen in the future.

*Why are time (A) and scale (B) important?*

Many relevant technologies are rapidly evolving – for example, electrolysers stack and system performance is improving, while costs are being slashed as a result of larger volume production and a higher degree of automation in manufacturing. Figure 31 below illustrates this installed cost decline with both the innovation and scale-up effects. It is important to choose a date and use that time frame consistently for the technologies required in the supply chain.

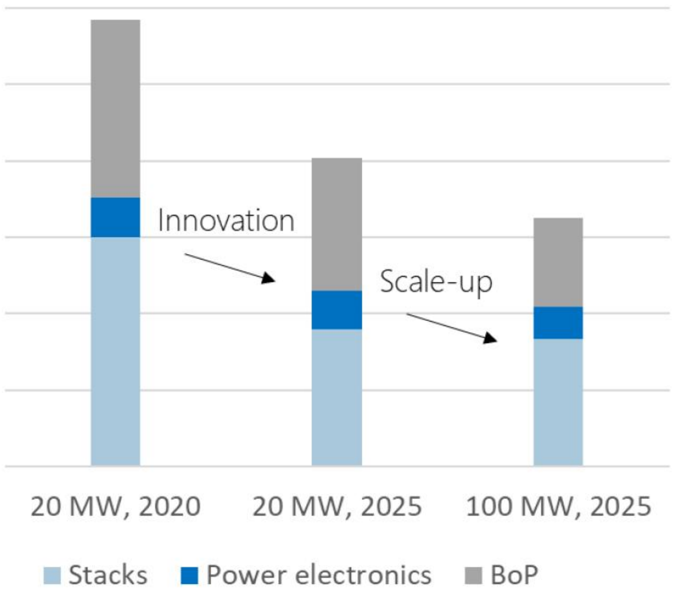



*Figure 31 Cost-reduction over time prognoses for electrolysers due to innovation and scale-up of production processes*

Economy-of-scale effects makes a significant difference in the utilization of sustainable energy process technologies. Two examples on the effect of scale on costs below:

- $O_2$ and $N_2$ suppliers charge vastly different prices depending on the flows requested. Relevant for the production of $N_2$ for green $NH_3$, but also for $CO_2$ from DAC (less steep though):

| **Scale** | **Commodity** | **Price (2019)** |
|---|---|---|
| Large scale (>100 tonnes per day) | Oxygen | € 23.5 – 27.5 per tonne |
| | Nitrogen | € 26.9 – 31.4 per tonne |
| Medium scale (0.5 – 100 tonnes/day) | Oxygen | € 49.9 – 54.9 per tonne |
| | Nitrogen | € 57.2 – 62.8 per tonne |
| Small scale (<0.5 tonnes/day) | Oxygen | € 849.8 per tonne |
| | Nitrogen | € 1244.5 per tonne |

- The storage tank cost curve is representative for standard equipment items, and often also for entire plants in the chemical industry. You can expect this type of cost curve for second step P-t-X conversion plant that produce $NH_3$, MeOH, F-T products, $H_2$ liquefaction/regasification and LOHC hydrogenation/dehydrogenation:

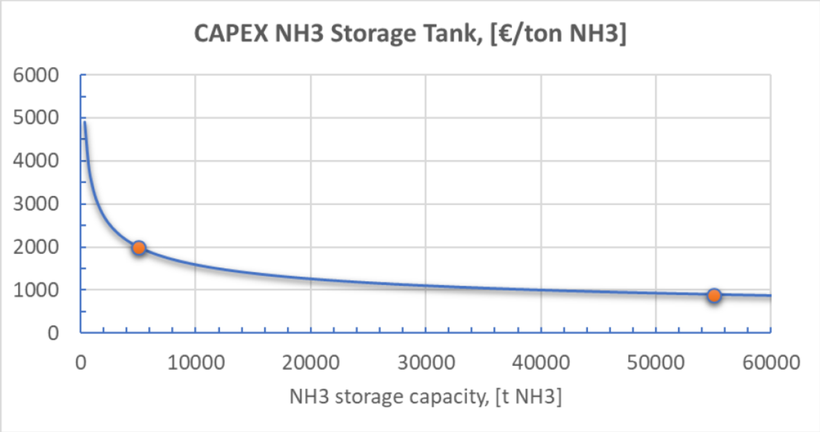



*Figure 32 Visualisation of typical economies of scale advantage for storage assets with a non-linear scaling factor of 0,65*

From the single point of reference scale, the installed RES, onwards, the scales of the technologies in the different supply chains will come to deviate based on the mass flows per supply chain element. The electrolyser is scaled at 90% of the RES capacity) and the subsequent hydrogen mass flow defines the size of the other assets, e.g. conversion plant, number of ships etc.

*Why are FLH (C), flexible operation (D), islanding (E) and over-dimensioning (F) important?*

Production profiles for wind and solar PV are intermittent and include extended periods of low output. Taking this into account when designing the configuration of the supply chain is essential, either by adding electricity or $H_2$ storage to strive for near-continuous operation throughout the year, or by assuming flexible operation of the integrated systems. Both will lead to higher costs. An extensive trade-off based on a comparative analysis between these two options is out of scope of this study. In succession of previously conducted studies on hydrogen production and conversion modelling, we took the second configuration alternative. The consequence of this assumption is that no investments for large-scale hydrogen storage are assumed.

The optimal strategy will be somewhere in the middle between oversizing and balancing via storage. A dynamic optimization between hydrogen supply (renewable electricity generation, electricity storage, hydrogen production and hydrogen storage) and hydrogen demand (hydrogen carrier conversion process) would be of great value to achieve an optimized balance between CAPEX, OPEX, production capacities and security of supply. Such a dynamic optimization was excluded from the scope of this study.

- Each region in the world has its specific renewable energy potential. These resource potentials per geographical region that are considered in this study are discussed in more detail in paragraph 6.6.1. Per location, the full-load hours of RES are the determining factor in the subsequent model logic.

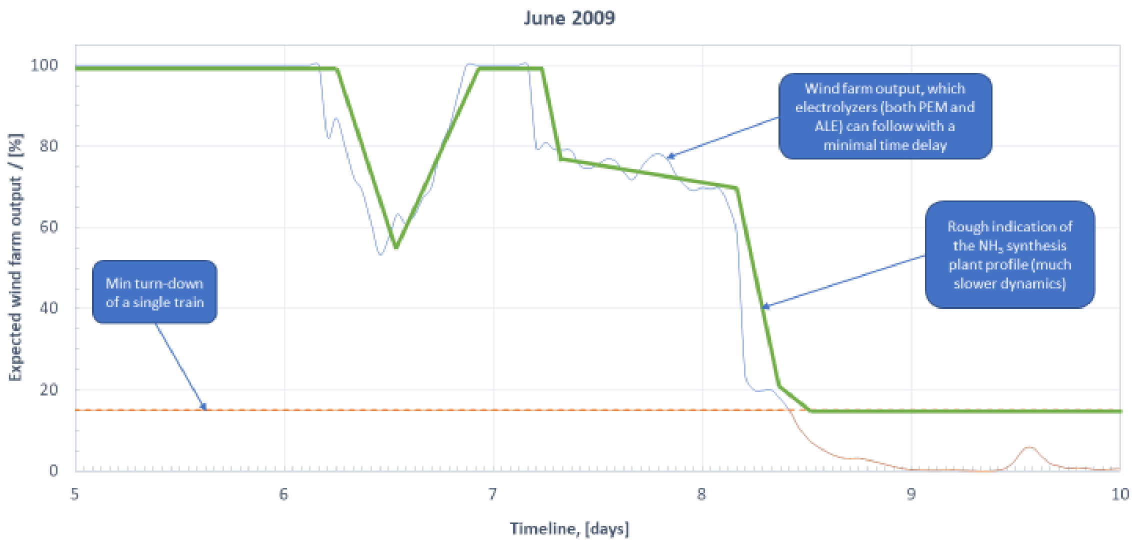



*Figure 33 Example of an operating profile of a green ammonia plant following a wind farm output profile*

- The figure above gives an impression of how such a system could operate under the following conditions and assumptions:
  - the plant runs entirely on renewable electricity without a grid connection or power storage
  - the electrolysers are designed to, and can, follow the renewable power profile
  - hydrogen carriers are produced in line with the running hours of the electrolyser. In order to have a sufficiently flexible operational hydrogen carrier conversion process, the production trains are duplicated. The synthesis unit thus consists of two trains in parallel. Each train as a minimum turnout of 30% and can be flexibly operated between 30-100% production capacity. These smaller parallel-connected trains are more expensive than a single train, but have higher flexibility and thus reduce the $H_2$ buffer storage capacity required. The $H_2$tX technology is sized and priced at the maximum Pt $H_2$ production capacity. This implies an oversizing of the $H_2$tX plant as the X plant will only be producing 4000-6500 hours annually.
  - intermediate compressed hydrogen storage capacity enables a temporary decoupling of hydrogen production from the electrolysers of hydrogen consumption by the synthesis plant. Hydrogen buffer storage needs to be large enough to compensate for the gap caused by different system dynamics and also to allow laws train running to transition to Hot standby mode when the wind farm output is close to 0 for a few consecutive days. 12 hours of storage is assumed to be sufficient for this function
  - ramp up and ramp down issues related to other equipment (for example compressors) or neglected in this example but could be a limitation in actual practice.

If hot standby mode is not a viable option for the synthesis units than either the compressed hydrogen storage offer needs to be increased in line with the RES profile expectations, and perhaps also combined with increasing the number of trains to allow for even more flexible (and lower) hydrogen conversion flows, or production losses due to temporary shutdowns have to be accepted as a compromise.

*Why is lifetime (G), discount rate (H), asset annuity (I) and explicit exclusion of price-influencing factors (J) important?*

The following considerations were made when calculating the landed cost of hydrogen:

- To arrive at a specific cost per unit of hydrogen, we will ultimately calculate the *levelized cost of hydrogen* by dividing the total amount of hydrogen produced by an asset by the total cost of that asset. For both of the values, the lifespan of the assets is of importance. The longer the asset operates, the more hydrogen can be produced and the longer the (investment) costs can be discounted over the years. Discounting these investment (or Capital Expenditure, CAPEX) costs over time requires a discount rate. This discount rate is used in the asset annuity method.
- The annuity method is a shortcut method commonly used as an alternative to more elaborate NPV calculations, in early phase project studies when the uncertainty of CAPEX estimates is still very high. Using a given interest rate (*i*), a lifetime (*n*) and the total capital investment (TCI), the annual cost of capital (ACC) is approximated as follows:

$$\mathrm{ACC} = \mathrm{TCI}\frac{(1+i)^n i}{(1+i)^n - i}$$

  This annual cost of capital is subsequently incorporated in the $LCoH_2$ calculations that are discussed later in this document.

## A5. Detailed model logic, assumptions and scope boundaries of the supply chains

Per supply chain element the following topics are addressed in the subsequent paragraphs to describe the logic, assumptions and scope boundaries of the analysis:

- What is the **high-level function** of a supply chain element?
- What is the **modelled logic**? And what are our assumptions in the SCM for that element?
- Techno-economic **data reference** to datasheets
- Which **parameters vary over time**?

## A5.1 Renewable hydrogen production (all chains)

### A5.1.1 Renewable electricity supply (RES)

**Function:** The renewable electricity supply (RES) powers the power-to-hydrogen asset as well as the hydrogen-to-carrier asset. The installed capacity of RES also defines the installed capacity of the power-to-hydrogen asset.

**Logic & assumptions:** All the hydrogen carrier import chains begin with the generation of renewable electricity. The main performance indicator chosen to measure the economic performance of renewable electricity generation plants is the levelized cost of electricity (LCoE). The LCOE is a measure of cost per unit energy produced over the course of the plant life. It is a convenient indicator because it allows the comparison between different energy technologies even if the scales of operation and level of investments are different.

In each of the archetype countries, the technologies that harvest the renewable energy differ based on the geographical characteristics.

*Table 0-3 RES technology choices per archetype country*

| ARCHETYPE COUNTRY | RES 1 | RES 2 |
|---|---|---|
| ARGENTINA | Onshore wind | Solar PV |
| AUSTRALIA | Onshore wind | Solar PV |
| CANADA | Pumped hydro | Onshore wind |
| ICELAND | Geothermal | Pumped hydro |
| MOROCCO | Onshore wind | Solar PV |
| OMAN | Onshore wind | Solar PV |
| SAUDI ARABIA | Onshore wind | Solar PV |
| UNITED KINGDOM | Offshore wind | Solar PV |

The RES technologies are not complemented by local electricity grid connections or energy storage. Adding additional technologies, or replacing the selected RES technology with a different type (e.g. concentrated solar power replacing onshore wind in Saudi Arabia) can increase the yield of the RES supply chain element.

Combining multiple renewable electricity supply (RES) technologies lead to one $LCoE_{combined}$ value and one $FLH_{combined}$ value per country. Both are used in the subsequent calculations in the analysis. The $LCoE_{combined}$ value and $FLH_{combined}$ value for each country is determined as described below:

*Combined Levelized Cost of Electricity:* LCoE for each individual RES technology was determined for each archetype country. Calculating the cost of import chains requires robust assumptions on Levelized Cost of Electricity (LCoE) and Full Load Hours (FLH). The LCoEs are not calculated in this study. The LCoE values are taken from a selection of reputable literature sources. A consistency in assumptions and methodologies is safeguarded by taking the LCoE projections for each technology and each archetype country from the same public literature sources via a systematic literature study.

Due to the substantial cost share of LCoE in the $LCoH_2$, a typical formula to calculate an LCoE is included below. Additional assumptions that target specific variables within this LCoE formula are included in this section.

$$Levelized\ Cost\ of\ Electricity\ \left[\frac{€}{MWh_e}\right] = \frac{Total\ RES\ asset\ lifetime\ \textbf{cost}\ [€]}{Total\ RES\ asset\ lifetime\ \textbf{output}\ [MWh_e]}$$

In which:

$$Total\ cost = \sum_{t=1}^{lifetime=n} \left\{\frac{I_t * (Asset + EPCm) + I_t * (Infra + EPCm) + fO\&M_t + vO\&M_t + Aba_t * (asset + infra)}{(1+r)^t}\right\}$$

- *t = time*
- *Lifetime n = the expected years of operation*
- *$I_t$ (Asset+EPCm) = total costs of RES asset and related engineering, procurement, construction and management costs*
- *$I_t$ (Infra+EPCm) = total costs of (electrical) infrastructure and related engineering, procurement, construction and management costs*
- *fO&M = total fixed operation and maintenance costs*
- *vO&M = total variable operation and maintenance costs*
- *$Aba_t$ (Asset+infra) = total abatement (removal and waste management costs of RES asset and infrastructure*
- *r = discount rate, the charged interest rate by the financial institutions*

$$Total\ output = \sum_{t=1}^{lifetime=n} \left\{\frac{Installed\ capacity * Capacityfactor_t * (1 - degradation\ rate_t)}{(1+r)^t}\right\}$$

- *Installed capacity = rated (full load) capacity of the RES asset*
- *Capacity $factor_t$ = total percentage of operational hours over a specified period (e.g. 1 year)*
- *Degradation $rate_t$ = total yearly reduction of asset performance*
- *vO&M = total variable operation and maintenance costs*
- *$Aba_t$ (Asset+infra) = total abatement (removal and waste management costs of RES asset and infrastructure*

Additional assumptions made during the LCoE literature study:

- The RES asset **lifetime** of the consulted studies are not altered. Typically, the lifetime assumptions for RES assets range from 25 up to 40 years. The lifetime of the stand-alone off-grid hydrogen carrier production sites is assumed to be 20 years. It may be realistic to assume an equal lifetime for the RES assets as re-purposing after plant decommissioning may be unrealistic in these off-grid locations. Reducing the RES asset lifetime assumption from 25-40 years to 20 years would increase the estimated LCoEs significantly.
- The **scope of the included costs** per RES asset is assumed to differ between the LCoE studies. No actions are undertaken to compensate for this scope creep between the studies as a complete list of included costs per LCoE calculation (It (Asset+EPCm), It (Infra+EPCm), fO&M, vO&M and Abat (Asset+infra)) assumptions was absent for the studies.
- No performance **degradation** is considered in this study.
- **Averaging the range of LCoE estimates** from the chosen studies resulted in point estimate input parameters in this study. By averaging the values, the location-specific level of detail that may be present in the LCoE estimates is lost. Considering the large range of uncertainties on (almost) all

the parameters within the LCoE calculation, this loss is considered acceptable. This approach results in area averages being used, rather than project-location level LCoEs, which corresponds with the chosen 'archetype country' approach.

- **Plausible ranges of location-specific LCoE estimates in 2030 and 2040 are explored via an uncertainty analysis by calculating the $LCoH_2$ with the 50% and 200% value of the LCoE estimates.**

Each type of renewable electricity generation has its own Levelized cost of Electricity (LCoE) and capacity factor (called the Full Load hours (FLH) in this study). From the combination of two renewable sources follows a calculated combined FLH and LCoE per country. To account for the hours of 'overlap' in production, which leads to curtailed renewable power plants, a so-called critical overlap is considered in the calculation of the combined FLH.

$$LCoE_{combined} = \frac{LCoE_{RES1} * FLH_{RES1} + LCoE_{RES2} * FLH_{RES2}}{FLH_{RES1} * (1 - critical\ overlap\ ) + FLH_{RES2} * (1 - critical\ overlap\ factor\ )}$$

*Combined full load hours:* The estimated amount of hours per year during which renewable power is generated at full-load capacity is of importance to the hydrogen import cost analysis, as this input parameter determines the amount of operational hours of the power-to-hydrogen asset, and therefore the total amount of hydrogen produced per year (see section A4). To maximize the full load hours of renewable electricity generation, two types of technologies are selected in each country. These two technologies are assumed to complement the production profile of the other, leading to more full-load hours per year. A partial overlap of production hours is assumed to be inevitable. This critical overlap is visualized in the figure below. The power produced in the hours under 'critical overlap' is assumed to be curtailed, causing a loss of power output.

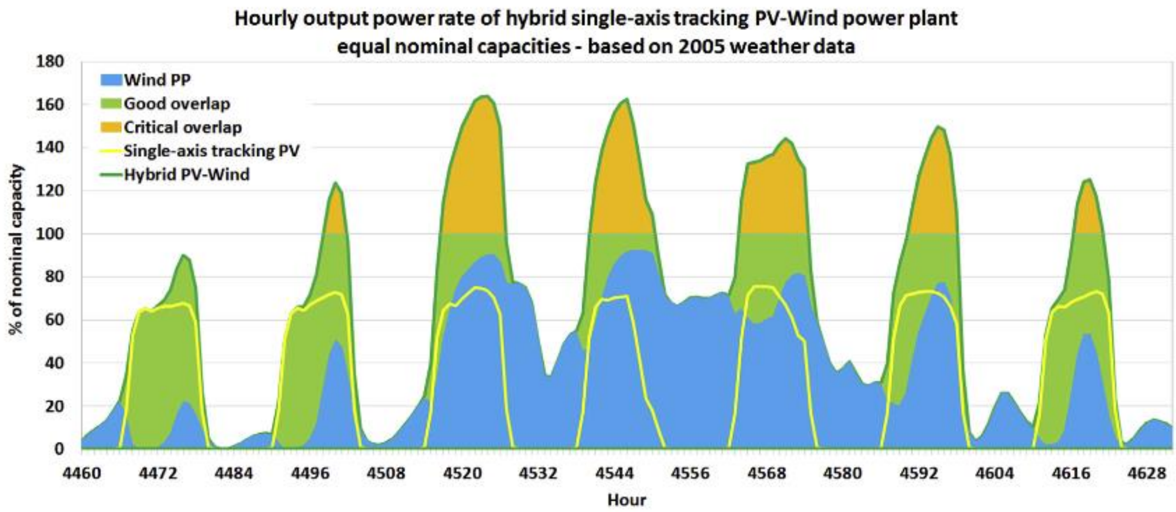



*Figure 34 Sample of complementary impact of solar PV and wind energy for increasing power FLH*[13]

[13] Fasihi and Breyer (2020) Baseload electricity and hydrogen supply based on hybrid PV-wind power plants

The assumed critical overlap factor differs per combination of RES technologies. Table1 presents the critical overlap factors in this study.

*Table 0-4 Critical overlap factor assumptions per RES technology combination*

| *Combinations of RES technology* | *Critical overlap factor* |
|---|---|
| *Onshore wind + utility-scale solar PV* | **10%** |
| *Offshore wind + utility-scale solar PV* | **10%** |
| *Onshore wind + pumped hydro power* | **20%** |
| *Geothermal + pumped hydro power* | **30%** |

The combined FLH is calculated by adding the FLH of RES1 and RES2 after compensating for their critical overlap.

$$FLH_{combined} = FLH_{RES1} * (1 - critical\ overlap\ factor) + FLH_{RES2} * (1 - critical\ overlap\ factor)$$

*Installed renewable electricity supply capacity:* The installed capacity of the combined renewable electricity plant that supplies power to the electrolyser is fixed and equal in each of the archetype countries: 2 $GW_e$.

*Backup electricity costs: the Levelized Cost of Storage:* The backup power for the hot standby mode of the power-to-hydrogen asset as well as the hydrogen-to-carrier asset, is assumed to be provided by an on-demand renewable electricity generation and storage technology combination at a fixed total cost of 120 €/$MWh_e$.

**Techno-economic input data (LCoE):** Depending on the country, the renewable sources are a combination of onshore wind, offshore wind, utility-scale solar PV or pumped hydroelectric. Table 3 shows which renewable sources have been selected per country in this analysis.

The predictions of levelized cost of electricity towards 2030 and beyond have large ranges in literature. In this study, both location-independent and location-specific LCoE data is combined to calculate the average LCoE estimates in 2030.

Location-independent LCoE data sources:

1. *Lazard (2020) Lazard's levelized cost of energy analysis version 14.0*
2. *IEA (2020) projected costs of generating electricity 2020*
3. *IRENA (2021) Renewable power generation cost in 2020*

Location-specific LCoE data sources:

4. *Ram et al (2018) A comparative analysis of electricity generation costs from renewable, fossil fuel and nuclear sources in G20 countries for the period 2015-2031*
5. *Fasihi and Breyer (2020) Baseload electricity and hydrogen supply based on hybrid PV-wind power plants*
6. *IRENA (2021) Renewable power generation cost in 2020*

The assumed LCoE input parameters are presented below for 2030 and 2040.

*Table 0-5 Assumed levelized cost of electricity per RES technology, 2030 and 2040*

| **Country-specific parameters** | LCoE for **onshore wind** power in 2030 | LCoE for **offshore wind** power in 2030 | LCoE for **solar PV** power in 2030 | LCoE for **geothermal** power in 2030 | LCoE for **pumped hydro** power in 2030 | LCoE for **combined RES** power in 2030 | Price of **stored** electricity 2030 | Average national **grid** power price 2030 |
|---|---|---|---|---|---|---|---|---|
| *Unit* | | | | *€/MWh_el* | | | | |
| **Argentina** | 27 | | 27 | | | 30 | 120 | |
| **Australia** | 33 | | 22 | | | 32 | 120 | |
| **Canada** | 35 | | 33 | | 52 | 55 | 120 | |
| **Iceland** | | | | 63 | 60 | 88 | 120 | |
| **Morocco** | 35 | | 23 | | | 34 | 120 | |
| **Netherlands** | | | | | | | | 55 |
| **Oman** | 43 | | 21 | | | 36 | 120 | |
| **Saudi Arabia** | 46 | | 20 | | | 38 | 120 | |
| **UK** | | 60 | 45 | | | 54 | 120 | |

| **Country-specific parameters** | Average n **ational grid** power price 2040 | LCoE for **offshore wind** power in 2040 | LCoE for **solar PV** power in 2040 | LCoE for **geothermal** power in 2040 | LCoE for **pumped hydro** power in 2040 | LCoE for **combined RES** power in 2040 | Price of **stored** electricity 2040 | Average national **grid** power price 2040 |
|---|---|---|---|---|---|---|---|---|
| *Unit* | | | | *€/MWh_el* | | | | |
| **Argentina** | 19 | | 14 | | | 20 | 120 | |
| **Australia** | 24 | | 10 | | | 21 | 120 | |
| **Canada** | 35 | | | | 52 | 55 | 120 | |
| **Iceland** | | | | 56 | 60 | 82 | 120 | |
| **Morocco** | 25 | | 11 | | | 22 | 120 | |
| **Netherlands** | | | | | | | | 55 |
| **Oman** | 45 | | 9 | | | 30 | 120 | |
| **Saudi Arabia** | 50 | | 8 | | | 34 | 120 | |
| **UK** | | 36 | 27 | | | 32 | 120 | |

**Techno-economic input data (FLH):** While the full load hour parameter of a RES asset is an input value to the LCoE calculation (i.e. capacity factor), the FLH estimates in this study are not compiled by averaging the underlying capacity factors of all the LCoE literature sources. The FLH of onshore wind and utility-scale solar PV are based on the estimates of Fasihi and Breyer (2020)[14] as shown in figure 25 The FLHs of offshore wind, geothermal and pumped hydro are based on IRENA (2021)[15].

[14] Fasihi M, Breyer C. (2020) Baseload electricity and hydrogen supply based on hybrid PV- wind power plants. J Clean Prod; 243:118466. https://doi.org/10.1016/j. jclepro.2019.118466.
[15] IRENA (2021) Renewable Power Generation Costs in 2020

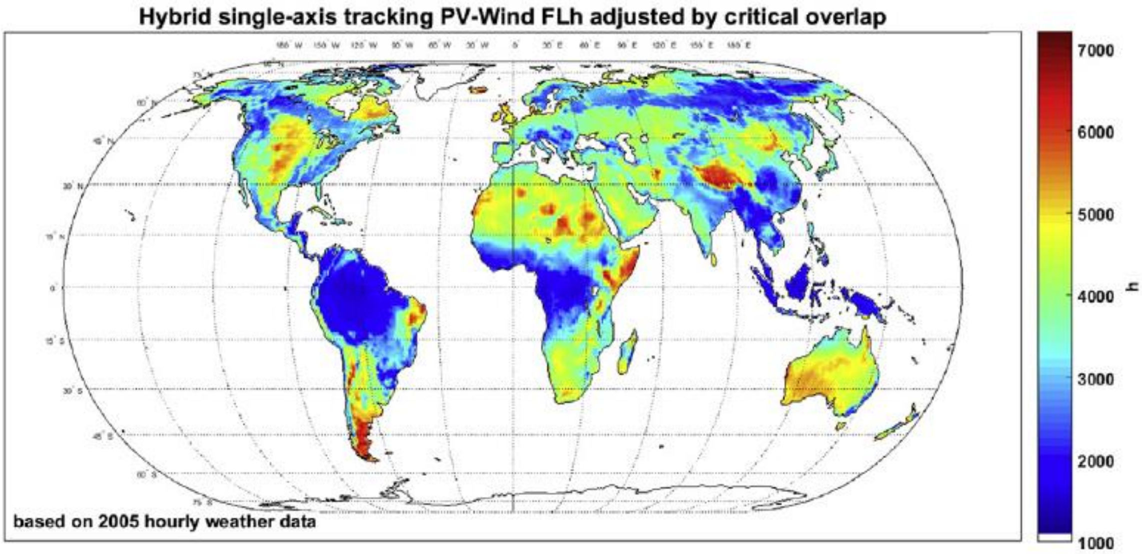



*Figure 35 Illustration of high FLH areas around the globe*[16]

The assumed FLHs per technology, and the combined FLHs, are shown in Table 7 below:

*Table 0-6 Assumed annual full load hours per RES technology*

| **Country-specific parameters** | Full-load hours (FLH) for onshore wind power | Full-load hours (FLH) for offshore wind power | Full-load hours (FLH) for solar PV power | Full-load hours (FLH) for geothermal power | Full-load hours (FLH) for pumped hydro power | Installed intermittent RES capacity | Overlap of intermittent primary and secondary RES source FLHs | Full-load hours (FLH) for combined intermittent RES power | Full-load hours (FLH) for combined intermittent RES power |
|---|---|---|---|---|---|---|---|---|---|
| *Unit* | *%* | *%* | *%* | *%* | *%* | *MW* | *%* | *%* | *h* |
| **Argentina** | 51% | 47% | 18% | 0% | 0% | 2000 | 10% | 63% | 5490 |
| **Australia** | 43% | | 25% | 0% | 0% | 2000 | 10% | 62% | 5400 |
| **Canada** | 46% | | 8% | 0% | 50% | 2000 | 20% | 77% | 6704 |
| **Iceland** | 46% | | | 83% | 50% | 2000 | 30% | 93% | 8156 |
| **Morocco** | 43% | 47% | 23% | 0% | 0% | 2000 | 10% | 60% | 5220 |
| **Oman** | 25% | | 25% | 0% | 0% | 2000 | 10% | 45% | 3960 |
| **Saudi Arabia** | 30% | 0% | 25% | 0% | 0% | 2000 | 10% | 49% | 4320 |
| **UK** | 40% | 49% | 9% | 0% | 0% | 2000 | 10% | 52% | 4583 |

**Variance over time:** The LCoE estimations for 2040 are extrapolated using the 2020 cost data from IRENA (2021)[17] and the averaged estimated value for 2030. The FLHs are assumed to remain constant over time.

[16] Fasihi and Breyer (2020) Baseload electricity and hydrogen supply based on hybrid PV-wind power plants
[17] Global Trends (irena.org)

### A5.1.2 Power-to-hydrogen conversion ($PtH_2$)

**Function:** The function of this supply chain element is to convert water into hydrogen by means of water electrolysis using renewable electricity.

**Logic & assumptions:** The operating hours of the electrolyser are equal to the full load production hours of combined RES1 and RES2 FLHs. It is assumed that the electrolyser is able to follow the dynamic operational profile of the RES1+RES2 sources. In the present study an alkaline electrolyser is used, and it is assumed that back-up power required for a stand-by mode is 1% of the total installed capacity of the electrolyser. It is assumed that back-up power is coming from either stored electricity, with the electricity price equal to the Levelized costs of Storage (LCoS).

The RES-to-electrolyser capacity ratio is 1:0.9. It is recognized that the optimal electrolyser-to-RES capacity is an important dimensioning decision that can be thoroughly optimized. This optimization is placed out of scope of this analysis as the focus of this study is to analyse the supply chain from an integral perspective. No feedstock costs for water purchase or desalination are included and the power consumption of the auxiliary equipment is excluded from the analysis.

The electrolyser efficiency is assumed to be constant and no electrolyser stack replacement investments are assumed. Detailed techno-economic optimizations are recommended to determine the optimal operational strategy to minimize costs (including stack replacement delay) and maximize efficiency over the course of the operational lifetime of 20 (or more) years.

**Techno-economic input data:** The techno-economic input parameters are reported as datasheets P1 and P2 [in D7B.1 DOI hyperlink and D7B.2 DOI hyperlink] . The CAPEX is calculated using a scaling factor of 0.9 as the electrolyser stacks are the key components to electrolyser and thus a scaling advantage is merely received from the balance of plant economies of scale. An installation factor of 1,45 is assumed.

**Variance over time:** The technology is mature on small scale applications. There is room for improvement in efficiency and production costs when moving to large-scale utilization and production globally towards 2030 and 2040.

### A5.1.3 Intermediate compressed hydrogen storage

**Function:** Damp the irregularities in mass flows between the carrier production technologies due to hydrogen production ($PtH_2$) and/or hydrogen consumption ($H_2tX$)

**Logic & assumptions:** To accommodate for electricity production (and thus hydrogen production) irregularities and the related ramp-up and ramp-down delays in both the electrolyzer and hydrogen carrier conversion processes, a gaseous hydrogen buffer with a capacity of 12 hours of hydrogen delivery to the conversion process is assumed, using 150 bar compressed hydrogen tanks. The net storage volumes are derived from the annual hydrogen production and therefore differ per country.

Hydrogen holds much promise as an energy carrier and, compared to other forms of energy storage (e.g. electricity in batteries), can be stored in large volumes for long duration. However, being the lightest molecule, the properties of hydrogen make large scale storage challenging. Therefore, this hydrogen storage is not meant to offer a solution for the seasonal intermittency issues, as is above discussed.

**Techno-economic input data:** The techno-economic input parameters are reported as datasheet C1 [in D7B.1 DOI hyperlink and D7B.2 DOI hyperlink].

**Variance over time:** Compressed hydrogen storage talks are mature technologies. No techno-economic improvement is therefore assumed.

## A5.2 Supply chain description per carrier

### A5.2.1 Ammonia supply chain

Recently, ammonia ($NH_3$) has attracted extensive attention due to its high hydrogen content (17 wt%) and ease of liquidation at mild conditions. Ammonia has a 50% higher volumetric energy density than liquid hydrogen. Ammonia production requires hydrogen ($H_2$) and nitrogen ($N_2$) as feedstock, which react using the Haber-Bosch process. The ammonia is referred to as green ammonia when $H_2$ is produced by electrolysis and the $N_2$ is separated from cryogenic air, both consuming renewable electricity. The $NH_3$ is transported in liquid form (-33 ºC) via shipping and then converted back to $H_2$ by $NH_3$ cracking, which requires high temperatures and a subsequent purification step to separate $N_2$ and $H_2$. Considered energy conversion chain for $NH_3$ production is given in Figure 36.

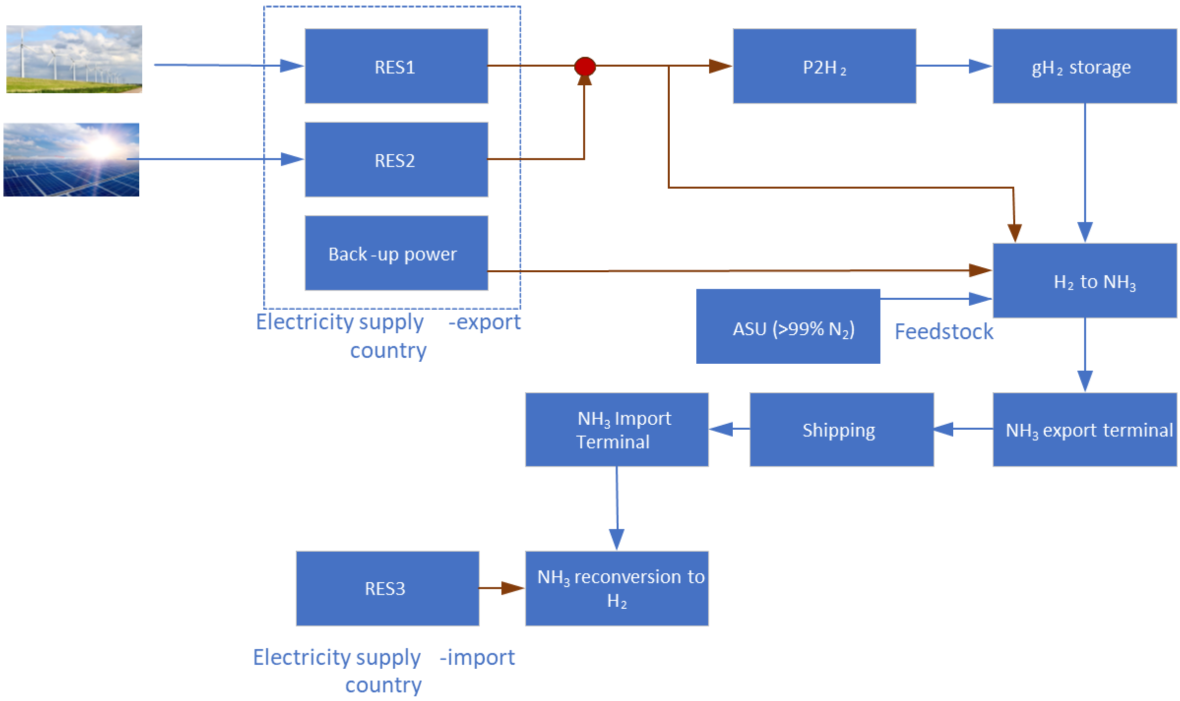



*Figure 36: Block diagram illustrating the configuration for a $NH_3$ chain*

### A5.2.2 Hydrogen-to-ammonia conversion

**Function:** The ammonia conversion through the Haber-Bosch process converts hydrogen and nitrogen into ammonia.

$$\text{Chemical reaction: } 3H_2 + N_2 \Leftrightarrow 2NH_3$$

**Logic and assumptions:** The electricity required for operating of the $H_2$ to $NH_3$ plant, producing of the feedstock for $H_2$ to $NH_3$ plant is supplied from the renewable resources. Back-up power for the $H_2$ to $NH_3$ plant is required for plant on hot stand-by. The electricity price used for back-up power is equal to the Levelized costs of Storage (LCOS).

$N_2$ is produced in the cryogenic air separation unit. For this electricity is required. This electricity will be supplied from the renewable electricity sources. The $N_2$ production runs over the whole year.

Since both reactants ($H_2$ and $N_2$) are introduced with very high purity, the purge flow will be minimized and conversion to $NH_3$ is assumed to be close to 100%. Additionally, $H_2$ storing is very impractical and thus expensive, and minimization of $H_2$ storage requirements prior conversion is desired. For that reason, a capacity factor of 100% of hourly rate is assumed, which means that the $H_2$ produced by the electrolyzers is directly converted to $NH_3$. Based on this information the design capacity and the maximum design capacity are calculated. Ammonia plants can, like any other industrial plant, not be operated 100% of the time and require frequent turnarounds. Hence, the utilization is set at 95%. Similarly to ammonia production, 2 trains are used, as they offer higher flexibility and reduce the required $H_2$ buffer storage capacity. Apart from the power required for the hydrogenation reaction, back-up power is also needed for the operating hours without RES input, which is calculated using minimum turn-down rate equal to 30%. $NH_3$ production goes to standby mode if electrolyser does not produce $H_2$. The $H_2$ that is stored is used to bring system safely to stand-by mode.

The ammonia synthesis reaction is exothermic which implies that no additional energy input is needed to supply process heat. However, the plant requires additional power to run the air separation unit, the storage/syngas & recycle gas compressors, as well as auxiliary equipment. The average power consumption is calculated based on the maximum capacity, and that value 0.45 kWh/kg $NH_3$. Additionally, the back-up power demand to keep $NH_3$ production in the hot stand-by mode for the operating hours without RES input is calculated using minimum turn-down rate equal to 30%. The overall efficiency of $H_2$ to $NH_3$ conversion slightly varies between the different countries of operation due to different electrolyzer FLH hours, which result in varying back-up operation hours. For the back-up electricity supply a generic Levelized Cost of electricity Storage of 120 EUR/$MWh_e$ is assumed.

**Techno-economic input data:** The techno-economic input parameters are reported as datasheet C3 [in D7B.1 DOI hyperlink and D7B.2 DOI hyperlink]. Specific installed cost for the Haber-Bosch loop is estimated at 0.8 M€/ktpa, including the syngas compressors, $NH_3$ storage etc. The anchor capacity is 100 ktpa, which is approximately 10 times lower than the required capacity. This will lead to inaccuracies in cost estimation. The scaling factor is set at 0.65.

**Variance over time:** Despite the high maturity of the Haber-Bosch process, there would be improvements in efficiency and cost requirements of the process over the coming years. In the current study, this factor was not included in the cost estimations due to unavailability of data.

### A5.2.3 Ammonia-to-hydrogen reconversion

**Function:** The ammonia reconversion happens through the $NH_3$ cracking process, during which $NH_3$ is cracked to $H_2$ and $N_2$ under high pressure and temperature over a catalyst.

Chemical reaction: $2NH_3 \Leftrightarrow N_2 + 3H_2$

**Logic and assumptions:** The heat consumption of the $NH_3$ cracking is calculated for 90% reconversion rate. The overall $H_2$ yield from reconversion and PSA is assumed at 85%. For the supply of the required high-temperature heat to the process, PSA off-gas and part of the $H_2$ product is used (see Figure 37).

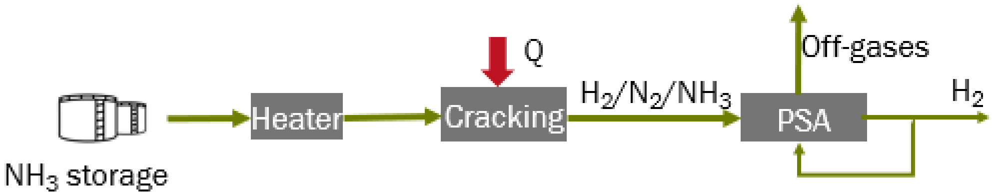



*Figure 37: Schematic diagram of ammonia reconversion step*

The $H_2$ pressure after reconversion is set to 30 bar, so the produced $H_2$ is compressed up to 70 bars before usage. The overall energy efficiency (including compressor) of the reconversion step is 89% regardless the country of operation.

**Techno-economic input data:** The techno-economic input parameters are reported as datasheet R2 [in D7B.1 DOI hyperlink and D7B.2 DOI hyperlink]. The CAPEX cost for the reconversion plant is calculated using an anchor capacity of 438 ktpa. That is approximately 2-3 times lower than the required capacity. Hence, that provides a relatively accurate cost estimation using a scaling factor of 0.7. Additional costs to the reconversion step, are the PSA for $H_2$ purification and the $H_2$ compressor to meet the $gH_2$ product specification. PSA is scaled using a reference cost for a slightly smaller PSA unit (59,010 $Nm^3/h$ impurities) and a scale factor of 0.6. The compressor cost is calculated using a specific CAPEX formula (M€/MWe) for different motor power and an installation factor of 3.

**Variance over time:** The technology is still immature, so there is plenty of room for improvement in energy efficiency and cost requirements. However, no such improvement is considered in this study due to unavailability of data. The $H_2$ compression technology attracts a lot of interest, so we can expect small improvements in that part over the coming years.

### A5.2.4 Methanol supply chain

Methanol is a commodity chemical, predominantly produced for the fertilizer industry, with global production capacity in excess of 110 Mt/yr. It is used in the production of as much as 30% of global industrial chemicals, ranging from acetic acid to adhesives, paints and foams. Demand for methanol is forecasted to increase, not only linked to growth in the chemical sector but also because of its increased direct use as a fuel. Most importantly for this study, it is considered a great $H_2$ carrier containing 12.6 wt% hydrogen, and having a boiling point of 65 °C.

Conventional methanol production technology relies on converting either natural gas or coal to syngas, followed my methanol synthesis in multi-tubular reactors. It is possible, though, to produce renewable methanol, starting directly from green $H_2$ and pure $CO_2$, or by adding a reverse water-gas shift reactor to partially convert $CO_2$ to CO prior to the methanol synthesis step.

Capture from concentrated sources could also be used as a source of $CO_2$ and would be considerably cheaper than Direct Air Capture, but it would still result in $CO_2$ emissions. $CO_2$ captured from fossil-based industrial processes will eventually be emitted into the atmosphere when methanol is burnt. Direct Air Capture, in turn, allows to have a closed carbon cycle through the atmosphere.

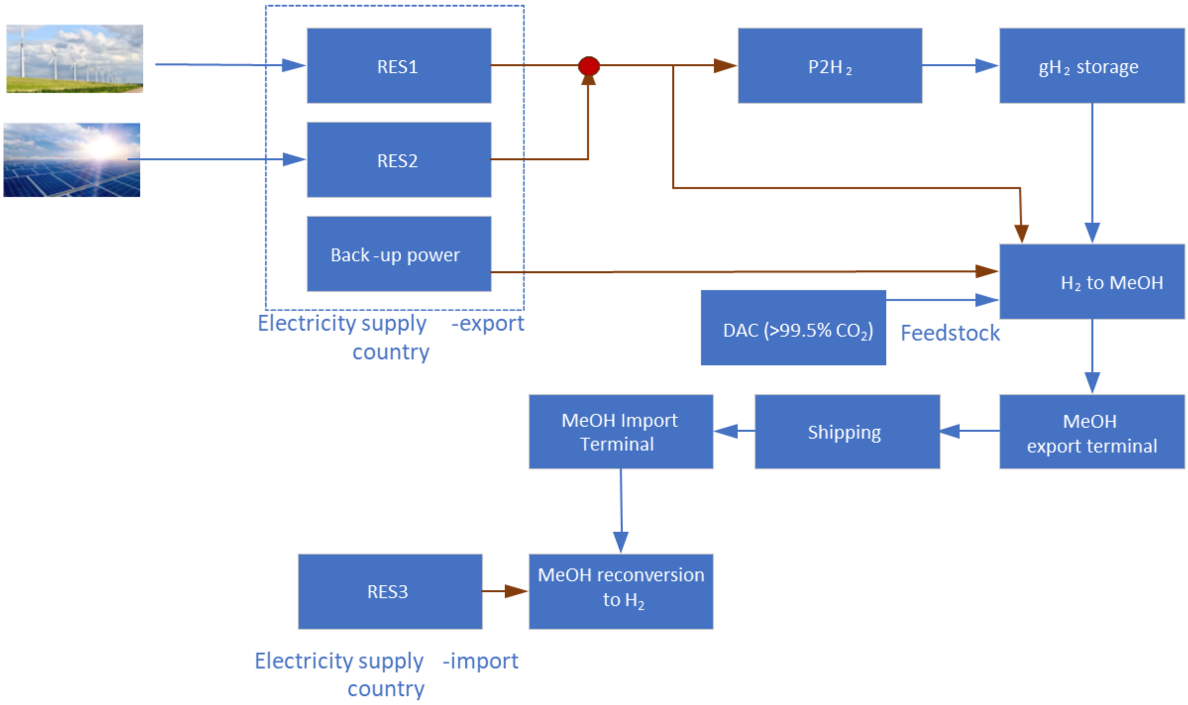



*Figure 38: Block diagram illustrating the proposed configuration for a MeOH chain*

### A5.2.5 Hydrogen-to-methanol conversion

**Function:** The $CO_2$ and $H_2$ stream are compressed to approximately 50 bars and heated to a temperature of around 498 K. Methanol is produced according to following reaction:

$$\text{Chemical reaction: } CO_2 + 3H_2 \Leftrightarrow CH_3OH + H_2O$$

**Logic and assumptions:** For production of $CO_2$ the Direct Air Capture (DAC) technology is used. DAC technology uses electricity and heat. Electricity is supplied from renewable electricity sources. For the heat supply it is assumed that DAC plant can be integrated with the methanol plant. It is assumed that $CO_2$ is 100% utilized in the methanol plant by means of recycling, and that the DAC production runs the whole year.

The electricity required for operating of the $H_2$ to MeOH plant, producing of the feedstock for $H_2$ to MeOH plant is supplied from the renewable resources. Back-up power for the $H_2$ to MeOH plant is required for plant on hot stand-by. The electricity price used for back-up power is equal to the Levelized costs of Storage (LCOS).

Unless underground storage in (e.g. salt caverns is available), storing $H_2$ is very expensive. Most likely, it's best to directly convert most or all of the $H_2$ as it is produced by the electrolyzers. Methanol plants are not 100% reliable and also require frequent turnarounds. Hence, the utilization is set at 95%. Similarly to ammonia production, 2 trains are used, as they offer higher flexibility and reduce the required $H_2$ buffer storage capacity. Apart from the power required for the hydrogenation reaction, back-up power is also needed for the operating hours without RES input, which is calculated using minimum turn-down rate equal to 30%. Additionally, there is a significant amount of electricity needed for the $CO_2$ capture, estimated at 0.25 kWh/kg $CO_2$. The overall energy efficiency of $H_2$ to MeOH process step is approximately 76%.

**Techno-economic input data:** The techno-economic input parameters are reported as datasheet C4 [in D7B.1 DOI hyperlink and D7B.2 DOI hyperlink]. Reported CAPEX was 200 M€ for a 335 ktpa plant. This is approximately 3 times lower than the capacity required in this work, so it provides an accurate estimation of the capital cost. A scaling factor of 0.65 is assumed, similarly to the ammonia synthesis loop.

**Variance over time:** The energy efficiency of methanol conversion is expected to increase until 2040 by approximately 3%, due to expected reduction in energy and electricity requirements.

### A5.2.6 Methanol-to-hydrogen reconversion

**Function:** A methanol reformer can produce pure hydrogen gas and carbon dioxide by reacting a methanol and water (steam) mixture.

Chemical reaction: $CH_3OH + H_2O \rightarrow CO_2 + 3\ H_2$

**Logic and assumptions:** All the heat required for the MeOH reconversion is supplied using $H_2$ off-gas from the PSA. An overall $H_2$ yield of 75% is assumed from reconversion and PSA (see Figure 39). The power required is 0.5 kWh el/ kg $H_2$. The operating pressure of PSA is 20 bars, and the produced $H_2$ is compressed to 70 bars for end-use. The overall energy efficiency of the reconversion step is 81%, which is independent of the country of $H_2$ production.

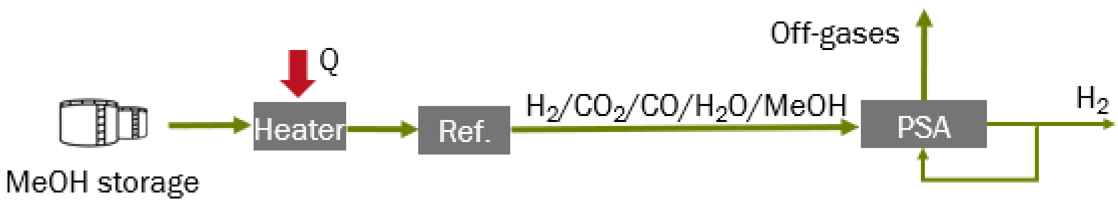



*Figure 39: Schematic diagram of methanol reconversion step.*

**Techno-economic input data:** The techno-economic input parameters are reported as datasheet R3 [in D7B.1 DOI hyperlink and D7B.2 DOI hyperlink]. It is important to mention that a small capacity of 5.5 kt MeOH per year is used as an anchor point for the CAPEX calculation. The annual capacity in the study is 1375 kt MeOH per year, 250 times larger, which results into great uncertainty of the cost estimation. The scaling factor is assumed to be the same as the scaling factor for an ammonia cracking (0.7). Additional costs to the reconversion step, are the PSA for $H_2$ purification and the $H_2$ compressor to meet the $gH_2$ product specification. PSA is scaled using a reference cost for a slightly smaller PSA unit (59,010 $Nm^3/h$ impurities) and a scale factor of 0.6. The compressor cost is calculated using a specific CAPEX formula (M€/MWe) for different motor power and an installation factor of 3.

**Variance over time:** The energy efficiency and the cost of the reconversion process would probably decrease in the future. However, no change is considered in this study due to unavailability of data. The $H_2$ compression technology attracts a lot of interest, so we can expect small improvements in that part over the coming years.

### A5.2.7 Liquid Hydrogen chain

The most straightforward option for an export chain is to liquefy hydrogen and transport it with vessels carrying cryogenic tanks, similar to how methane is transported over long distances in the form of LNG.

The density of liquid hydrogen at about 70.8 $kg/m^3$ is still low compared to typical bulk organic liquids (around 750-950 $kg/m^3$). This means that a vessel comparable to current world-class LNG carriers with a combined volumetric capacity of 160,000 $m^3$ would transport an equivalent weight of roughly 11.4 kton $H_2$.

The concept for hydrogen production, storage, and export facilities for the liquid $H_2$ case is shown below:

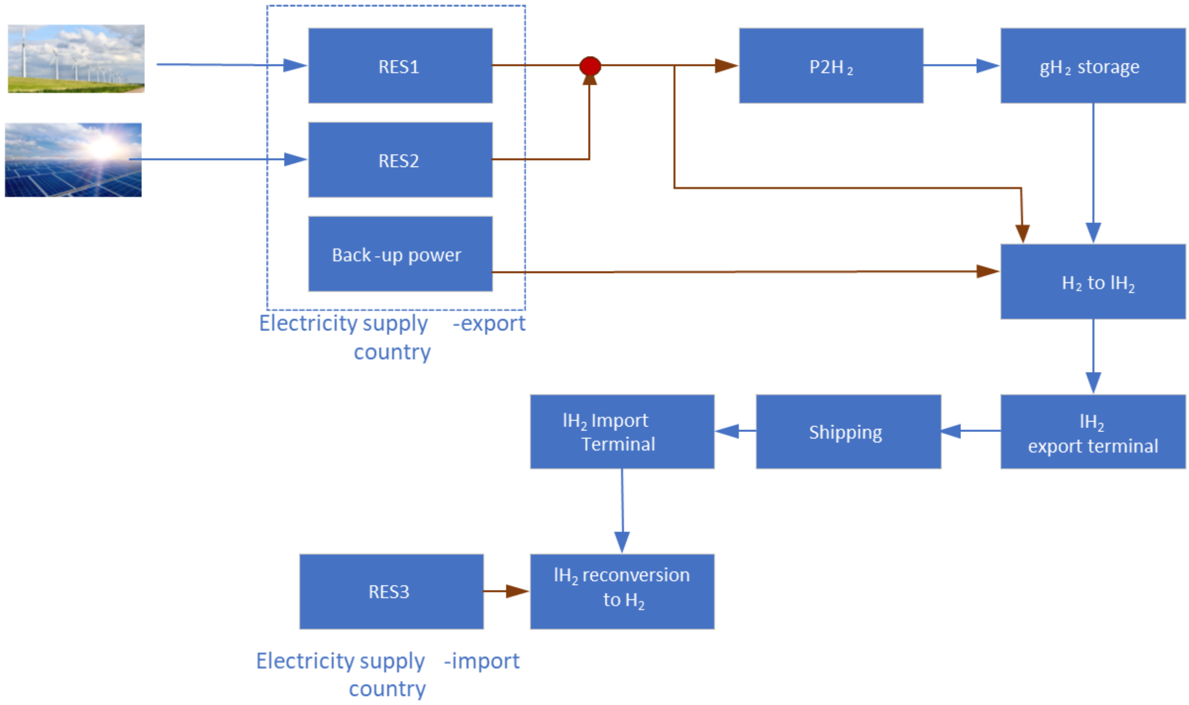



*Figure 40: Block diagram illustrating the proposed configuration for a liquid $H_2$ chain*

### A5.2.8 Hydrogen-to-L$H_2$ conversion

**Function:** Gaseous hydrogen is liquefied by cooling it to below −253°C.

**Logic and assumptions:** Besides electrolysis, the most energy-intensive step in this chain is the liquefaction process. It requires very low temperature (about -250 °C) and very high energy for cooling. It is estimated to consume about 45% of the energy brought by $H_2$. The conversion of $LH_2$ is set at 98.33%, due to losses leakage and impurity regeneration.

$H_2$ liquefaction is a known process, but currently deployed at relatively small scale with total global capacity in the order of 350 tpd [1]. Conventional technology is assumed to have power requirements of 12.5 kWh/kg $H_2$. Similarly to $NH_3$ and MeOH conversion, 2 trains are used to minimize the $H_2$ storage prion to conversion, and 30% minimum turn down ratio is assumed.

Due to the low boiling point of $H_2$ (-253°C), boil-off losses are significant and estimated at 0.1% per day for large-volume tanks onshore and 0.2% per day for large-volume transport vessels. [2] NASA developed the Integrated Refrigeration and Storage (IRaS) system, allowing control of the fluid inside the tank.[18] Combining IRaS with novel glass "bubble" insulation technology allows the liquid $H_2$ to be stored in a zero boil-off state. The heat leak entering the tank is removed by a cryogenic refrigerator

[18] Article published on the NASA website https://www.nasa.gov/feature/innovative-liquid-hydrogen-storage-to-support-space-launch-system (accessed on 10.03.2020)

with an internal heat exchanger. The utilization of the plant is assumed to be 95%, similarly to $NH_3$ and MeOH conversion.

**Techno-economic input data:** The techno-economic input parameters are reported as datasheet C2 [in D7B.1 DOI hyperlink and D7B.2 DOI hyperlink]. Uncertainty of the results is low, because the anchor capacity is 109.5 ktpa, which is very close to the required capacity. The specific CAPEX is set at 0.96 M€/ktpa using a scaling factor of 0.67. The water supply cost is assumed 1.25 €/ton and the fixed OPEX is 4% of the CAPEX.

**Variance over time:** The energy efficiency of hydrogen liquefaction is expected to significantly increase until 2040. The power consumption is expected to reduce substantially with a projected use of 6-7 kWh/kg $H_2$ in future large-scale plants, which is about half of the current energy consumption. One of the most important reasons behind this, is the use of helium refrigerant cycles.

### A5.2.9 $LH_2$-to-gaseous hydrogen reconversion

**Function:** Regasification is a process of converting $LH_2$ at -253 °C back to hydrogen gas at atmospheric temperature.

**Logic and assumptions:** The $gH_2$ is produced at 3 bars. Reconversion to gaseous $H_2$ is a simple process with a minimal power consumption of 0.2 kWh/kg $H_2$. However, additional power is needed to compress the hydrogen to 70 bar, estimated at 1.85 kWh/kg $H_2$. The main advantage of $H_2$ regasification, is that high purity $gH_2$ is produced without the need of dehydrogenation and purification.

Contrary to the conversion step, the anchor capacity, which is taken form a different source, is higher than the target capacity. The anchor capacity is 3,000 tpd, which is 6-10 times larger than the target one.

**Techno-economic input data:** The techno-economic input parameters are reported as datasheet R1 [in D7B.1 DOI hyperlink and D7B.2 DOI hyperlink]. The anchor capacity is 3,000 tpd, which is 6-10 times larger than the target capacity. This is the only case where the anchor point is not lower than the target one. A scaling factor of 0.65 and an installation factor of 3 are assumed. Additional cost to the reconversion step, is the compressor to meet the $gH_2$ product specification. The compressor cost is calculated using a specific CAPEX formula (M€/MWe) for different motor power and an installation factor of 3.

**Variance over time:** The $LH_2$ reconversion to $gH_2$ is a very simple process, which is expected to increase in the future because of advancements in the compression technology. However, that is difficult to quantify due to the lack of data, so the costs were assumed constant until 2040.

### A5.2.10 LOHC chain

Liquid Organic Hydrogen Carriers are an attractive alternative to liquid hydrogen for long distance transport, primarily thanks to ease of handling and storage. Typical examples are organic molecules containing aromatic rings, such as toluene, naphthalene, or dibenzyl-toluene. When hydrogenated, these molecules contain nearly as much hydrogen per cubic meter as liquid hydrogen, without requiring the use of special materials and storage under cryogenic conditions. The below illustrates the basic principle of a $H_2$ supply chain using this carrier.

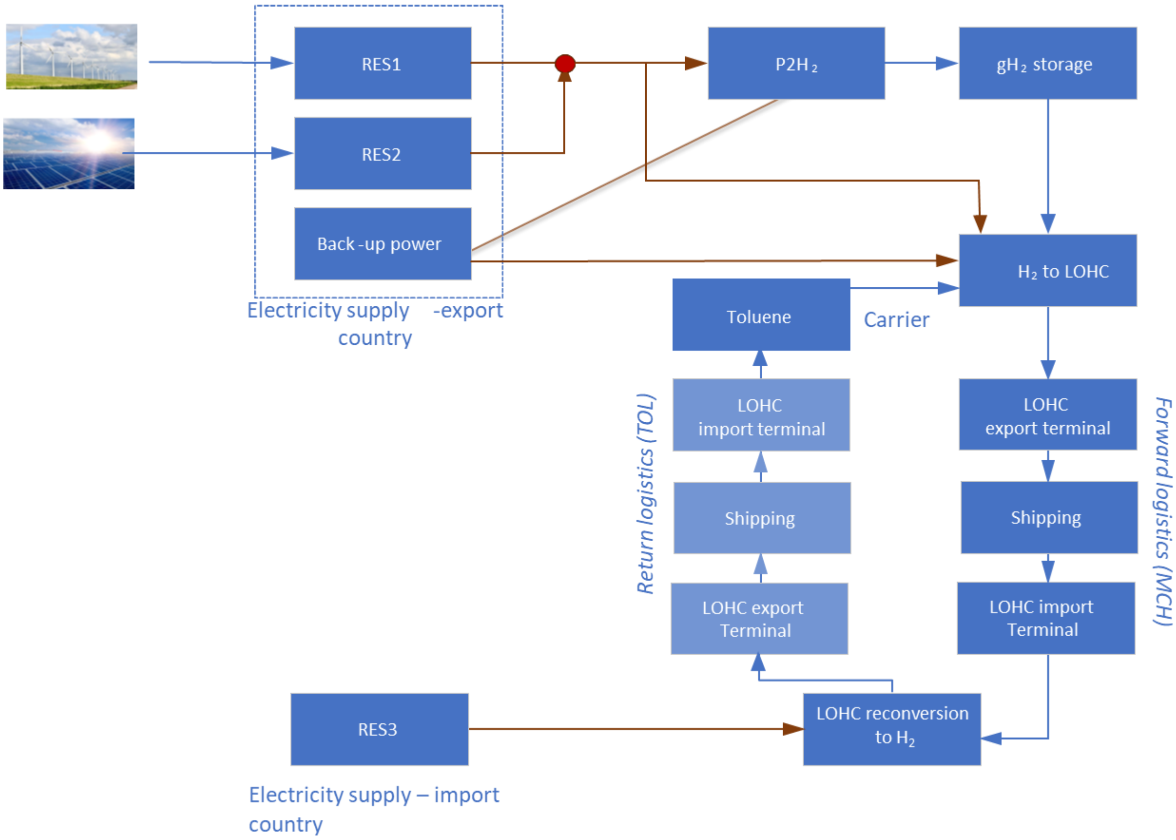



*Figure 41:Block diagram illustrating the proposed configuration for a LOHC carrier chain*

The toluene-methylcyclohexane (TOL/MCH) cycle was selected for this study, because it is currently the most mature LOHC option with techno-economic data available in literature. This option is being commercialized by Chiyoda Corporation as SPERA Hydrogen®.[19] Toluene is attractive as an LOHC because it is a low-cost molecule and can be hydrogenated to MCH with high conversion at relatively low pressure (20 bar). The $H_2$ content in methylcyclohexane (MCH) is 6.1 wt%. MCH has a boiling point of 101°C and a liquid density of 770 kg/m$^3$. It is easy to transport but its low flash point (-4°C) makes it highly flammable and adequate fire safety measures are necessary. The "hydrogen density" of MCH is about 48 kg/m$^3$.

### A5.2.11 Hydrogen-to-LOHC conversion

**Function:** Hydrogen is reacted with toluene to form methylcyclohexane (MCH), a compound that can be transported at ambient temperature and pressure. The process is called toluene hydrogenation:

Chemical reaction: $C_7H_8 + 3H_2 \Leftrightarrow C_7H_{14}$

**Logic and assumptions:** The reactor operates at 240°C and 20 bar for nearly complete conversion. The conversion is kinetically limited. The energy efficiency of toluene hydrogenation is approximately 95%.

Similarly to the other carriers, 2 smaller trains in parallel are considered, which are more expensive than a single train, but have higher flexibility and reduce the required $H_2$ buffer storage capacity. However the minimum turn-down rate is higher than the other carriers, set at 50%. This depends on

[19] https://www.chiyodacorp.com/en/service/spera-hydrogen/

the scale at which the technology is implemented & on the specific design of the plant. It's unclear at this point how flexible such a hydrogenation plant would be, so 50% is a safe assumption.

The power consumption of an LOHC plant is estimated 0.4 kWh/kg $H_2$. Finally the utilization of the plant is set at 95%, which is a typical value used for industrial-scale chemical plants that shut down periodically for inspection and maintenance.

**Techno-economic input data:** The techno-economic input parameters are reported as datasheet C5 [in D7B.1 DOI hyperlink and D7B.2 DOI hyperlink]. The anchor capacity is 4200 ktpa MCH, which is very close to target capacity, and it requires minimal scaling. This results in accurate cost estimation. An installation factor of 1.45 is used, while the scaling factor is 0.66, assumed to have the same economy-of-scale as ammonia plants.

**Variance over time:** The process is not mature yet, so improvements in efficiency and cost are expected in the coming years. However, there are not enough data available, so no change of parameters was considered for the next 20 years was considered in this study.

### A5.2.12 LOHC-to-hydrogen reconversion

**Function:** The dehydrogenation of methylcyclohexane (MCH) is a reversible reaction in which MCH is dehydrogenated to toluene and hydrogen in the forward reaction:

$$\text{Chemical reaction: } C_7H_{14} \Leftrightarrow C_7H_8 + 3H_2$$

**Logic and assumptions:** The reactor operates at 350°C and 2 atm. Conversion is 98% with 99.9% toluene selectivity. No side-reactions are considered. An overall of 90% recovery, including the purification steps, is assumed in this study. The heat consumption for the dehydrogenation is set at 9.4 kWh/kg $H_2$ and the power consumption at 1.5 kWh/kg $H_2$. Additionally, 1.85 kWh/kg $H_2$ are required to raise the $gH_2$ pressure from 3 to 70 bars. The heat need is supplied using $H_2$ product, which corresponds to 18% of total $gH_2$ product.

The overall energy efficiency is 89.9%, which is relatively high, despite the fact that 18% of produced $H_2$ is used for heating. The reason behind this, is that large amounts of toluene are released. Toluene has a LHV equal to 40.6 MJ/kg, and it is included in the total energy balance calculations.

**Techno-economic input data:** The anchor capacity is 4200 ktpa MCH which is very close to the target capacity. It requires minimal scaling, which leads to more accurate cost estimation. A scaling factor of 0.65 is used. Additional cost to the reconversion step, is the compressor to meet the $gH_2$ product specification. The compressor cost is calculated using a specific CAPEX formula (M€/MWe) for different motor power. The installation factor is 3 both for the reconversion plant and the extra compressor to raise the $gH_2$ pressure to 70 bars.

**Variance over time:** The LOHC dehydrogenation is not extensively studied. It is expected that new catalysts will be developed in the coming year, enhancing the conversion and efficiency of the process. The $H_2$ compression technology attracts a lot of interest, so we can expect small improvements in that part over the coming years. However the cost reduction over the coming years is difficult to estimate.

### A5.2.13 Compressed hydrogen chain

Pipeline transport for hydrogen gas is an attractive alternative shipping chains due to its very large capacities and transport distances. While only 4500 km of hydrogen pipeline infrastructure is currently operational globally, with the longest trace spanning 500 km, there are multiple future scenarios under consideration in which a large-scale hydrogen backbone infrastructure is developed using parts of the natural gas infrastructure in Europe. It is this grid that is assumed to be the means of transport in the compressed hydrogen import chain. The diagram (Figure 42) illustrates the basic principle of a $H_2$ supply chain using this approach.

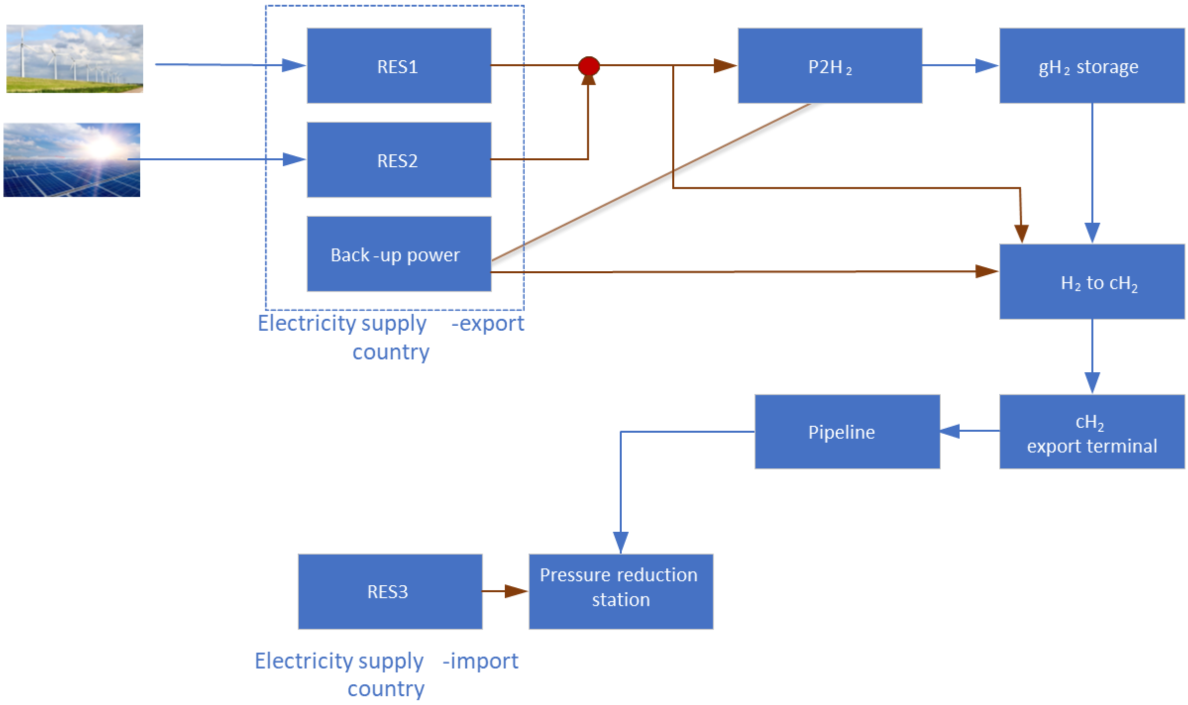



*Figure 42 Block diagram illustrating the proposed configuration for a gaseous hydrogen pipeline chain*

**Function:** Transport compressed hydrogen gas by means of an international pipeline infrastructure network.

**Logic and assumptions:** The gaseous hydrogen is assumed to be transported using a dedicated pipeline towards an international hydrogen backbone network, and subsequently the utilization of this backbone to transport the gas to the Netherlands.

<u>$CH_2$ export terminal and dedicated pipeline:</u> For this first dedicated pipeline it is assumed that the electrolyzer is at 100 km distance from the general International Hydrogen Backbone and for the specific hydrogen production site these 100 km of pipeline will need to be built. In addition to this pipeline, an export station with compression equipment are assumed at the location of production. For the 100 km new pipeline, greenfield investment costs and maintenance are taken into account.

The pipeline for hydrogen systems usually operate at 20-40 bar (40-80 for Natural Gas). Overpressure is required to more easily control the flow rate that is injected. Choking conditions are established when the pressure ratio is above the critical value, which is roughly a factor of 2 for hydrogen. Hence, it is assumed that the $cH_2$ storage pressure in the export terminal is 80 bar (higher that 60 bar in order to ensure choking conditions and also save some storage space). This higher pressure is assumed to be preferred as it provides more flexibility and control in operation.

The backbone feed-in agreements between the backbone operator and the hydrogen supplier are simplified in this study. While the actual feed-in profile depends on the type of contract, a flat profile and corresponding contract is assumed in this study and it is assumed that the large international network of pipeline is able to deal with feed-in mass flow fluctuation.

After the hydrogen is produced at 30 bar, a 30-to-80 bar compression is assumed. A storage tank is included in between the compressor and the pipeline to (partially) regulate the feed-in mass flow. To size the compression equipment, the power requirements are computed using the following formula[20]:

$$\dot{W} = \dot{m} \cdot \frac{R\, T_1}{M_w} \cdot \frac{\gamma}{\gamma - 1} \cdot \frac{Z_1 + Z_2}{2} \cdot \frac{1}{\eta_s\, \eta_m} \left[ \left( \frac{P_2}{P_1} \right)^{\frac{\gamma-1}{\gamma}} - 1 \right]$$

where:

- $\dot{m}$ the mass flow rate (in [kg/s])
- $P$ the pressure of the compressor at suction (1) and discharge (2),
- $Z$ the hydrogen compressibility factor at suction (1) and discharge (2),
- $T$ the inlet temperature of the compressor (333.15 K),
- $\gamma$ the specific heat ratio (1.4),
- $M_w$ the molecular mass of hydrogen (2.016 kg/kmol),
- $\eta_s$ the isentropic compressor efficiency (80% [21]),
- $\eta_m$ the mechanical losses from the driver (98%),
- $R$ the universal constant of ideal gas R = 8314 J/(K kmol).

For feed-in to the network pressure will need to be above roughly 45 bar. Feed-in is based on waterfall principles where the higher-pressure gas flows into the lower-pressure backbone pipelines, through which the differences in pressure are eliminated at the feed-in point. It is assumed that within 100 km of standard pipeline the pressure drop will be small enough to ensure that pressure at the connection with the European network will be high enough to ensure feed-in. Hence no additional compression is needed for the 100 km of private pipeline. When increasing the length of dedicated pipeline, it should be reassessed whether additional compression is necessary.

<u>International $cH_2$ backbone network:</u> For this study it is assumed that a pipeline network connecting a wide range of countries amongst which Morocco, the United Kingdom, Iceland and the Netherlands is operational from 2030 onwards. The feasibility of this backbone is considered beyond the scope of this study. Despite the variety of challenges that would need to be overcome to realize this backbone system, it is still considered useful to assess the range of costs of pipeline transport and compare these costs with the cost of hydrogen carrier shipping.

A tariff logic is assumed to represent the cost of transportation via this network. The cost of transport, and thus the utilization cost of such a large-scale networked infrastructure, is considered highly uncertain.

[20] NorthSeaEnergy: Technical assessment of Hydrogen transport, compression, processing offshore Microsoft Word - FINAL NSE3-D3.1 Final report technical assessment of Hydrogen transport, compression, processing offshore.docx (north-sea-energy.eu)
[21] From OEM catalogues.

**Techno-economic input data:**

CH$_2$ export terminal and dedicated pipeline: The techno-economic input parameters are reported as as datasheets C1 and ST1 [in D7B.1 DOI hyperlink and D7B.2 DOI hyperlink].

International cH$_2$ backbone network: As the transport cost uncertainty is substantial, this study considers one low cost of 60 €/ton H$_2$, and one high cost extreme of 2000 €/ton H$_2$. These extreme values are adopted from Energy Transition Study (2021)[22]. ETS (2021) concludes that "*transmission pipeline costs could range from $0.05/kg for a few kilometers, to $0.5-3/kg for intercontinental distances (1000 km to 5000 km). However, as hydrogen use grows, ultra-high-capacity transmission lines may be developed to transport up to 6000 tonnes per day, adding only $0.07-0.23 per kg and 1000 km, based on Guidehouse (2020)*[23]*"*.

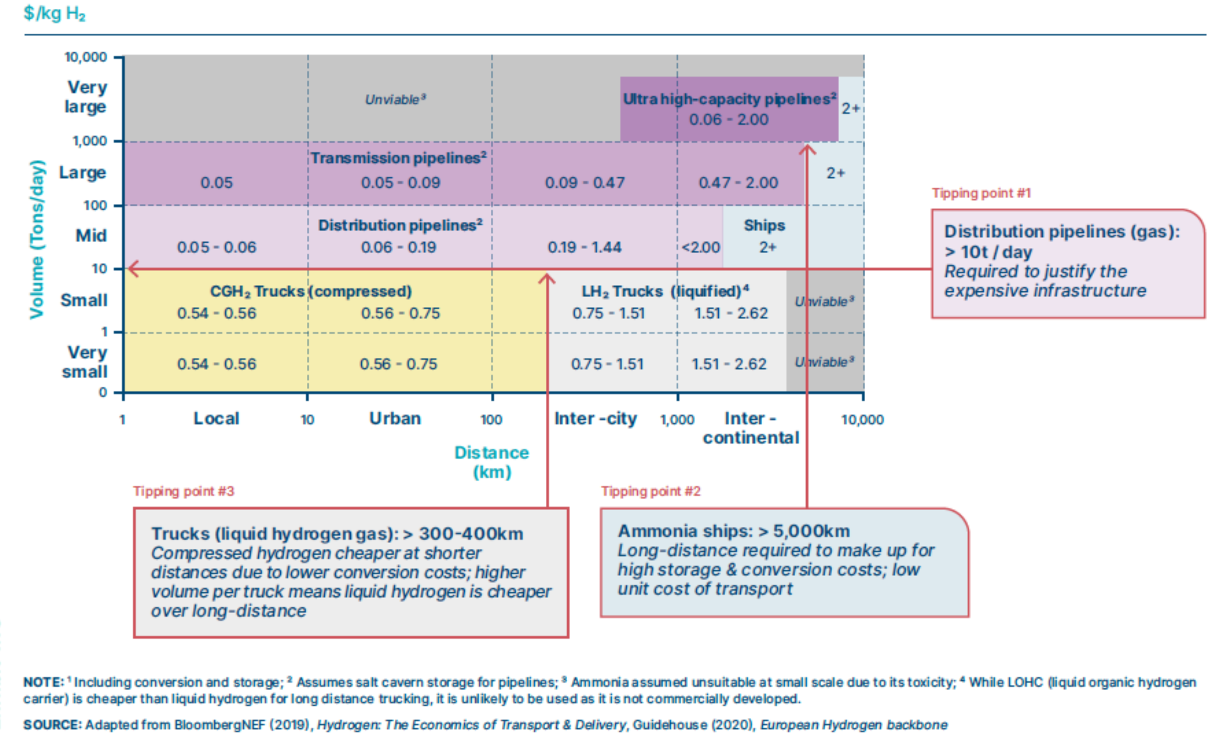



*Figure 43 Lowest cost form of hydrogen transportation [1] based on volume and distance*

**Variance over time:**

CH$_2$ export terminal and dedicated pipeline: No cost reductions over time are assumed for the dedicated compression and pipeline assets as both are mature technologies.

International cH$_2$ backbone network: The large cost range for international pipeline transport is considered for both 2030 and 2040.

## A5.3 Export and import terminals (all shipping chains)

**Function:** Import and export terminals are the required steps to load the ships with the produced

[22] Energy Transition Commission (2021) Making the hydrogen economy possible: accelerating clean hydrogen in an electrified economy, April 2021, V1.2
[23] Guidehouse (2020) European hydrogen backbone

hydrogen carrier and to unload the ships to proceed with the reconversion. In case of compressed $H_2$, import terminal is not required, and export terminal constitutes only of storage tanks.

**Logic and assumptions:** Import and export terminal storage is designed in the same way for all carriers. It sized using the maximum size of a single storage vessel. This means that no optimization of the costs was done (e.g. using two smaller vessels with completely utilized capacity vs. two large vessels in which only in the one vessel a storage capacity is completely utilized). Both import and export terminals include storage tanks, a jetty, a pipeline and loading facilities. In every case (each hydrogen carrier), one jetty is needed. In ammonia, methanol and liquid hydrogen case the reference jetty is downscaled from a reference capacity of 4000 ktpa, while in the LOHC case, the reference capacity is almost similar to the required capacity.

In every case, the energy efficiency of the storage in terminals is assumed to be 100%, apart from the $LH_2$ where refrigeration requires a noticeable amount of power. The import terminal of $LH_2$ shows an energy efficiency of 98.2%. This is because the power consumption is 0.61 kWh/kg $H_2$ for the refrigeration of liquid hydrogen storage. Also, the storage required is higher for in the import than in the export terminal due to the vessel fuel consumption and thus shipping efficiency loss.

**Techno-economic input data:** The techno-economic input parameters are reported as datasheet T1 and T2 [in D7B.1 DOI hyperlink and D7B.2 DOI hyperlink]. The terminal cost is constituted from the storage tanks, the jetty and the pipeline. The storage is by far the most costly element of the three, accounting from 88% (MeOH case) up to 99.8% (cryogenic storage $LH_2$) of the total terminal cost. Assumed hydrogen pipeline costs are 13M€/km. The jetty is estimated at 4M€ for capacity 4000 ktpa of any hydrogen carrier. The scaling factor for the jetty is 0.67 and a jetty flow capacity design is developed at 120% of the required capacity. The fixed OPEX rate is set at 2% for the jetty and 2.5% for the pipeline terminal. The cost of loading facilities is included in the jetty calculations.

**Variance over time:** No improvements are expected over the next years in the terminals cost. The cost variation until 2040 is considered negligible.

### A5.4 Bulk carrier ship transport (all shipping chains)

**Function:** Hydrogen is transported form the country of production to the Netherlands. The transport of compressed gaseous hydrogen is conducted via pipeline, which is restricted by the distance of the two countries. In the model there is no such a limitation, but it should be noted that the option of transferring compressed $gH_2$ is only suitable for countries in close distance to the Netherlands (eg. Europe).

The transport of ammonia, methanol, liquid hydrogen is conducted via shipping, where there are no restrictions on the distance.

**Logic and assumptions:** The easiest carriers to transport are MeOH and LOHC because of their liquid state in atmospheric conditions. Ammonia requires refrigeration at -33 °C, and $LH_2$ requires cryogenic tanks of -253 °C. Shipping is sized using the maximum ship capacity for each carrier. No optimization on the costs regarding shipping was considered, and no variation in shipping sizes is considered. For example using a smaller ship size if some of the large shipping capacity is not completely utilized. This can have important impact on the results especially when taking the long-transportation countries into account.

The maximum capacity (ktons) per ship and the cost of such ship are determined for each carrier, using different citations. The shipping speed is approximately 29 km/h and the energy consumption of each ship is determined in GJ/km. Using the Lower Heating Value of each fuel, the mass of fuel per trip is calculated. In every case, the ships use their own cargo as a fuel, apart from the case of LOHC. The LOHC cargo is used to produce $H_2$ fuel using a reconversion plant that is installed on the ship. $H_2$ is utilized in fuel cells, whereas $NH_3$ and MeOH fuels are utilized in ICE engines (combustion). According to C-job Naval experts the combustion efficiency is 50% for $NH_3$ and MeOH and the efficiency of $H_2$ PEM fuel cell is 53.7%. The latter value contradicts with the 60% assumed at IEA, but it was decided to use the data from C-job Naval.

The LOHC reconversion plant of every ship is designed to dehydrogenate hydrogen for ship fuel usage and an oversizing factor of 1.4 is used to provide sufficient to accommodate higher fuel consumption rates. Finally, no boil-off is considered for $LH_2$, after suggestion of DNV. According to TNO and DNV experts, the vessel can be sealed appropriately, so that boil-off starts after 40 days. In the current study, all trips last less than 40 days, so boil-off rate is set to 0%.

The maximum ship capacities for each carrier are:

| | | |
|---|---|---|
| $NH_3$: | 52.15 ktons | $H_2$ content: 9.2 ktons |
| MeOH: | 95.04 ktons | $H_2$ content: 11.88 ktons |
| $LH_2$: | 3.55 ktons | $H_2$ content: 3.55 ktons |
| LOHC: | 104.04 ktons | $H_2$ content: 6.35 ktons |

**Techno-economic input data:** The techno-economic input parameters are reported as datasheet SH1 and SH2 [in D7B.1 DOI hyperlink and D7B.2 DOI hyperlink]. Techno-economic optimization is possible by optimizing the size of ships, based on the frequency of the trips and the hydrogen demand. Additionally, the ships are assumed to be empty of cargo in the return-trip, which is highly uneconomical. Business integration and transport of different cargo from the Netherlands to the other country would greatly impact the economics of the project.

**Variance over time:** Significant improvements are expected over the next years in the shipping of/ hydrogen carriers, especially in terms of maximum tank capacity. This is considered in all hydrogen carriers, reaching an increase of up to 3 times by 2040 in maximum capacity of $LH_2$. However, there is uncertainty for the long future which restricts the current study. A few specific energy consumption, ship capacity and cost data are missing for either 2030 or 2040 for every hydrogen carrier.

The transport of compressed gaseous hydrogen is conducted via pipeline. The pipeline is restricted by the location of the hydrogen production. In the model there is no such a limitation, but it should be noted that the option of transferring compressed $gH_2$ is only suitable for countries in close distance to the Netherlands (e.g. North African countries and UK).

## A6. Input data quality and integrity

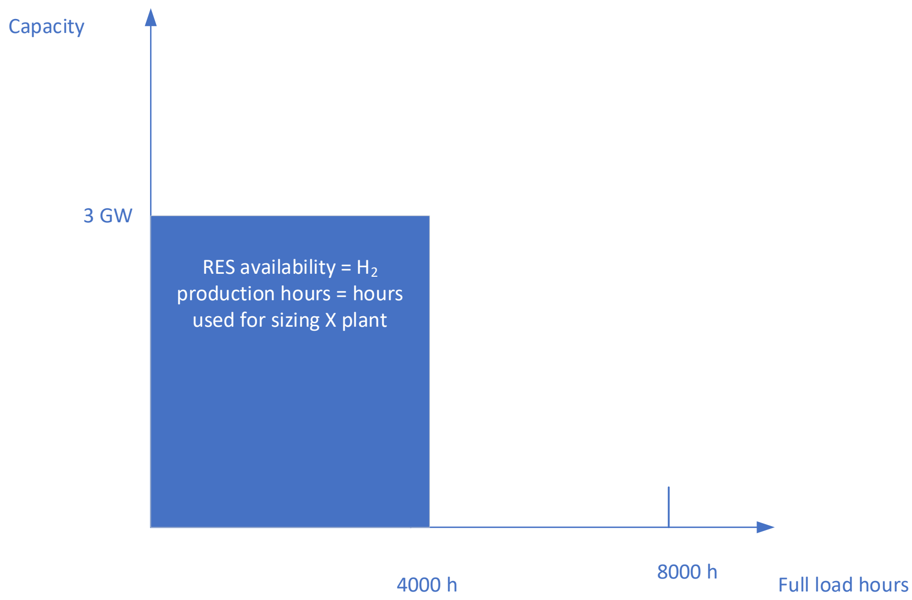
The logic and input parameters are based on various already existing models and recent reports and studies[24] carried out for TNO in cooperation with market parties, and by third parties. The model thus contains the most recent data of different technologies in the import chains available to TNO at the time of this study. Cost data in the datasheets is not inflation-corrected.

It is important to note that conversion plant CAPEX and scaling factor are highly uncertain parameters. Currently the infrastructure of this type and scale does not exist. Final cost estimates are also highly sensitive to these parameters. Thus, it is useful to study the input parameters and their sensitivities in more detail. Roughly speaking, the accuracy of the estimations in cost estimates may be +/- 50% per process block.

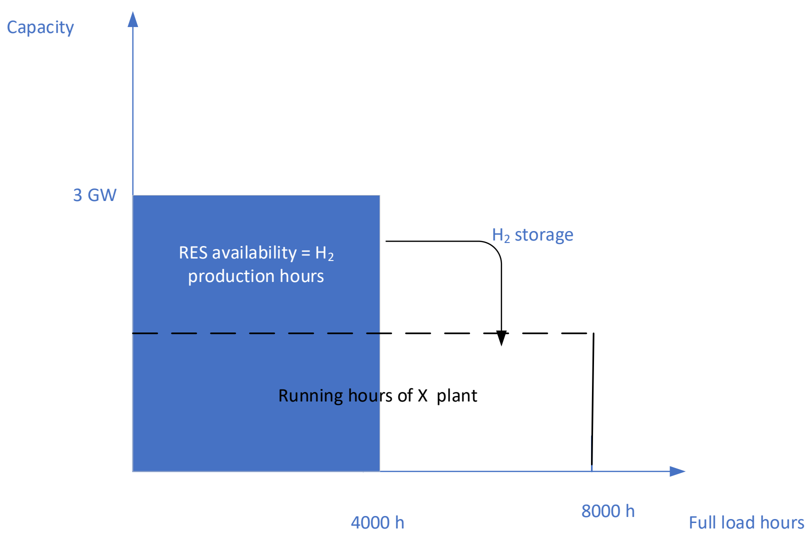
[24] E.g. HyChain 2 model en HyChain 3 database, North Sea Energy 1-4, VoltaChem Power-2-integrate studies, HyDelta, TNO energy.nl factsheets

# Appendix B: Dimensioning decision of carrier production asset capacity

The hydrogen-to-X technology is sized and costed on the max $PtH_2$ production capacity. This implies a major oversizing of the X plant, as the X plant would then only be operational more or less for the half the year.




When using this assumption, a conservative approach was taken in scaling the different supply chain elements. Thereby avoiding discussion on the optimization of the hydrogen storage size, for which dynamic studies would be required. It is advised that more attention is given to this topic, by evaluating RES profiles and determining actual hours in which $H_2$ excess production or deficit is expected, and how intermediate hydrogen storage can aid in smoothing the hydrogen production profile. This will imply longer operating hours of the X plant and a decrease of installed plant capacity (and thus CAPEX), as show in the following figure.



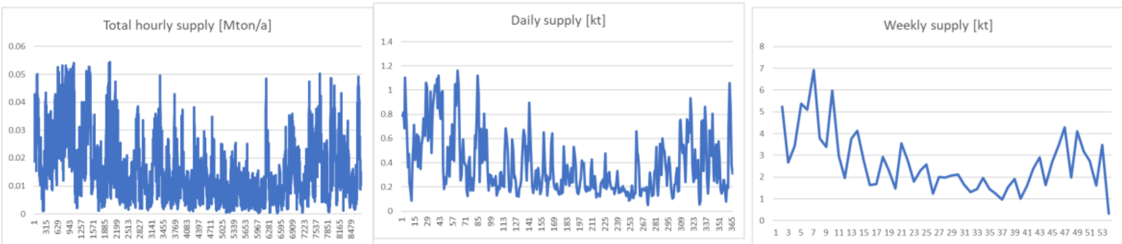
*Justification of the conservative asset scaling:*[25]

To be able to downsize the $H_2$-to-X plant and increase the operational hours of the trains producing X, the cH2 storage facilities should facilitate a constant cH2 supply. Thereby leveling out the intermittent cH2 production that follows the intermittent RES profile. A quick scan of the required storage capacity of cH2 is presented below. On the basis of this scan, we currently conclude it is **not** realistic to add this logic into the Supply Chain Model.

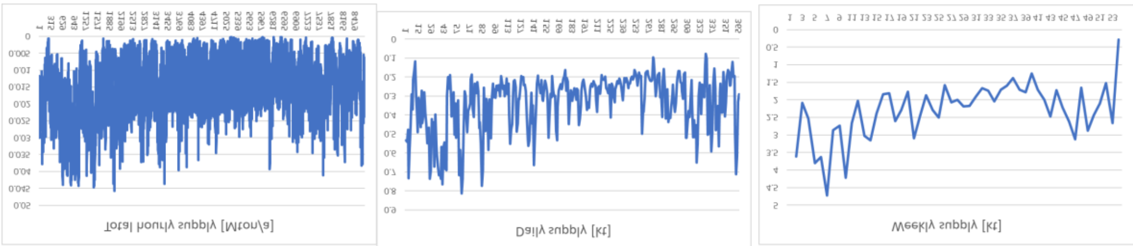
*Step 1: Assume an intermittent compressed $H_2$ production profile*

3 GW of AEL capacity, fed by 3 GW of a combined wind and solar farm in Spain (high renewable harvesting potential with wind and solar profiles from EMHIRES database[26]). The high wind and high solar profiles have an average Load Factor of 28% and 17% respectively.

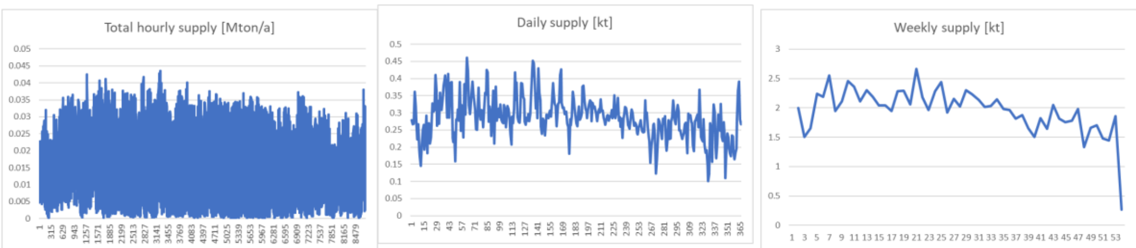
Configuration A: 80% wind, 20% solar capacity




Configuration B: 50%/50%



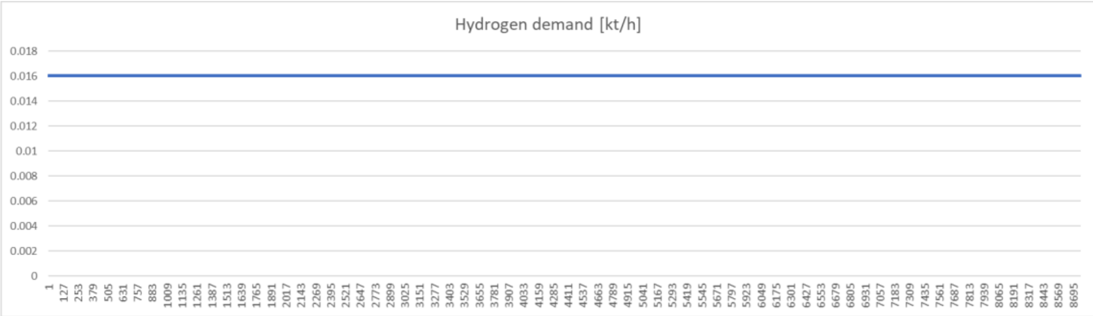

Configuration C: 20%/80%




*Step 2: assume a constant $cH_2$ demand profile*

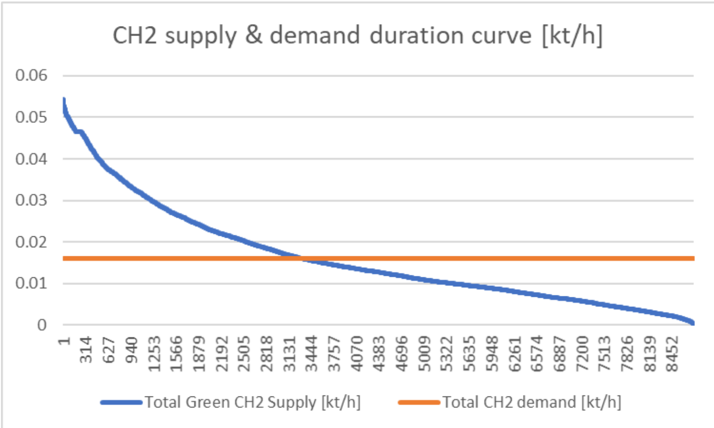
The sum of the annual hydrogen production is divided by 8760 hours to determine the hourly $cH_2$ demand of the industrial feedstock needs of the hydrogen-to-X plant: 0.016 kt/h

[25] All graphs: Copy of Entec_model_v3_SC_Test.xlsx
[26] EMHIRES dataset . Part I, Wind power generation - Publications Office of the EU (europa.eu)



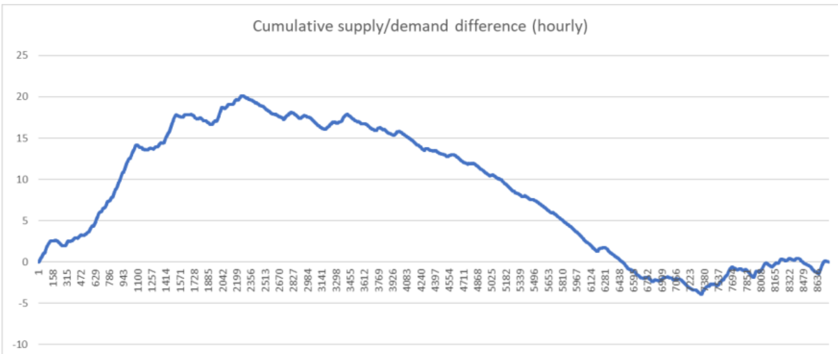

*Step 3: Determine the required* c$H_2$*storage capacity to match supply and demand*

The mismatch of supply and demand becomes visible when reorganizing the hours in a load duration curve. Hours of over and underproduction of c$H_2$ are both clearly present. The challenge is to deal with the mismatch over time.

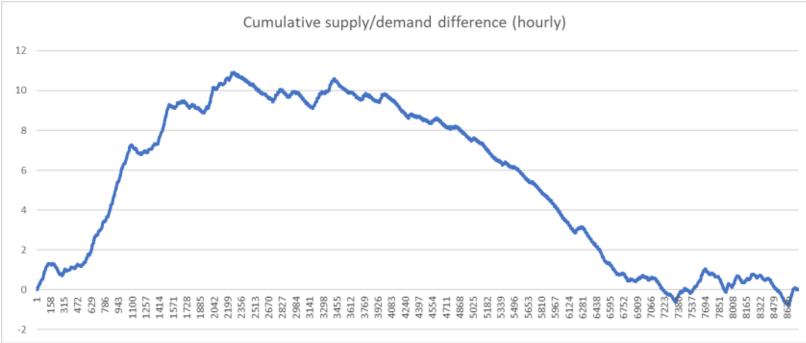



The total required c$H_2$ storage capacity is found by calculating the cumulative delta between supply and demand, and subsequently calculating the difference between the maximum excess c$H_2$ and shortage of c$H_2$. With the subsequent storage capacity, one year of c$H_2$ supply can be flattened out to match the continuous demand.

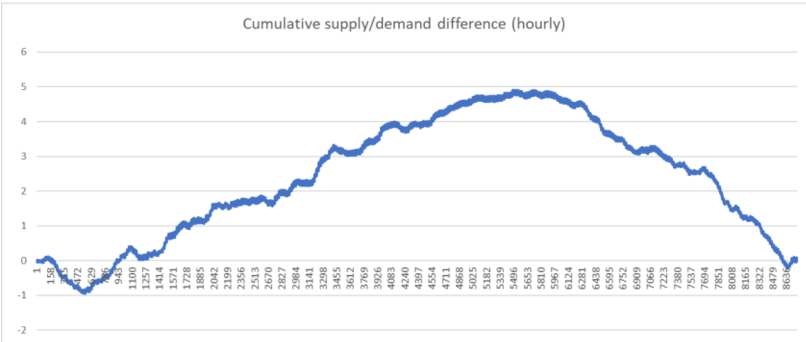
Configuration A: Storage requirement 24060 ton




Configuration B: Storage requirement 11720 ton




Configuration C: Storage requirement 5840 ton




*Step 4: Determining the amount of storage assets required*

Assuming that one $cH_2$ storage tank has a max. capacity of 0.5 ton of $cH_2$ (150 bar), configurations A, B and C need 48120, 23440 and 11680 tanks respectively. Alternative storage options (salt caverns, depleted gas fields and liquid $H_2$ storage) are not yet considered in the model but can reduce the amount of tanks needed drastically (against a higher (levelized) cost).

***Concluding remark regarding the conservative scaling approach:***

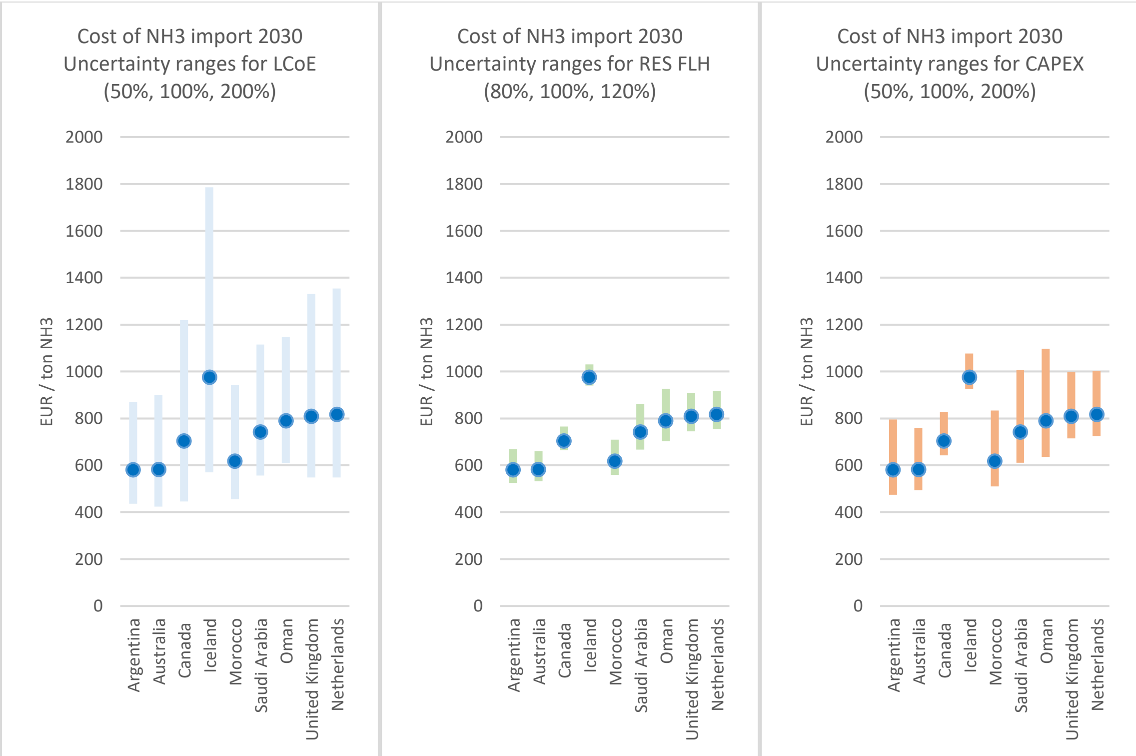
**Needless to say, it is unrealistic to assume that this amount of tanks will be built to facilitate the flattening of the intermittent $cH_2$ production and minimize the $H_2$-to-X plant size. To determine the optimal 'plant oversizing', amount of storage required ánd operational hours of the $H_2$-to-X plant, a site-specific and dynamic analysis is required taking into consideration the RES profiles, installed RES capacity, operational modes of the $PtH_2$ electrolysis, storage capacity and risk-mitigating buffer margins and a more detailed operational behavior of the $H_2$-to-X plant.**

As the main goal of using the Supply Chain Model is to be able to compare different supply chains, the assumptions and operational logic of each supplying country and different carrier needs to be as similar as possible. Time and resources are currently insufficient to thoroughly analyse the above mentioned dynamic behaviour and subsequent scaling. Therefore, the conservative scaling decision for oversized $H_2$-to-X plant is justified.

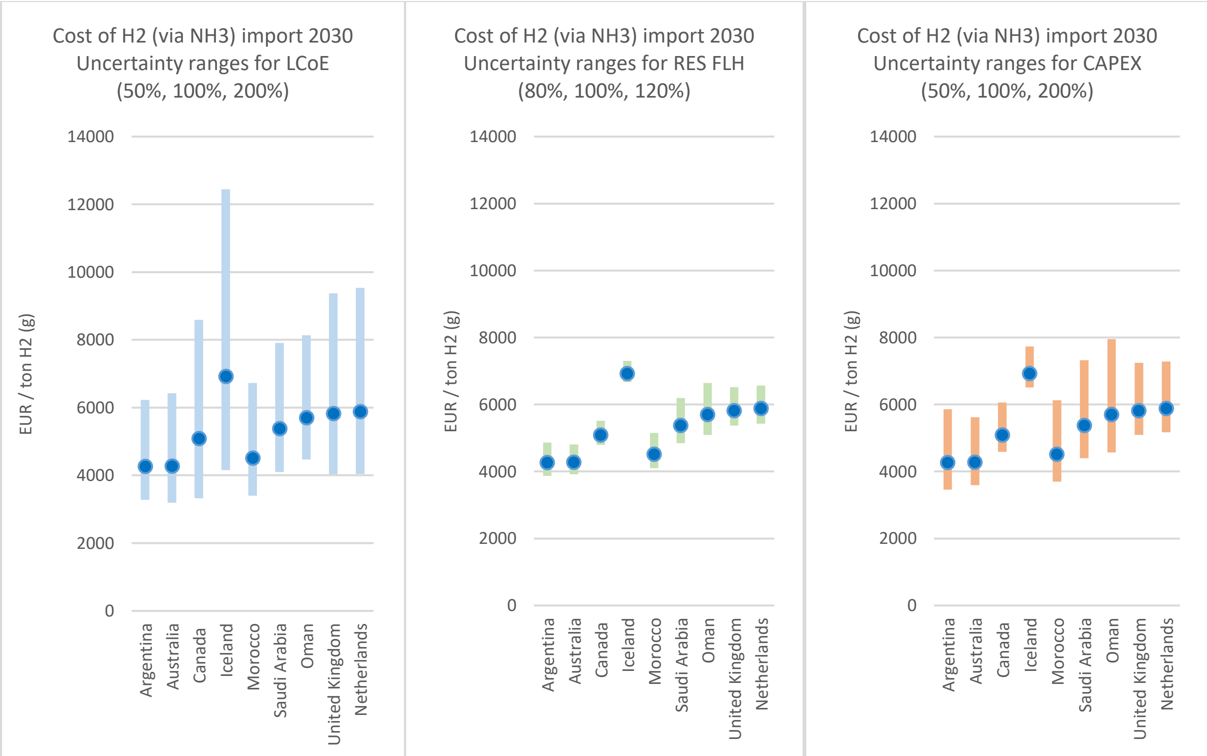
# Appendix C: Sensitivity analysis results

For all carriers, the sensitivity analysis results for 2030 have been plotted for the LCoE (50% - 100% - 200%), RES FLH (80% - 100% - 200%) and CAPEX (50% - 100% - 200%) parameters. Finally, also the combined sensitivity results are presented.

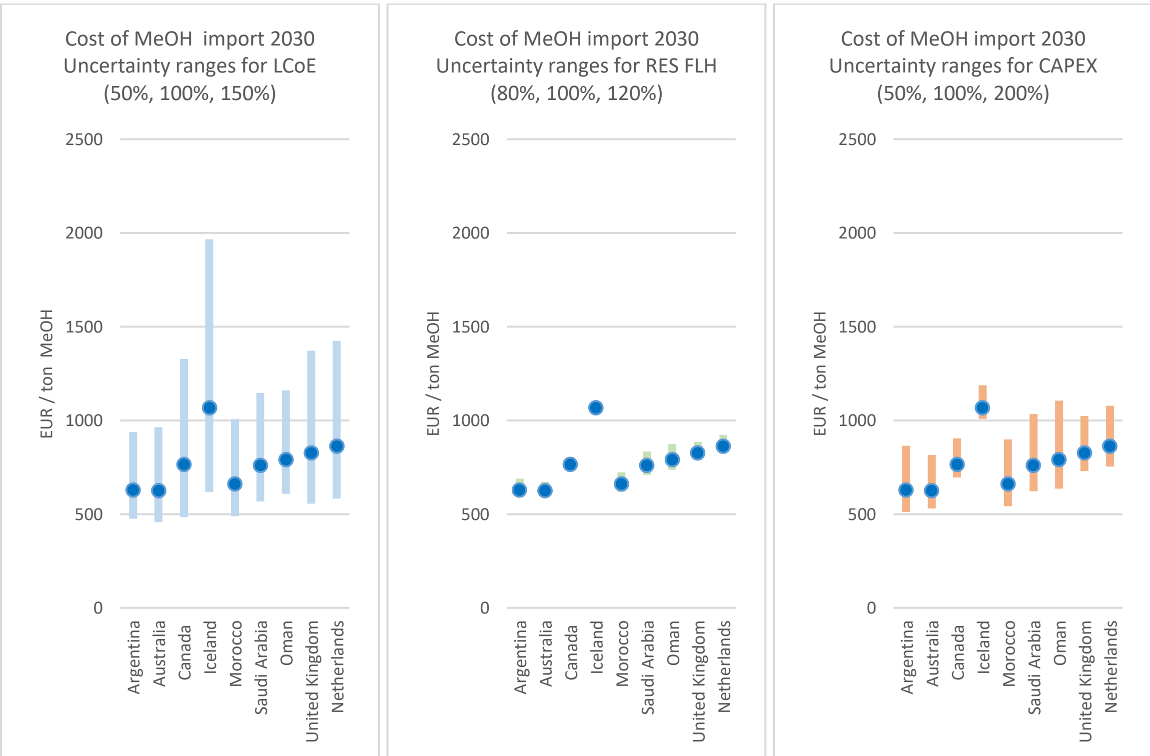
## C1.1 Sensitivity analysis results of ammonia import



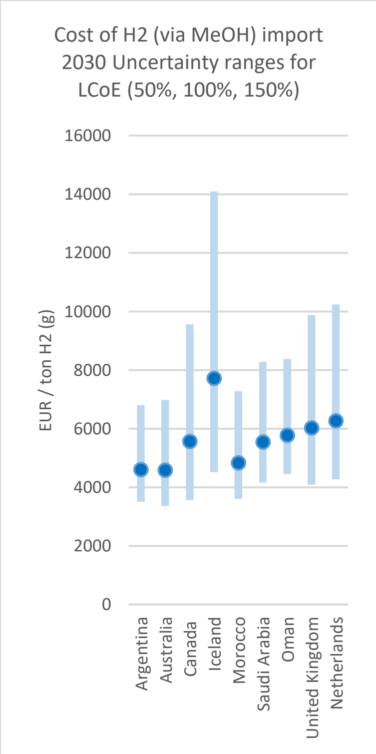
## C1.2 Sensitivity analysis results of hydrogen import through ammonia

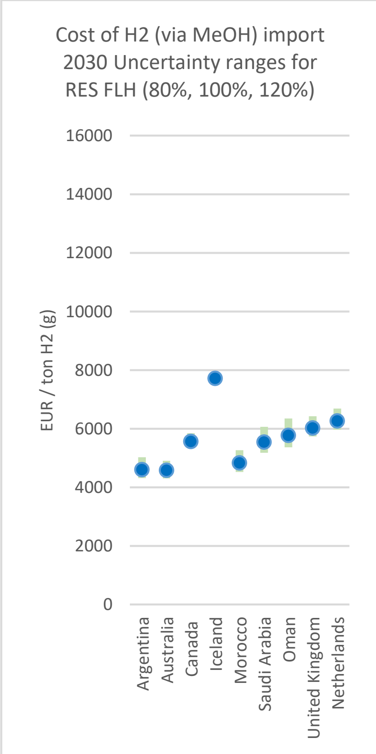


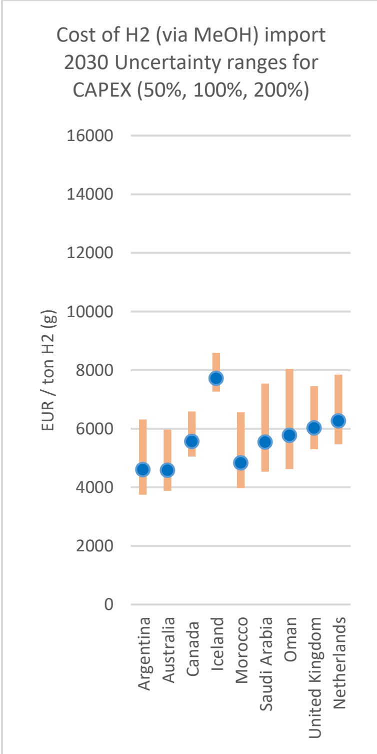

## C1.3 Sensitivity analysis results of methanol import



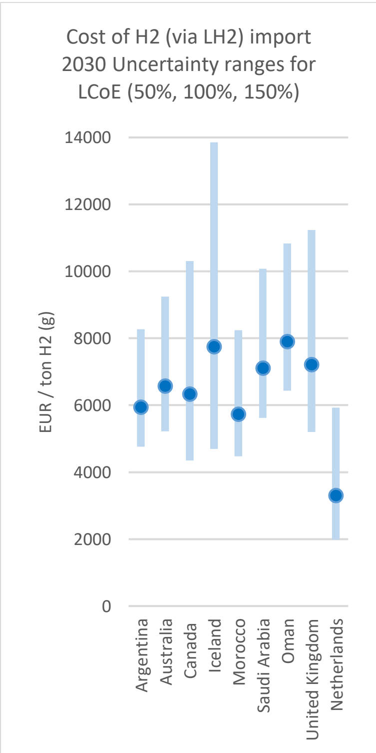
## C1.4 Sensitivity analysis results of hydrogen import through methanol

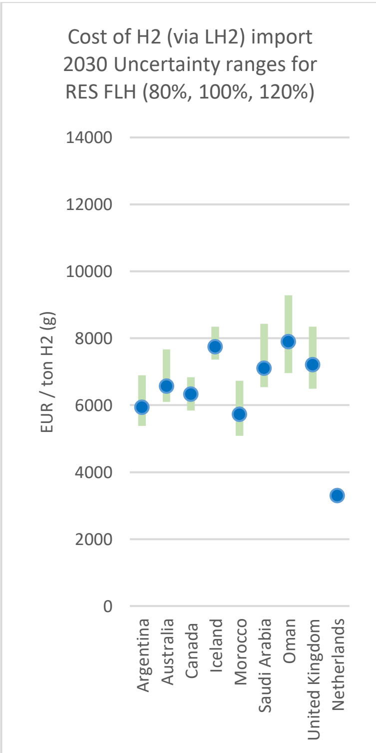


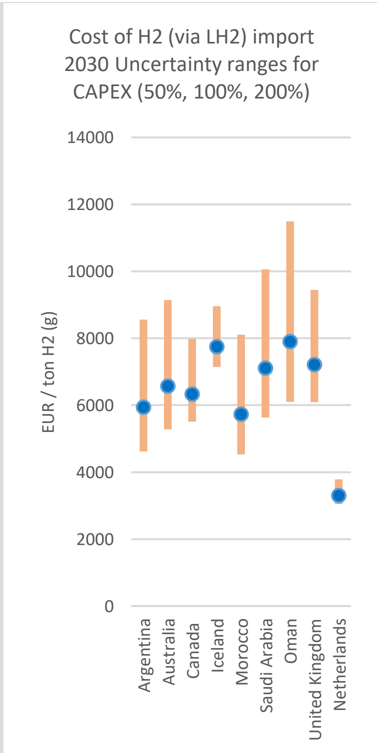



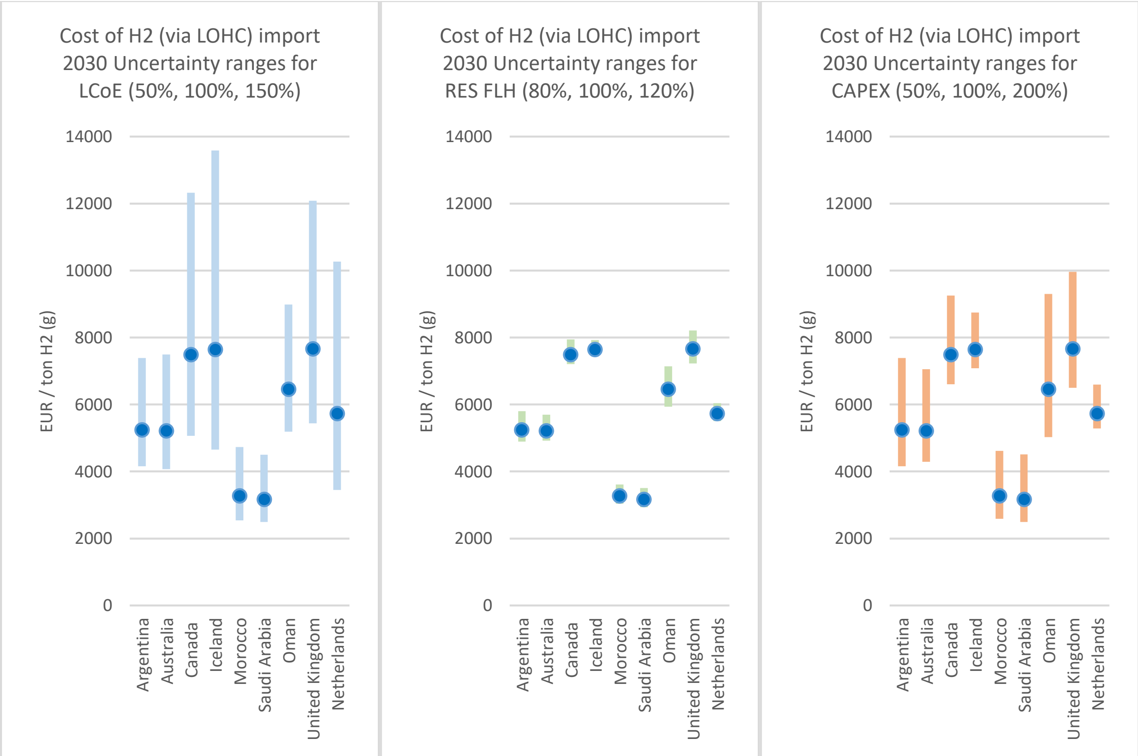

## C1.5 Sensitivity analysis results of liquid hydrogen import



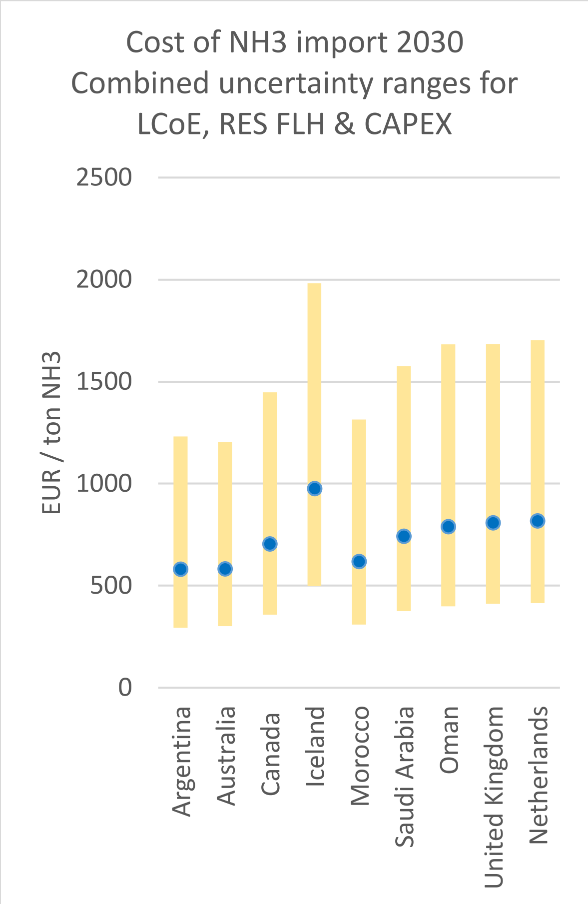



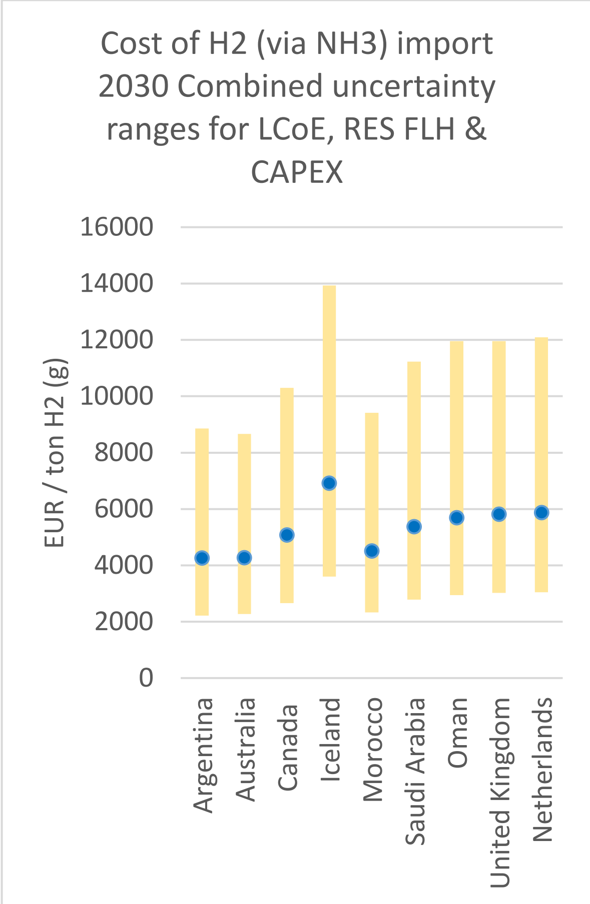
## C1.6 Sensitivity analysis results of hydrogen import through LOHC

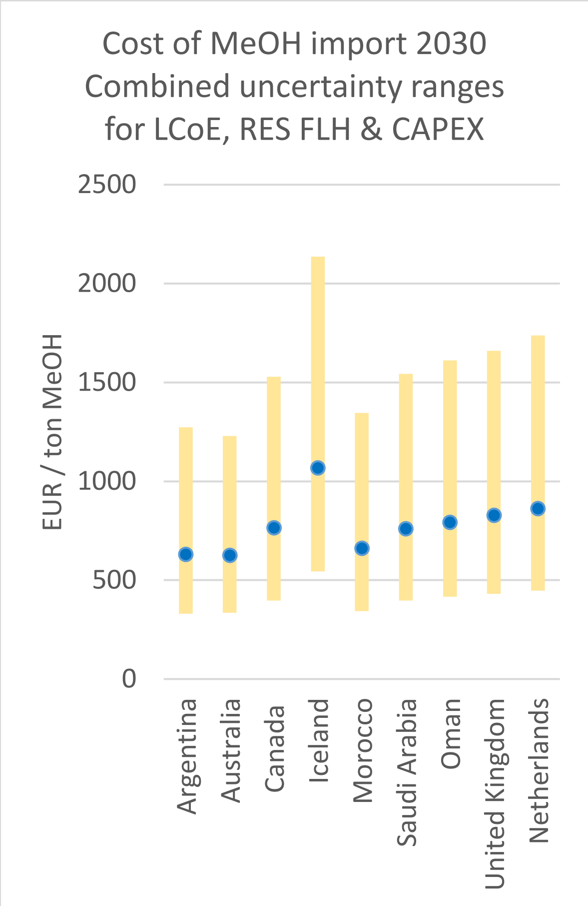


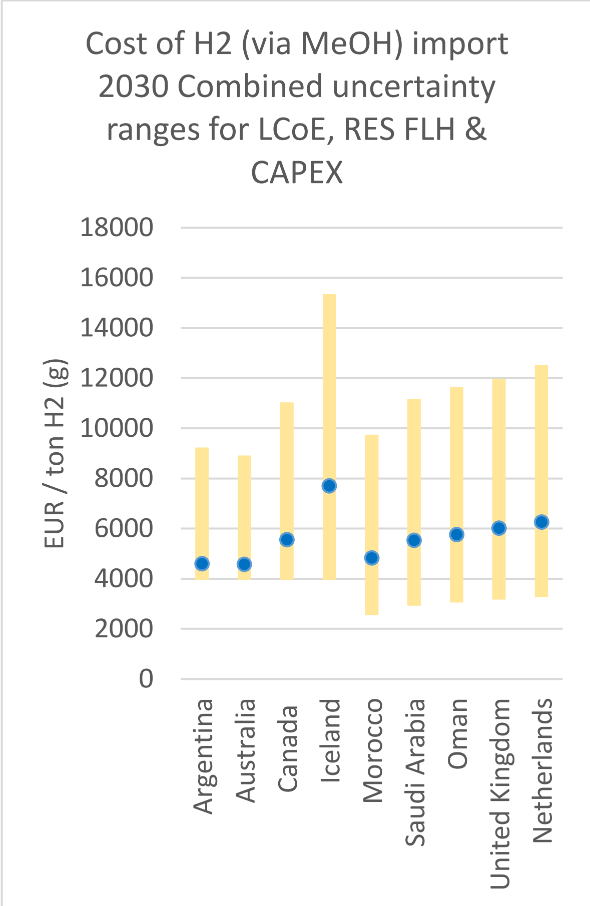
## C1.7 Cumulative Sensitivity analysis results

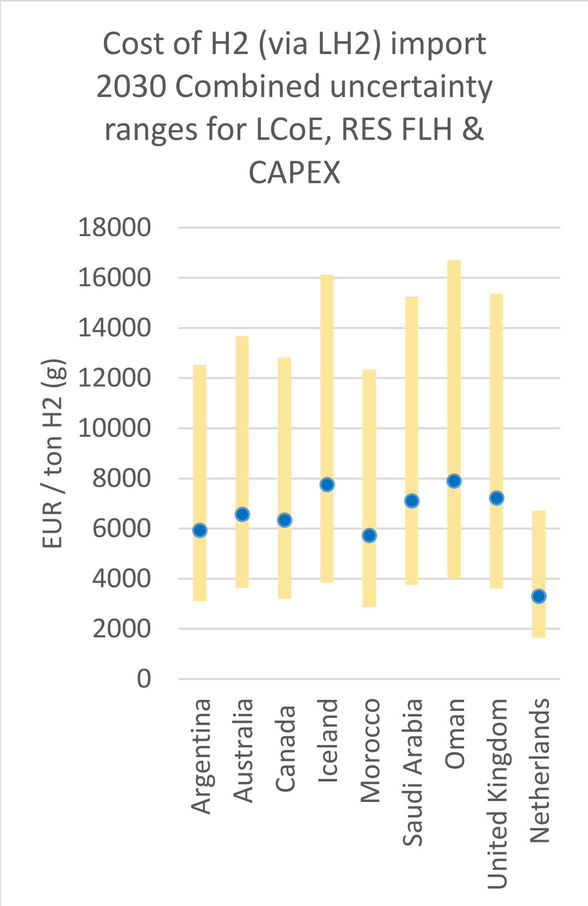
Running the model with all sensitivity parameters combined, results in the following graphs. The lowest import cost result is the outcome of a low LCoE, a high RES FLH and a low CAPEX, whereas the highest import cost result is the outcome of a high LCoE, a low RES FLH and a high CAPEX. The cumulative sensitivity gives a more realistic range of the import cost prices, as in practice these three variation in these three parameters can occur simultaneously.

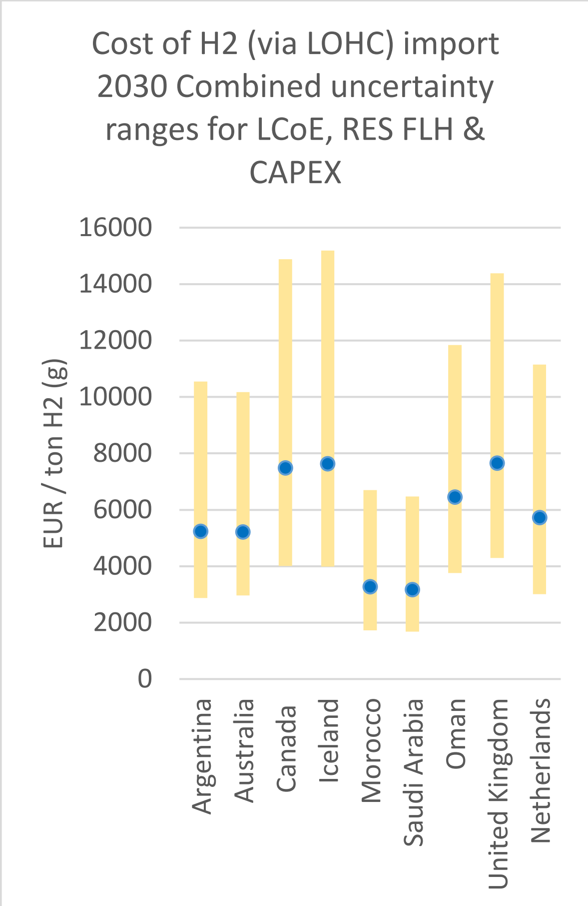



Cost of MeOH import 2030 Combined uncertainty ranges for LCoE, RES FLH & CAPEX
EUR / ton MeOH
2500
2000
1500
1000
500
0
Argentina
Australia
Canada
Iceland
Morocco
Saudi Arabia
Oman
United Kingdom
Netherlands


Cost of H2 (via MeOH) import 2030 Combined uncertainty ranges for LCoE, RES FLH & CAPEX
EUR / ton H2 (g)
18000
16000
14000
12000
10000
8000
6000
4000
2000
0
Argentina
Australia
Canada
Iceland
Morocco
Saudi Arabia
Oman
United Kingdom
Netherlands


Cost of H2 (via LH2) import 2030 Combined uncertainty ranges for LCoE, RES FLH & CAPEX
EUR / ton H2 (g)
18000
16000
14000
12000
10000
8000
6000
4000
2000
0
Argentina
Australia
Canada
Iceland
Morocco
Saudi Arabia
Oman
United Kingdom
Netherlands


Cost of H2 (via LOHC) import 2030 Combined uncertainty ranges for LCoE, RES FLH & CAPEX
EUR / ton H2 (g)
16000
14000
12000
10000
8000
6000
4000
2000
0
Argentina
Australia
Canada
Iceland
Morocco
Saudi Arabia
Oman
United Kingdom
Netherlands