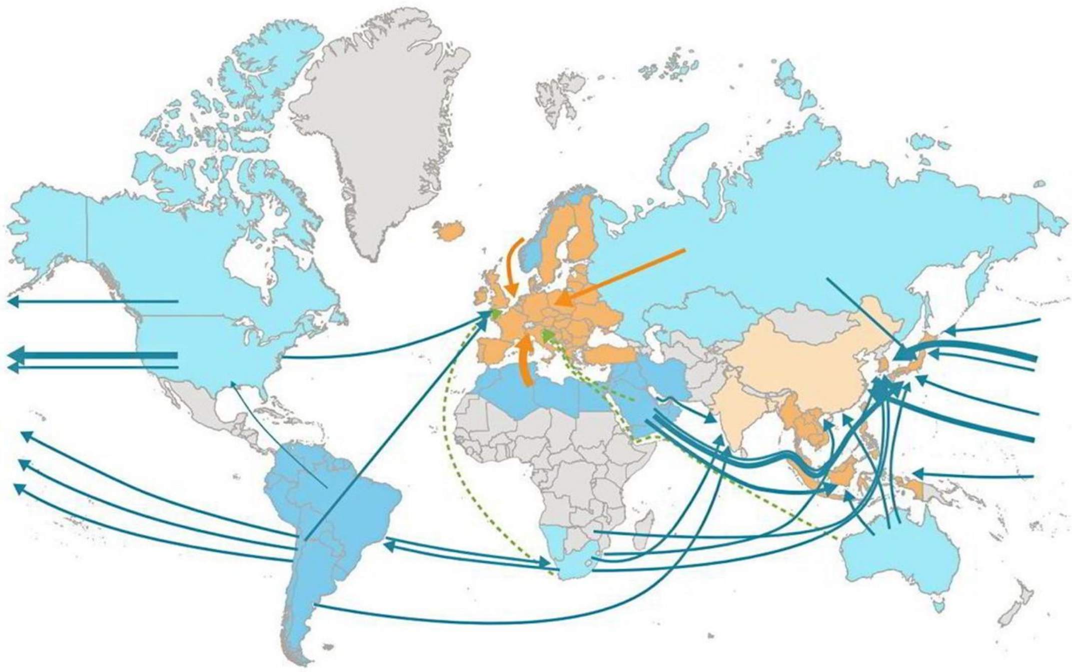
Costs and greenhouse gas emissions of international hydrogen supply chains

An analysis of levelised costs, annual quantities and GHG emissions for typical international hydrogen, ammonia and methanol supply chains



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An analysis of levelised costs, annual quantities and GHG emissions for typical international hydrogen, ammonia and methanol supply chains

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Summary

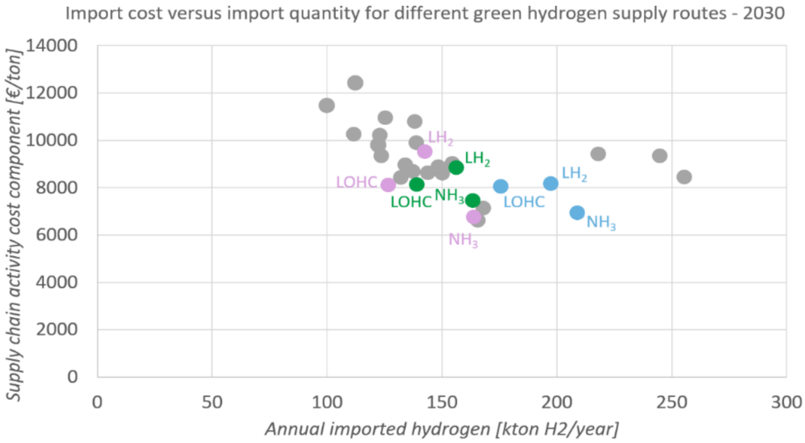
The decarbonization of industrial and transport sectors requires, amongst many others, a sufficient and timely supply of hydrogen, ammonia and methanol with minimal associated environmental impact. Hydrogen supply chains need to be initiated and scaled up rapidly to meet decarbonisation targets in 2030 and meet climate goals on the longer term. This includes the realisation of supply chain activities associated with the supply, logistics and the demand.
Many different stakeholders are involved in realising those supply chains, including hydrogen (derivative) producers, shipping companies, storage infrastructure & terminal operators, port authorities, governments, regulatory bodies and a variety of end-users. Many, if not all of those stakeholders, need to make decisions that lead to the realisation of the supply chain. And those decisions are (inter)dependent on each other which introduces the need for supply chain coordination to overcome typical chicken-and-egg problems, or prisoner's dilemmas.

The investments necessary for this upscaling these supply chains as a whole, and individual supply chain elements are currently lacking due to uncertainties perceived by public and private stakeholders. This study provides insights on three important uncertainties: the investment and operational costs per supply chain element, the annual volumes of molecules available on a project-scale and the associated greenhouse gas emissions of the delivered hydrogen, ammonia and methanol.

This research concludes that design choices of international hydrogen supply chains have substantial and interrelated effects on the levelised costs, greenhouse gas emissions and quantities produced.

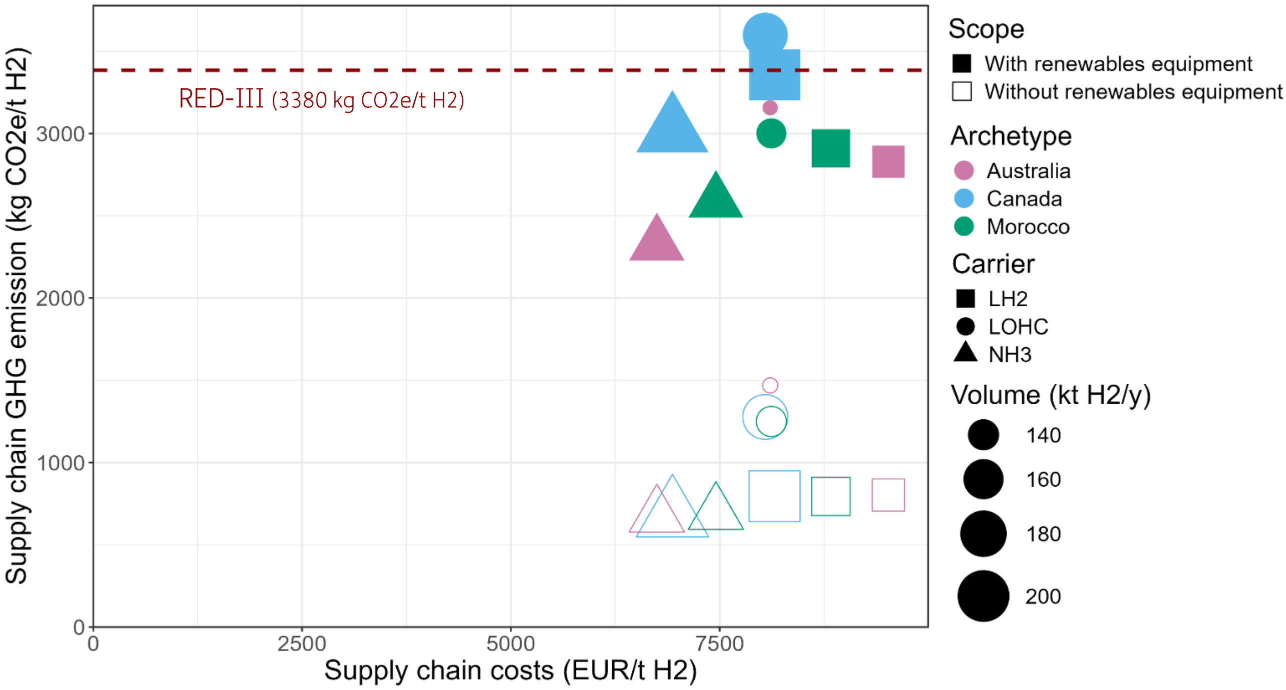
Two insights are drawn from this study and support the conclusion.

- **Insight 1:** **In designing international supply chains for green hydrogen (and its derivatives), there are decisions to be made that impact three KPIs simultaneously: the levelised cost of imported hydrogen ($LCoH_2$), the annual quantities of that supply chain and the greenhouse gas emissions emitted per unit of hydrogen (derivative).**



Copy of Figure 3.2 - Import cost versus annual import quantity for a variety of hydrogen supply routes

❖ <u>Insight 2:</u> The Renewable Energy Directive III (RED-III) scope and methodological assumptions do not include the embedded GHG emissions of renewable energy technologies dedicated to electricity generation. This study demonstrates that embedded GHG emissions have a major impact across green hydrogen (derivatives) supply chains and failing to account for them can underestimate the overall GHG emissions performance of green hydrogen imports.



Copy of Figure 5.1. Trade-offs between supply chain costs, GHG emissions, and quantity for green hydrogen delivery with and without renewable electricity equipment in scope of GHG assessment.

The stakeholders involved in realizing international hydrogen supply chains are encouraged to use the insights provided in this report when exploring the feasibility of their supply chains under development.
In addition to the supply chain cost and greenhouse gas emission analysis, three methodological developments regarding TNOs Hydrogen Supply Chain Model (H2SCM) were successfully explored with the aim to improve the quality and accessibility of the model. This exploration resulted in one recommendations:

❖ The establishment of a *Community of Practice* and the realisation of an *openly accessible hydrogen import software tool* is recommended to facilitate discussions, create consensus on supply chain designs and overcome investment barriers amongst supply chain stakeholders.

An open access approach to renewable molecule import analysis is concluded to be viable from both an envisioned community of practice end-user, and a software development point of view.

Establishing a neutral, transparent and openly accessible cost and GHG emission calculation tool for hydrogen and other renewable molecules can help create a common, neutral and transparent basis for hydrogen supply chain calculations for the many stakeholders involved in developing the hydrogen supply chains

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1 Introduction, context and objectives of the study

Discussions about the import of renewably produced hydrogen and hydrogen carriers or derivatives such as ammonia and methanol have been on the public policy and corporate strategy agenda for more than 5 years in the Netherlands. By importing these products it is assumed that hydrogen derivative molecules can become an essential contributor to the future energy and material system and thereby partially meet the need for hydrogen as a raw material and energy carrier in the Netherlands and Northwest Europe. Preconditional to this assumption is the low(er) cost, minimal associated greenhouse gas emissions and a secured supply of sufficient quantities.
Developing supply chains, from regions around the world with expected low cost renewable power towards countries with a high potential demand for renewable molecules, requires a thorough understanding of the future performances of such a supply chain. Therefore, an increasing number of public policy-makers and private stakeholders have expressed the need to gain insight into the quantification of costs and greenhouse gas emission benefits of hydrogen (derivative) import chains.

- ❖ **The primary objective of this study is to analyse the import costs, import quantities and greenhouse gas emissions for various hydrogen, ammonia and methanol import routes in a transparent and consistent fashion.**

The tool that we use to provide these insights is the TNO Hydrogen Supply Chain Model (H2SCM). It was developed in 2020 to perform consistent and transparent comparisons of hydrogen carrier import supply chain alternatives for the Netherlands. The H2SCM is able to evaluate multiple archetype-level export countries and hydrogen carriers on several key performance indicators, such as energy and mass flows, roundtrip efficiencies, levelised cost of imported hydrogen ($LCoH_2$) and import quantity.

The H2SCM modelling approach focusses on three basic end-user needs:

I. to be able to quickly calculate different import routes for different carriers
II. to be able to take into account various variables to explore and recognize the applicable band widths of uncertainties
III. to be able to quickly serve different supply chain stakeholders with specific questions

The most recent publication of H2SCM results is *The development of costs of green and blue hydrogen* (TNO, 2023). The H2SCM is based on a large variety of studies, amongst which the HyChain publications coordinated by ISPT and has been further developed in the VoltaChem and HyDelta research programs since 2020.
The energy and material transition requires an increased pace of hydrogen project investments and the need to overcome associated challenges to realise progress and meet stated policy targets. The H2SCM benefits from further development to aid stakeholders more effectively.

- ❖ **The secondary objective of this study is to further develop the H2SCM as a scalable tool for public and private stakeholders in future hydrogen import supply chains.**

Three methodological developments are in scope of this study and discussed in this report:

1. Explore the need to add more renewable molecule types to the H2SCM
2. Coupling the H2SCM with a dynamic simulation software tool to explore the benefits of detailed operational simulation and optimization calculations
3. Open access modelling approach: broader validation of the input data and modelling logic by a range of different stakeholders.

Both the content-focussed and methodology-focussed outcomes of this study are documented in this report in Part A and B respectively. The table below illustrates the report structure.

Table 1.1 Report structure visualisation

<table>
<tr><td colspan="4" align="center">Ch. 1 - Introduction</td></tr>
<tr><td colspan="4" align="center">Ch. 2 - Introduction of the H2SCM</td></tr>
<tr><td>Part A</td><td>Hydrogen import supply chain costs, quantities and GHG emissions</td><td>Part B</td><td>Methodological developments of hydrogen import assessments</td></tr>
<tr><td>Ch. 3</td><td>Import cost analysis</td><td>Ch. 6</td><td>Context of H2 (derivative) import and other carriers to consider</td></tr>
<tr><td>Ch. 4</td><td>GHG emission analysis</td><td>Ch. 7</td><td>Dynamic supply chain optimization approach</td></tr>
<tr><td>Ch.5</td><td>Relations between import cost and GHG emissions</td><td>Ch. 8</td><td>Open access tooling and community-based cost and GHG assessment</td></tr>
<tr><td colspan="4" align="center">Ch. 9 - Conclusions and next steps</td></tr>
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2 TNOs hydrogen import supply chain model

TNO developed the Hydrogen Supply Chain Model (H2SCM V2.3) to perform systematic and transparent comparison analysis of hydrogen carrier import supply chains. In this we introduce the H2SCM logic, the different hydrogen derivatives included in the current scope and introduce the archetypal supply chain design approach at the basis of the supply chain cost and GHG emission analysis.

2.1 Supply chain design options and the H2SCM

This H2SCM evaluates the cost of importing hydrogen or hydrogen derivatives from archetype-level exporting countries to the Netherlands. Currently, six hydrogen derivative molecules are included in the model: gaseous hydrogen, liquid hydrogen, ammonia, e-methanol, bio-methanol and the Liquid Organic Hydrogen Carrier (LOHC) methylcyclohexane (MCH). These derivatives can be used both as a hydrogen carrier or as a commodity for direct consumption. In the latter case, the derivative is not imported with the aim to be reconverted to gaseous hydrogen, but imported for direct (end) use by consumers. In addition, the H2SCM includes two modes of transport: large-scale shipping and international pipelines. Though pipelines are only an option for countries that are sufficiently close to the Netherlands (e.g., countries within Europe or Northern Africa). Moreover, it includes 12 different archetype countries, and the analysis can be performed for three time horizons: 2020, 2030 and 2040.

A large amount of supply chains can be designed using these design variables. This study focusses on a selection of these supply chain design options to assess their performances. Many additional supply chain designs may be worth exploring, depending on the stakeholders involved in developing these supply chains. The supply options, archetypal countries and time horizon included in this study are outlined in Table 2.1.

Table 2.1 - Supply options, archetypal countries and time horizons included in this study.

Supply options		Modes of transport	Archetype countries	Time horizon
Option name	Abbreviation			
Hydrogen import with ammonia as carrier	H_2 (via NH_3)	Ship	Canada, Morocco, Australia	2030
Hydrogen import with liquefied hydrogen as carrier	H_2 (via LH_2)	Ship	Canada, Morocco, Australia	2030
Hydrogen import with the Liquid Organic Hydrogen Carrier methylcyclohexane (MCH) as carrier	H_2 (via LOHC)	Ship	Canada, Morocco, Australia	2030
Ammonia import (end use, no reconversion back to hydrogen)	NH_3	Ship	Canada, Morocco, Australia	2030
Methanol import (end use, no reconversion back to hydrogen)	MeOH	Ship	Canada, Morocco, Australia	2030

The calculations assume 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 scales of chains have an equal starting point for all renewably produced energy carriers within the model: the installed renewable power production capacity (2 GW_e). The scale of the subsequent supply chain elements differs per supply chain design due to carrier and/or country-specific design choices.

Import chains are simplified by defining a sequence of supply chain elements. Figure 2.1 shows these chain elements schematically. The detailed description of the cost modelling logic and assumptions of the TNO Supply Chain Model were published in a study part of the HyDelta 2.0 project.[1]

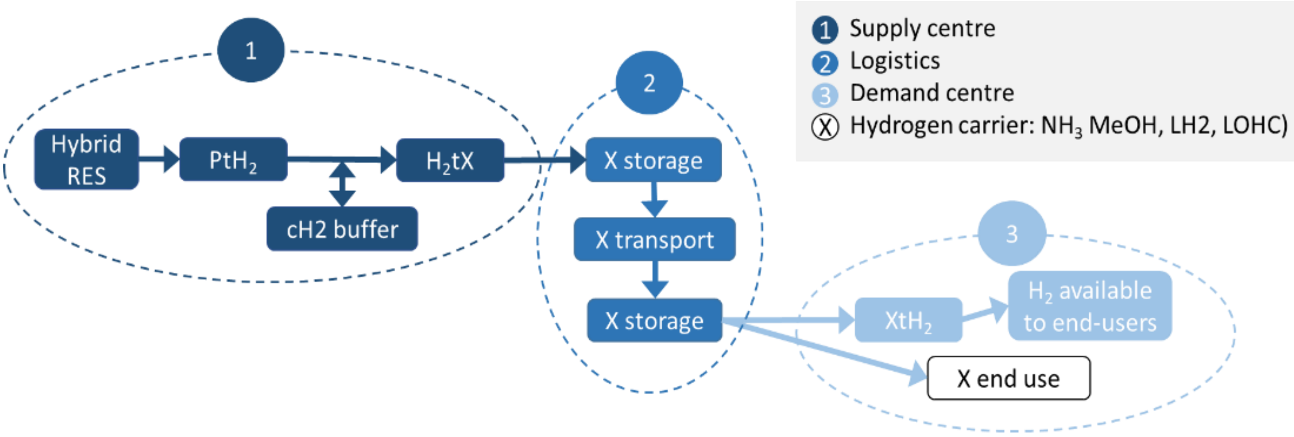


Figure 2.1: Schematic representation of a methanol supply chain in the Supply Chain Model

A high-level modelling logic per supply chain element is presented below:

- Two renewable power sources (Hybrid RES) are generating power with a country-specific capacity factor and levelised cost of electricity.
  Every import chain begins with the production of renewable electricity. Depending on the country, production is based on solar energy, wind energy, hydropower, or a combination of two options. Each type of renewable electricity production has its own Levelised Cost of Electricity (LCoE) and a specific number of full load hours (capacity factor, CF). From the combination of different forms of production, an average LCoE and a combined number of full load hours (FLH) per country are calculated. For both, the overlap in production profiles (critical overlap in the table) is considered, resulting in the combined number of full load hours being slightly less than the sum of the two options.

- The electricity generated by these renewable sources is converted to hydrogen through water electrolysis (PtH_2).
  When renewable electricity is available, hydrogen is produced. In all cases, the installed electrolysis capacity is the same. In this study, a capacity of 2 GW is assumed. During the remaining hours, when renewable electricity is not available, the electrolyser is kept in hot standby mode. To keep the electrolyser in hot standby, backup power is required. It is assumed that an amount of electricity equal to 1% of the installed electrolysis capacity is needed during the hours when there is no supply of renewable electricity. We have made assumptions about how investment costs, operational costs, and full load hours per year (capacity factors) of electrolysers will change until 2030. These assumptions are used to perform annual calculations. The results approximate the average production costs of green hydrogen over a period of 20 years from the year a facility is commissioned. The price paid for green hydrogen will depend on many other factors, such as the costs of other installations commissioned earlier or later, the demand for and availability of green hydrogen, distribution costs, subsidies,

[1] See: D7B.3 Cost analysis and comparison of different hydrogen carrier import chains and expected cost development (zenodo.org), Appendix A.

compensations, taxes and the willingness to pay of end-users. These factors are not included in this analysis.

- The hydrogen is converted to a derivative X through a process depending on the carrier. For some derivatives, feedstocks are required, such as nitrogen (N2) for ammonia production and CO2 for methanol production. A compressed hydrogen (cH2) storage is included to compensate process upsets or ramping up/down production. In the current version of the model, the assumption is that the hydrogen from the electrolyser is directly converted into the desired form in which the hydrogen is transported. The conversion plant is sized for the maximum hydrogen production by the electrolyzer and has a comparable number of operating hours. To accommodate the difference in controllability between the electrolyzer and subsequent processes, the system modelling includes a buffer for gaseous hydrogen with a capacity to supply hydrogen to the conversion plants for 12 hours. Furthermore, for flexibility, the production lines in the model are duplicated. The smaller, parallel-connected plants are more expensive than a single plant, but the philosophy is that greater flexibility limits the hydrogen buffer and negates the need for large-scale hydrogen storage.

- At the export terminal, the produced derivative is temporarily stored in between shipments. The derivative is shipped by means of bulk carrier ships to the import country. At the import terminal the derivative is temporarily stored.
  The number of tankers for hydrogen transport is determined based on the annual amount of hydrogen carrier produced, the typical capacity of the required type of ship, and the round-trip distance from the production location to the Netherlands. For each chain, the round-trip journey is included in the travel time of the ships. The storage at export and import terminals is sized based on the capacity of a tanker for transport, including an extra buffer of 25%. The number of required tanks is determined based on the maximum design capacity of a tank for storing the respective form of hydrogen.

The large amount of variables that can be changed when designing renewable molecule supply chains for leads to an overwhelming amount of supply chain configurations. While not all combinations are sensible, an indicative 150.000 supply chain designs could be explored when making combinations from the variables shown in the table below.
We therefore switch the approach in this assessment to archetypical supply chains as is elaborated upon in the next paragraph.

Table 2.2 Indicative amount of supply chain designs possible with 10 variables

Variable	Options currently in the H2SCM						Total options
Year	2020	2030	2040				3+
Country of export	Australia	Canada	Morocco	Netherlands, Argentina, Oman, Iceland, Brazil, Indonesia, South Africa, United Kingdom, Saudi Arabia			12+
Renewable electricity supply technology	Onshore wind	Offshore wind	Solar PV	Concentrated Solar PV	Hydro-power	Geo-thermal	6+
Scale of RES and supply chain	1000	2000	Any scale between 600 and 4000 MW RES can be selected				2+
Hydrogen electrolysis production technology	Alkaline	PEM					2+
Carrier / derivative type	Ammonia	Synthetic methanol	Bio methanol	LOHC MCH	Liquid hydrogen	Gaseous hydrogen	6+
Feedstock source	Nitrogen	MCH	Carbon dioxide via DAC	Bio feedstock (e.g. agricultural residues, forestry residue)	Carbon dioxide via point capture (e.g. ethanol fermentation, solid biomass firing, municipal waste firing, cement production)		5+
Means of transport	Bulk carrier ship	Long-distance pipeline					2+
Country of import & reconversion	The Netherlands						1+
End use	Fuel	Feedstock	Strategic storage reserves				3+
Total combinations: (without removal of infeasible combinations)				155.520 +			

2.2 Defining three archetype export locations

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. The Hydrogen Supply Chain model includes 12 archetypal export locations. In this study, three archetype export locations were chosen to give an impression of the import costs for green hydrogen (derivatives) from different supplying countries: archetype Australia (A), Canada (C) and Morocco (M). See (IRENA, 2022a).

The Australian archetype is a prospective export location with large wind and solar power resources, seeking to become a green hydrogen exporter, though at a large distance from Northwestern Europe. The Canadian archetype relies on the export of fossil fuels but is aiming to decarbonize its economy. It has rich wind power and hydropower resources, which could be exploited for export-oriented green hydrogen production. The Moroccan archetype is an energy importer today, but has the potential to become an energy exporter due its large wind and solar power resources. (IRENA, 2022a)

The philosophy behind the use of archetype export locations instead of a detailed assessment of export locations is to focus on fundamental supply chain design choices rather than supply route-specific details. Using archetype export locations offers freedom to the reader to translate the results presented to export locations that have similar characteristics (e.g., Morocco to Portugal). The chosen approach allows for the comparison of different combinations of supply chain configuration choices (e.g. renewable electricity production, CO_2 sources, transport distances) typical for the archetypal export locations. As such, this approach enables a deeper understanding of the cost contributions per chain configuration choice.

Figure 2.1 – Overview of archetypal export locations considered in this study: Canada, Morocco and Australia. Other archetypal export locations included in the TNO Hydrogen Supply Chain Model but not considered in this study are coloured dark grey. Map created using mapchart.net.

The archetype supply chains thus provide insight into the different influencing factors on the import costs of hydrogen, ammonia and methanol which are associated with the specific designs of that supply chain.

The configuration design variables per archetypical supply chain are:

- CO_2 source available and the associated cost (levelised cost of CO_2)
- Type of renewable electricity generation technology with associated capacity factors (or full load hours, FLH)
- Electricity costs (levelised cost of electricity, LCoE)
- Distance to be travelled per ship
- Local interest rate

Three supply chain archetype designs were chosen. All archetypes have an initial installed renewable electricity generation capacity of 2 GW_e in total, divided equally over the chosen renewable electricity types. This implies that, since each export location features two renewable electricity sources, they have a capacity of 1 GW_e each. Archetype C uses pumped hydropower and onshore wind as a power source, and biomass and waste as a carbon source. Archetype M uses solar PV and onshore wind power, and direct air capture to supply carbon. Archetype A also uses solar PV and onshore wind power but uses point capture at industrial plants as a carbon source. Table 2.3 provides details on the archetypal export locations.

Table 2.3 - Overview of archetype export countries selected in this study and some key characteristics.

Archetype name	C	M	A
Example of country corresponding with archetype:	Canada	Morocco	Australia
Characteristic / parameter	Assumption		
Interest rate	5%	10%	6%
LCoE onshore wind power[2]	35 €/MWh	35 €/MWh	33 €/MWh
LCoE solar PV power[3]	-	23 €/MWh	22 €/MWh
LCoE pumped hydro power[3]	73 €/MWh	-	-
Capacity factor onshore wind power	46%	43%	43%
Capacity factor solar PV power	-	23%	25%
Capacity factor pumped hydro power	50%	-	-
Full load hours of electricity production per annum[4]	77 %	60 %	62 %

[2] 2030 LCoE estimates including cost reductions (Fasihi et al., 2016; Ram et al., 2018)
[3] No cost reductions expected for mature hydropower technologies. LCoE estimate taken from (IRENA, 2022b)
[4] The combined capacity is computed by summing the capacity factors of the individual renewable energy sources while assuming an overlap factor of 10-20%.

Archetype name	C	M	A
Example of country corresponding with archetype:	Canada	Morocco	Australia
Characteristic / parameter	Assumption		
LCoE combined renewable energy sources[5]	55 €/MWh	34 €/MWh	32 €/MWh
CO_2 from solid biomass firing	50%	0%	0%
CO_2 from waste firing	50%	0%	0%
CO_2 from cement production	0%	0%	100%
CO_2 from direct air capture	0%	100%	0%
Feedstock (CO_2) cost[6]	60 €/tCO_2	204 €/tCO_2	62 €/tCO_2
GHG onshore wind power[7]	16 kg CO_2e/MWh	14 kg CO_2e/MWh	33 kg CO_2e/MWh
GHG solar PV power[7]	-	23 kg CO_2e/MWh	22 kg CO_2e/MWh
GHG pumped hydro power[7]	51 kg CO_2e/MWh	-	-
GHG combined renewable energy sources[5]	43 kg CO_2e/MWh	32 kg CO_2e/MWh	37 kg CO_2e/MWh

[5] The hybrid-technology levelised cost and GHG emissions for renewable power consists of relative contributions per technology based on the corresponding full load hour ratio of those technologies, taking into account the aforementioned overlap factor.
[6] See Appendix B for calculation of the feedstock cost.
[7] Life cycle GHG emissions for renewable electricity production were obtained from the ecoinvent database v3.9.1, cut-off system. Note that the GHG intensity of different renewable energies varies according to location, given the difference in specific location-based characteristics such as resource availability and intensity. For more information, please see https://support.ecoinvent.org/energy

Part A: Hydrogen import supply chain costs, quantities and GHG emissions

In Part A, we discuss the study's primary objective: **to analyse the import costs, import quantities and greenhouse gas emissions for various hydrogen, ammonia and methanol import routes in a transparent and consistent fashion** (see **Introduction, context and objectives of the study**). These analyses have been performed with the TNO Hydrogen Supply Chain Model (H2SCM), which was introduced in Chapter 2.

In Chapter 3, the import costs and import quantities are analysed of the supply routes discussed in Chapter 2.

Chapter 4 presents an analysis of the greenhouse gas emissions associated with these same supply routes. Greenhouse gas emissions as a key supply chain performance indicator have been added to the H2SCM as part of this study. Therefore, we also present the Lifecyle Assessment (LCA) method used for this analysis. Finally, in Chapter 5, we consider the three studied performance indicators from an integral perspective and discuss the trade-offs to be made between them in the design of green hydrogen supply chains.

3 Import cost ranges of green hydrogen, ammonia and methanol

In this chapter we present the results for the supply chain costs computed with the H2SCM. The **levelised cost of imported hydrogen (LCoH$_2$)** ranges between 6748 euro/ton and 9520 euro/ton and the **import quantity** ranges from 127 to 209 ktpa (kiloton per annum), depending on the supply route. We define supply route as the combination of a hydrogen carrier and an export location. For the supply of ammonia meant for end use (so without reconversion to hydrogen) the LCoH$_2$ ranges from 942 to 1046 euro/ton, depending on the archetypal country. For methanol (end use) the LCoH$_2$ ranges from 984 to 1268 euro/ton.

The differences in performance of the supply routes can be attributed to characteristics of the archetypal export location and properties of the hydrogen carrier.

Considering the characteristics of the archetypal export location, the **levelised cost of electricity (LCoE) will have a considerable impact on the LCoH$_2$**, constituting 33-49% of the LCoH2. However, this is not the full story, and the **capacity factor of the renewable electricity resources** must also be considered. The capacity factor significantly determines the amount of hydrogen that flows through the import chain: a higher capacity factor leads to a higher hydrogen production with the same installed renewable electricity capacity. Hence, export locations with a relatively high LCoE can still yield a low LCoH2 as long as its capacity factor for renewable electricity resources is sufficiently high.

Moreover, the impact of properties of the hydrogen carrier is discussed: physical properties like the volumetric energy density and volumetric hydrogen density and the energy consumption associated with (re)conversion, storage and transport. These **characteristics affect both the *absolute* costs per supply chain element as well as the *relative* costs**; the quantity of imported hydrogen differs per carrier due to varying supply chain efficiencies. Hence, even though the absolute cost for, e.g., local hydrogen production are the same, the relative costs may vary.

3.1 Results for levelised cost of supply and import quantities

For the range of supply routes specified in Table 2.1, the levelised cost of supplied product X (LCoX) has been determined (X being either hydrogen, ammonia or methanol). The LCoX is calculated by dividing the annual chain costs by the annual amount of product delivered in Rotterdam: either gaseous hydrogen (via a carrier), ammonia or methanol. Figure 3.1 shows the results.

The results show that importing gaseous hydrogen via a carrier ammonia (NH_3) may feature the lowest costs, followed by LOHC and liquefied hydrogen (LH_2), respectively. Comparing the archetypal export locations, it can be observed that, according to this analysis, the Australian archetype yields the best results for the H_2 via NH_3 route and the Canadian archetype for the H_2 via LH_2 route. For the H_2 via LOHC route, the archetypal export locations are more or less on par regarding the supply costs. However, one should be careful to draw conclusions from these results about the competitiveness of certain export locations regarding hydrogen export. That is because these results are highly dependent on the assumptions made for the respective archetypal export locations. A detailed assessment for specific export locations may yield different results. See Section 2.2 for more information about the logic of using archetypal export locations in this analysis.

In assessing the differences in supply chain performance for different hydrogen carriers, it should also be noted that the hydrogen gas purity level of hydrogen gas via liquid hydrogen is higher than via ammonia or LOHC carrier, which can be considered an advantage. This sets apart the liquid hydrogen route.

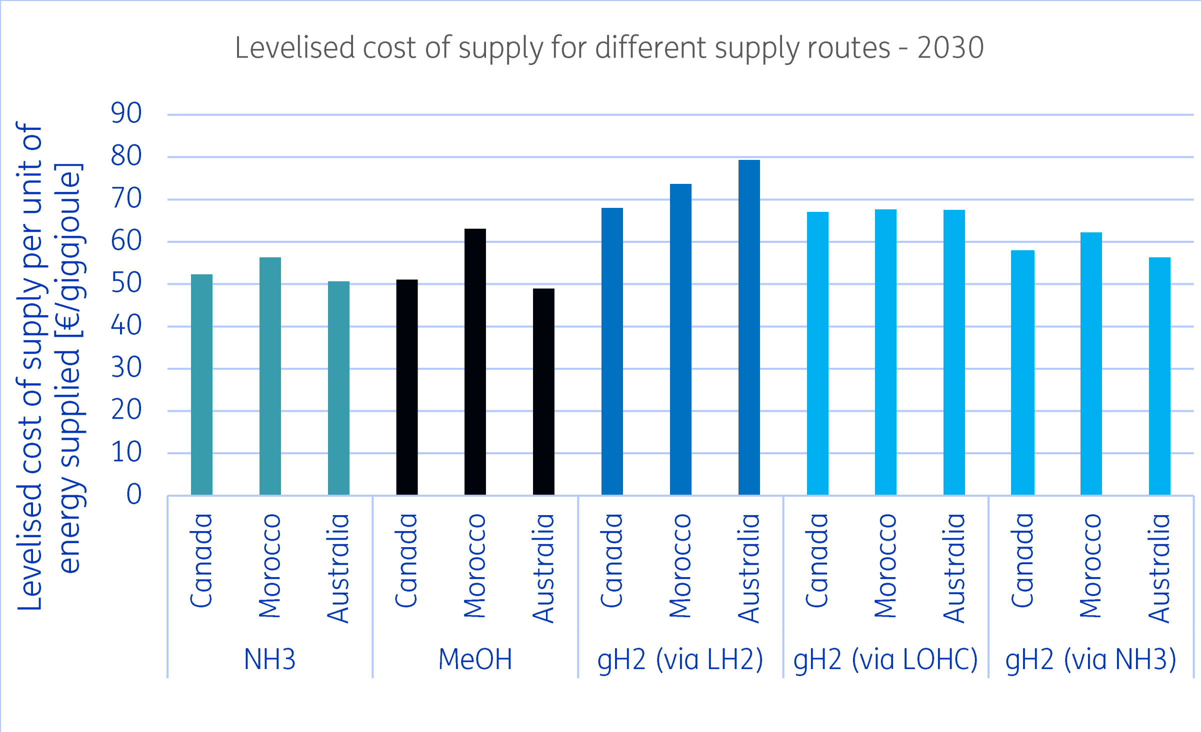


Figure 3.1 – Levelised cost of supply in euro/gigajoule for the import of hydrogen (via a carrier), ammonia and methanol from archetypal export locations Canada, Morocco and Australia to the Port of Rotterdam. On the left side we find the import of ammonia (NH_3) and methanol (MeOH) as commodities for end use (so without reconversion to hydrogen). On the right side we find import of gaseous hydrogen (gH_2) via three types of carriers: liquefied hydrogen (LH_2), the Liquid Organic Hydrogen Carrier (LOHC) methylcyclohexane and ammonia (NH_3). Dark blue indicates very high purity hydrogen, light blue lower purity hydrogen.

In considering different import options, not only supply costs are relevant, but also the yearly volumes produced and imported (referred to as annual import quantity in this report) since hydrogen offtakers will strive for security of supply. Figure 3.2 shows the import cost and annual import quantity for the different hydrogen supply routes considered in this study: three different archetypal countries (Canada, Morocco and Australia) and three different hydrogen carriers (ammonia, methanol and liquefied hydrogen). The import quantities ranges from 127 to 209 ktpa (kiloton per annum). One can observe that, although hydrogen import via ammonia from the Australian archetypal export location may yield slightly lower cost, hydrogen import via ammonia from Canada yields a significantly larger import quantity. Hydrogen import via LH_2 and LOHC from Australia may turn out to be rather unfavourable options due to a combination of a high import cost and smaller import quantity, relatively.

3.2 Analysis of differences in costs and import quantities between supply routes

To explain the differences in costs and import quantities between the various supply routes, we should consider the distinguishing characteristics of the archetypal countries and the hydrogen carriers. For the sake of comparison, we only consider the import of hydrogen via a carrier here, not the import of ammonia or methanol. For the archetypal countries these are mainly three factors: 1) the local levelised cost of electricity (LCoE), 2) the capacity factor of the renewable electricity sources (full load hours, FLH) and 3) the local interest rate (see Table 2.1). Regarding the hydrogen carrier, it is important to consider the efficiencies associated with conversion and its consumption as a fuel

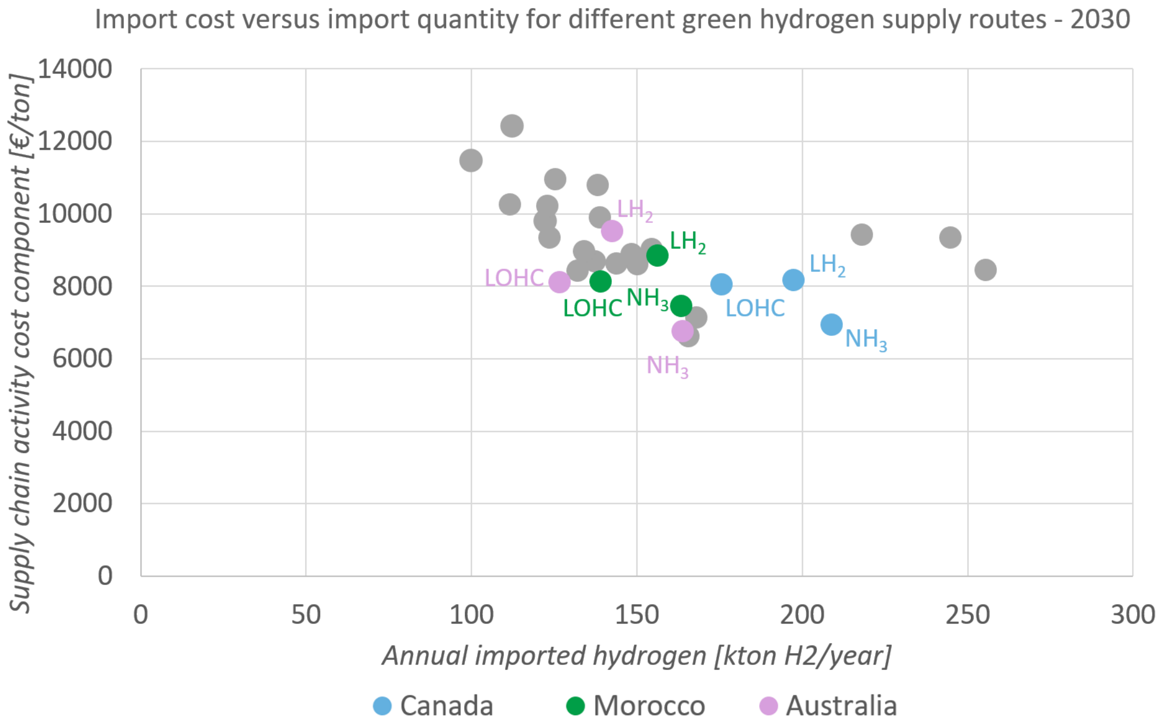


Figure 3.1 – Levelised import cost versus import quantity for different hydrogen supply routes: combinations of archetypal countries and hydrogen carriers. The grey-coloured points show supply routes that are not considered in this study but have been included in the TNO Hydrogen Supply Chain Model.

during shipping. In the following, the impact of the characteristics of the archetypal export locations and the impact of the hydrogen carrier characteristics are discussed separately.

3.2.1 Impact of characteristics of the archetypal export locations

To analyse the relative impact of each of the characteristics of the archetypal export locations on the levelised cost of imported hydrogen ($LCoH_2$), we should dive deeper into the cost breakdown per supply chain element. Figure 3.3 shows the cost breakdown per supply chain element for hydrogen import via the carrier ammonia, for the three different archetypal countries. It can immediately be observed that the local hydrogen production (through assumed alkaline electrolysis technology) has by far the largest share in the levelised cost of supply of hydrogen: 76% for Canada, 73% for Morocco and 71% for Australia. Hence, it is worthwhile to look at the costs associated with each supply chain element more closely.

Figure 3.4 shows the breakdown of asset annuity, fixed OPEX and variable OPEX per supply chain element for hydrogen import via ammonia from Canada. We consider three types of costs:

1. Fixed costs are related to the amortisation or repayment of investments, and the costs or returns on the financing of these investments (Asset Annuity in Figure 9).
2. Fixed operational costs (fixed OPEX) refer to the annual fixed maintenance costs per supply chain element.
3. Variable operational costs (variable OPEX) are mainly the costs of electricity and fuel

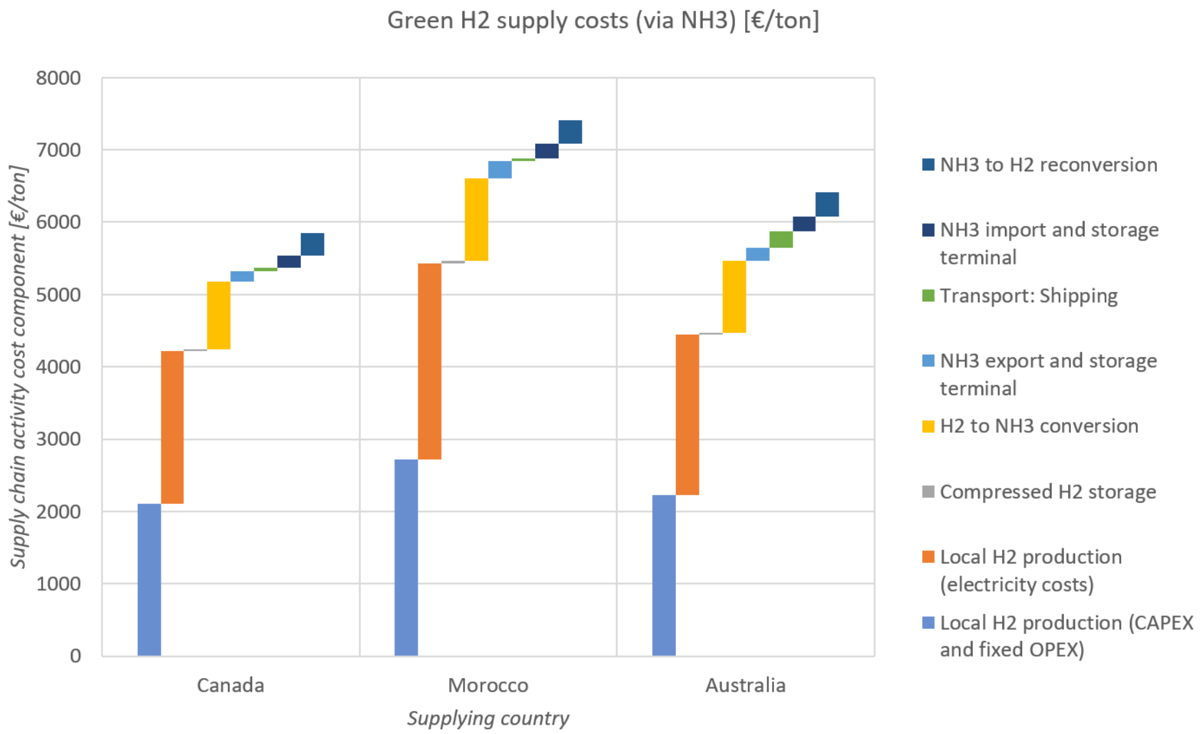


Figure 3.2 – Cost breakdown of the levelised cost of hydrogen ($LCoH_2$) in euro/ton of hydrogen, imported via ammonia (NH_3) as a carrier, for three different archetypal export locations (Canada, Morocco and Australia).

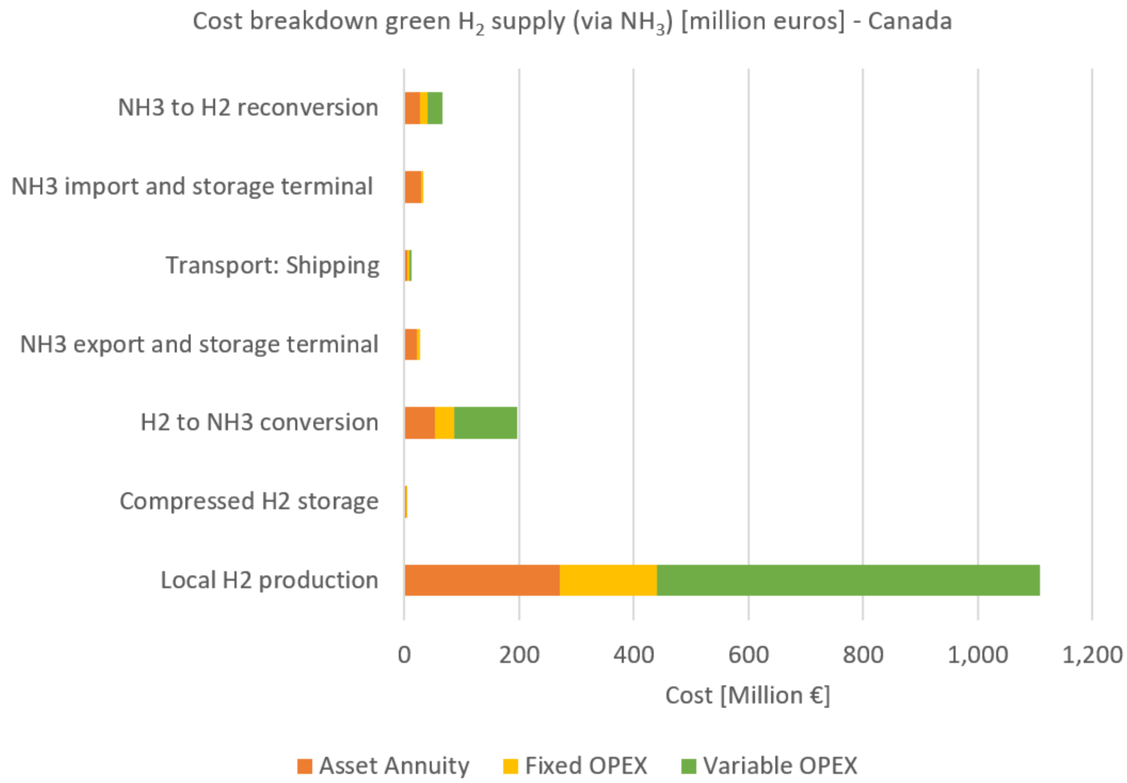


Figure 3.4 – Overview of the breakdown of asset annuity and fixed and variable OPEX per supply chain element for hydrogen import via ammonia from Canada.

The two largest cost factors contributing to the total levelised cost of supply are 1) local hydrogen production, and 2) hydrogen-to-ammonia production. Due to the electricity consumption of electrolyzers and the hydrogen-to-ammonia conversion installation, the variable OPEX constitutes 60% and 55% of the costs of these two supply chain elements respectively. As a result, the LCoE constitutes 33-49% of the $LCoH_2$ and in the case of either ammonia import or methanol import: 38-50% of the levelised cost of NH_3 and 33-53% of the levelised cost of MeOH, respectively.

Therefore, one can conclude that the levelised cost of electricity (LCoE) will have a considerable impact on the levelised cost of supply. However, this is not the full story, and the capacity factor of the renewable energy sources must also be considered. The capacity factor significantly determines the amount of hydrogen that flows through the import chain: a higher capacity factor leads to a higher hydrogen production with the same installed renewable electricity capacity. Thus, with low variable OPEX and a large amount of produced hydrogen, a low supply cost ($LCoH_2$) is achieved. This is seen in Table 2.2, where despite having the highest LCoE of the three countries considered, Canada has the highest capacity factor for renewable energy sources. Thus, it exhibits lower levelised cost of supply for hydrogen import via ammonia than Morrocco, and the lowest levelised cost of supply for LH_2 of all three archetypal countries.

The CAPEX and OPEX distribution throughout the supply chain clearly shows the large cost contributing role of the electrolyser CAPEX and, to a lesser extent, the CAPEX of the Haber-Bosch ammonia production step and subsequent logistical assets. As those technologies are considered location-independent, cost reductions can also be considered country-a-specific. Such as reductions in investment costs and increases in the efficiency of electrolyzers and other conversion installations, will lead to cost reductions in every chain. However, it will not result in the same cost reduction for hydrogen in every chain because the quantities of hydrogen differ per chain.

3.2.2 Impact of properties of the hydrogen carrier

Beside differences between the archetypal export locations regarding $LCoH_2$ and import quantities, also differences between hydrogen carriers can be observed. Figure 3.5 shows the cost breakdown per supply chain element for hydrogen import from Canada via ammonia, liquefied hydrogen and LOHC. Among the hydrogen carriers, ammonia (NH_3) seems to result in the lowest supply costs or $LCoH_2$. The choice of hydrogen carrier does not only impact the absolute costs per supply chain element (conversion, transport, storage, etc.) but also the quantity of the hydrogen delivered at the import location. This becomes evident from Figure 3.5: in *absolute* sense, the local cost of hydrogen production is the same for each carrier, but because LOHC results in a lower annual quantity of hydrogen imported than ammonia, the *relative* local cost of hydrogen production is higher for LOHC than for ammonia. Several factors play a role in the cost performance of each hydrogen carrier, notably: 1) physical properties of the carrier, 2) energy consumption of the (re)conversion processes and 3) energy consumption during storage and transport.

Regarding physical properties of the carriers, it is relevant consider the volumetric energy density and volumetric hydrogen density (see Table 3.1). One can observe that ammonia has the highest hydrogen density among the three carriers. Hence, ammonia requires the lowest shipping capacity to transport the same quantity of hydrogen. And though the volumetric energy density of ammonia is lower than of LOHC (therefore requiring a relatively higher volume for the ship's energy need) the hydrogen density of LOHC is relatively low, requiring more ships to transport the same energy quantity of hydrogen.

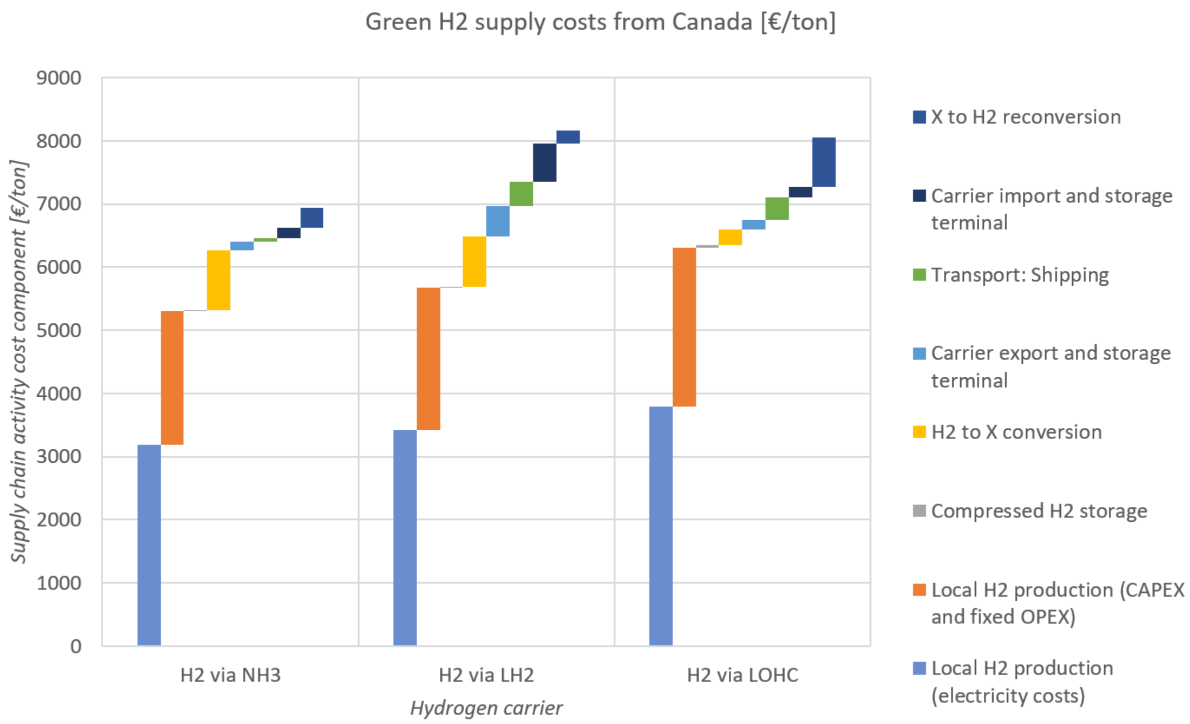


Figure 3.5 - Cost breakdown per supply chain element for hydrogen import from Canada via three different hydrogen carriers: ammonia, liquefied hydrogen and LOHC. Note that the choice of hydrogen carrier does not only impact the absolute costs per supply chain element but also the quantity of the hydrogen delivered at the import location. In absolute sense, the local cost of hydrogen production is the same for each carrier, but because LOHC results in a lower quantity of hydrogen imported than ammonia, the relative local cost of hydrogen production is higher for LOHC than for ammonia.

Table 3.1 - Physical properties of the hydrogen carriers studied in this report. (Aziz et al., 2020; Wijayanta et al., 2019)

Carrier	Volumetric energy density [GJ/m^3]	Volumetric hydrogen density [kg H_2/m^3]
Liquid hydrogen (LH_2)	8.5	70.9
Liquid Organic Hydrogen Carrier (LOHC) methylcyclohexane (MCH)	33.3	47.1
Ammonia (NH_3)	12.7	120.3

Secondly, the energy consumption during the (re)conversion process has an impact on the supply costs of hydrogen. For instance, the relatively high cost for the reconversion process from LOHC to hydrogen is due to the high CAPEX for the LOHC reconversion plant and the high heat demand of the reconversion process. This heat demand requires additional hydrogen to be supplied, decreasing the overall hydrogen yield.

Lastly, the energy consumption during transport and storage plays a role. This becomes evident from the relatively high costs associated with the storage and shipping of LH_2. LH_2 needs to be kept at a cryogenic temperature during storage and transport, requiring a high amount of electricity for cooling. Hence, even though LOHC features a lower import quantity than LH_2, LH_2 still results in higher overall hydrogen supply costs.

4 Life cycle greenhouse gas emissions of hydrogen import to the Netherlands

This chapter describes the addition of life cycle greenhouse gas (GHG) emissions to the hydrogen supply chain model. The chapter is divided in four sections: (1) the Life Cycle Assessment (LCA) method, (2) available guidelines and their main characteristics, (3) selection of guidelines and applied method, and (4) key results.

4.1 Introducing the Life cycle assessment method

LCA is a method applied to evaluate the environmental impacts of a product, process, or activity throughout its entire life cycle, including all life-cycle stages: from the extraction of raw materials through production, use, and end-of-life. LCA aims to provide a comprehensive understanding of the environmental impacts associated with a product or activity so that informed decisions can be made to mitigate these impacts The LCA is a method applied to evaluate the environmental impacts of a product, process, or activity throughout its entire life cycle, including all life cycle stages: from the extraction of raw materials through production, use, and end-of-life. LCA aims to provide a comprehensive understanding of the environmental impacts associated with a product or activity so that informed decisions can be made to mitigate these impacts (ISO, 2006)(ISO, 2006).
An LCA is composed of four main steps (see Figure 4.1):

1. **Goal and scope definition**: defining the assessment purpose and determining the study boundaries and assumptions. It sets the goals and identifies which environmental indicators will be assessed.
2. **Life Cycle Inventory** (LCI): data is collected on all inputs (e.g., materials, energy) and outputs (e.g., emissions, waste) associated with each stage of the product life cycle.
3. **Life Cycle Impact Assessment** (LCIA): evaluating the environmental impacts associated with the inventory data collected in the previous step. LCIA can assess impacts such as global warming potential, acidification, eutrophication, or resource depletion.
4. **Interpretation**: the results of the assessment are interpreted and communicated to stakeholders. This step involves analysing and visualizing results leading to recommendations.

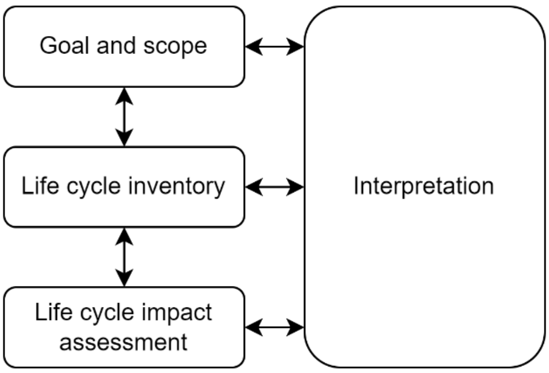


Figure 4.1. Four main steps of LCA

In this study it becomes apparent how influential the scoping decisions can be on the results of an LCA. See section 5 for more details.

4.2 Guidelines and frameworks for GHG emission calculations

LCAs are often used to provide clarity on the environmental impacts of (innovative) products, processes or activities. Sector- or product-specific guidelines can be used in combination with generic LCA standards, notably to assess the impacts in relation to relevant threshold.
Three main guidelines are developed to calculate the life cycle GHG emissions of hydrogen (import) supply chains:

- A methodology for determining the greenhouse gas emissions associated with the production of hydrogen. A working paper by the International Partnership for Hydrogen and Fuel Cells in the Economy (IPHE), the hydrogen production task force, July 2023
- A methodology for determining the greenhouse gas emissions associated with the production, conditioning, and transport of hydrogen to consumption gate. A working paper by the International Organization for Standardization (ISO). ISO 19870-1 – Working document, December 2023
- The Renewable Energy Directive (RED) which provides the legal framework for the development of clean energy across all sectors of the EU economy. This directive entered into force in 2018 under the Renewable Energy – Recast to 2030 (REDII) name and was amended in 2023 (REDIII). This directive provides the methodology for assessing GHG emissions savings from renewable liquid and gaseous transport fuels of non-biological origin and recycled carbon fuels.

To understand the differences and similarities between guidelines, three LCA concepts are key:

- **Functional unit**: the quantity of a product or product system based on the performance it delivers in its end-use application. For example, a functional unit for coffee beverages could be one cup of brewed coffee at 55°C.
- **Reference flow**: the quantity of a product or product system required to fulfil the functional unit, for instance, 200 ml of coffee in our example. The functional unit and reference flow allow consistent comparison between products or services within the same product category.
- **Multifunction and allocation**: multifunctionality refers to situations where a single process or product provides multiple functions or outputs. System expansion and allocation are used to distribute the environmental impacts when dealing with multifunctional processes or products. System expansion refers to expanding the LCA system boundary to include the additional functions of the co-products. In most cases, this means including alternative single-function production routes of co-products. This accounts for the environmental impacts that are avoided by substituting this alternative production route. Allocation is used to partition the environmental impacts of a multifunctional process among the different co-products. Allocation can be carried out based on the product system outputs mass, energy content, or economic value. The method choice in dealing with multifunctional systems is directly related to the system's applied guidelines, goal, scope, and nature. Figure 4.2 shows a simplified example of dealing with multifunctional processes for hydrogen production via electrolysis.

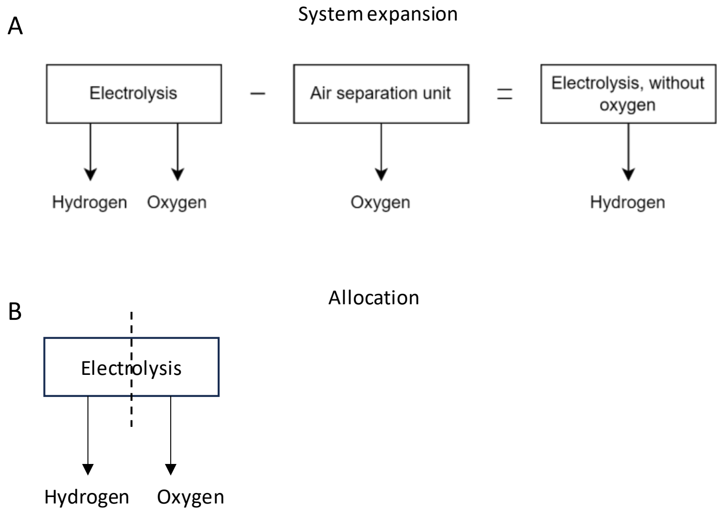


Figure 4.2. Example of system expansion (A) and allocation (B). (A) Emissions of oxygen production from the air separation unit are subtracted from the emissions of electrolysis to isolate emissions associated with hydrogen. This can be interpreted as avoiding emissions due to the oxygen production in the air separation unit. (B) Emissions from the electrolysis process are allocated between the main outputs, hydrogen and oxygen.

Table 4.1 show the main characteristics and scope of the three guidelines considered. In the RED, the functional unit is not explicitly mentioned and depends upon the characteristics and end-use of the product. The RED defines "renewable liquid and gaseous transport fuels of non-biological origin” as “liquid or gaseous fuels which are used in the transport sector other than biofuels or biogas, the energy content of which is derived from renewable sources other than biomass". This might, for example, cover the following functional unit: *ammonia production from green hydrogen via electrolysis to be used as fuel in the transport sector.*

Table 4.1. Main characteristics of the guidelines considered. Equipment GHG emissions are life cycle emissions associated with the construction of equipment and machinery (e.g. electrolysis plant or hydrogen compressor).

Ref	Functional unit	Reference flow	Handling of multifunctional processes	Equipment GHG emissions
IPHE	H2 at 3MPa and 99% pure (or more)	Not explicitly mentioned	1) energy content allocation, 2) system expansion, 3) economic allocation	Not included
ISO	H2 at "required" pressure and purity (no less than 99%)	1kg	1) system expansion, 2) physical allocation, 3) economic allocation	Not included
RED	It is not explicitly mentioned and depends upon product characteristics and end-use.	1MJ	Energy content allocation	Not included

Figure 4.3 illustrates the different scope of the RED, IPHE, and ISO guidelines.

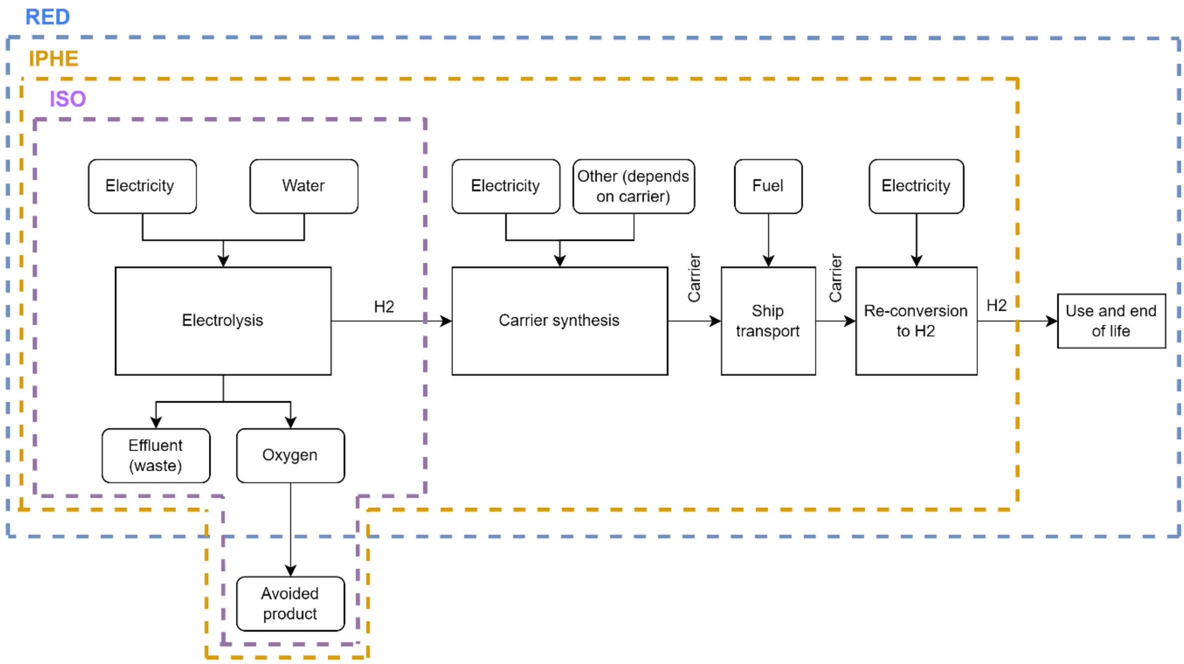


Figure 4.3. System boundaries of the guidelines considered. This figure is not comprehensive.

4.3 The GHG calculation approach chosen in this study

The GHG emissions of the supply chains assessed by means of the H2SCM are assessed following the LCA approach introduced in section 4.1. The four standard steps of LCA were followed.

1. **Goal and scope**: The aim was defined alongside the functional unit and system boundaries. All inventory flows and GHG emissions relate to the functional unit.
2. **Life cycle inventory (LCI)**: All flows going in (e.g., energy and materials) and out (e.g., emissions and waste) of the system boundaries across the life cycle of the processes modelled were collected in the LCI.
3. **Life cycle impact assessment (LCIA)**: The LCI was converted to environmental impacts in common units and organized into impact categories. Here, only GHG emissions were considered, expressed in kg CO_2 equivalents (kg CO_2 eq. or kg CO2e)
4. **Interpretation**: The results were interpreted, including scenario analyses and an investigation of the trade-offs between GHG emissions, costs, and annual quantities (see section 5).

The model aims to provide a high-level estimate of life cycle GHG emissions associated with green hydrogen production supply chains. The functional unit was defined as *delivering 1 ton of hydrogen or 1 GJ of feedstock (ammonia and methanol) to a port in the Netherlands in 2030*. Well-to-gate system boundaries were chosen as shown in Figure 4.4 (aligned with IPHE and H2SCM). All key operational inputs were included, while most of the machinery and equipment production was excluded, with the exception of renewable electricity equipment (e.g. wind turbines or solar panels). This scoping choice is discussed further in section 4.3. Three archetypes and five supply options were considered (see Table 2.1 and Table 2.3).

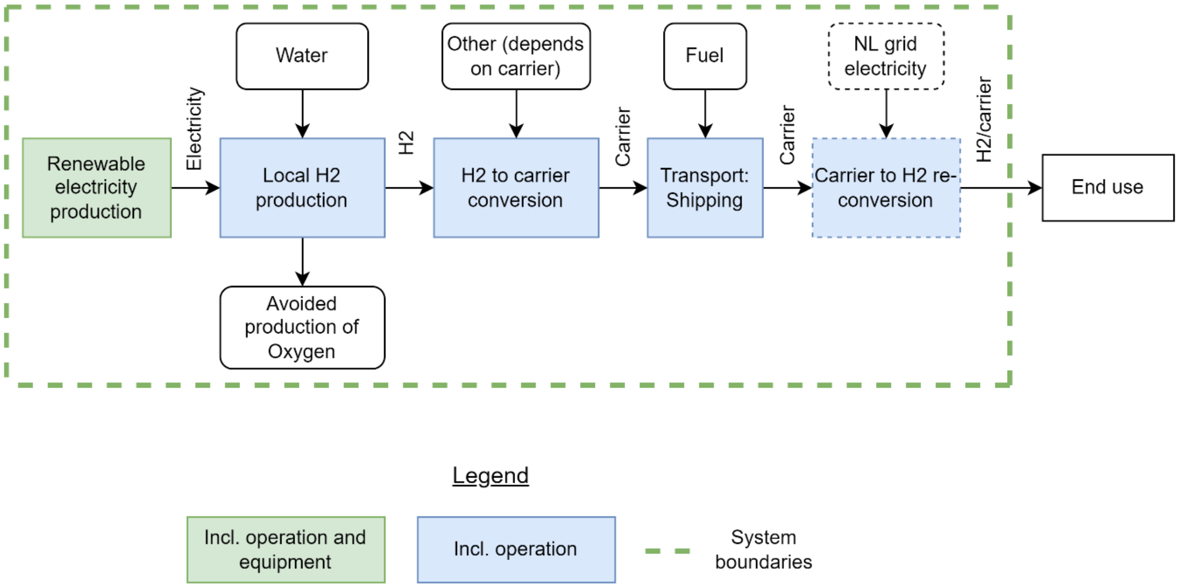


Figure 4.4. Scope for the life cycle GHG emissions of hydrogen. The green dotted line shows the system boundaries. Steps coloured in blue include GHG emissions associated with operational inputs (energy and materials). Green steps include GHG emissions associated with operational inputs and with the production of machinery and equipment (e.g. wind turbine manufacturing).

To build the foreground[8] LCI, the values and assumptions of the H2SCM cost module were used whenever possible. This covered all the electricity and heat demand of the hydrogen supply chain as well as most of the key operational inputs. For the background inventory, we mainly relied on the Ecoinvent LCI database using version 3.9.1 released in 2023 (Wernet et al., 2016). This was complemented by a literature survey where necessary. A list of assumption and inventory data is reported in Appendix C.

Future GHG emissions were forecasted for 2030 by including external developments using a prospective LCA database. External developments consist of future changes in background supply chains that are extrinsic to the hydrogen supply chain but influential to its life cycle GHG emissions. This includes, for instance, expected developments in energy supply and demand from major energy-intensive sectors. We modelled those external changes based on future scenarios defined by IPCC (shared socio-economic pathways, SSP) coupled with an integrated assessment model. Specifically, SSP2 under RCP2.6 (representative concentration pathway) was used, coupled with the IMAGE integrated assessment model.

4.4 Key results of GHG emissions for hydrogen (derivative) import routes

Life cycle GHG emissions were calculated for the three archetypes and five supply options considered (see Table 2.1 and Table 2.3) and are reported for 2030 in Figure 4.5. For delivery of hydrogen and the three archetypes considered here, GHG emissions range from 19 to 30 kg CO2e/GJ (or 2240 to 3600 kg CO2e/t H2). Using an ammonia (NH3) carrier yields the lowest GHG emissions, followed by liquid hydrogen (LH2) and liquid organic hydrogen carrier (LOHC). For commodity delivery, GHG emissions range between 13 and 38 kg CO2e/GJ. Ammonia shows lower GHG emissions per unit of energy delivered than methanol. On average, across the five supply options, delivery from the Moroccan archetype leads to the lowest GHG emissions, followed by the Australian and Canadian archetypes.

[8] The foreground LCI are the inventory values directly connected to the system under study, for instance the inputs of water or electricity for the electrolysis step. The background LCI covers everything else, i.e. all the activities upstream and downstream of the system under study.

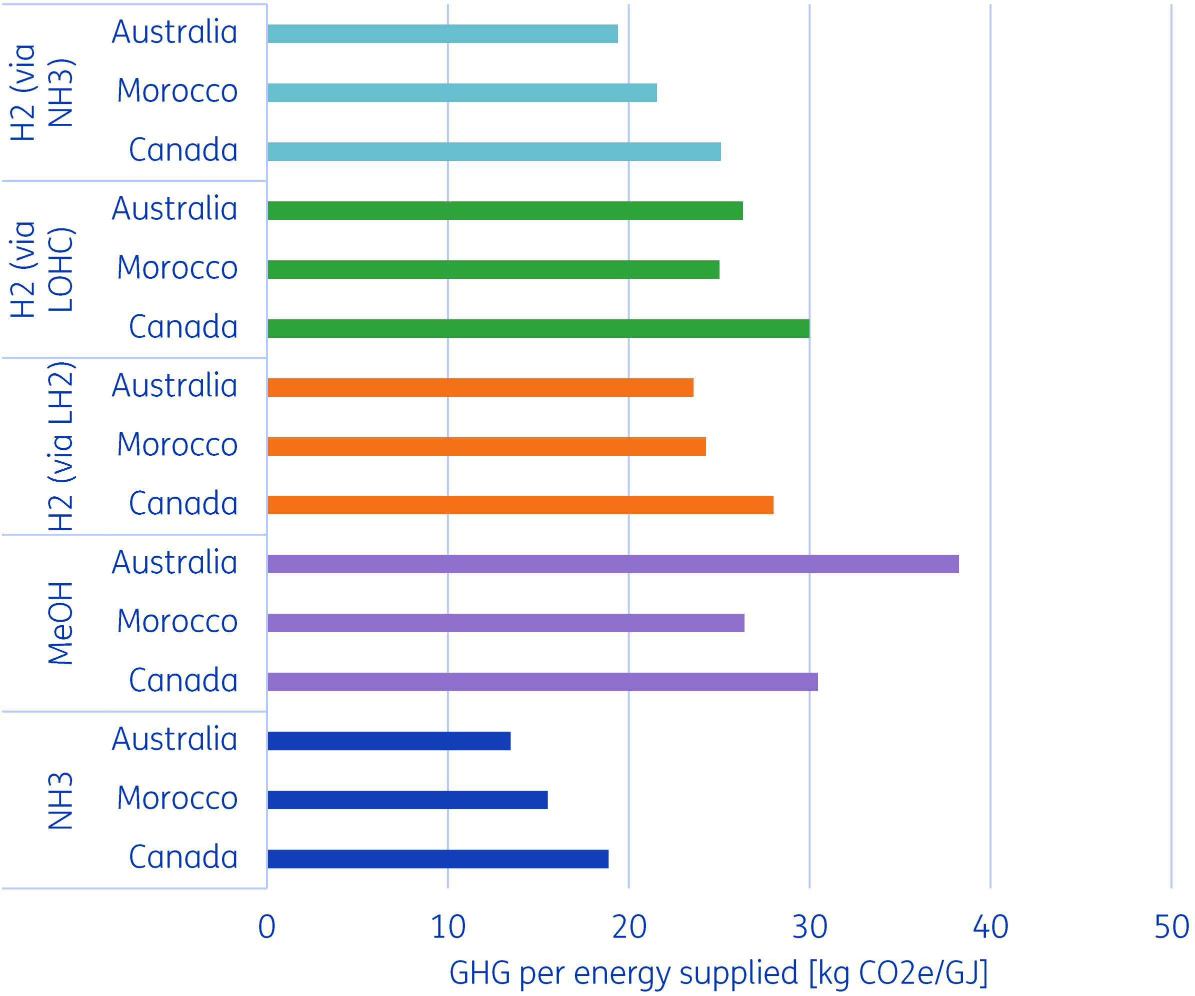


Figure 4.5. Life cycle GHG emissions for three country archetypes and five supply options in 2030. GHG emissions are reported per GJ of product delivered, based on lower heating values. NH3 stands for ammonia, MeOH for methanol, H2 for hydrogen, LH2 for liquid hydrogen, and LOHC for liquid organic hydrogen carrier.

Life cycle GHG emissions can be further investigated by considering a breakdown per activity along the supply chain, as shown for hydrogen delivery via ammonia in Figure 4.6. Across the three archetypes, the majority of emissions result from local H2 production (57-65%), followed by reconversion to hydrogen (21-27%), and conversion to ammonia (14-16%). Renewable electricity production causes the majority of emissions during local hydrogen production (95-97%) and conversion to ammonia (100%). GHG emissions embedded in the production of renewable electricity equipment (e.g. wind turbines or solar panels) are consequently responsible for the majority of emissions across the entire supply chain (71-78%).

The remaining emissions are due to electricity consumption during compression and cracking for ammonia reconversion. Dutch grid electricity was used for the reconversion of carriers to hydrogen because, if renewable electricity was available locally in the Netherlands, it could be used for local hydrogen production instead. As a result, emissions related to the reconversion of the carrier are equal for all three archetypes (618 kg CO2e/t H2 for ammonia carrier), meaning that differences between archetypes are due to the configuration of renewable electricity production (see Table 2.3).

The efficiency of supply chain activities are modelled in the H2SCM but are not explicitly visible in results such as Figure 4.6. Hydrogen (or its carrier) is used along the supply chain, for instance, as transport fuel during shipping or to generate heat during ammonia cracking. These efficiencies are reported separately in Appendix C.

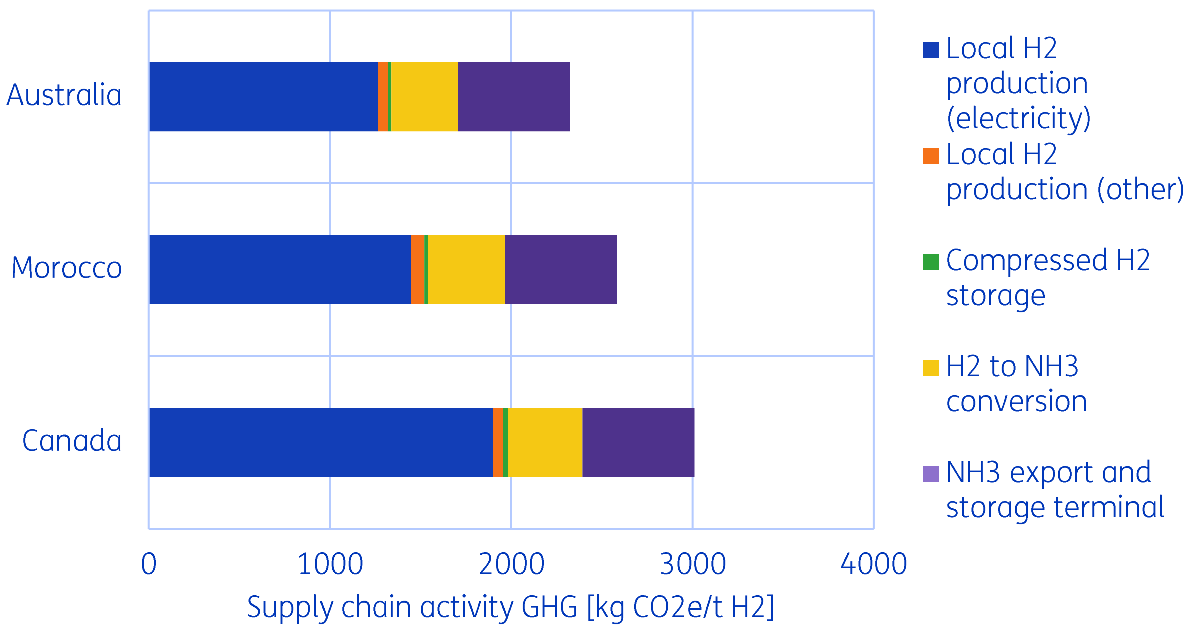


Figure 4.6. Breakdown of life cycle GHG emissions of green hydrogen supply via ammonia in 2030. NH3 stands for ammonia and H2 for hydrogen.

Figure 4.7 shows a breakdown per supply chain activity for delivery of green methanol. The majority of emissions are caused by local hydrogen production (29-53%) and the CO2 feedstock (44-70%). The CO2 feedstock for the Australian archetype is noticeably higher because CO2 is assumed to come from point source capture during cement production with higher GHG emissions intensity compared to the other two archetypes (see Appendix C).

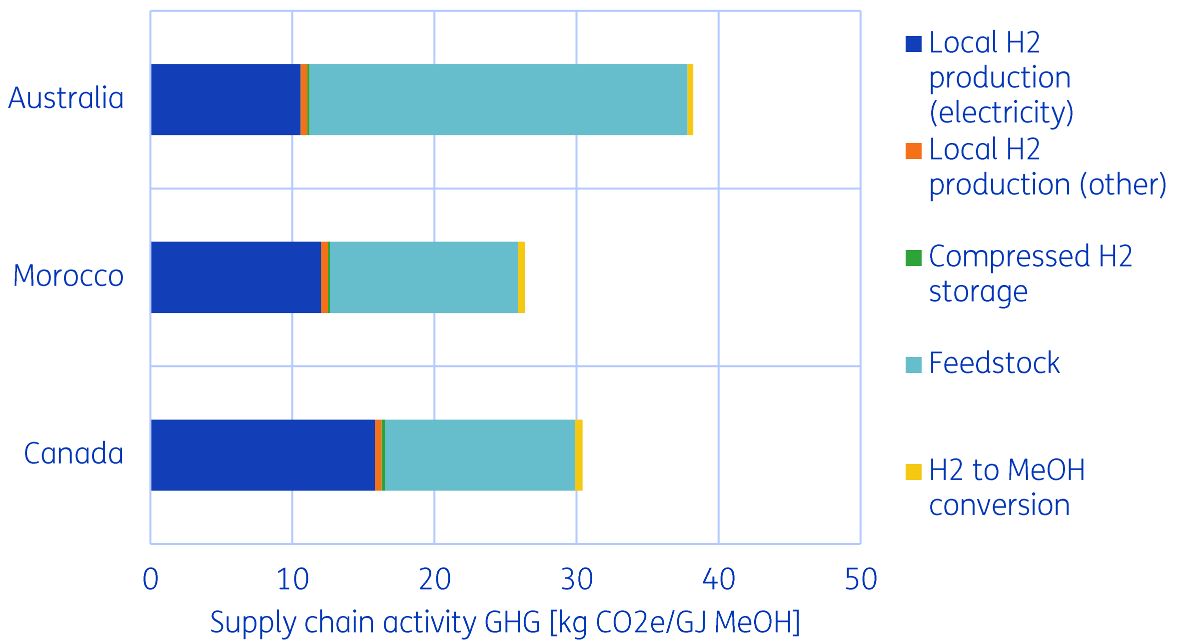


Figure 4.7. Breakdown of life cycle GHG emissions of green methanol supply in 2030. MeOH stands for methanol and H2 for hydrogen.

5 Discussing import cost, annual quantities, GHG emissions and RED-III regulations

Ideal supply routes have low cost, high quantity and low GHG emissions. Finding those rare supply chain configurations that meet all three optimal performances will be on the agenda of many public and private organisations. Optimizing all performance indicators is a challenge and trade-offs are, therefore, unavoidable between supply chain costs, GHG emissions, and delivery quantity. Given the supply options considered (see Table 2.1), two main questions can be explored with our results:

- How do renewable hydrogen import chains perform compared to grey hydrogen?
- Which renewable ammonia and methanol import chains comply with the RED-III?

The renewable energy directive (RED-III) is used as a legislative threshold in this study because it is currently the only European legislation covering GHG emissions associated with importing green hydrogen. RED-III, however, is only relevant for sustainable fuels where green hydrogen, methanol, and ammonia are classified as *renewable liquid and gaseous transport fuels of non-biological origin* (RFNBOs). In the RED-III, the maximum GHG emission intensity threshold for RFNBOs has been defined as a 70% reduction of a fossil fuel comparator set at 94 kg CO2e/GJ. This corresponds to no more than 28 kg CO2e/GJ (equivalent to 3380 kg CO2e/t H2).

It is essential to highlight that RED-III only covers a part of the possible end uses of green hydrogen, methanol, or ammonia. It is used in this assessment because of the lack of more comprehensive European regulations. Note that GHG emissions of renewable electricity equipment should be excluded to comply with the RED-III scope. However, these emissions were included as they significantly influence the results (see section 4.4) and their interpretation. This scoping choice is further investigated in section 5.1.

5.1 The importance of scoping GHG emissions

GHG emissions associated with the production of renewable electricity generation equipment are included, such as the production of wind turbines or solar panels. The rationale is that these emissions account for a large share of the total GHG emissions of green hydrogen import (see section 4.4). However, the RED-III guideline excludes renewable electricity equipment.

To visualize the influence of this scoping choice, Figure 5.1 shows trade-offs for hydrogen delivery with and without renewable electricity equipment. As expected, excluding renewable electricity equipment results in a significant reduction in supply GHG emissions across all supply options considered. Consequently, all supply options without renewable electricity equipment are well below the RED-III threshold. Moreover, when renewable electricity equipment is excluded, the range of variation of GHG emissions between archetypes is narrower. This further confirms that the main source of variation between archetypes is the configuration of local renewable electricity generation. Finally, higher GHG emissions are observed for hydrogen delivery via LOHC due to the higher electricity consumption of dehydrogenation compared to ammonia cracking or liquid hydrogen regasification.

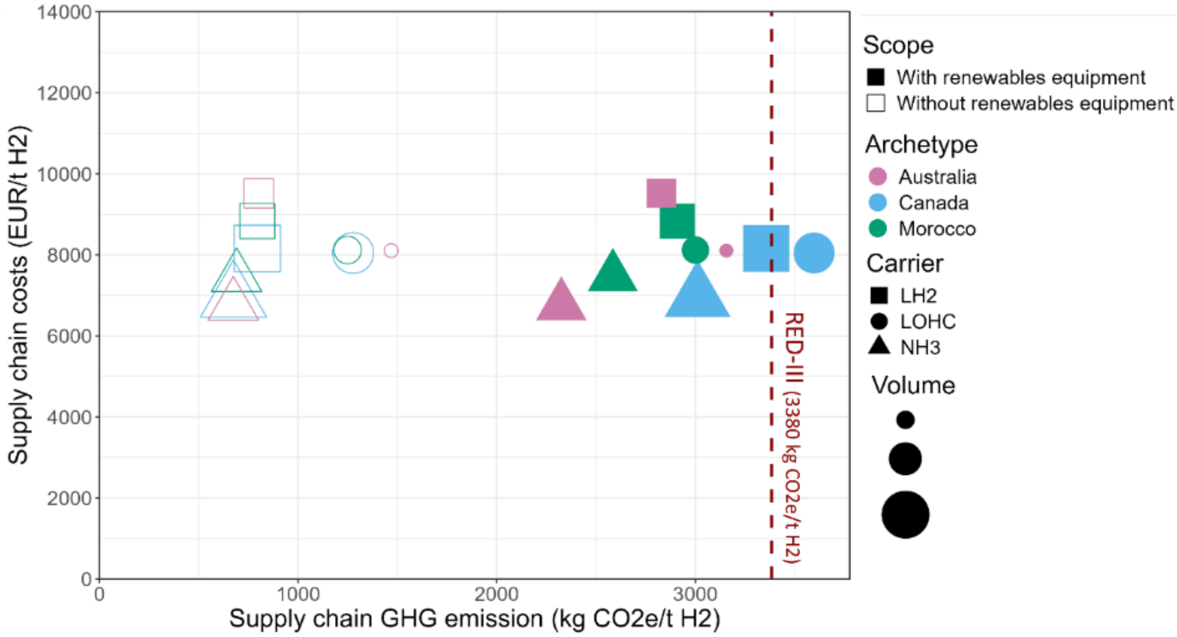


Figure 5.1. Trade-offs between supply chain costs, GHG emissions, and quantity for green hydrogen delivery with and without renewable electricity equipment, in 2030. GHG associated with grey hydrogen are 12000 kg CO2e/t H2.

The results of Figure 5.1 highlight the importance of the scoping choice and we argue that the scope of RED-III should be re-examined for green hydrogen import. Future guidelines focused on green hydrogen should recognize this scoping choice when defining legislative thresholds and carefully consider the risk of severely underestimating the GHG emissions of green hydrogen import.

5.2 Delivery of green hydrogen gas

Figure 5.2 shows the trade-offs between supply chain costs, GHG emissions, and quantity for hydrogen delivery. All supply options are well below (four times lower on average) the grey hydrogen alternative at 12000 kg CO2e/t H2. All supply options are also below the RED-III threshold, except for delivery of H2 via LOHC in the Canadian archetype with emissions at 3600 kg CO2e/t H2. Hydrogen delivery in the Canadian archetypes yields higher GHG emissions due to a higher amount of GHG emissions embedded in Canadian hydropower relative to other options (see Table 2.3). However, note that to comply with the scope set by RED-III, embedded emissions related to electricity production should be excluded.

Delivery of hydrogen via ammonia yields lower supply chain costs, followed by LOHC and LH2. The Australian and Moroccan archetypes lead to comparable delivery quantity (approx. 150 kt H2/y), while higher quantities can be reached with the Canadian archetype (approx. 195 kt H2/y). This is due to the higher availability of hydropower in the Canadian archetype compared to solar power in the Moroccan and Australian archetypes (see Table 2.3).

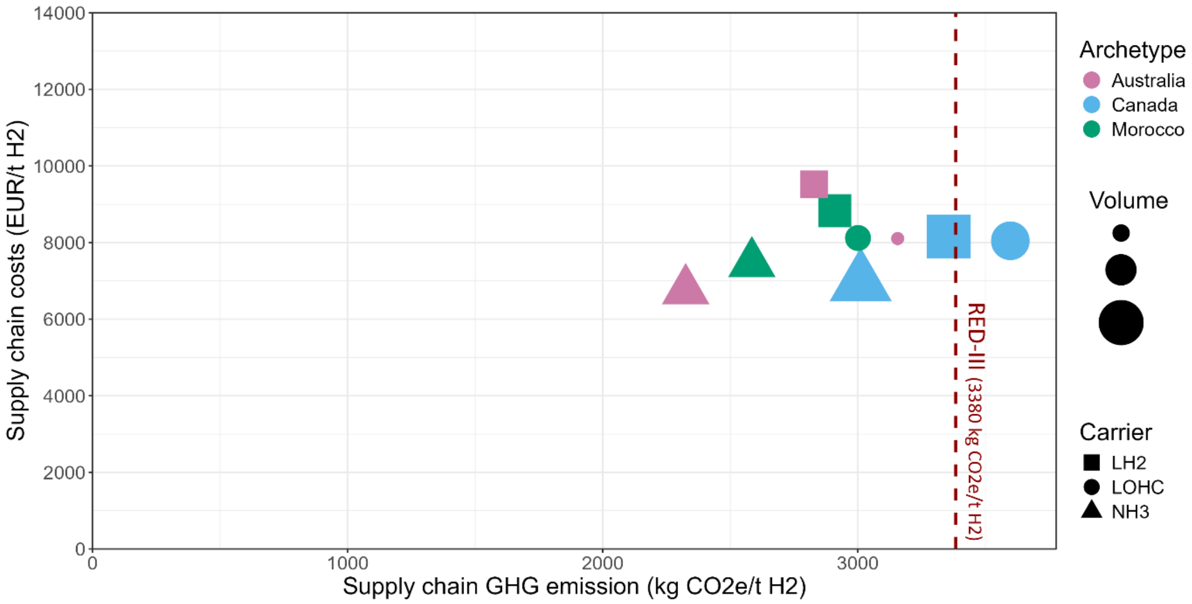


Figure 5.2. Trade-offs between supply chain costs, GHG emissions, and yearly delivery delivered for green hydrogen delivery, in 2030. GHG associated with grey hydrogen are 12000 kg CO2e/t H2 and are not represented

The options shown in Figures 4.2 (and Figures 4.1 or 4.3Figure 5.3) represent only a subset of what is possible in reality. These results are thus not exhaustive, but rather an illustration of possible trade-offs and of the value of this type of multi-criteria trade-off analysis.

As a thought experiment: Assuming a price of CO2 of the EU emissions trading system at 100 EUR/t CO2, the average life cycle GHG emissions observed for green hydrogen import in Figure 5.2 result in an additional cost of approx. 300EUR/t H2. This would represent an increase of cost ranging from 3 to 4% across the supply options considered here, which is relatively minor. The consequences for financial motivation to further mitigate emissions should be explored in more detail.

5.3 Delivery of the green hydrogen derivatives methanol and ammonia

Figure 5.3 shows the same trade-offs for the delivery of green ammonia and methanol. The supply options considered here for ammonia are far below the grey alternative (145 kg CO2e/GJ), nine times lower on average. For methanol delivery, however, the green options are close to the grey, for instance with the Australian archetype crossing the grey threshold with emissions at 41 kg CO2e/GJ. Similarly, methanol delivery with the Canadian archetype is above the RED-III threshold. This is because we assumed that the CO2 feedstock required for methanol production is provided by various carbon capture technologies that are connected to grid energy.

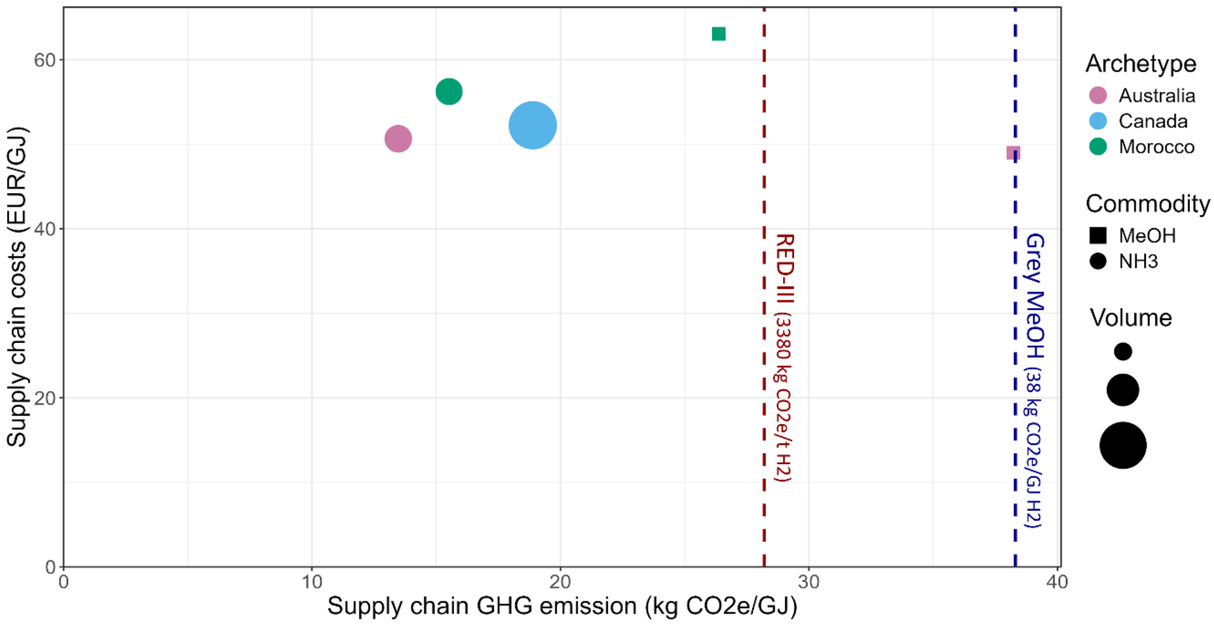


Figure 5.3. Trade-offs between supply chain costs, GHG emissions, and yearly quantity delivered for green ammonia and methanol delivery, in 2030. GHG associated with grey ammonia are 145 kg CO2e/GJ and are not represented. Methanol import via the Canadian archetype is not represented[9].

Figure 5.3 illustrates the nature of the trade-offs that need to be made between supply chain costs, GHG emissions, and quantity. For instance, the Moroccan archetype is the only methanol supply option considered here, and it is below the indicative RED-III threshold. However, compared to the Canadian archetype, it results in additional supply costs of 12 EUR/GJ (24% increase) (as it relies on direct air capture, which is more expensive than other CO_2 sourcing pathways) and yields 5400 TJ lower quantity per year (22% decrease).

[9] Methanol import via the Canadian archetype is not shown in Figure because RED-III is included as an indicative threshold. Methanol falls under the *Renewable Fuel from Non-Biological Origin* (RFNBO) RED-III classification and the Canadian archetype includes carbon capture through solid biomass firing, which is a biological source.

Part B: Methodological developments of hydrogen import assessments

In the past four years the H2SCM has been applied and improved in various studies on an ad-hoc basis for public and private audiences while being maintained by TNO. To make the H2SCM and its insights available to a larger user group on a continuous basis, a variety of developments is considered of importance. Therefore, the **secondary objective of this study is to prepare the H2SCM for further deployment as a scaled analysis and comparison tool for public and private stakeholders.**

In the previous chapters the addition of the greenhouse gas emission KPI was already discussed and demonstrated. Adding this environmental performance dimension, in addition to the levelised cost of imported hydrogen ($LCoH_2$) and annual import quantities, has been crucial to shift the focus from cost-driven to multi-criteria decision support by the H2SCM.

Next to this greenhouse gas emissions dimension, preparations and explorations were performed in three other topics:

1. Exploration of additional hydrogen derivatives to be added to the H2SCM.
2. The coupling with a dynamic simulation software tool to enhance the accuracy of the power-to-X calculations.
3. Shifting to an open access modelling approach to broaden use of the model and the validation of the input data and modelling logic by practiced stakeholders in hydrogen import supply chain development.

This part B reports on the findings of these three topics.

6 Possibilities for expanding the Hydrogen Supply Chain Model with additional hydrogen carriers and derivatives

Currently, the H2SCM can compare the performances of hydrogen import supply chains for five renewable carriers: compressed gaseous hydrogen (via pipeline), liquid hydrogen (via ship), ammonia, methanol, and the liquid organic hydrogen carrier (LOHC) methylcyclohexane (MCH). Other carriers may play an important role as a renewable commodity of the future that are not currently included in this comparison. And in addition to traded commodity type of molecules, intermediates (e.g. high value chemicals, fuels, hot-briquetted) or end-products may also be the preferred traded goods, depending on their relative performances.

As part of this study, we have explored which additional hydrogen derivatives or intermediates could be considered meaningful competitors of future hydrogen, ammonia and methanol trade and therefore be required to include in the comparisons by the H2SCM. This exploration was done through a brief literature review and discussions with TNO researchers.

6.1 A literature analysis of future renewable hydrogen-based commodities

For this literature scan we have consulted the following sources that all include hydrogen (derivative) demand projections:

- DNV (2022). Hydrogen forecast to 2050 – Energy Transition Outlook 2022. DNV AS, Høvik, Norway.
- IEA (2023). Global Hydrogen Review 2023. International Energy Agency, Paris.
- Scheepers et al. (2024). Towards a sustainable energy system for the Netherlands in 2050 – Scenario update and scenario variants for the industry. TNO, The Hague.
- Hydrogen Council, McKinsey & Company (2023). *Global Hydrogen Flows – 2023 Update.*

The sections below summarize the possible needs for additional renewable molecules within the H2SCM based on these publications

6.1.1 Insights from *Hydrogen forecast to 2050* (DNV)

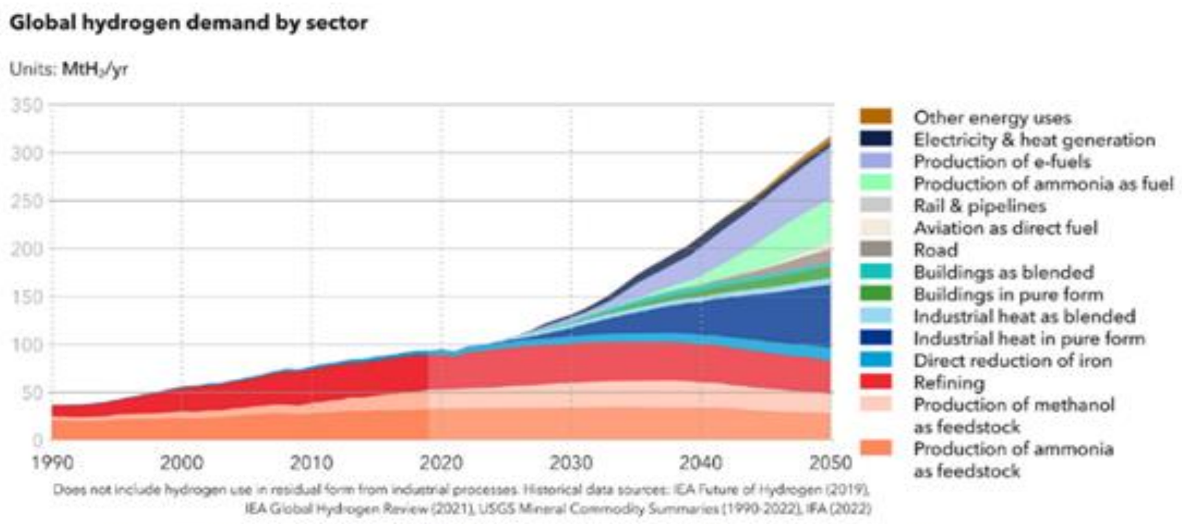


Figure 6.1 - Projected development of global hydrogen demand by sector until 2050. Source: (DNV, 2022)

Using their system dynamics simulation model ETO, DNV projects an increase in global hydrogen from 90 megatons per year to over 300 megatons per year DNV, 2022). See Figure Figure 6.1. This increase is mainly driven by the demand from new hydrogen applications; whereas currently almost all hydrogen is used for non-energy purposes (refining, the production of ammonia as a raw material, and steel production via direct reduction of iron), non-energy use of hydrogen will only account for 30% of the total hydrogen demand in 2050. In contrast, 39% of the hydrogen will be for direct use and 31% for the production of fuels (such as ammonia and e-fuels).

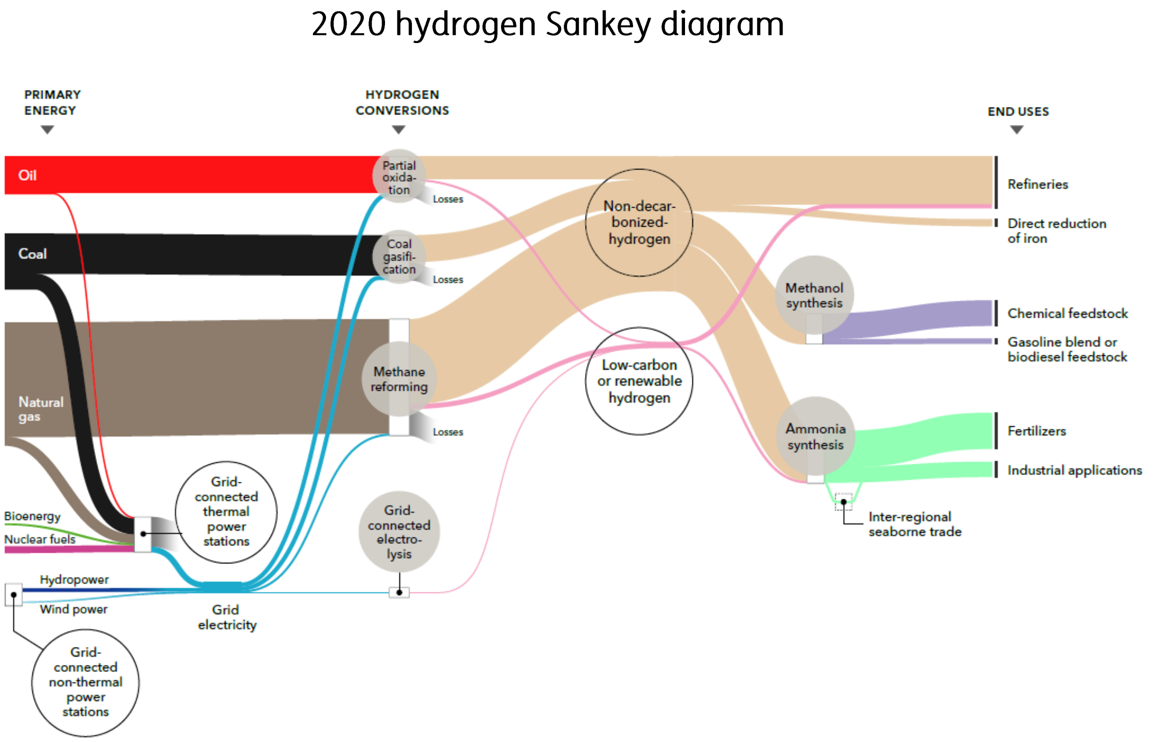


Figure 6.2 – Sankey diagram of source and end use of hydrogen globally, 2020. Source: (DNV, 2022)

According to (DNV, 2022) until 2030 hydrogen demand will mainly be driven by the production of methanol as a raw material, refining, and steel production (direct reduction of iron, DRI). After 2030, the demand for hydrogen for industrial heat and the production of e-fuels (e-methanol and e-kerosene) will rise rapidly. The demand for hydrogen for the production of ammonia as fuel will only play a significant role after 2040. At the same time, the demand for hydrogen for refining and for the production of methanol and ammonia as raw materials will decrease from the mid-2030s.

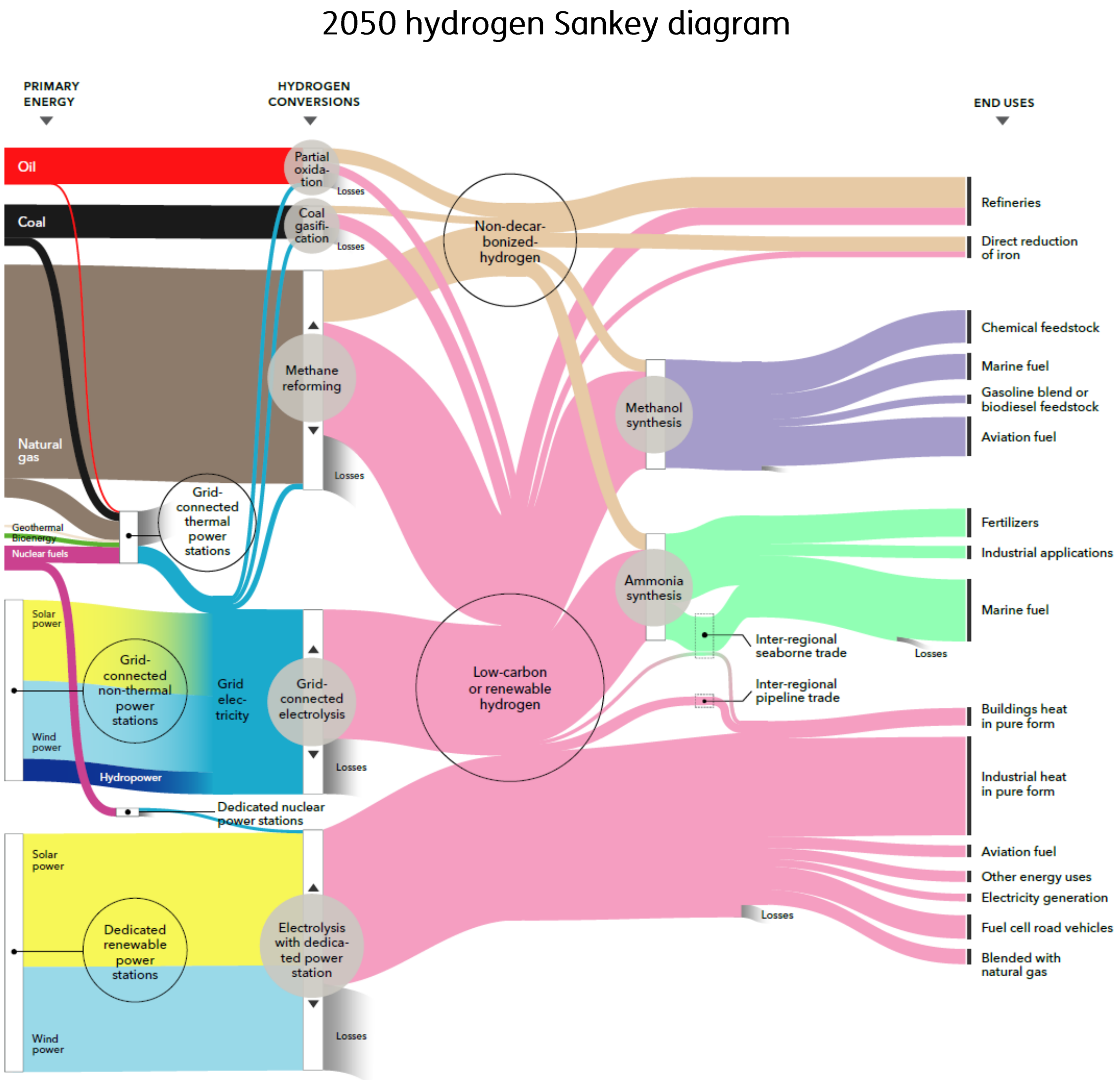


Figure 6.3 - Sankey diagram of projected source and end use of hydrogen globally, 2050. Source: (DNV, 2022)

Looking at the development of hydrogen demand per sector in Figure 6.1, Figure 6.2 and Figure 6.3, methanol and ammonia are the most important hydrogen derivatives in the coming decades, both as raw materials and sustainable fuels, although the use of ammonia as fuel appears to gain importance only after 2040. For shipping, ammonia will be the main sustainable fuel, while e-kerosene (produced with methanol) will be crucial for aviation. DRI-based intermediate products could also become an important trade product. In the hydrogen supply in 2050, green hydrogen will dominate, although the share of blue hydrogen will be significant.

6.1.2 Insight from *Global Hydrogen Review 2023* (IEA)

According to the Net Zero Emissions 2050 (NZE) scenario of the International Energy Agency, global hydrogen demand will exceed 150 megatons in 2030, see Figure 6.4 for a breakdown of the historic and projected hydrogen demand by sector. The growth will be driven by higher methanol production and higher hydrogen demand for direct reduction of iron (DRI) (under *Industry* in Figure 6.4) and the rise of new applications like hydrogen for fuel cells (*Transport*), the production of synthetic fuels (synfuels) and power generation (IEA, 2023).

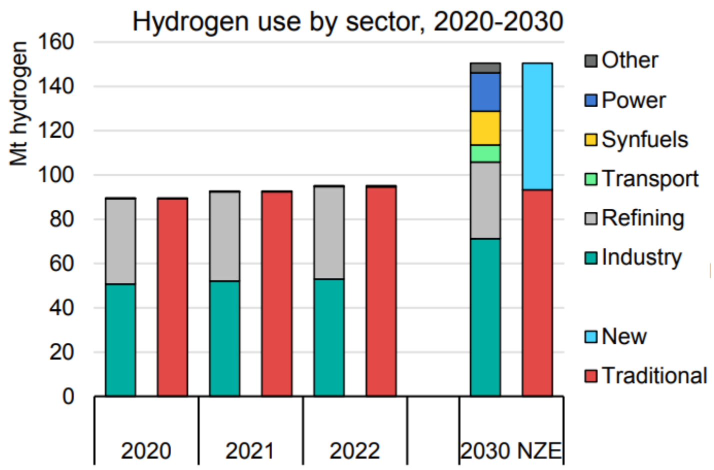
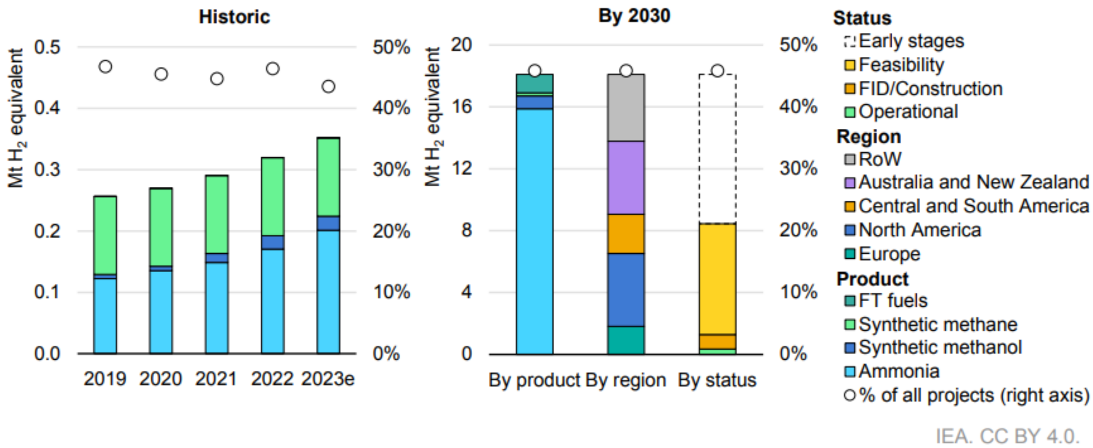


Figure 6.4 – Global hydrogen demand by sector, historically and 2030 projected according to the Net Zero Emissions 2050 scenario. Source: (IEA, 2023)

In already announced projects for the production of hydrogen-based fuels, ammonia as a fuel accounts for 80% (see *By Product in 2030* in Figure 6.5). This seems to contradict DNV's projection, which barely anticipates a role for ammonia as fuel in 2030 (see Figure 6.1) (DNV, 2022).



Notes: FID = final investment decision; FT = Fischer-Tropsch; RoW = rest of world.
Source: IEA Hydrogen Projects, (Database, October 2023 release).

Figure 6.5 - Global production of hydrogen-based fuels, according to announced projects, broken down by project status, region, and fuel type. Source: (IEA, 2023)

Additionally, according to the IEA, ammonia will by far be the most significant hydrogen carrier in international hydrogen supply chains, accounting for 80% of production (see Figure 6.5). The remaining 20% is mainly filled by "unknown carriers," synthetic fuels, and compressed gaseous hydrogen. There is a small role foreseen for liquid hydrogen, while the share of LOHC and methanol in global trade is negligible according to already announced projects.

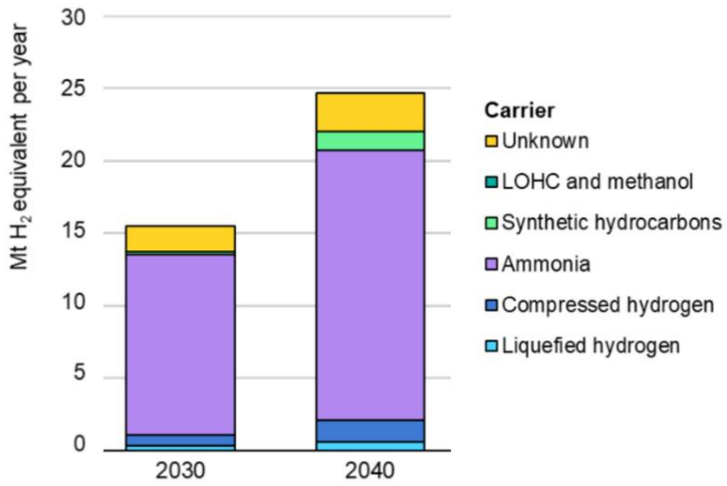


Figure 6.6 - Global trade in blue and green hydrogen according to already announced projects, for the years 2030 and 2040, broken down by project status and hydrogen carrier. Source: adaptation from (IEA, 2023)

6.1.3 Insights from *A climate-neutral energy system for the Netherlands* (TNO)

In its study "A climate-neutral energy system for the Netherlands" (Scheepers et al., 2024). TNO has developed two model-based[10] scenarios for a climate-neutral energy system in 2050: Adapt and Transform.

In the Adapt scenario, the Netherlands largely maintains its current economic structure and lifestyle, but the energy system and industrial processes are adjusted and optimized to reduce CO_2 emissions. Structural changes to the energy system are only planned for after 2050. Fossil fuels will continue to play a role in the energy system but their emissions are abated through carbon capture and storage (CCS). There is limited policy coordination on an EU level; member states pursue their own climate policies.

In the Transform scenario, the changes are more profound: a high level of environmental awareness among the population leads to behavioural changes and individual and collective climate action by citizens, resulting in lower energy consumption, the transformation of industrial processes through sustainable technologies, and sustainable agriculture, among other changes. Moreover, animal husbandry and international travel decrease, further reducing greenhouse gas emissions. CCS has a limited role.

Figure 6.7 shows the results of these scenarios for the hydrogen consumption in the Netherlands. Note that these graphs only consider merchant hydrogen, captive hydrogen (i.e., hydrogen produced and used onsite) is therefore not considered In both scenarios, the hydrogen demand increases strongly to 422 PJ (or 3.58 Mton, Adapt) and 561 PJ (or 4.77 Mton, Transform). In the Adapt scenario we can observe that the hydrogen consumption grows due the production of methanol, synthetic fuels and fertilizers. In the Transform scenario the hydrogen consumption increases more strongly. This is due to a higher demand for ammonia as shipping fuel and other e-fuels (labelled “P2L” in Figure 6.7), as a result of higher ambitions regarding sustainable bunker fuels and feedstocks. Unlike the Adapt scenario, the Transform scenario foresees a role from green hydrogen to decarbonize steel production. In the Adapt scenario, steel-making will switch to Hisarna direct reduction of iron (DRI) with CCS (Tata Steel Europe, 2020). In the Transform scenario, there will also be considerable hydrogen exports.

[10] The study by (Scheepers et al., 2024) used the energy system optimization model OPERA, developed by TNO.

In both Adapt and Transform, electrolysis will develop into the main source of merchant hydrogen production while natural gas will be completely phased out towards 2050. (It may still continue to exist for captive hydrogen production but this is not covered in the study.) Hence, since system cost optimization is the starting point of this study, electrolysis is projected to become more competitive than steam-methane reforming (SMR) with CCS after 2030.

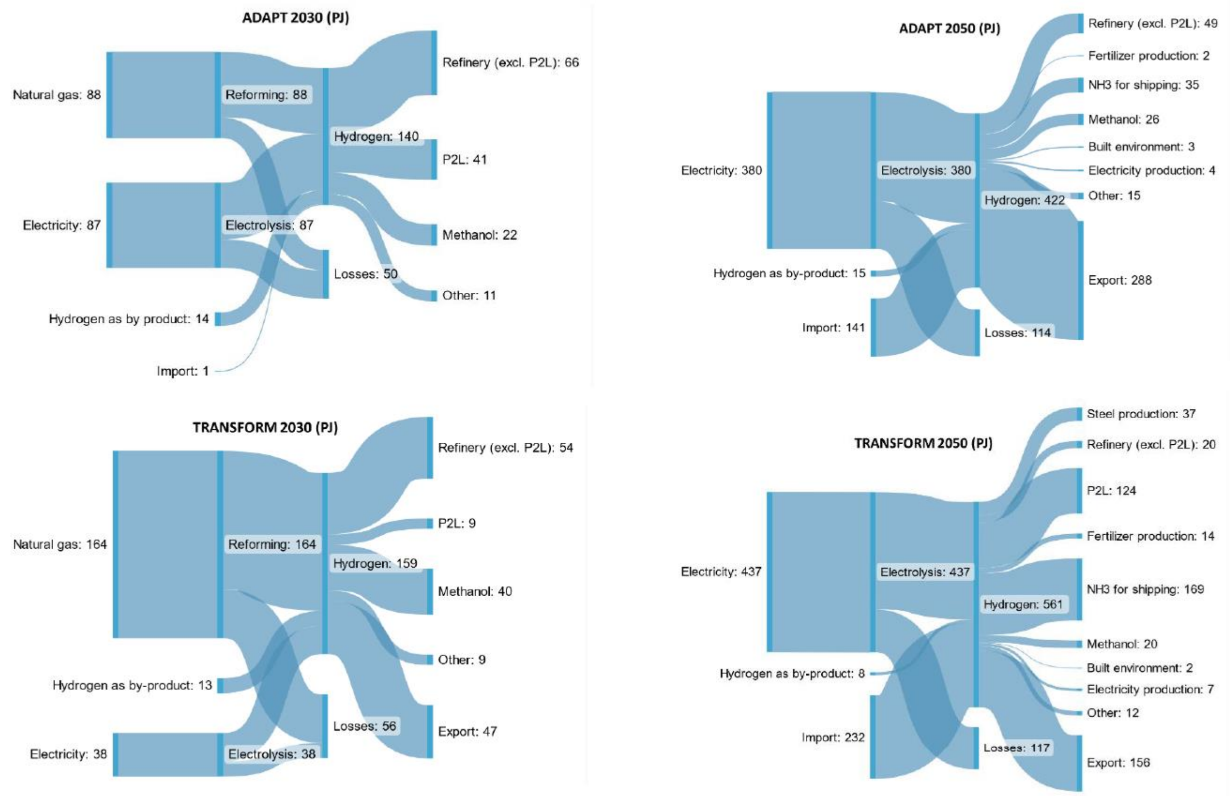


Figure 6.7 – Sankey diagrams of hydrogen production and consumption according to TNO's Adapt and Transform scenarios for 2030 and 2050. Note that these graphs only consider merchant hydrogen, captive hydrogen (i.e., hydrogen produced and used onsite) is therefore not considered. Source: (Scheepers et al., 2024)

6.1.4 Insights from *Global Hydrogen Flows – 2023 Update* (Hydrogen Council, McKinsey & Company)

This research by Hydrogen Council and McKinsey & Company focuses on long-distance hydrogen trade globally. Its starting point is a scenario called "Further Acceleration" (FA). This is a scenario in which the energy transition is accelerated compared to today's pace but fails to keep global warming to below the 1.5°C target. According to this scenario the demand for clean (blue and green) hydrogen and derivatives may be 40 Mt hydrogen-equivalent globally, 18 Mt of which is transported over long-distances. In 2050, the FA scenario projects a growth to 375 Mt, with long-distance transport accounting for 200 Mt.

Among other topics, the study analyses the share of countries and regions around the world in the production and offtake of hydrogen (derivatives) and the share of each hydrogen carrier in the total trade flows. The results are shown in Figure 6.8 and Figure 6.9.

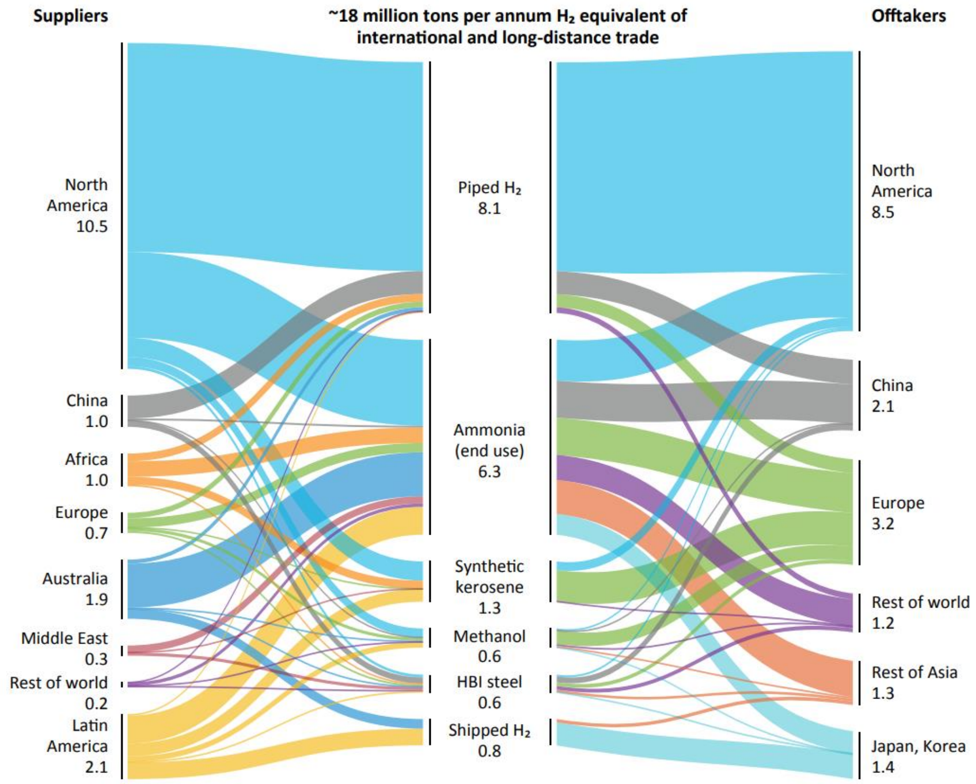


Figure 6.8 – Global trade flows of "clean" (blue and green) hydrogen in 2030 according to the Further Acceleration scenario. Source: (Hydrogen Council & McKinsey & Company, 2023)

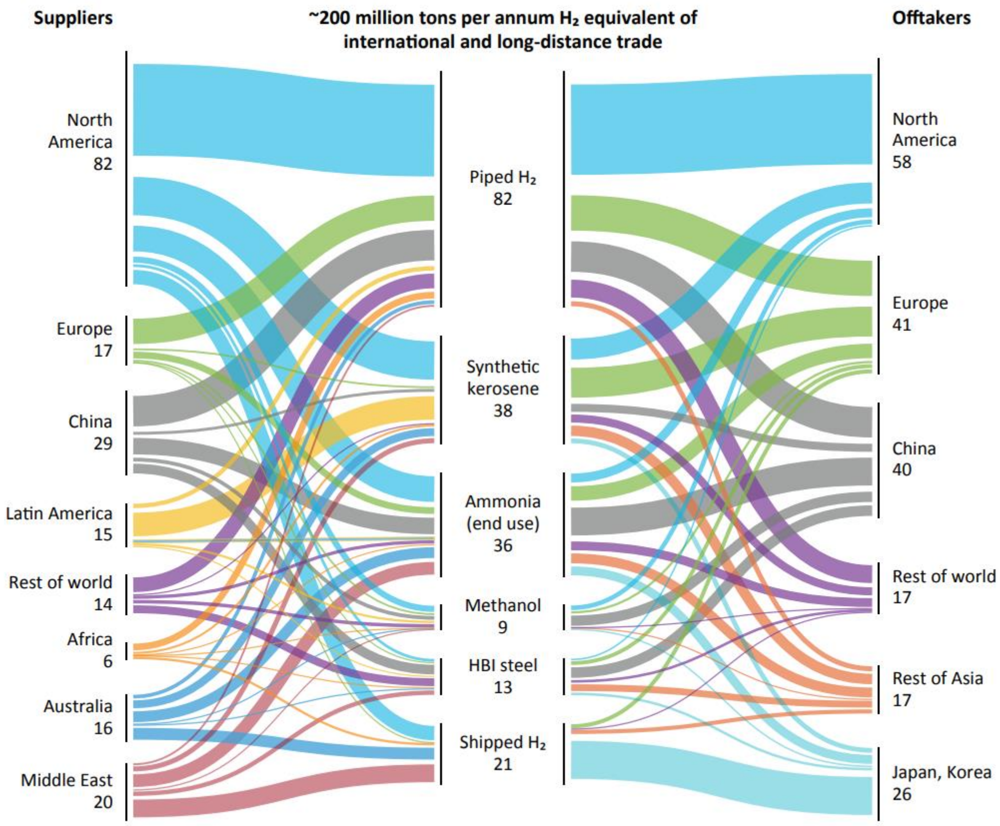


Figure 6.9 - Global trade flows of "clean" (blue and green) hydrogen in 2030 according to the Further Acceleration scenario. Source: (Hydrogen Council & McKinsey & Company, 2023)

6.1.5 Synthesis of the four literature studies

Due to their differences in scope, the TNO study focuses on the Netherlands rather than the world; Hydrogen Council and McKinsey study focus on long-distance trade only, none of the studies can be compared one-on-one. Still, we attempt to draw some comparisons here. In Table 6.1, a comparative overview of the studies is shown. The DNV and IEA studies are the only studies that make projections for the global hydrogen (fossil-based and renewable/low-carbon) demand in 2030. IEA's projection at least 15% higher than DNV's projection. The difference between the two scenarios can be explained mainly by the greater demand in the IEA study for synthetic fuels produced with hydrogen (synfuels), as shown in Figure 6.4. (IEA, 2023)

In all scenarios, the rising hydrogen demand is driven by demand for ammonia as shipping fuel, e-fuels, methanol as chemical feedstock and green steel production, though in varying degrees. DNV projects a significant share of the global hydrogen demand will be used for industrial heat, while this is not foreseen in the TNO study; the IEA study projects a small share.
Regarding hydrogen production, the DNV scenario projects fossil fuel-based (blue and grey) hydrogen production will still account for almost 50% of the total hydrogen production, while in the TNO scenarios Adapt and Transform, blue and grey hydrogen are almost fully phased out (at least for merchant hydrogen; captive hydrogen is not considered in these scenarios).

Table 6.1 – Comparative overview of the four sources reviewed in this study.

	DNV	IEA	TNO*	Hydrogen Council & McKinsey
Modelling method used	System dynamics simulation	Simulation	Integrated assessment (optimization)	Optimization
Projected H_2 demand in 2030 and 2050 globally	2030: ~130 Mt 2050: ~300 Mt	2030: ~150 Mt	N/A (only covers the Netherlands)	2030: 40 Mt** 2050: 375 Mt**
Main end use sectors (in order of magnitude)	2030: refining, NH_3 for fertilizers, MeOH as chemical feedstock 2050: H_2 for industrial heat, refining, NH_3 as shipping fuel	2030: NH_3 production, MeOH production and refining	*Adapt scenario* 2030: refining, e-fuels, MeOH production, 2050: export, refining, NH_3 as shipping fuel *Transform scenario* 2030: refining, MeOH production, export 2050: NH_3 as shipping fuel, export, e-fuels	Not considered in the study

** TNO study considers only merchant hydrogen; captive hydrogen (i.e., hydrogen produced and used onsite) is therefore not considered. Therefore, traditional hydrogen applications like fertilizer production are left mostly out of scope.*

*** Only "clean" hydrogen: blue (low-carbon) and green (renewable).*

**** DNV considers the following regions:*

	DNV	IEA	TNO*	Hydrogen Council & McKinsey
Development of traditional versus new hydrogen applications	Demand for new applications will really start to emerge in 2030, mainly H_2 for industrial heat and e-fuel production. Demand for NH_3 as fuel will only become substantial after 2040. Demand for traditional applications will rise only to decrease after 2035 to levels comparable to 2020.	New applications will be wholly responsible for the rise in H_2 demand until 2030 (as H_2 demand for traditional applications will stay stable) and constitute about one third of the H_2 demand in 2030.	*Adapt scenario* E-fuels already emerge as major H_2 application from 2030 onwards; in 2050 majority of H_2 produced will be exported. H_2 consumption is mainly for NH_3 as shipping fuel accounts (25%) and refining (36%). *Transform* H_2 for export and methanol production develop more quickly in 2030 compared to Adapt. In 2050, H_2 consumption is dominated by NH_3 as shipping fuel and e-fuel production, with smaller shares for methanol and green steel production	Synthetic kerosene (7%), hot briquetted iron (HBI) (3%) and methanol (3%) will already occupy considerable shares in global clean H_2 long-distance flows in 2030. In 2050, synthetic kerosene will have a 20% share in these flows, on par with ammonia.
Global hydrogen trade	Trade volumes will increase, mainly ammonia as shipping fuel, of which 60% will be traded between regions***. Gaseous H_2 will be mainly produced and consumed in the same region, with only 4% traded between regions via pipelines.	Global trade about 10% of worldwide hydrogen consumption	Not considered in this study	Long-distance trade 45% of clean hydrogen demand in 2030 and 53% in 2050.
Hydrogen carriers for global trade	100% ammonia for seaborne trade	80% ammonia, 20% other carriers	not applicable due to scope of research	Not specified
Other major hydrogen-derived commodities	Ammonia as shipping fuel, methanol for e-kerosene production	Ammonia, Fischer-Tropsch fuels	not applicable due to scope of research	Synthetic kerosene (exported from Latin America to Europe and Asia, driven by local availability of low-cost CO_2), ammonia (end use)

6.2 An expert consultation on future renewable hydrogen-based commodities

According to various TNO experts, the most relevant hydrogen derivatives are already included in the model if we consider hydrogen derivatives for the purpose of being a hydrogen carrier. However, from an end-use perspective, it would be worthwhile to add synthetic molecules (especially Fischer-Tropsch fuels) and bio-routes for several molecules in the model. It is relevant to compare synthetic molecules with their bio-counterpart (e.g., e-methanol versus bio-methanol) since industries will look to both options to decarbonize. Moreover, it was suggested to add blue hydrogen since it is likely to play an important role in the near future as alternative to green hydrogen and may act as an enabler of the hydrogen economy. The EU REDIII specifies blue hydrogen may be counted as low-carbon hydrogen if its emissions are 70% lower than for grey hydrogen (Fonseca, et al., 2023).

To determine which renewable molecules could be added to the Hydrogen Supply Chain Model, it is useful to consider the renewable molecules that could potentially play an important role in the decarbonization of each end-use sector. Here, for each end-use sector, the potentially interesting renewable (hydrogen-based) molecules are listed.

Table 6.2 – Overview of (hydrogen-based) renewable commodities and alternative processes that could play an important role in the decarbonization of industrial sectors. Source: TNO expert consultation.

Relevant (hydrogen-based) commodities or alternative processes	Examples of end-use application areas
Ammonia*	Fertilizers, shipping
E-methanol*	Synthetic fuels, methanol-to-olefins**, aromatics
Bio-methanol*	Biofuels, methanol-to-olefins**, aromatics
Syngas	Fischer-Tropsch fuels, methanol, power generation, direct reduction of iron
Fischer-Tropsch fuels	Shipping, aviation, heavy-duty road transport
Hydrotreated vegetable oil (HVO) fuels	Shipping
Hot-briquetted iron (HBI)	Steel industry
Dimethylether (DME) (a synthetic diesel)	Heavy-duty road transport
Bio-oil	Refining, high-value chemicals
Bio-ethanol	Refining, high-value chemicals
Bio-naphtha	Steam cracking
Bio-BTX (benzene/toluene/xylene mixture)	Aromatics

* Already included in the H2SCM.

** Methanol-to-olefins is an alternative route to naphtha steam cracking to produce olefins

Possible extensions in the field of hydrogen carriers could still be considered, provided that these carriers have a sufficiently high TRL (Technology Readiness Level) / feasibility level so there is sufficient data available to include them in the H2SCM.

- Solids/salts such as borohydrides
- Synthetic Liquefied Natural Gas (SLNG)
- Differentiation of LOHC varieties: currently the model only includes the methylcyclohexane-toluene (MCH-TOL) system. Examples are cyclohexane-benzene and dibenzyl toluene-perhydro-dibenzyltoluene (DBT-PDBT) (Asif et al., 2021).

Based on the literature scan and the expert consultation, the expansion of the H2SCM with the following hydrogen derivatives and supply routes is deemed useful to be able to facilitate a more complete comparison of renewable hydrogen-based commodities:

- Blue hydrogen, since its inclusion as "low-carbon hydrogen" in the EU RED-III and interest from the industry. This includes both the grey hydrogen production (SMR and/or ATR) and the required carbon capture and storage.
- Syngas, a mixture of hydrogen and carbon monoxide in various ratios which is already frequently used as a commodity gas in the process industry.
- Fischer-Tropsch fuels (e.g. diesel, kerosine) and dimethyl ether (DME) given their relevance for the decarbonization of the aviation and maritime sectors.

7 Exploring a dynamic simulation approach to improve power-to-X cost analysis

As discussed in Chapter 2, the H2SCM was developed to facilitate quick and transparent analyses of hydrogen import chains. The model uses annual averages for the utilization of renewable electricity for the electrolyzer and other assets, such as conversion to hydrogen carriers. As such, the H2SCM calculations do not optimize the sizing of the individual chain elements.

Due to the dynamic operation of technologies in the Power-to-X supply chain, a more advanced modelling approach that is able to address these dynamics may yield more accurate insights in the performance of Power-to-X supply chains. Examples of such topics are the storage capacities required to guarantee a secured supply of a produced molecule to match demand, intermediate storage capacities in between the processes (e.g. electrolysis and Haber-Bosch) and the operational limitations to safeguard process operation safety. By considering such dynamics on an hourly or quarter-hourly basis from a multi-technology perspective offers an opportunity to optimize CAPEX, OPEX, operational profiles and other KPIs by, for example, sizing of different components.

The (static and non-optimized) calculations of the H2SCM are expected to benefit from an integration with software that does account for this dynamic behaviour and optimizes asset dimensions. PyDOLPHYN is a TNO-developed software tool that can optimize the dimensions of multiple assets and provide differences for multiple types of operation (e.g., off-grid installations vs grid-connected in baseload). The capabilities of PyDOLPHYN are introduced in the exhibit below using an example of a power-to-hydrogen-to-power supply chain.

<u>Note</u>: the configuration in this example does not align with the scope of the hydrogen import assessments presented in earlier chapters with the H2SCM.

Exhibit – Introduction of PyDOLPHYN dynamic optimization software

Figure 7.1 shows a system design using static analysis and annual averages for energy flows. A dynamic simulation of such a system reveals that the hydrogen storage capacity is depleted within 6000 hours (9 months). Therefore, the storage capacity appears to be insufficient. In practice, either demand would not be fulfilled or power/hydrogen would need to be sourced from elsewhere, with a high cost penalty.

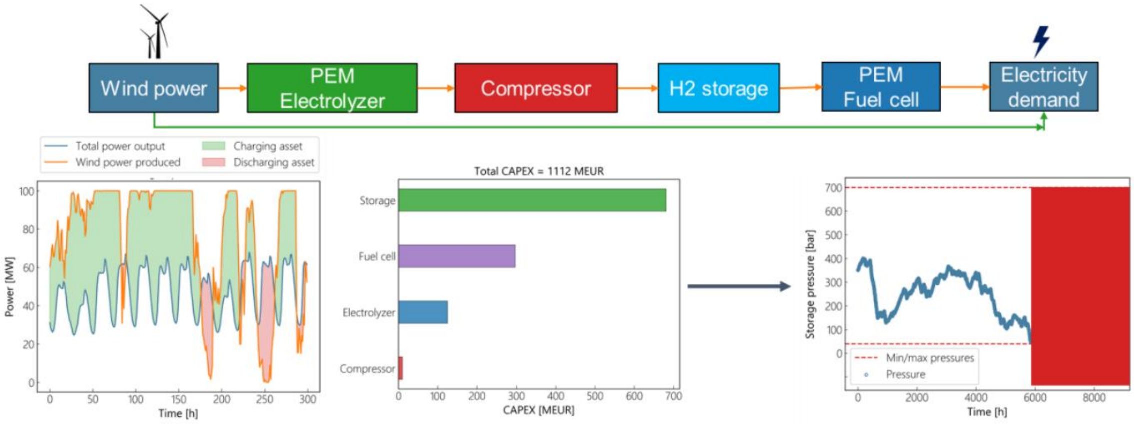


Figure 7.1 – Illustration of a power-to-power system designed using static analysis. Note that the hydrogen storage becomes depleted after less than 6000 hours (9 months) as is indicated in red.

Exhibit *(continued)* – Introduction of PyDOLPHYN dynamic optimization software

The asset design choices in the PtH_2tP chain are optimized by for three demand fluctuation (volatility) scenarios by calculating hourly dynamics of the technologies in the supply chain. It can be observed in Figure 7.2 that there is a significant CAPEX difference between the designs (892-1411 million euro. In addition, when faced with high demand variations, even a significantly oversized storage asset is *not sufficient* to return to the starting fill level, as the cumulative profile shows a declining trend. PyDOLPHYN provides detailed simulations to explore that the design of *feasible* technological solutions and quantifying their cost, and technical KPIs. In this particular exhibit, feasibility refers to an asset fulfilling its purpose (e.g., a storage that can dampen fluctuations). Feasibility can also be related to producing the required energy carrier or to satisfy physical, market or regulatory constraints.

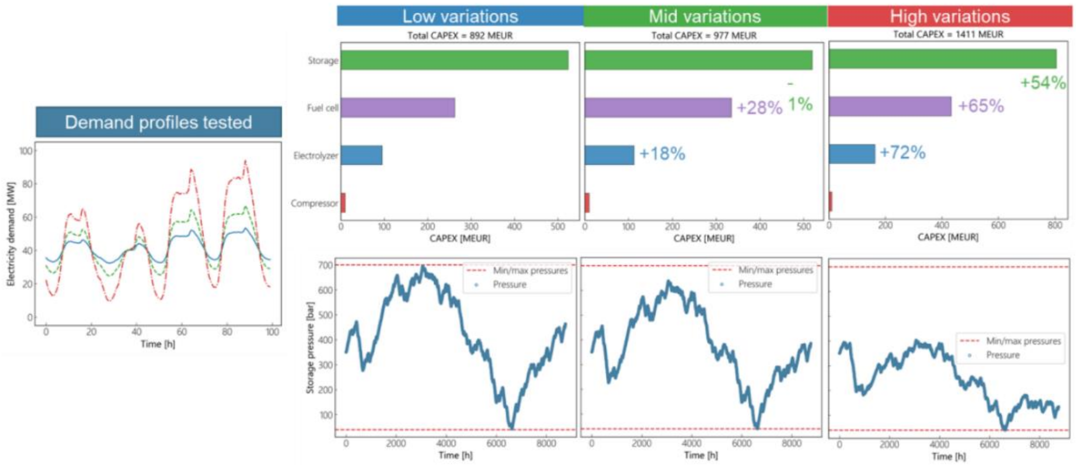


Figure 7.2 – Illustration of a value chain that considers three electricity demand profile fluctuations, asset CAPEX and storage pressure-over-time (fill level) graphs.

This example demonstrates that the optimal sizing of assets can largely depend on the dynamics of energy flows between technologies. Since availability profiles for renewable power vary globally, dynamic optimization could support import supply chain designs and assess the costs of hydrogen (carriers) in more detail.

To investigate the impact of dynamic simulations on the sizing of assets in hydrogen import chains, we have used the PyDOLPHYN software to experiment with a power-to-ammonia supply chains through two test case examples.

- Example 1: RES ratios. A dynamic power-to-ammonia cost analysis with 2 GW RES in varying wind-to-solar ratios and 2 GW electrolysis.
- Example 2: RES overplanting. A dynamic power-to-ammonia cost analysis with 2-4-6-8-10 GW RES for 2 GW electrolysis.

Both examples have their scope limited to the following supply chain element technologies: Hybrid renewable power plant (onshore wind far and solar PV park), electrolyser using alkaline technology, gaseous hydrogen compressor and ammonia synthesis Haber-Bosch process.

7.1 Example 1: RES ratios. A dynamic power-to-ammonia cost analysis with 2 GW RES in varying wind-to-solar ratios and 2 GW electrolysis

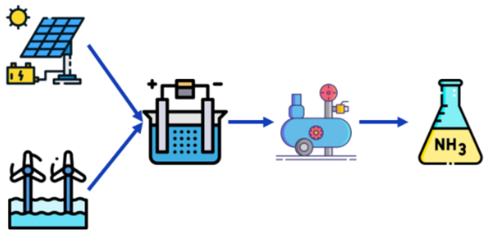


Figure 7.3 – Case study overview. Wind and solar power capacities are optimized.

Figure 7.3 shows the qualitative example of the potential capabilities of a coupled approach between the Supply Chain Model and PyDOLPHYN. In this first example, due to time and scope limitations, not all the assumptions have been fully coupled. Hence, there may be some differences between both results that are due to the assumptions taken. These will be noted in the comparison.

The goal is to optimize the Levelised Costs of Ammonia (LCOA) by varying the capacities of wind and solar power. The location chosen is The Netherlands, with a wind profile located around the Dutch offshore wind farm area of IJmuiden Ver and a solar profile onshore, in De Kooy (Den Helder). The electrolyzer technology is alkaline, with performance and assumptions characteristic to typical European alkaline electrolyzers, including its minimum load factor and operation characteristics. The ammonia synthesis plant has been scaled according to the electrolyzer capacity. For simplicity in the dynamic calculations and due to the small scope of this example, the electricity used in the NH3 synthesis plant is bought at market price, which is modelled using assumptions from the *Integral energy system exploration 2030-2050,* II3050 (Nederland, 2023). While this additional electricity might not be always necessarily green, it could be considered that there is an external agreement (e.g., floating/variable PPA) that provides green electricity at market rates. It should be noted that this contribution for the LCOA was not included in the dynamic optimization, but only in the comparison with the static analysis. It only accounts for 1-2% of the ammonia production component of the LCOA in the tested cases (and well below 1% of the total LCOA), so it does not affect the fundamental trends. The installation is set with 20 operation years, and a discount rate of 8%.

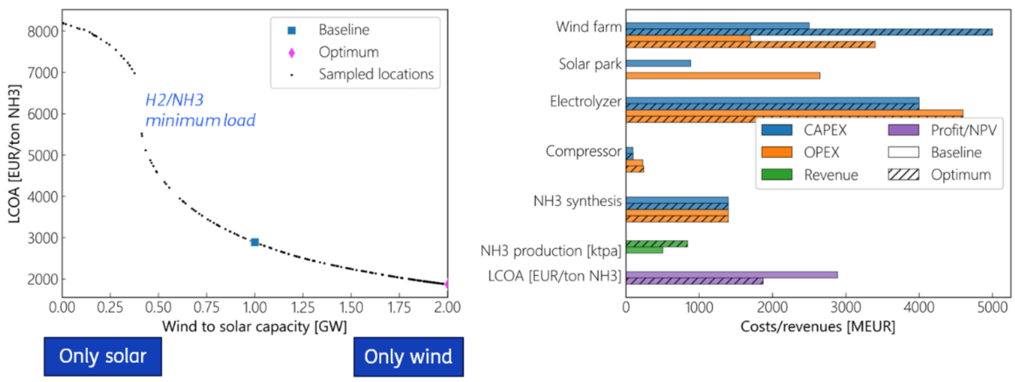


Figure 7.4 – Left, LCOA for different ratios of wind to solar capacities. Right, detailed overview of cost and revenue streams for baseline (1 GW wind, 1 GW solar) and optimum (2 GW wind, 0 GW solar).

In this first example, the parameters that are varied are the ratios of wind and solar power, while keeping a total of 2 GW installed. Hence, the ratio between them can be shown in Figure 7.4. For these particular assumptions, constraints and boundary conditions, there is a clear trend favoring wind over solar power. There is an S-shaped profile, as seen in the left part of the figure. The LCOA increases significantly if there is not enough wind power to be above the minimum load factors of the H2/NH3 production plants. If that is the case, the production will be very low throughout several months in the year, increasing the levelised costs due to the low yield compared to the CAPEX/OPEX. Adding more wind capacity after this point keeps being beneficial, asymptotically bringing less and less benefits. With respect to the baseline (1 GW wind, 1 GW solar) compared to the optimum (2 GW wind, 0 GW solar), the optimum has 67% more NH3 production (842 vs 505 ktpa), with only marginally higher CAPEX/OPEX (4%). There is a significant difference with respect to the full load hours in a year: 2450 in baseline, 4200 in optimum. For an electrolyzer with no constraints, an upper limit of around 5000 full load hours could be achieved with these renewable energy source. However, safety considerations (particularly minimum load) decrease this number. The effect of changing the wind-to-solar power ratio and the addition of safety loading constraints is significant which highlights the added value of a dynamic analysis in an early supply chain design exploration phase.

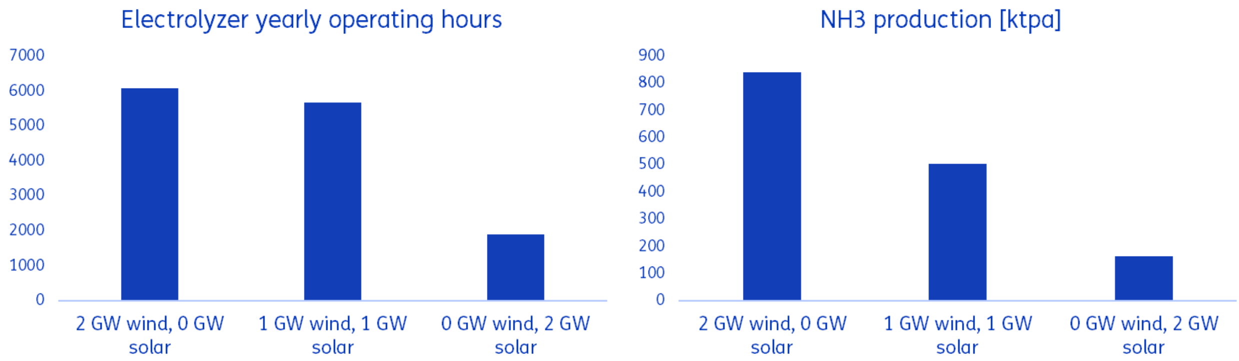


Figure 7.5: Operational hours of the electrolyzer and ammonia production for different RES capacities.

Figure 7.5 shows that the number of operating hours of the electrolyzer is similar for the cases with 2 GW wind and 1 GW wind combined with 1 GW of solar installed capacity. However, due to the significantly lower electricity production of the solar farm, there is a large difference in the ammonia produced

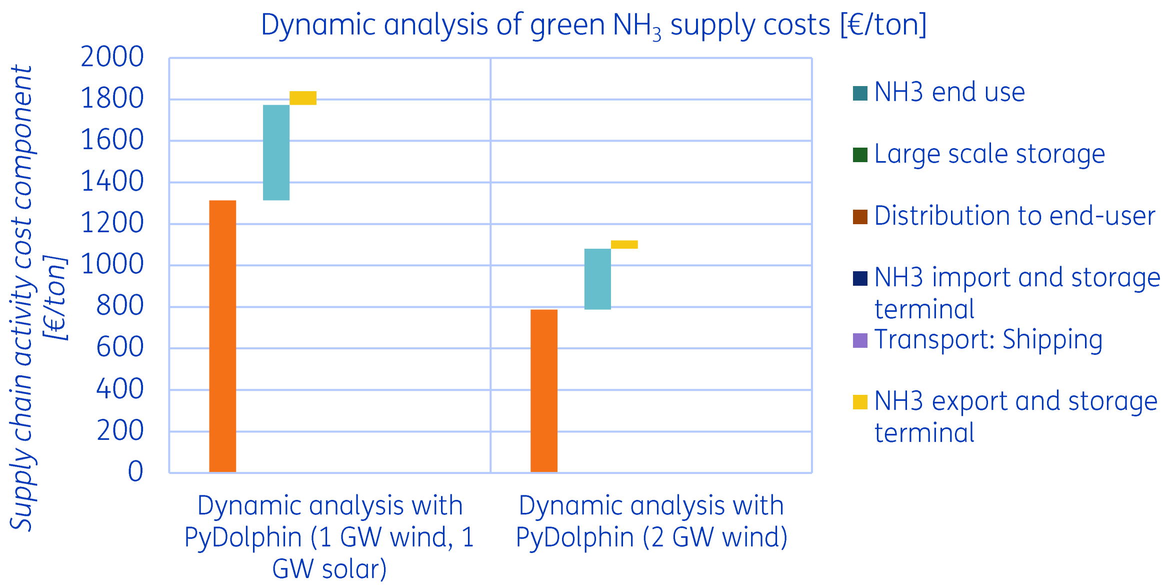


Figure 7.6 – Comparison of ammonia production on two different scales (2 vs 4 GW renewable electricity capacity) using dynamic analysis.

Figure 7.6, shows a direct comparison between the results obtained with the H2SCM and PyDOLPHYN. The first difference that can be appreciated is the notable difference between the three cases. The LCoA can either increase or decrease when using the dynamic analysis. The LCoA using wind + solar (using PyDOLPHYN) is 11% higher than in the static case (using the H2SCM). This is mainly due to the limited production, as mentioned before. The static analysis assumes 979 ktpa, while the dynamic analysis produces 505 ktpa for wind + solar and 842 ktpa for only wind power Due to the lack of direct coupling in this first test case, the H2SCM numbers for certain costs are slightly different: they may include a scaling factor with an anchor point, where the PyDOLPHYN numbers are scaled linearly with their size for electrolysis and ammonia synthesis. Also note that, whereas the investment costs for the renewable electricity capacity are currently not part of the H2SCM, the wind farm and the solar park were part of the optimization process in the dynamic analysis and included explicitly in the costs depending on their size.

These figures should be taken in a *qualitative sense*. They highlight the importance of performing a dynamic analysis, and also to ensure that the right assumptions are taken when comparing and evaluating results between two different methodologies, as they can provide significant differences. In addition, they show that physical constraints (e.g., minimum load factor due to safety reasons) can play a significant role in the overall levelised costs, even for relatively simple supply chains.

7.2 Example 2: RES overplanting. A dynamic power-to-ammonia cost analysis with 2-4-6-8-10 GW RES for 2 GW electrolysis

In this section, some additional metrics related to overplanting renewable electricity sources compared to the electrolyzer capacity are shown. In this case, it is assumed that the abundant power can be sold at a power market spot price every hour.

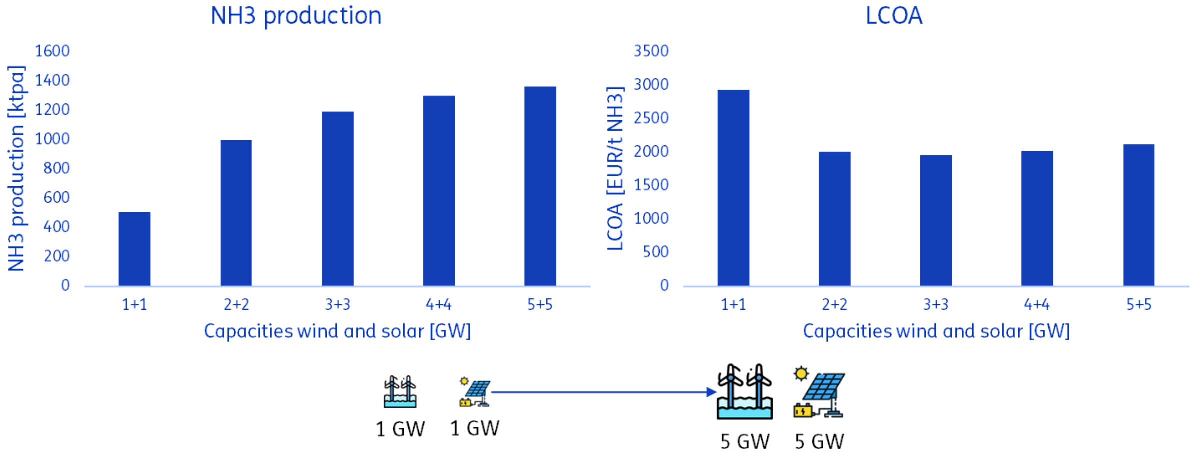


Figure 7.7 – Ammonia production and levelised costs (dynamic analysis) when overplanting wind and solar power compared to 2 GW electrolyzer capacity.

Figure 7.7 Figure 7.7 shows the results of using more than 2 GW of renewable electricity sources (RES) to produce hydrogen. As expected, the yield of ammonia increases, particularly from 2 GW RES (1 GW of wind and 1 GW of solar) to 4 GW RES (2 GW wind and 2 GW solar). This yield asymptotically reaches 1400 ktpa. With respect to the levelised costs, there is a substantial difference when passing from 1 to 2 GW of each of the RES. However, the LCOA remains quite stable under the current assumptions, suggesting that based on them, from that point the decision of how much to overplant could be mainly influenced by the target yield and other constraints. The optimum solution in this case, without optimization of wind-to-solar ratios, is 6 GW RES (3 GW of wind + 3 GW of solar) and has a 33% reduction in the LCOA compared to the reference case of 2 GW RES (1 GW of wind and 1 GW of solar).

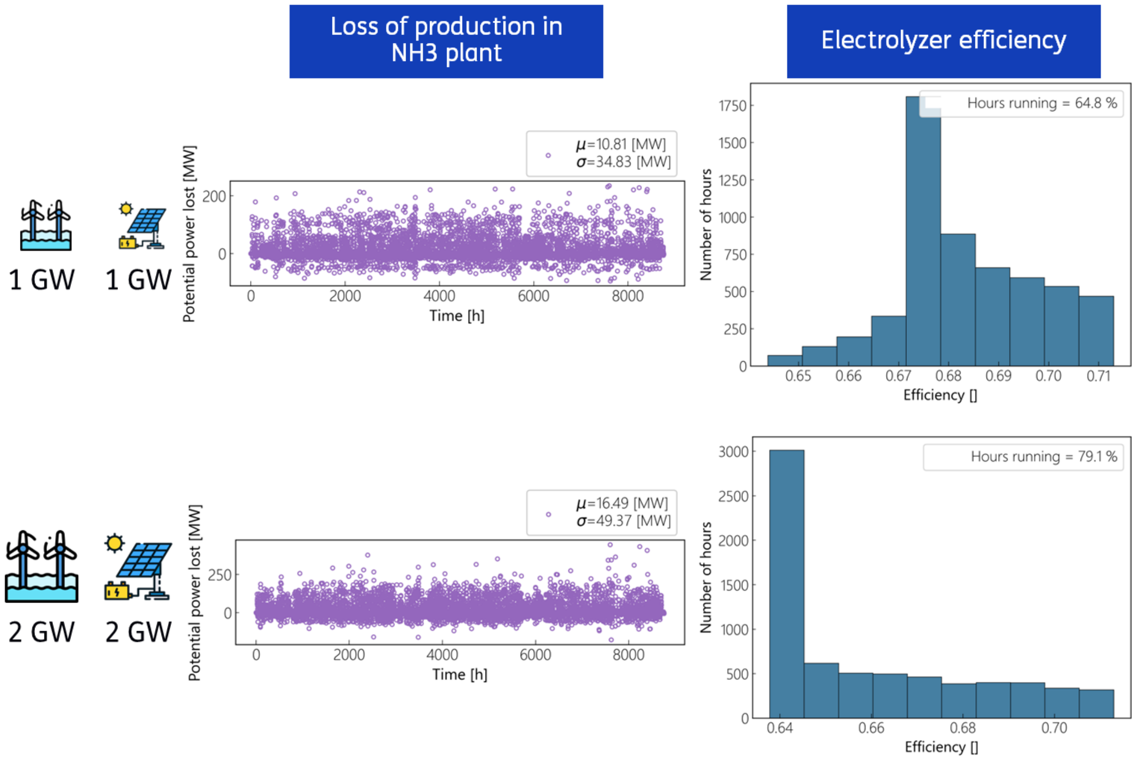


Figure 7.8 – Loss of production in the ammonia synthesis plant due to transient effects and electrolyzer efficiency histogram. Note that the y-axis of graphs have different scales

Figure 7.8 Figure 7.8 shows the effect in the dynamics of the ammonia synthesis plant when using 2 GW of wind and 2 GW of solar power compared to the reference case of 1 GW and 1 GW. It is observed how a penalty in the efficiency of different parts of the system is introduced, despite the increase in production due to the increased electricity availability. By doubling the RES capacity there are significantly more potential power losses in the ammonia synthesis plant (around 50% more) as indicated in purple and the electrolyzer often operates at a lower efficiency. This varies from case to case, and might also present operational problems in the plant, which should be analysed in more detail in a further stage.

7.3 Possible next steps for the coupling of the H2SCM and PyDOLPHYN

We have also explored the potential for using dynamic simulation to explore optimized and dynamically simulated Power-to-X asset designs. Dynamic simulation tools for asset optimization based on hourly demand and supply profiles of renewable electricity, such as TNO's PyDOLPHYN, could add value to the current use of the static H2SCM by improving the accuracy of operational behaviour of assets that are currently assumed to be annual averages and have no optimized technology sizes. PyDOLPHYN also takes into consideration safety-based load and dynamic efficiency factors, which also depend on the relative sizes of the different components, the operational perspective of power-to-x design choices.

Figure 7.9 shows a potential future combination of the two models. This combination would allow for a rapid deployment of techno-economic updates within the dynamic models, providing an automated or semi-automated workflow.

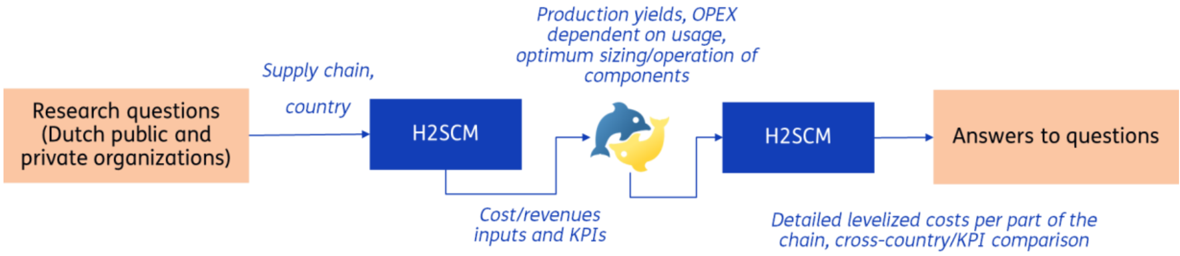


Figure 7.9 – Potential usage of H2SCM combined with PyDOLPHYN for detailed analysis of multiple supply chains and countries.

This coupled approach can merge the strengths of both models: questions regarding end-to-end supply chain performances of multiple carriers, locations and time horizons (H2SCM) in combination with a selective but detailed optimization module (PyDOLPHYN) can be expected to yield more extensive insights on supply chain performances. And multiple operational strategies per asset in the supply chain could be tested (e.g., discrete arrival of ships with ammonia, or the effect of using local market conditions to minimize the LCoH and LCoA). In addition, the optimum sizing for each of the elements of the supply chain (production, conversion and storage) for a certain KPI could be calculated and compared among multiple countries and conditions.

8 An open access approach to hydrogen (derivatives) import supply cost analysis

An open access approach could help create a common basis for hydrogen supply chain modelling and hence facilitate discussions and consensus on supply chain performance comparisons amongst stakeholders involved. With our analyses of green hydrogen supply chains, TNO strives to support corporate and governmental decision-making and facilitate discussions in various stakeholder platforms (such as VoltaChem (www.voltachem.com) and SHIP>NL (SHIPNL: Sustainable Hydrogen Import Program Netherlands | Nationaal Waterstof Programma).

TNO aims to make our analyses more broadly available while also improving the quality of the input data and modelling logic through validation by various stakeholders. Open access tooling can help to achieve these goals. Moreover, the open access H2SCM could act as a reference to achieve more transparency and consistency in hydrogen supply chain modelling approaches nationally and internationally. To make the roll-out of an open access H2SCM a success, an active Community of Practice (CoP) is essential. Not only to guarantee that the model is sufficiently used but also to improve and validate the model's underlying data and logic. Therefore, building such a community while investigating the potential for usage of and contribution to the model by stakeholders, is an important first step. Once there is sufficient commitment from the envisioned community of practice, TNO can proceed with release of a final open access software tool that fits the needs of these end-users.

8.1 The need for an open access approach of cost modelling

In the emerging value chains for the import of hydrogen and hydrogen derivatives, a range of stakeholders will play a role, including international energy companies, port authorities, energy import terminal operators, the chemical and fuel industries, regional and national governments, and environmental agencies. Each of these stakeholders has strategic or operational questions regarding hydrogen import.

To adequately support policy and investment decisions regarding hydrogen import across the entire chain and to facilitate dialogues on cost and risk distribution among hydrogen chain parties within collaborative frameworks (e.g., the SHIP>NL platform), TNO seeks to share the expertise it has built with market and public parties by equipping parties with knowledge and openly accessible online modelling tools. Therefore, we seek to develop a more transparent and open modelling approach regarding hydrogen (derivative) supply chains in the form of an open access tool.

8.2 Our vision on open access H2SCM

Many stakeholders are involved in setting up hydrogen import chains, and many of these parties have their own cost models for calculating future costs (and benefits) of importing hydrogen (derivatives). The current discussions around the construction and underlying assumptions of hydrogen import costs could benefit from a validated quantitative tool. In our vision, this tool will be publicly available to all parties who wish to use it in the Netherlands (and beyond) starting next year. It is important to form a specialist group of cost analysts from across the (import) value chain, a community of practice (CoP), who actively and regularly engage in discussions to promote transparency and mutual understanding.

The open access availability of the H2SCM contributes in the following ways to supporting parties with their questions and facilitating discussions:

- The H2SCM will be widely and simultaneously used across the entire value chain of hydrogen (derivatives) import. Moreover, individual parties in the value chain can exchange information and insights, creating an independent collection and processing point for this information.
- The reliability of input data and model assumptions and the quality of presentation formats of output data will be increased as parties can contribute to the model themselves and have recent insights processed and/or independently perform calculations based on party-specific questions. These contributions improve the quality of model data (as data is validated by various parties) and ensure data is updated more frequently. This is crucial as data and assumptions quickly become outdated due to rapid technological and market developments.
- Many different institutions worldwide are working on modelling hydrogen import chains. The H2SCM could serve as a reference for other parties besides TNO who are active in modelling hydrogen import chains. In this way, we can work together with these parties towards a common validation and exchange of the best methodologies and assumptions. As such, we will be continuously developing insights regarding input data for modelling hydrogen and hydrogen derivatives supply chains.

In our vision, the H2SCM is the designated tool for supporting decision-making by public and private parties regarding hydrogen import. Parties frequently use the model, and there is an active community of practice of contributors and users, ensuring high reliability of model data and logic. TNO can train users to apply the model within their organizations.

8.3 The scope and definition of open access, including associated user rights

"Open access" means that the H2SCM is available online to use by anyone with appropriate user rights. Unlike "open source," users cannot change the underlying model calculations to maintain the functional integrity of the model and the traceability of model adjustments.

Three levels of user rights are defined in a future open access H2SCM situation:

- The general public has access to the H2SCM and can use the model for analysing hydrogen supply chains. These users can vary input values to generate different outcomes.
- Contributors and users within the H2SCM community of practice have more user rights through a personal account. They have access to more functionalities and can also modify source data based on their expertise, thereby improving the quality of this data.
- Individual or consortia of stakeholders can still, as in the current situation, request TNO to expand the model with specific functionalities or create a case-specific elaboration of the H2SCM according to their needs.

Figure 8.1 visualizes these different forms of access and use.

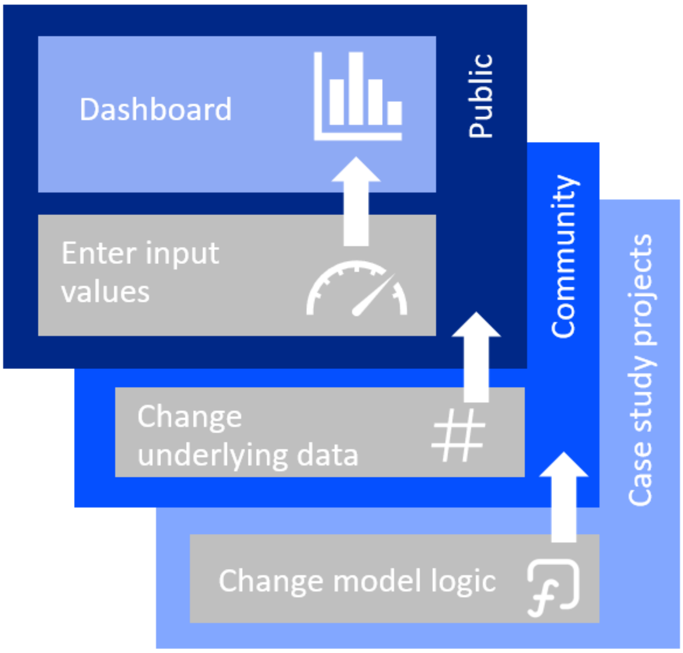


Figure 8.1 – Illustration of the various access and user rights associated with an open access Hydrogen Supply Chain Model.

Figure 8.2 shows a concept user workflow for an open access H2SCM: the steps that users will follow when logging in to the H2SCM user interface.

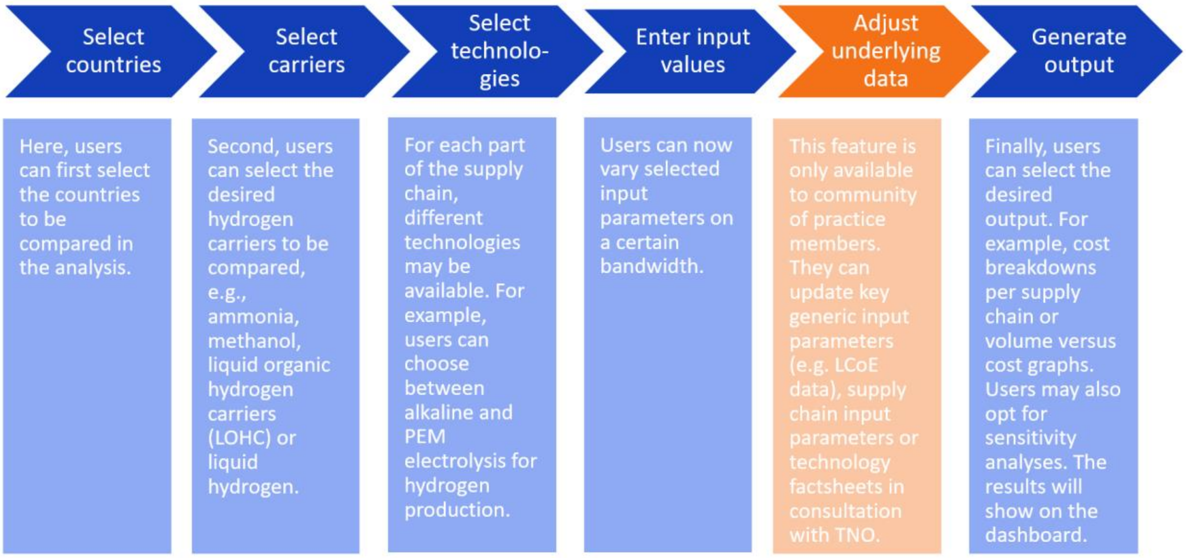


Figure 8.2 - Concept user workflow for users of an open access Hydrogen Supply Chain Model.

An impression of the dashboard in the current H2SCM is shown in Figure 8.3.

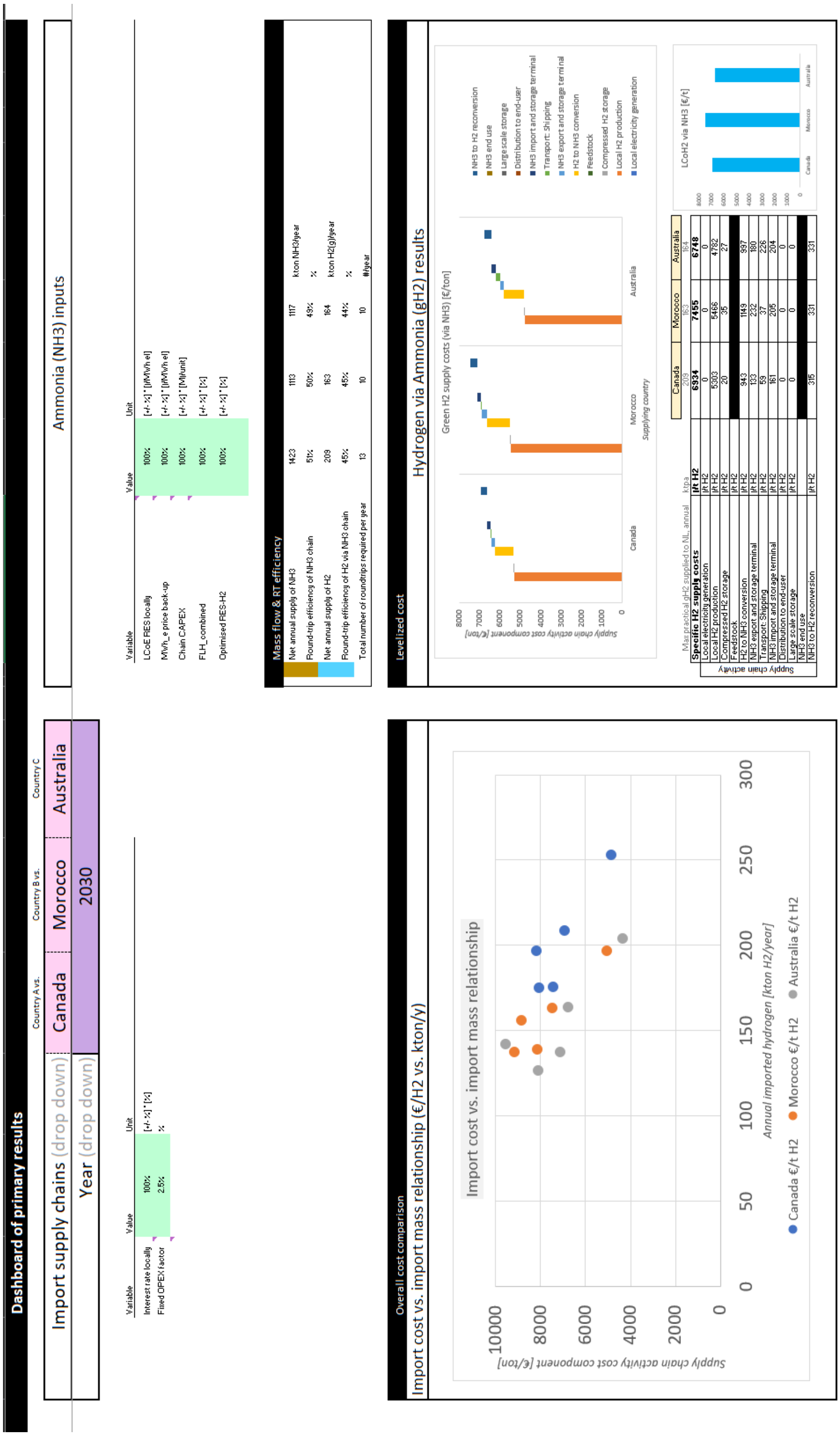


Figure 8.3 - Screenshot of a part of the current dashboard in the TNO Hydrogen Supply Chain Model. On the top left countries can be selected. Results for the ammonia supply chain are shown on the right side. The bottom left shows import quantities and supply costs for all supply chains.

8.4 Envisioned open access H2SCM roll-out in four phases

We aim to achieve an open access H2SCM through four phases of activities:

1. **Building the Community of Practice**. In this phase, we will first assess the need for an open access H2SCM within the SHIP>NL platform. Subsequently, we will use this platform as a basis to establish an active community of practice around the H2SCM.
2. **Developing Proof of Concept**. We will gather user requirements from the community of practice to develop a proof of concept. This proof of concept will include the design of an initial user interface.
3. **Developing a full-fledged open access H2SCM**. In this phase, the proof of concept will be further developed into a fully functional open access tool within a user-friendly online environment, including a helpdesk function. Additionally, it is important to focus on user account management and security during this phase.
4. **Implementation of the open access H2SCM**. The roll-out of this phase requires setting up IT support. Simultaneously, the organization on TNO's side must be arranged so that content experts are ready to answer user questions that come in through IT support.

8.5 Attention points and prerequisites for a successful realisation

To ensure the successful implementation of the H2SCM as an open access model, several prerequisites must be met:

- **Sufficient potential users**: There must be a clear picture of enough potential users.
- **Commitment from public and private parties**: There should be sufficient commitment from both public and private parties (both Dutch and international) to contribute to and use the model via a community of practice (e.g., as a specialized part of the SHIP>NL platform).
- **Value addition for users**: The open access model should add sufficient value for all involved parties for a minimum of 3-5 years of use.
- **Usability and robustness**: The model must be user-friendly, insightful, scalable, and robust in use.
- **Support organization**: The TNO organization must be set up to answer user questions.
- **IT Support**: There should be (external) IT capacity for resolving IT-related issues and problems.

Before the H2SCM can be made open access, several model developments are necessary:

1. **Continuous cost data updates**: implementation of a methodology to ensure that all cost data in the model are continuously updated.
2. **Inclusion of recent publications and insights**: incorporation of important recent publications and insights in the field of hydrogen import chains.
3. **Update of technology data sheets**: the H2SCM relies on technology data sheets that provide input for various technologies in the import chains, such as renewable electricity, electrolysis, conversion, and storage technologies. These need to be updated.
4. **Transition from Excel to Python**: conversion of the H2SCM from Excel to a Python-based environment, which is likely necessary to enable the H2SCM to function in an online setting.

By addressing these prerequisites and developments, the H2SCM can be successfully transitioned to an open access model, providing valuable support for policy and investment decisions in hydrogen import chains.

9 Conclusions and recommended next steps

This chapter presents the conclusions and key insights on the hydrogen import cost, annual quantities and GHG emission assessment (Part A) in paragraph 9.1 and the methodological H2SCM developments (Part B) in paragraph 9.2. The last paragraph synthesizes the recommended in the next steps for the near future on both the cost-quantity-GHG assessment content, as well as the methodological developments.

9.1 Conclusions of Part A: Hydrogen import cost and GHG emission

The decarbonization of the industry and transport sectors requires, amongst many other aspects, a sufficient and timely supply of hydrogen with minimal associated environmental impact. To meet decarbonisation targets in 2030 and meet climate goals on the longer term, hydrogen supply chains need to be initiated and scaled up rapidly. International hydrogen supply chains include: the generation of renewable power and subsequent hydrogen electrolysis, the production of a hydrogen carrier for long distance transport and transport by bulk carrier ship.

Many different stakeholders are involved in such a supply chain, including hydrogen (derivative) producers, shipping companies, storage infrastructure & terminal operators, port authorities, governments, regulatory bodies and a variety of end-users. Many, if not all of those stakeholders, need to make decisions that lead to the realisation of the supply chain. And those decisions are (inter)dependent on each other which introduces the need for supply chain coordination to overcome typical chicken-and-egg problems, or prisoner's dilemmas.

The investments necessary for this upscaling these supply chains as a whole, and individual supply chain elements are currently lacking due to uncertainties perceived by public and private stakeholders. This study provides insights on three important uncertainties: the investment and operational costs per supply chain element, the annual volumes of molecules available on a project-scale and the associated greenhouse gas emissions of the delivered hydrogen, ammonia and methanol.

Hydrogen supply chains constitute of many technologies and therefore have many design variables and operational strategies. And decisions made at one supply chain element can positively or negatively impact the performance of another element. This study makes those relations explicit by quantifying hydrogen, ammonia and methanol import supply chains towards the Netherlands. Three archetypical supply chains are assessed and insights are drawn based on the performance assessments of these three supply chains.

This research concludes that design choices of international hydrogen supply chains have substantial and interrelated effects on the levelised costs, greenhouse gas emissions and quantities produced.

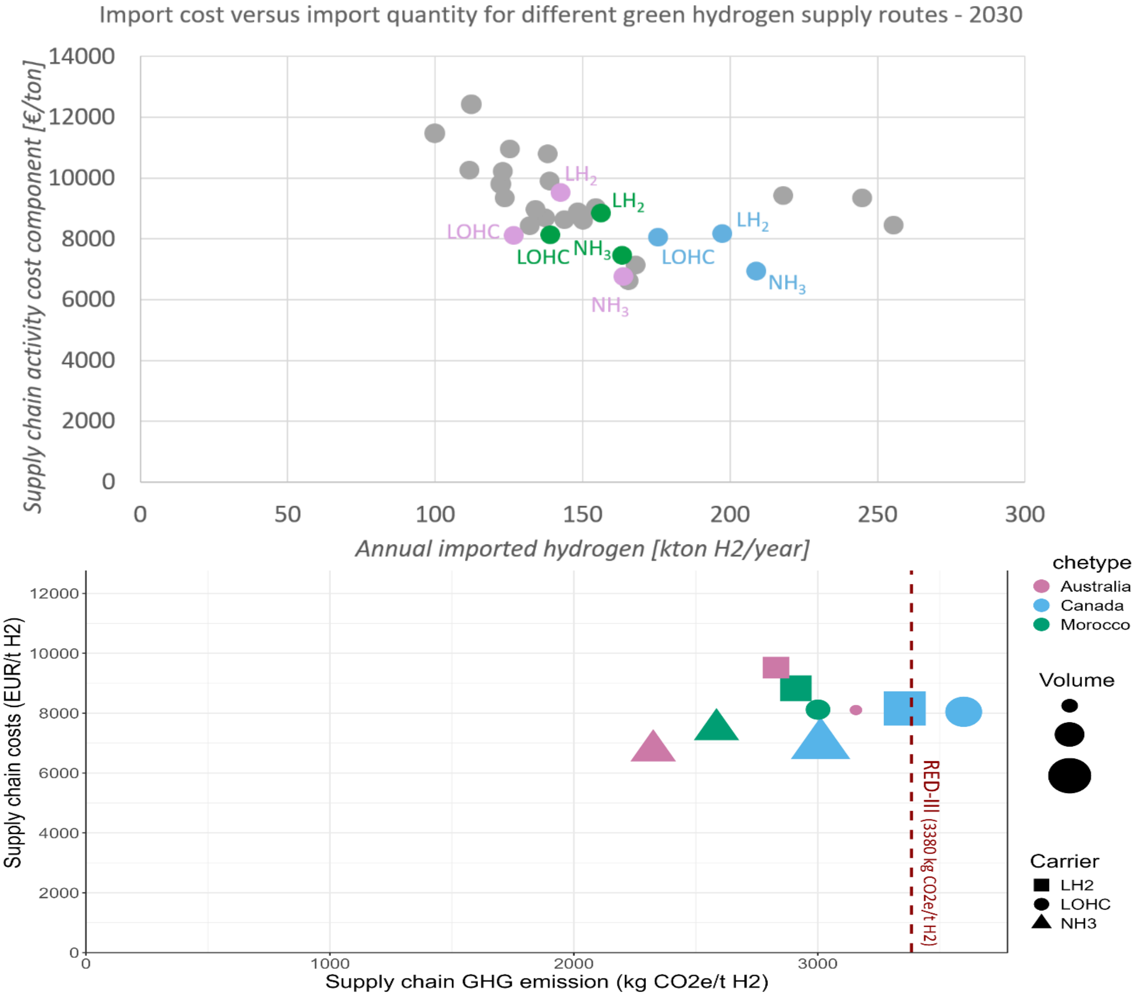
The stakeholders involved in realizing international hydrogen supply chains are encouraged to use the insights provided in this report when exploring the feasibility of their supply chains under development.

For example, the quantity of hydrogen carrier produced is higher for islanded export locations that feature a high capacity factor and this increased quantity may compensate for higher electricity costs which yields a low $LCoH_2$. However, certain renewable electricity sources, such as hydropower, may have relatively high associated greenhouse gas emissions which is sub-optimal from a decarbonization point of view.

The following two insights are drawn from this study and support the conclusion.

❖ **Insight 1: In designing international supply chains for green hydrogen (and its derivatives), there are decisions to be made that impact three KPIs simultaneously: the levelised cost of imported hydrogen (LCoH$_2$), the annual quantities of that supply chain and the greenhouse gas emissions emitted per unit of hydrogen (derivative).**

For the majority of the supply chain designs analysed, the LCoH$_2$ mainly depends on the levelised cost of electricity (LCoE) and electrolysis CAPEX. Import quantities are mainly driven by the capacity factor of renewable electricity and Power-to-X process efficiencies. And greenhouse gas emissions are mostly determined by the embedded emissions of renewable electricity equipment.



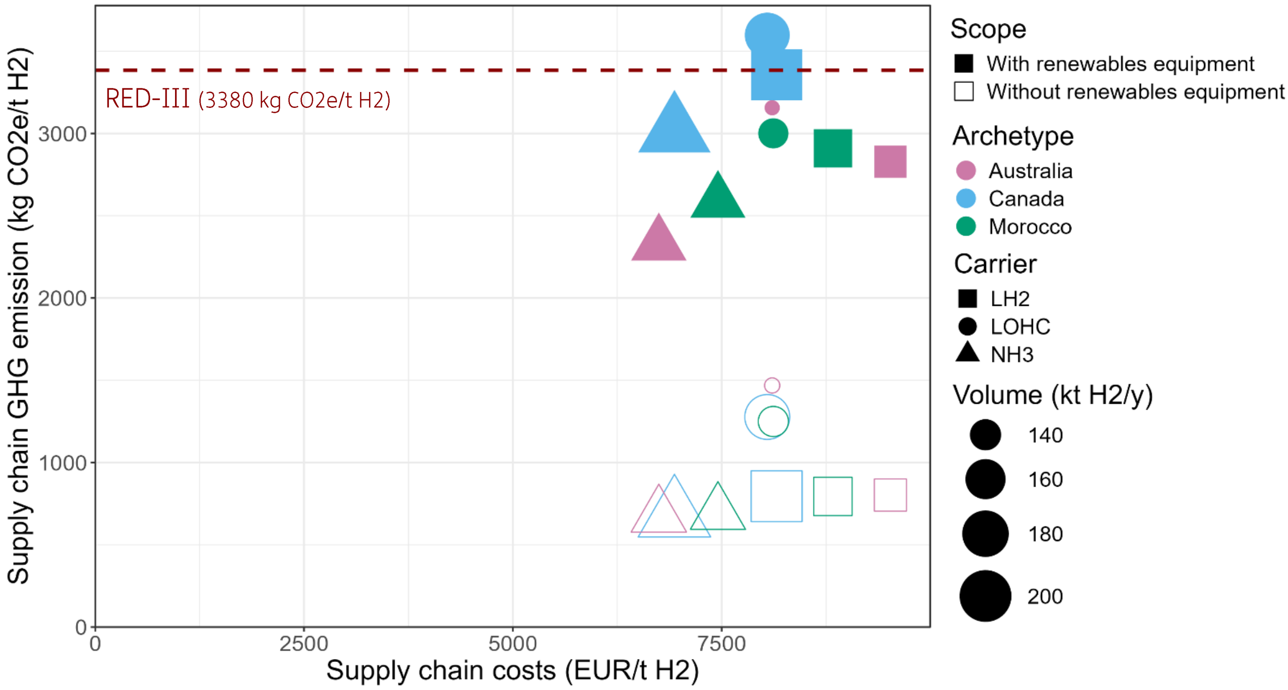
Top: Copy of Figure 3.2 - Import cost versus annual import quantity for a variety of hydrogen supply routes
Bottom: Copy of Figure 5.2 – Import cost versus greenhouse gas emission for three hydrogen supply routes

Regarding the **levelised cost of imported hydrogen (LCoH$_2$)** we found a range between 6700 euro/ton and 9500 euro/ton depending on the three selected archetypal export locations (Canada, Morocco and Australia) and the hydrogen carrier (ammonia, liquefied hydrogen and the Liquid Organic Hydrogen Carrier MCH). And this LCoH$_2$ is determined to a large extent by the costs of local hydrogen production, for which the levelised cost of electricity (LCoE) and capital expenditures are the major drivers: The LCoE constitutes 33-49% of the LCoH$_2$. In case of ammonia or methanol import, without reconversion to hydrogen gas, the LCoE accounts for 38-50% of the levelised cost of NH_3 and 33-53% of the levelised cost of MeOH.

The **quantity of molecules imported through a single supply chain**, ranges between 127 and 209 kiloton per annum (ktpa) when assuming islanded Power-to-X configurations without grid electricity. Locations and technologies featuring a higher capacity factor for renewable electricity sources are able to supply higher quantities of hydrogen (derivatives) for the same installed renewable electricity capacity, thus decreasing the levelised cost of hydrogen, ammonia and methanol as an end-product. The same effect is observed for the choice of hydrogen carrier: more efficient carrier (re)conversion processes result in higher import quantities and thus, lower $LCoH_2$.

For delivery of hydrogen via the supply route archetypes assessed, and considering a fuel end-use of the imported molecules in accordance with RED-III's RNFBOs status, we found a range of **greenhouse gas emissions** between 19 to 30 kilogramme CO_2-equivalent per GJ hydrogen (or 2240 to 3600 kilogramme CO_2-equivalent per ton hydrogen. Ammonia and methanol, when used as a fuel, have GHG emissions of 13-19 kg CO2eq/GJ ammonia and 26-38 kg CO2eq/GJ methanol respectively.

- Insight 2: The Renewable Energy Directive III (RED-III) scope and methodological assumptions do not include the embedded GHG emissions of renewable energy technologies dedicated to electricity generation. This study demonstrates that embedded GHG emissions have a major impact across green hydrogen (derivatives) supply chains and failing to account for them can underestimate the overall GHG emissions performance of green hydrogen imports.



Copy of Figure 5.1. Trade-offs between supply chain costs, GHG emissions, and quantity for green hydrogen delivery with and without renewable electricity equipment in scope of GHG assessment.

For the three hydrogen supply chain archetypes we found a range of greenhouse gas emissions between 2240 to 3600 kilogram CO_2-equivalent per ton hydrogen (or 19 to 30 kilogram CO_2-equivalent per GJ) when including the emissions of renewable power equipment. The *type of end use* of the hydrogen derivative determines which GHG regulations to comply with; RED-III for fuels and currently unknown regulations for other end use. Without RES equipment, the GHG emission performance of all nine hydrogen supply chain designs are well below the RED-III threshold.

GHG emissions embedded in the production of renewable electricity equipment (e.g. wind turbines or solar panels) are responsible for the majority of emissions across the entire supply chain (71-78%). Those emissions are not included in the RED-III scope. However, when included in the GHG emission performance assessment due to their major share of the emissions, the GHG emissions of all nine hydrogen supply chains increases substantially to 2240 to 3600 kilogram CO_2-equivalent per ton hydrogen (or 13 to 30 kilogram CO_2-equivalent per GJ) which overshoots, in two supply chain designs, the RED-III threshold of 3380 kg CO_2-eq per GJ.

This second insight underlines the importance of clear and correct scope demarcations regarding life-cycle assessments for renewable hydrogen and derivatives with a focus on envisioned end users, inclusion of key direct and indirect embedded emissions and transparency regarding potential double counting challenges.

9.2 Conclusions of Part B: Methodological H2SCM developments

The secondary objective of this study is to further develop the TNO Hydrogen Supply Chain model (H2SCM) as a scalable tool for public and private stakeholders in future hydrogen import supply chains. Therefore, apart from the supply chain performance analysis for three archetypical supply chain designs presented above, we present several conclusions regarding methodological developments of the H2SCM.

In Chapter 6 of this study, we have explored several options for expanding the H2SCM with additional renewable hydrogen-based commodities to be able to compare prominent decarbonisation routes for the fuel and feedstock purposes under congruent assumptions and modelling logic. We conclude that the most relevant hydrogen carriers, with the aim to be reconverted to hydrogen gas, are already included: ammonia, liquid hydrogen, LOHC MCH and gaseous hydrogen (for pipeline transport).

From a renewable molecules perspective beyond end-uses as a hydrogen gas, it is worthwhile to add additional synthetic molecule production routes (Fischer-Tropsch kerosine and diesel, DME and syngas), additional biogenic production routes, amongst which biogas reforming, and low carbon (often referred to as blue) hydrogen based routes to the H2SCM.

The added value of coupling the H2SCM to a dynamic Power-to-X optimization and simulation model such as PyDOLPHYN (developed by TNO) is demonstrated in Chapter 7 by means of a brief exploration. We conclude that coupling can add value to the current use of the static H2SCM as it would merge the strengths of both models; questions regarding end-to-end supply chain performances of multiple carriers, locations and time horizons (H2SCM) in combination with a selective but detailed optimization module (PyDOLPHYN).

Finally, an open access approach to renewable molecule import analysis is concluded to be viable from both an envisioned community of practice end-user, and a software development point of view.

Establishing a neutral, transparent and openly accessible cost and GHG emission calculation tool for hydrogen and other renewable molecules can help create a common, neutral and transparent basis for hydrogen supply chain calculations for the many stakeholders involved in developing the hydrogen supply chains. This neutral basis enables and facilitates the exchange of individual stakeholder perspectives from a supply chain, or overarching, perspective. Consequentially, discussions on the prioritization of cost and greenhouse gas emission reduction, as well as and annual import quantity increases, can be held that may yield better supply chain coordination and synchronized investment and decision strategies amongst the key stakeholders involved. Those discussions can be held in a *Community of Practice* environment and under the umbrella of existing platforms such as SHIP>NL and VoltaChem.

An *open access tool* for modelling green hydrogen supply chains is preconditional to share and synthesize the knowledge and expertise on green hydrogen supply chains from this *Community of Practice* and make hydrogen import cost and GHG analysis more accessible and transparent. To achieve such a tool, an active community of practice is essential for three reasons: (1) to have sufficient and well-informed stakeholder representation to have in-depth discussions; (2) to secure the effectiveness and user-friendliness of the open access tool for decision-support for public and private stakeholders; (3) to improve and validate the model's underlying data and logic while respecting the commercial sensitivity of information provided by stakeholders.

9.3 Recommendations for further research and next steps

9.3.1 Content-wise recommendations

The trade-offs between cost, GHG emissions, and quantity will be further explored. This will be done by investigating the results for other archetypes included in the TNO hydrogen supply chain model (as shown in Figure 3.2). It will lead to a wider understanding of the different archetype configurations and their influences on results. A sensitivity analysis will also be conducted by quantifying the influence of changes in key modelling parameters and assumptions on results. For instance, we can examine the influence of the LCoE and life cycle GHG emissions of renewable electricity generation or the sensitivity of results to changes in CAPEX.

We will also consider the next steps for the calculation of GHG emissions. GHG emissions with technological alternatives along the import chain will be modelled such as polymer electrolyte membrane (PEM) electrolysis. Additional hydrogen will be considered, including compressed hydrogen and bio-methanol. Fugitive and boiloff emissions of hydrogen and carriers will be modelled, which are expected to have a negligible impact except for hydrogen import via LH2. Finally, GHG emissions forecast for 2040 will be modelled based on the same middle-of-the-road scenario as for 2030. Other future scenarios (IPCC's shared socioeconomic pathways) can also be integrated with the TNO hydrogen supply chain model to account for the uncertainty associated with forecasts.

The current assessment will strongly benefit from extensive sensitivity analysis of the effects of design choices on costs, annual quantities and GHG emissions to provide better insights in low and high impact decisions for the optimization of supply chain designs.
The quality and accuracy of the GHG emission calculation module developed and included in the H2SCM can benefit from additional work and discussions on a variety of topics, amongst which:

- What is the reasoning for choosing different sources of CO2 capture in different archetypes?
- How will CO2 be transported between industrial point sources (e.g. cement or steel) to islanded green hydrogen production sites? Is that realistic?
- Hotspot analysis GHG: which processes and technologies have the highest contribution to the CO_2 eq. emissions? And are assumptions regarding the LCA background inventory Ecoinvent sufficiently up to date for this analysis? E.g. green steel in wind turbines 10 MW+ turbine may be common practice in the near future.
- How can the temporal aspect of GHG developments be best dealt with?

9.3.2 Methodological next steps

Regarding expansion of the H2SCM with additional hydrogen-based commodities, we will first conduct a high-level multi-criteria analysis on multiple aspects (costs, greenhouse gas emissions, safety, spatial integration, security of supply, etc.) before deciding to add particular molecules to the model.

In the context of coupling the H2SCM to a dynamic simulation tool such as PyDOLPHYN, a first step would be to perform a comparison of one supply chain (e.g., ammonia) between the two models based on harmonized assumptions. In this way, it can be investigated how the results compare between the static, non-optimized and the dynamic, optimized analysis. As such, a clearer picture can be gained of the magnitude of the accuracy improvement using dynamic simulation and in which segments of the supply chain it would add most value.

Lastly, we envision several next steps regarding an open access approach to hydrogen (derivatives) import analysis. In the analysis, it was concluded that a building an active community of practice is key. Therefore, building such a community while investigating the potential for usage of and contribution to the model by stakeholders, is an important first step. Once it is concluded that there is sufficient commitment and interest of stakeholders in open access hydrogen (derivatives) import analyses, we can pursue the development of a proof-of-concept of an open access tool based on the input of the community regarding its functionalities. In this process, a capable software development company should be engaged. This proof-of-concept can then be tested with the community and developed further into a final product in an iterative process, while continuously engaging with the community. In launching the final product, there should be sufficient capacity at the side of TNO for answering content-related stakeholder questions, as well as at the side of the IT company involved for maintaining the open access software (platform).

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Appendix A Selected supply route options

In this study, we consider the following supply options:

- Ammonia import
- Hydrogen import via ammonia as a carrier
- Hydrogen import via liquid hydrogen
- Hydrogen import via Liquid Organic Hydrogen Carrier (LOHC) methylcyclohexane (MCH)
- Methanol import

In the following, we will discuss each of these supply options. Note that in the H2SCM we assume a 2 GW_e renewable electricity capacity and, based on an electrolyser capacity factor of 90%, a 1.8 GW_e electrolyser capacity.

In the ammonia route, high-purity nitrogen (N_2) and electrolysis-based hydrogen are compressed under 200 bar before entering the Haber-Bosch process where ammonia (NH_3) is synthesized. Liquefied NH_3 (at -33 °C) is then loaded onto a bulk carrier ship and transported. Upon imported, the NH_3 is reconverted into H_2.

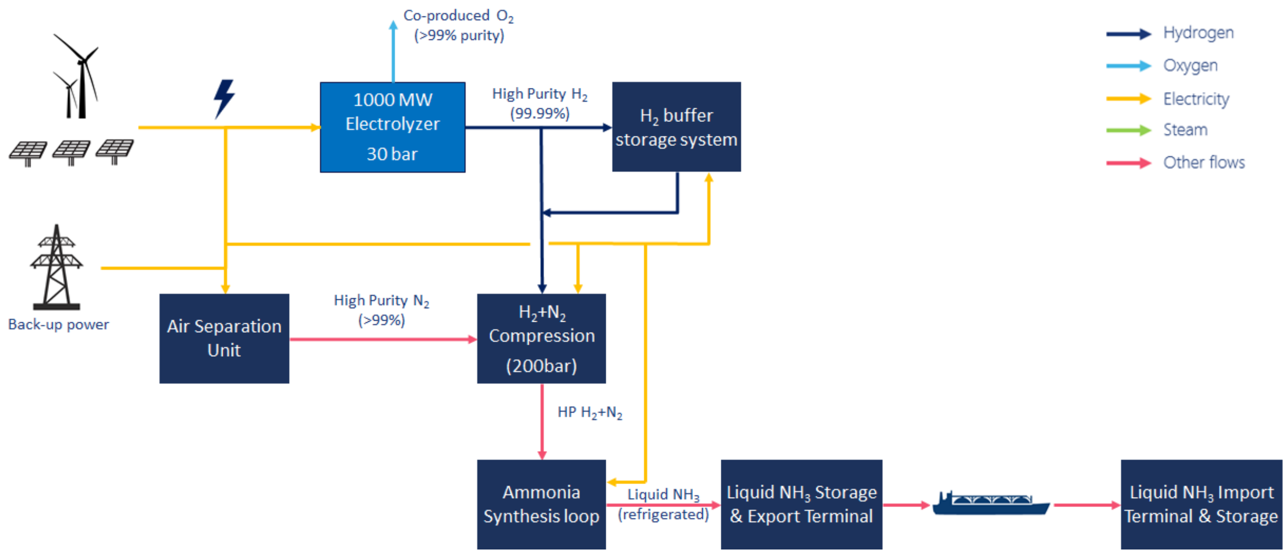

Figure A.1. Schematic representation of the ammonia route in the TNO Hydrogen Supply Chain Model. The step where ammonia is reconverted to hydrogen is not shown here. Note that in the H2SCM, an electrolyser capacity of 1800 MW is used, rather than the 1000 MW shown here. The second route included is the liquefied hydrogen (LH_2) route. In this route, the produced hydrogen is compressed and liquefied under cryogenic conditions (-253 °C) before being transported. Upon arrival at the import location, it is stored under cryogenic conditions and regasified to gaseous H_2 to be available for end users

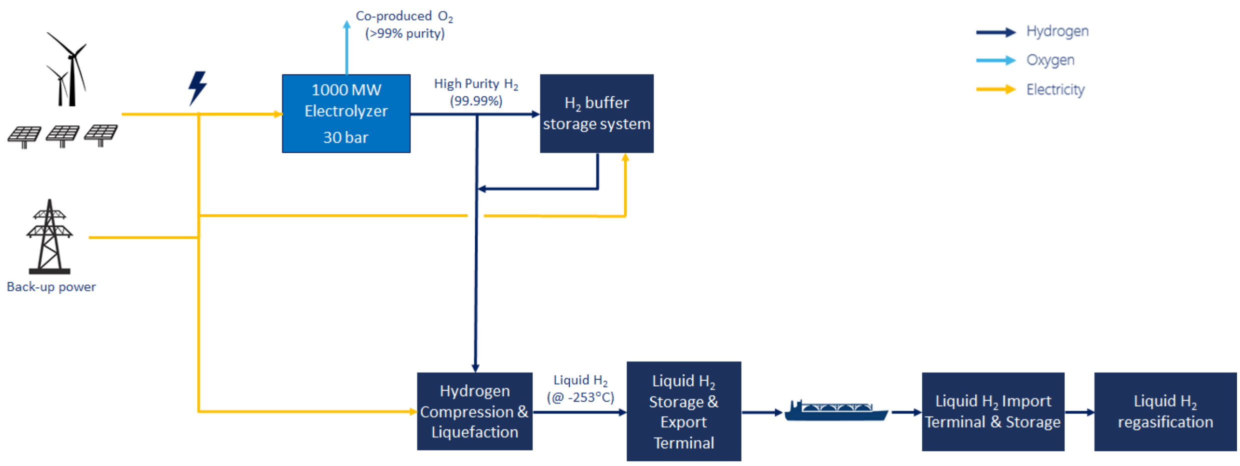

Figure A.2. Schematic representation of the liquefied hydrogen (LH_2) route in the TNO Hydrogen Supply Chain Model. Note that in the H2SCM, an electrolyser capacity of 1800 MW is used, rather than the 1000 MW shown here.

The third hydrogen derivative included in the Liquid Organic Hydrogen Carrier (LOHC) methylcyclohexane, or MCH. In this route, the produced hydrogen reacts with toluene in a process called toluene hydrogenation to form methylcyclohexane (MCH), which is then transported. Upon arrival at the import location, MCH is dehydrogenated, resulting in toluene and hydrogen. The toluene is then transported back to the export location to be bounded again to hydrogen.

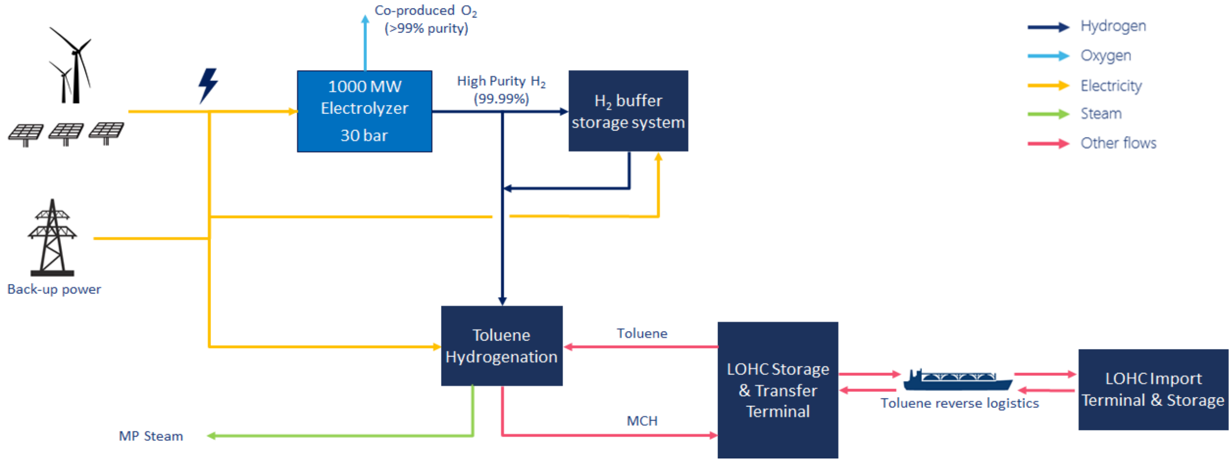

Figure A.3. Schematic representation of the Liquid Organic Hydrogen Carrier (LOHC) route in the TNO Hydrogen Supply Chain Model. Note that in the H2SCM, an electrolyser capacity of 1800 MW is used, rather than the 1000 MW shown here.

The final route concerns methanol produced from green hydrogen and CO_2 (e-methanol). Methanol is produced by the direct hydrogenation of CO_2. This CO_2 is either captured from the air through Direct Air Capture, from flue gases or directly from industrial processes. Hence, the carbon feedstock of the e-methanol route is CO2. This study focusses on the e-methanol route and therefore focusses on CO2 as the main carbon feedstock.

The H2SCM also includes the bio-methanol route in which methanol is produced through gasification of biomass or carbon rich waste streams, such as plastic waste or through reforming of biogas similarly to conventional methanol production from natural gas. However, in this study, we do not consider this route.

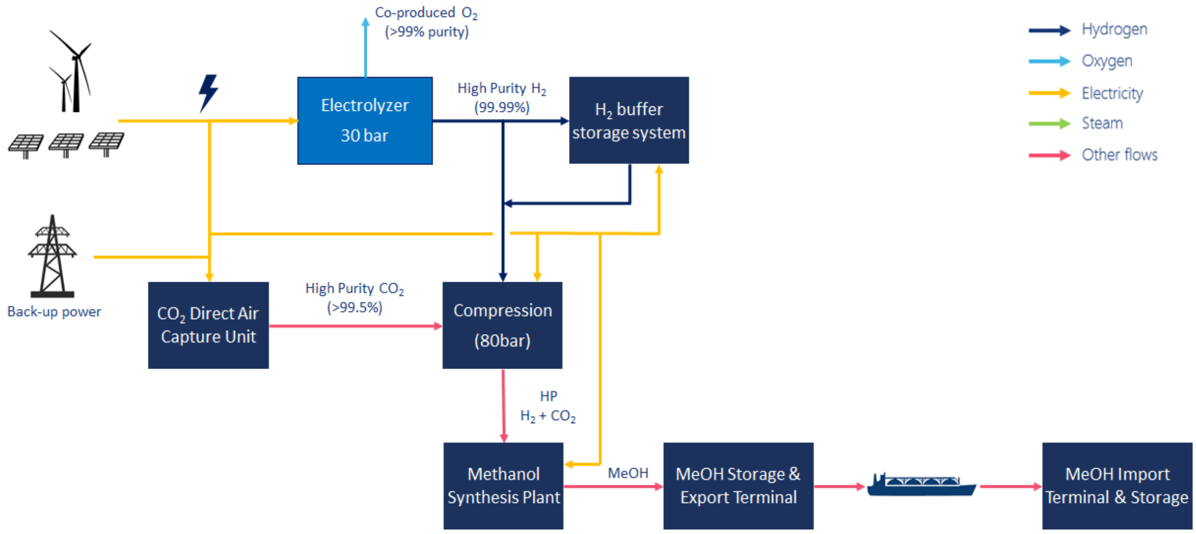

Figure A.4. Schematic representation of the e-methanol (MeOH) route in the TNO Hydrogen Supply Chain Model. Note that in the H2SCM, an electrolyser capacity of 1800 MW is used, rather than the 1000 MW shown here.

Appendix B Carbon feedstock cost

Table B.1. Carbon feedstock prices

	IEA (IEA, 2020)			IRENA (IRENA, 2020)		
	LOW [USD/tCO2]	MID [USD/tCO2]	HIGH [USD/tCO2]	LOW [USD/tCO2]	MID [USD/tCO2]	HIGH [USD/tCO2]
Ethanol fermentation	25	31,5	38	10	15	20
Solid biomass firing	55	60	65	-	-	-
Waste firing	-	-	-	-	-	-
Natural gas firing (NGCC)	50	75	100	90	100	110
Cement	58	89	120	55	69	84
Kiln	-	-	-	-	-	-
Pre-calciner	-	-	-	-	-	-
MEA	-	-	-	63	91,5	120
Calcium looping	-	-	-	56	73	90
Full-oxidation	-	-	-	45	53	61
Partial oxidation	-	-	-	55	59	63
Iron and steel	58	79	100	61	110	159
COREX plant	-	-	-	-	-	-
Blast furnace	-	-	-	-	-	-
Lime calcining	-	-	-	-	-	-
Sinter plant	-	-	-	-	-	-
Ammonia	25	31,5	38	14	26,5	39
Natural gas processing	16	22	28			
Hydrogen production unit (SMR)	50	65	80	50	63	76
Direct air capture	134	233	332	-	-	-

Table B.1 (continued). Carbon feedstock prices

	CCS INSTITUTE (Kearns et al., 2021)			AVERAGE		
	LOW [USD/tCO2]	MID [USD/tCO2]	HIGH [USD/tCO2]	LOW [USD/tCO2]	MID [USD/tCO2]	HIGH [USD/tCO2]
Ethanol fermentation	0	**5**	10	10,3	15,0	19,8
Solid biomass firing	60	**71**	82	50,4	57,4	64,4
Waste firing	60	**71**	82	52,6	62,2	71,9
Natural gas firing (NGCC)	69	**93**	117	61,1	78,3	95,5
Cement	46	**55**	64	46,4	62,3	78,1
Kiln	49	56,5	64	-	-	-
Pre-calciner	43	53,5	64	-	-	-
MEA	-	-	-	-	-	-
Calcium looping	-	-	-	-	-	-
Full-oxidation	-	-	-	-	-	-
Partial oxidation	-	-	-	-	-	-
Iron and steel	-	**67,9**	-	52,2	75,0	113,4
COREX plant	43	48,5	54	-	-	-
Blast furnace	46	51,5	57	-	-	-
Lime calcining	59	73,5	88	-	-	-
Sinter plant	72	98	124	-	-	-
Ammonia	0	**5**	10	11,4	18,4	25,4
Natural gas processing	0	**5**	10	7,1	11,9	16,7
Hydrogen production unit (SMR)	50	**62,5**	75	43,8	55,7	67,5
Direct air capture	-	-	-	117,4	204,1	290,8

Appendix C GHG assessment

General assumptions

The inventory and assumptions made in the H2SCM for the calculations of costs were used for the calculation of GHG as much as possible. This covers inventories for electricity and heat consumption along the import supply chain. This also covers efficiencies for supply chains steps such as conversion, re-conversion, intermediate storage, and transport. For details on these inventories and efficiencies, we refer to the published H2SCM documentation.[11]

Additionally, we made the following assumptions:

- Renewable electricity use – RES are used for the electrolyser, the conversion to the carrier, and for the air separation unit for the nitrogen supply needed for ammonia production.
- Non-renewable electricity input – Average country mixes were used for background activities whenever possible, generic mixes were used otherwise.
- Ship transport – The cargo (i.e. the hydrogen carrier or hydrogen fuel cells) was used as fuel.
- Electrolyser – Alkaline electrolysis was modelled. Due to the islanded nature of green hydrogen production, desalination and demineralization of sea water were modelled (Shahabi et al., 2015). The input of potassium hydroxide was also modelled (Delpierre et al., 2021).

The oxygen output of electrolysis was accounted for with system expansion and substitution (see Figure 4.2) as per the advice of the ISO and IPHE guidelines since energy content allocation would not be appropriate. For this substitution, we assumed that the air separation unit for oxygen production runs with renewable electricity in order to be consistent with assumption for the air separation unit for nitrogen input in the case of ammonia production. An electricity consumption of 1.42 kWh/kg O2 was assumed based on the corresponding ecoinvent entry (Wernet et al., 2016).

- Grey alternatives – The hydrogen, ammonia, and methanol grey alternatives used in section 4 were all derived from ecoivent version 3.9.1 with the cut-off system model (Wernet et al., 2016). Grey hydrogen is assumed to be produced via steam methane reforming of natural gas (12 t CO2e/t H2), grey methanol from natural gas (0.77 t CO2e/t MeOH), and grey ammonia from stream reforming (2.7 t CO2e/t H2).
- Fugitive and boiloff emissions of hydrogen and/or carriers – These emissions were excluded due to the high uncertainty associated with loss rates across the hydrogen import supply chains. Consequently, global warming potential of hydrogen emissions to the atmosphere were not accounted for (Sand et al., 2023). These emissions are typically negligible for the supply options considered here, except for LH2 (Arrigoni et al., 2024).

For the local hydrogen production, we assumed that alkalyne electrolyzers were used. Beyond the electricity input calculated in the cost module, some additional material inputs were included for GHG calculations in order to have consistent system boundaries. Those items are reported in Table C.1.

[11] : D7B.3 Cost analysis and comparison of different hydrogen carrier import chains and expected cost development (zenodo.org), Appendix A.

Table C.1. Material inputs for operation of alkalyne electrolyzers.

Item	Unit	Value	Source
Potassium hydroxide, input	kg /t H2	2.5	(Delpierre et al., 2021)
Demineralised water, input	t/t H2	10	(Delpierre et al., 2021)
Potassium hydroxide, GHG	kg CO2e/kg KOH	2.7	Ecoinvent
Deionised water, GHG	g CO2e/kg water	0.35	Ecoinvent
Desalination, GHG	g CO2e/kg water	3.6	(Shahabi et al., 2015)

For hydrogen import via LOHC, toluene is used as an input in the hydrogenation plant in order to form methylcyclohexane (MCH). The use of toluene is mostly circular, as toluene is reconverted from MCH in alongside the hydrogen and shipped back to the local hydrogen production site. However, some toluene is lost during shipping as we assumed that MCH is used as a shipping fuel. Therefore, an annual input of toluene is required. The GHG emissions associated with the production of toluene were set at 1.6 kg CO2e/kg toluene, according to ecoinvent.

Renewable electricity generation

Life cycle GHG emissions intensities for renewable electricity generation were collected from Ecoinvent, version 3.9.1. All values are reported in Table C.2. Ecoinvent entries are scaled per MWh of electricity produced based on the size of the national capacity for each renewable electricity source. Finally, GHG emissions intensities for back-up power were also modelled at 0.98 kg CO2e/kWh for all archetypes (da Silva Lima et al., 2021).

Future GHG emissions were forecasted for 2030 using scenarios defined by IPCC (shared socio-economic pathways, SSP) coupled with an integrated assessment model. Specifically, SSP2 under RCP2.6 (representative concentration pathway) was used, coupled with the IMAGE integrated assessment model. The premise software package (v1.8.1) was used to generate the prospective background database on the basis of Ecoinvent v3.9.1.

Table C.2. Life cycle GHG emission intensities of renewable electricity generation, including equipment. Emissions intensities are expressed in kg CO2e per kWh of electricity generated.

Archetype	Source	2020	2030	Ecoinvent entry
Canada	Wind	0.017	0.016	Electricity, high voltage {CA-ON}|wind, 1-3MW turbine, onshore
Canada	Hydro	0.051	0.051	Electricity, high voltage {CA-ON}|hydro, reservoir, non-alpine region
Morocco	Wind	0.014	0.014	Electricity, high voltage {RoW}|wind, 1-3MW turbine, onshore
Morocco	Solar	0.077	0.058	Electricity, low voltage {RoW}|photovoltaic, 570kWp open ground installation, multi-Si
Australia	Wind	0.013	0.012	Electricity, high voltage {AU}|wind, 1-3MW turbine, onshore
Australia	Solar	0.060	0.045	Electricity, low voltage {AU}|photovoltaic, 570kWp open ground installation, multi-Si

CO_2 capture for methanol conversion

For conversion to methanol, different sources of carbon are considered for each archetype. Canada is equally split between point sources at solid biomass and waste firing, Morocco uses direct air capture (DAC), and Australia uses point source during cement production. Life cycle GHG emissions for these carbon capture options were obtained from literature and are reported in Table C.3.(Deutz & Bardow, 2021; Müller et al., 2020; Yang et al., 2019). All carbon dioxide supply is assumed to be available when required by the methanol production process. We modelled a net balance of zero for CO_2 capture and methanol combustion, meaning no credits were modelled during capture and null emissions were modelled for methanol combustion during shipping or use.

Table C.3. Life cycle GHG emission intensities of CO_2 capture. Emissions intensities are expressed in kg CO_2e/kg CO_2 captured.

CO_2 capture source	Canada	Morocco	Australia	Literature source
Solid biomass firing	0.22	-	-	(Yang et al., 2019)
Waste firing	0.17	-	-	(Müller et al., 2020)
Cement production	-	-	0.38	(Müller et al., 2020)
Direct air capture	-	0.19	-	(Deutz & Bardow, 2021)

Efficiency of supply chain activities

The efficiency of supply chain activities are modelled in the H2SCM and reported in Table C.4. These efficiencies represent the both the use of energy (e.g. electricity for electrolyzer) and the use of hydrogen (or its carrier) along the supply chain (e.g. transport fuel during shipping or to generate heat during ammonia cracking).

Table C.4. Energetic efficiency breakdown of supply chain activities.

Item	Carrier	Canada	Morocco	Australia
Local H2 production	Ammonia	70%	70%	70%
Compressed H2 storage	Ammonia	100%	100%	100%
H2 to NH3 conversion	Ammonia	73%	72%	72%
NH3 export and storage terminal	Ammonia	100%	100%	100%
Transport: Shipping	Ammonia	99%	100%	97%
NH3 import and storage terminal	Ammonia	100%	100%	100%
NH3 to H2 reconversion	Ammonia	89%	89%	89%
Local H2 production	Methanol	70%	70%	70%
Compressed H2 storage	Methanol	100%	100%	100%
H2 to MeOH conversion	Methanol	81%	81%	81%
MeOH export and storage terminal	Methanol	100%	100%	100%
Transport: Shipping	Methanol	99%	100%	96%
MeOH import and storage terminal	Methanol	100%	100%	100%
MeOH to H2 reconversion	Methanol	81%	81%	81%
Local H2 production	LH2	0.7	0.7	0.7
Compressed H2 storage	LH2	1	1	1
H2 to LH2 conversion	LH2	42%	54%	52%
LH2 export and storage terminal	LH2	100%	99%	99%
Transport: Shipping	LH2	97%	98%	87%
LH2 import and storage terminal	LH2	98%	98%	98%
LH2 to H2 reconversion	LH2	94%	94%	94%
Local H2 production	LOHC	70%	70%	70%
Compressed H2 storage	LOHC	100%	100%	100%
H2 to LOHC conversion	LOHC	95%	95%	95%
LOHC export and storage terminal	LOHC	100%	100%	100%
Transport: Shipping	LOHC	97%	98%	87%
LOHC import and storage terminal	LOHC	100%	100%	100%
LOHC to H2 reconversion	LOHC	90%	90%	90%

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