HyDelta

WP7A – Value Chain Analysis

D7A.2 – Techno-economic analysis of hydrogen value chains in the Netherlands: value chain design and results

Status: final

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Document summary

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Executive summary

Becoming a carbon neutral continent is one of the main political priorities of the European Commission. The Commission is currently spending a lot of attention in establishing the set of required legislations, known as the Fit for 55 package, to move towards the in-between goal of 55% emission reduction compared to 1990 in 2030. Similar intentions are made by the Dutch government, that initially aimed for 49% emission reduction in 2030, but the new government decided to target with its policies to achieve 60%. Many studies showed the need for green molecules to fulfil the energy and material demands in a sustainable manner. Hydrogen, renewable and/or low carbon, is foreseen as one of the important carriers to fulfil this transition.

In this study, levelized costs of potential hydrogen value chains, divided by five types of end-uses are modelled in the Dutch context in a systematic way. The study gives detailed insights in the foreseen 2030 cost breakdowns and compares the costs with the existing, and foreseen sustainable alternatives to give insights in their potentials and drawbacks. Broad attention is paid to the most impactful parameters that are uncertain, in order identify their sensitivities on the results. As in every modelling study, the quantitative results should be evaluated with sharp notice on the assumptions used, to fully understand them and to gather the correct insights. Related to the main aims of this study, specific attention is paid to the following aspects: to obtain insights in the most critical costs and determinants for acceptable business cases, to identify the impact of different hydrogen sources (domestic green, domestic blue or import) and to analyse the relations between the different value chains. Based on the results and analysis performed in this report, we conclude the following key insights related to different parts of the value chain:

1. **Hydrogen production. There is a high uncertainty range in the dominant cost factors that will determine what source of hydrogen will become most competitive in 2030.**

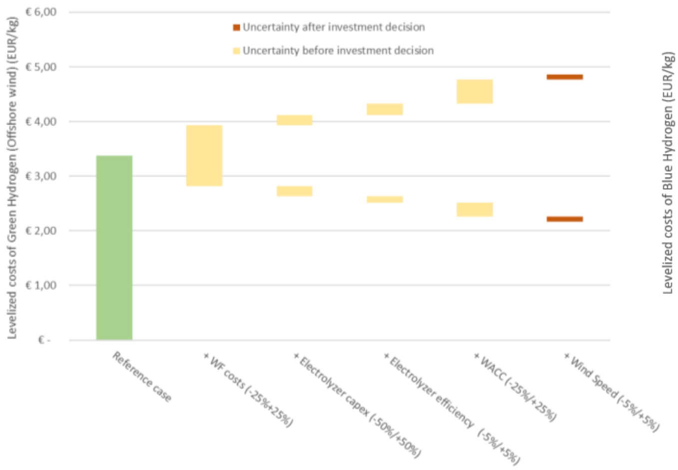


Figure 2 - Future cost of green hydrogen production via offshore wind (North Sea) in the Netherlands, 2030. Assumptions: Alkaline technology, CAPEX 450: EUR/kW, scaling factor: 0.9, annual OPEX: 2% of CAPEX, efficiency: 47.6 kWh/kg of hydrogen, stack lifetime: 60000 FLH, WACC: 7%, Dedicated Dutch offshore wind farm LCOE incl. 100km cabling: 60 EUR/MWh.

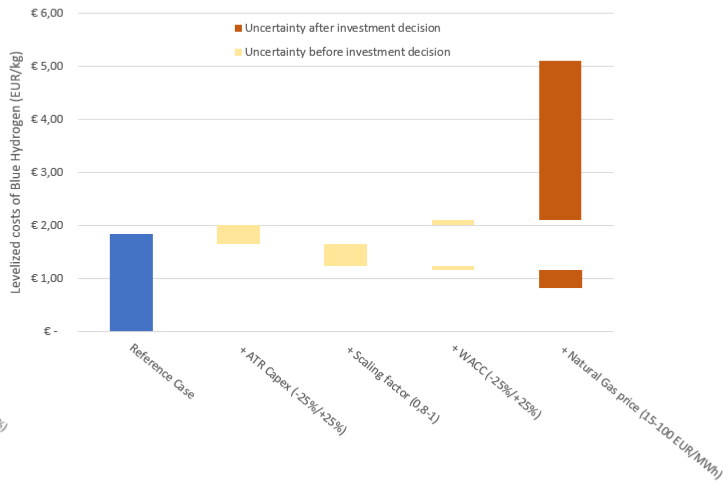


Figure 1 - Future cost of blue hydrogen production in the Netherlands, 2030. Assumptions: ATR+CCS technology, CAPEX 1.3 MEUR/MW, annual OPEX: 4% of CAPEX, capacity factor: 92%, base scaling factor: 1, Natural gas feed 1.2 MJ NG/MJ H2 LHV, Power consumption: 0.014 kWh/MJ H2 LHV, base natural gas price: 25 EUR/MWh, electricity price: 60 EUR/MWh.

A significant difference between green hydrogen production plants with dedicated offshore windfarms and newly constructed blue hydrogen production plants using ATR+CCS, is that the main cost uncertainty of green is in the CAPEX, before the investment decision, while for blue these are in the OPEX (i.e. natural gas price), which remain uncertain at the moment when the investment decision is made.

2. **Transport. Launching customers can act as steppingstones towards a cost-effective transport system for hydrogen on a national, regional and local level.**

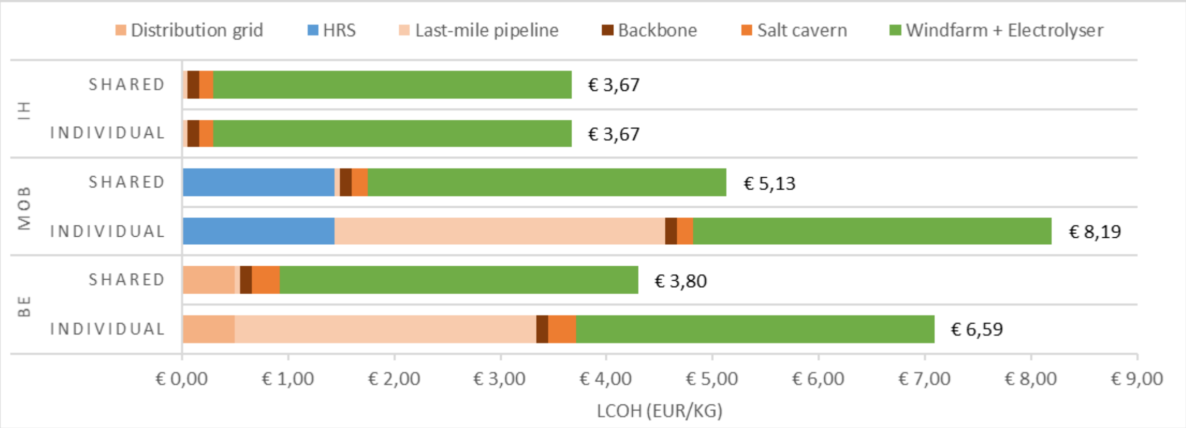


Figure 3 – Overall value chain costs and cost reduction of end user sharing last mile (regional) pipelines compared to using pipelines per individual end user. Assumptions: in case of transport use by a single end user (industrial plant (IH), HRS (MOB), or neighbourhood (BE)), 25 km of the last-mile pipeline is connected to the backbone. If that pipeline can be shared by the 3 end user categories, the pipeline use costs are based on joint consumption volumes.

Figure 3 shows an example how a cross-sectorial approach could benefit the transport costs of regional pipelines for different types of end users. In this example, the relatively large volumes of decentral industrial high temperature heat plants could help to achieve the volumes to make hydrogen locally available for other types of end users.

3. **End-users. In all types of hydrogen end uses, production costs represent the largest share in the total value chain costs. Note in this regard, however, that in the end no single value chain step can be missed to make hydrogen available at the right place, form and time. Situational aspects, technological details and/or mutual benefits of combinations between end-users strongly determine what options are available and cost effective, and where and when.**

We will give a brief overview of the main findings per type of end user.

Industrial feedstock: ammonia for the fertilizer industry

- Providing the required flexibility - assuming a variable production profile of green hydrogen produced with national offshore wind versus a stable demand for ammonia - is critical in the development and value chain costs of carbon neutral ammonia. Because seasonal gaseous hydrogen storage in tanks is very expensive and can only be implemented in very specific small-scale cases, one will typically have to resort to: 1) national hydrogen transport systems combined with large-scale hydrogen storage in salt caverns; 2) trying to increase the flexibility of the ammonia synthesis process; and/or 3) increasing hydrogen production flexibility (e.g. by combining domestically produced green hydrogen with blue hydrogen production and/or import of carbon neutral hydrogen; or by using other carbon neutral sources of electricity in the production process of hydrogen).
- The results of the value chain levelized cost assessments of green ammonia did not show significant cost differences between those of domestic versus imported green ammonia. A precondition for ammonia imports, however, is the availability of domestic transport modalities for ammonia[1]. In our study only the rail option has been assessed and may provide acceptable transport costs. However this transport mode is known for its practical hick-ups

[1] Theoretically reconversion of imported ammonia to hydrogen, followed by transport of hydrogen and conversion of hydrogen to ammonia at the end use location is possible, but this is a rather expensive option including significant energy losses.

due to rail availability, and safety and public acceptance issues. The practicality and costs of alternative inland ammonia transport options via trucks, inland barges or dedicated ammonia pipelines will therefore require further research.

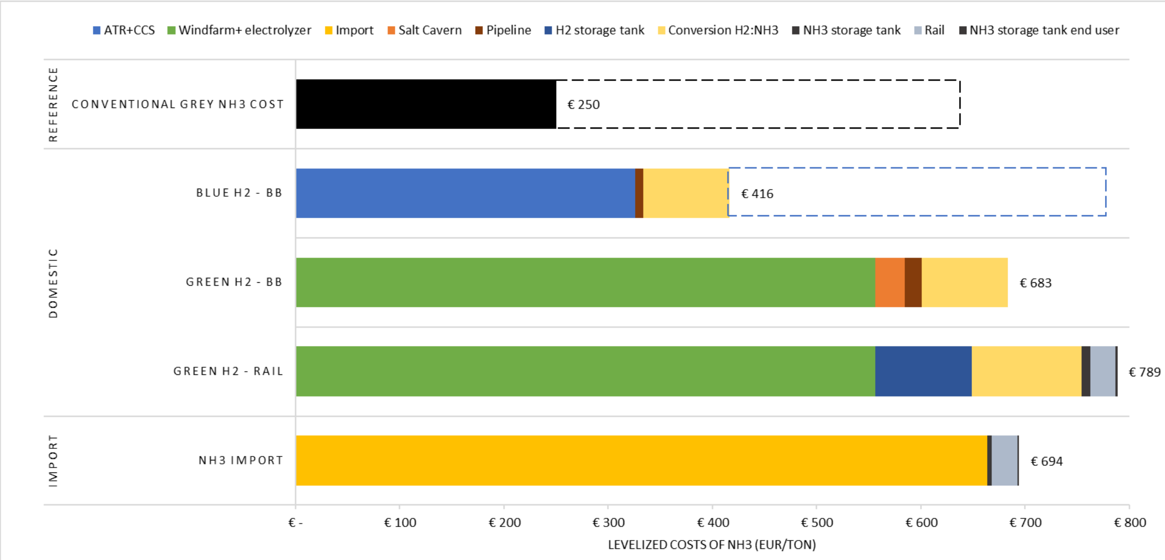


Figure 4 - Results of 2030 cost decompositions for ammonia value chains.

Main assumptions: natural gas price: 25 EUR/MWh (dotted bars show the impact of a natural gas price of 75 EUR/MWh: grey reference LCOA increases to 650 EUR/ton and blue H2 BB to 770 EUR/ton), electricity grid price: 60 EUR/MWh, LCOE of connected domestic offshore windfarm to electrolyser: 60 EUR/MWh, green NH3 import costs include the average import costs by ship from Canada, Australia and Morocco, for the Green H2 Rail chain results of flexible conversion operation mode are presented, which partially follows the offshore wind pattern.

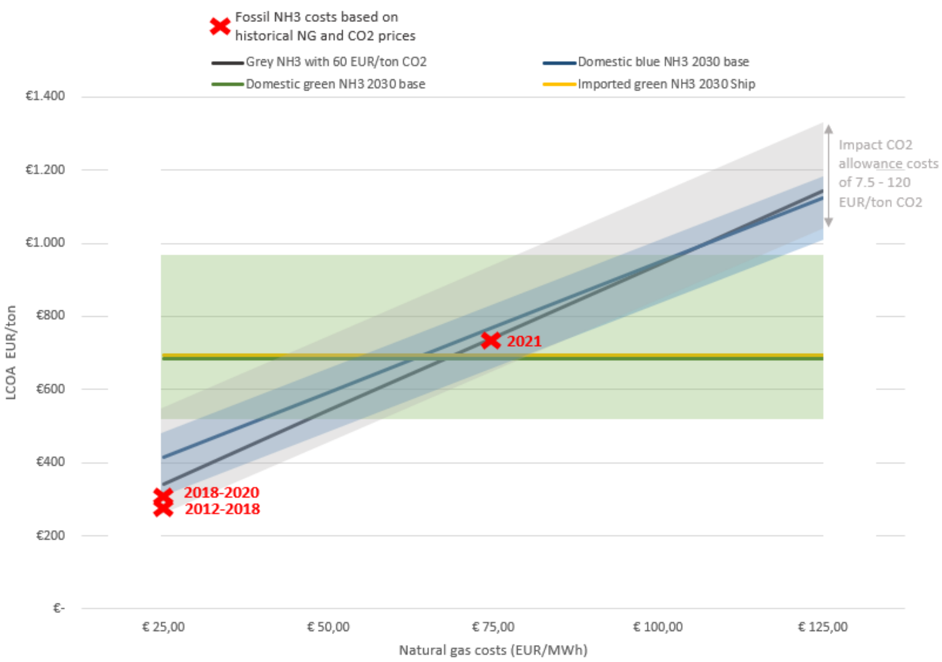


Figure 5 - Visualization of the impact of the natural gas and CO2 prices on the reference price of NH_3 and on carbon-neutral NH_3 produced from blue hydrogen. The resp. green and blue areas mark the uncertainty cost ranges of the green and blue hydrogen production cost developments until 2030; the grey area represents the uncertainty in fossil NH3 costs based on the CO2 allowance price (7.5 EUR/ton low, 120 EUR/ton high). The levelized costs presented include transport to end-use site. The reference costs of NH3 are calculated using 1.75-ton CO_2/ton NH_3 [1], the natural gas and CO_2 prices of the past decade have been, resp. some 25 EU/MWh and 5-15 EU/ton CO_2 [2] [3] [4]. However, in 2021 a sharp increase of both European natural gas and carbon emission allowance prices is seen (since the autumn of 2021 the natural gas price rose to 80-180 EUR/MWh and the allowance price to 60-90 EUR/ton CO_2).

The levelized costs of green ammonia computed in this study (683 €/ton domestic; 694 €/ton import) are significantly higher than the traditional costs of fossil ammonia of the past decade (250 €/ton).

Note, however, that natural gas prices showed a remarkable surge by the end of 2021, just as allowance prices did. These prices strongly affect the competitiveness of green vs grey and blue hydrogen so that whether or not the surge mentioned is part of a long-term trend is rather crucial for short-term chances of green ammonia becoming commercially feasible. For renewable ammonia, only biomethane (production costs of 50-100 €/MWh [5]) and some specific technologies in R&D readiness level are available.

Industrial feedstock: methanol for E-fuels

Just like ammonia, so does the fluctuating production profile of intermittent RES/green hydrogen-based methanol require some type of flexibility (by production, storage, conversion and/or end use) in order to match with the time profile of demand. That is why blue methanol is also considered to be a serious option, because securing a stable supply flow of it throughout the value chain is more easily possible than supply of green methanol, although the significant impact of the natural gas price can act as a backdrop.

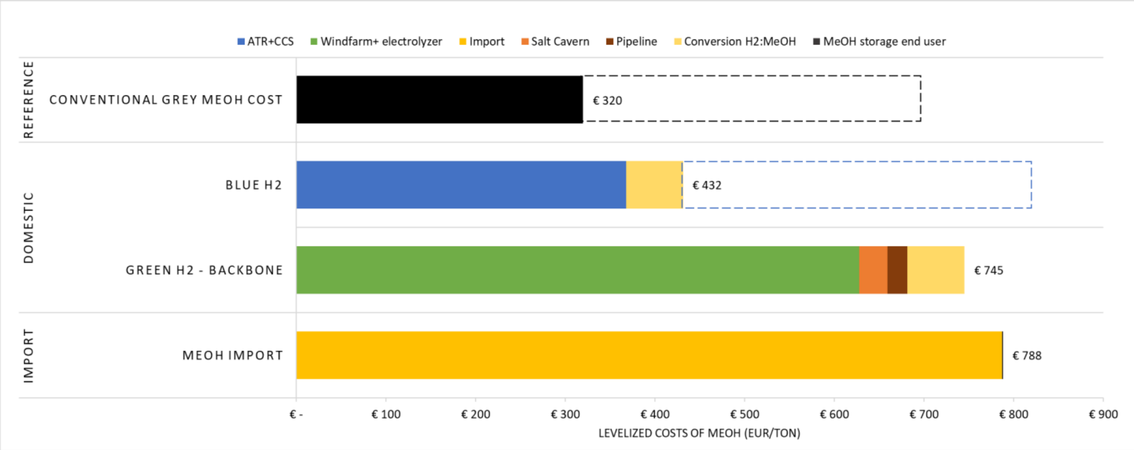


Figure 6 - Results of 2030 cost decompositions for methanol value chains.

Main assumptions: natural gas price: 25 EUR/MWh (dotted bars show impact of a natural gas price of 75 EUR/MWh: grey reference LCOM increases to 704 EUR/ton and blue H2 to 832 EUR/ton), electricity grid price: 60 EUR/MWh, LCOE of connected domestic offshore windfarm to electrolyser resulted in 60 EUR/MWh, green MeOH import costs include the average import costs by ship from Canada, Australia and Morocco.

Since the impact of the hydrogen production costs on the total methanol chain costs is larger than in the ammonia case, the uncertainty ranges (based on the uncertainty of hydrogen production costs) presented for blue and green are larger as well. Moreover, for fossil methanol CO_2 allowance costs have less impact on overall methanol production costs, so that for methanol a higher CO_2 allowance price is required to make the blue and green supply chains competitive to the grey alternative, than for ammonia.

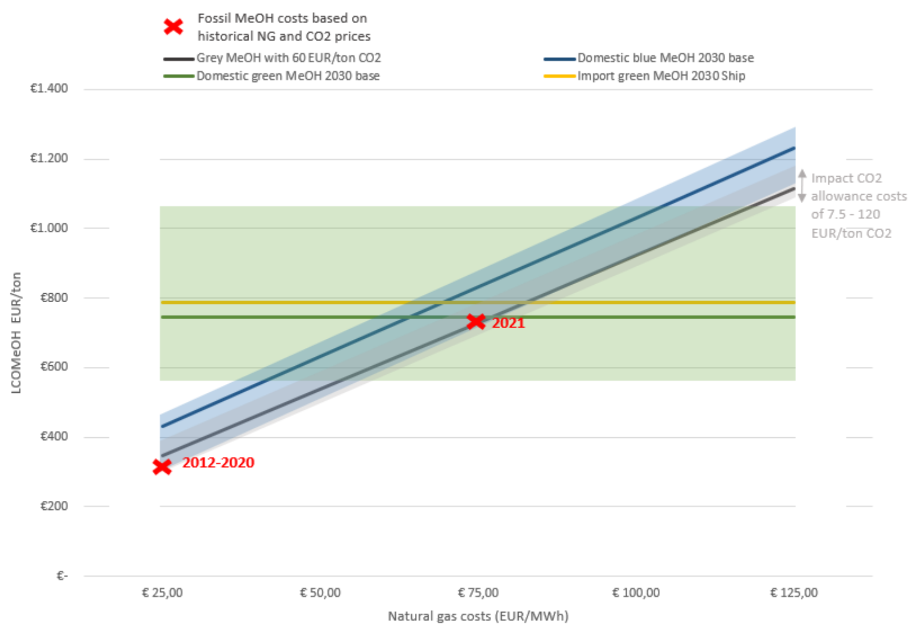


Figure 7 – Visualization of the impact of the natural gas and CO2 price on the reference price of MeOH and on carbon-neutral MeOH produced from blue hydrogen and sustainable CO2 extracted from the air. The resp. green and blue areas mark the uncertainty cost ranges of the green and blue hydrogen production cost developments until 2030; the grey area represents the uncertainty range of fossil MeOH costs depending on the CO2 allowance price (7.5 EUR/ton low, 120 EUR/ton high). The levelized costs presented include transport to end-use site. The reference costs of MeOH are calculated using 0.5-ton CO_2/ton MeOH [6]*, the natural gas price and the CO_2 price of the past decade have been used, respectively, +- 25 EU/MWh and 5-15 EU/ton CO_2* [2] [3] [4]*. However, in 2021 a sharp increase of both European natural gas and carbon emission allowance prices is seen (since the autumn of 2021, the natural gas price rose to 80-180 EUR/MWh and the carbon allowance price to more than 60 EUR/ton CO2).*

Decentralised industries using high temperature heat

- Since for generating heat gaseous hydrogen can be burned directly, import of hydrogen via a carrier for the purpose of generating heat is generally less attractive due to the additional conversion steps needed.
- Clearly for determining industrial heating value chain costs, the location and hydrogen demand volumes of decentral plant(s) matter a lot. Generally it holds that the closer a plant is located to a backbone and the larger its demand volume is, the more suitable pipelines are; and the smaller the demand volumes are and the more remote the plant is from other users and a backbone, the more suitable trucks are. As far as the applicability of transport with LOHC trucks is concerned, this depends significantly on the availability and costs of local heat.

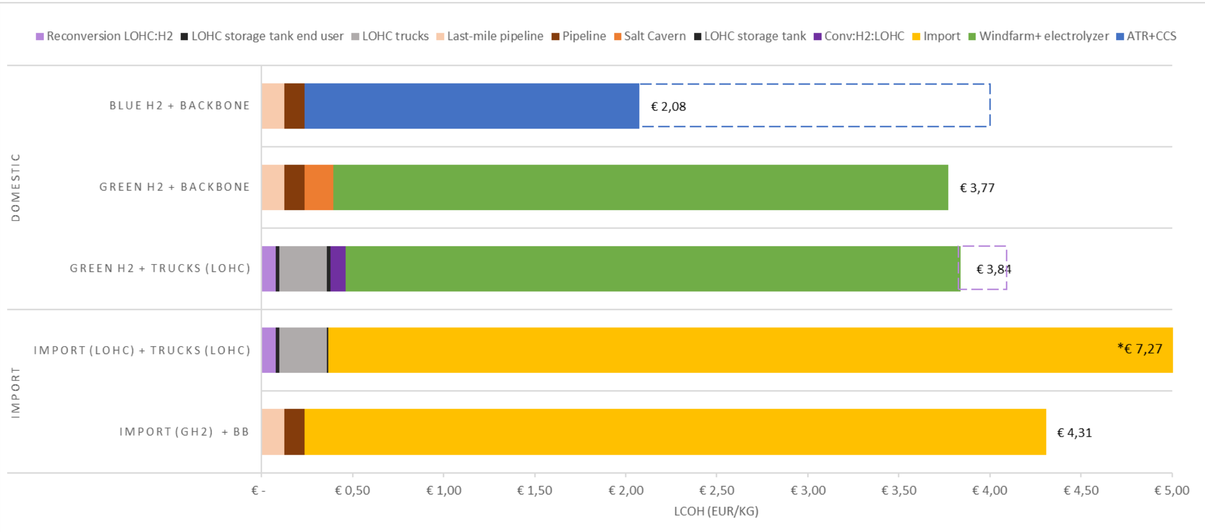


Figure 8 - Results of 2030 cost decompositions for industrial heating value chains.

**chain steps in the opposite direction in order to better compare the impact of the different transport options in the value chains*

Main assumptions: natural gas price: 25 EUR/MWh (dotted bars show the impact of a natural gas price of 75 EUR/MWh: Blue H2 value chain costs increase to 4,08 EUR/kg), electricity grid price: 60 EUR/MWh, LCOE of connected domestic offshore windfarm to electrolyser resulted in 60 EUR/MWh, green hydrogen import costs via LOHC include the average import costs by ship from Canada, Australia and Morocco, the green gaseous hydrogen import costs assumes the import costs from Morocco by pipeline, if an European Hydrogen Backbone would be available. Heat for LOHC reconversion is considered to be waste heat of 0 EUR/MWh. If these costs for heat would be 25 EUR/MWh, additional 0.24 EUR/kg costs are added in those chains. However, released heat during conversion to LOHC can potentially be sold as well. For national pipeline costs, 0.11 €/kg of hydrogen has been used, which is based on a general analysis (see section 5.3 in D7A.2 [7]*).*

Figure 9 shows that for both natural gas and CO_2 allowances fairly high prices are required for making green hydrogen for distributed heating plants to become a cheaper option than natural gas. Compared to biomethane (50-100 €/MWh production costs [5]) the production costs of hydrogen range higher (94 €/MWh, low and 63-141 €/MWh high) while transport to the distributed plants has more challenges. Note, however, that biomethane is generally less available and thus only provides a solution for some locations.

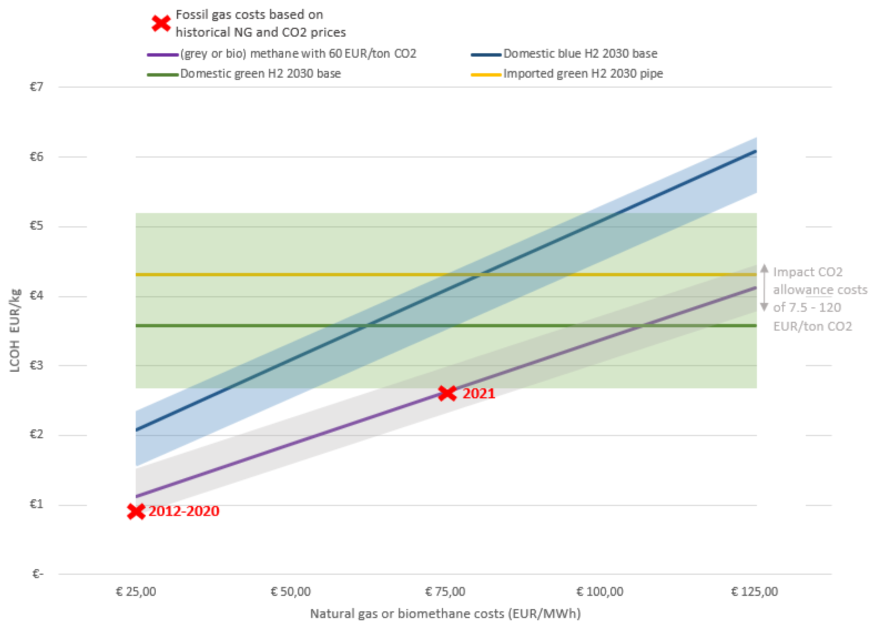


Figure 9 - Hydrogen supply costs (import, green and blue H_2) compared to the reference costs of natural gas. In comparing natural gas with hydrogen, an equivalent amount of energy has been used. This is presented via a hydrogen price equivalent (i.e. the required price for hydrogen to be competitive with natural gas given its price and allowances for polluting CO_2). The respective green and blue areas mark the uncertainty ranges of the green and blue hydrogen production costs until 2030; the grey area represents the cost range of burning methane depending on the CO2 allowance price (7.5 EUR/ton low, 120 EUR/ton high). The levelized costs presented include transport costs to the end-use site. The carbon costs of using natural gas are calculated using 0.203 ton CO_2/MWh of natural gas; the natural gas and CO_2 prices of the past decade have been used: respectively, +- 25 EU/MWh and 5-15 EU/ton CO_2 [2] [3] [4]*. However, in 2021 a sharp increase of both European natural gas and carbon prices took place (since the autumn of 2021, the natural gas price rose to 80-180 EUR/MWh and the carbon allowance price to over 60 EUR/ton CO2).*

Mobility

Different mobility chains result in comparable cost projections. However, for each chain situational local conditions must be fulfilled to be able to develop them cost effectively if at all:

- Local chains have only economic potential if part of the electricity is produced locally at suitable locations where (enough) demand from hydrogen vehicles can be expected;
- Domestic LOHC truck chains require central conversion to LOHC for more than 20 tank stations to reach economies of scale. Local heat should be available at the HRS to reconvert LOHC to gaseous hydrogen;

- To economically connect HRSs to a regional hydrogen grid, one has to be able to make regional combinations of end users that are all connected to the same hydrogen grid;
- In order to economically use LOHC trucks for last-mile transport only, also similar economies of scale for conversion and locally available heat for reconversion are required.

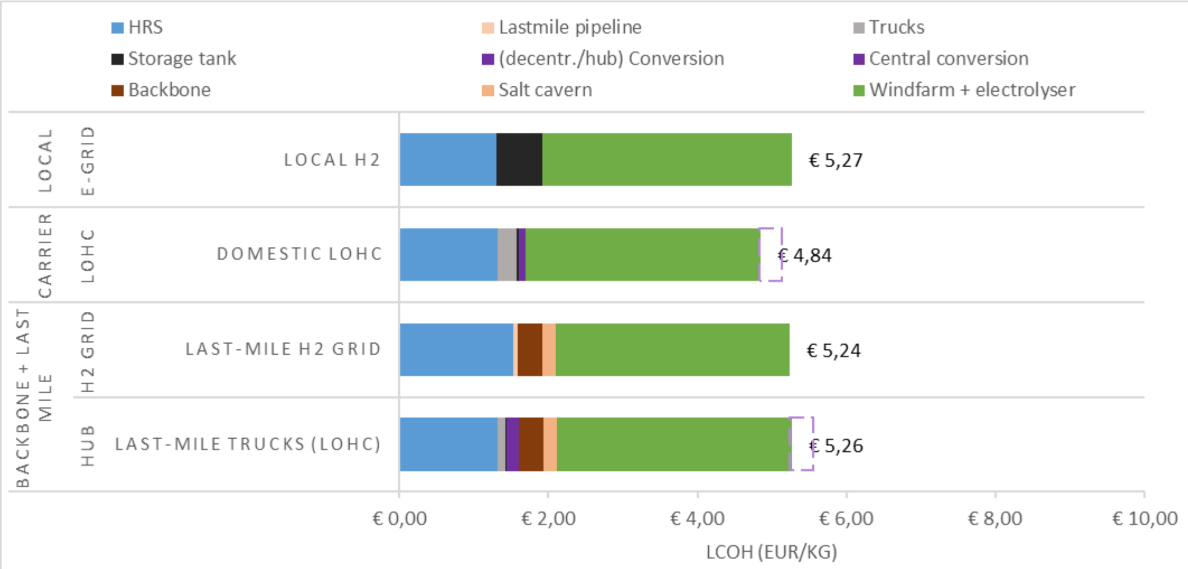


Figure 10 – Overview of cost-distributions of the lowest-cost value chain options for mobility.

**Chain steps have been presented in the opposite direction as in the other cases in order to better show the impact of the different transport options on value chain costs*

Main assumptions: 1000 HRS delivering 400 kg/day, the assumed demand pattern results in a 50% HRS utilization rate, national demand: 141 kT/y. LCOE of domestic offshore windfarm connected to electrolyser: 60 EUR/MWh, LCOE of local onshore windfarm: 53 EUR/MWh, but having a lower utilization (0.35 compared to 0.55) than offshore generation. Heat for LOHC reconversion is considered to be waste heat of 0 EUR/MWh. If costs for heat would be 25 EUR/MWh, 0.24 EUR/kg costs has to be added (see purple dotted boxes). However, heat released during conversion to LOHC can potentially be sold as well. National pipeline costs of 0.11 €/kg of hydrogen are taken into account based on a general (see section 5.3 in D7A.2 [7]*).*

So, there is potential for hydrogen to be used for long-range (>400km) or heavy-duty vehicles. The costs of fuels have less impact on the TCO of long-range vehicles than of heavy duty vehicles. In the end, it is the price formation at the HRS or electricity charging station that will determine which prices consumers actually will have to pay.

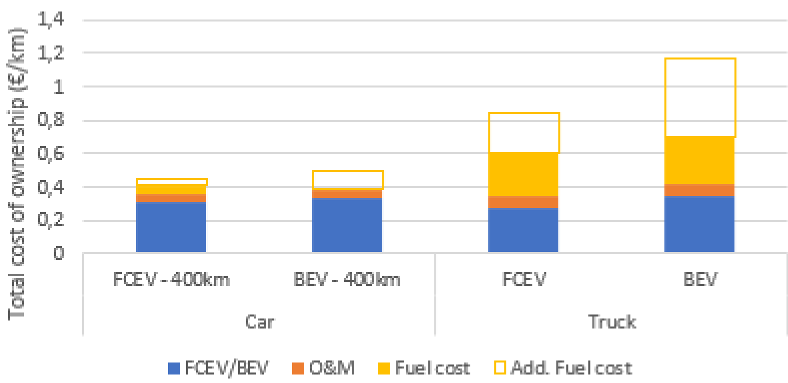


Figure 11 – Future Total cost of ownership comparison of BEV & FCEV based on [8].

Assumptions: cars with range >400km, charging costs FCEV car low: 0.04 EUR/kWh (self-generated electricity at home) high: 0.55 EUR/kWh fast charging costs excl. taxes. FCEV truck 0.2-0.55 EUR/kWh fast charging costs excl. taxes. Hydrogen fuelling costs 4.8-9.07 EUR/kg. For remaining assumptions see [8].

Built environment

- The seasonal demand profile has a strong impact on the built environment chain. Since the offshore wind production and demand both peak during winter, the required storage capacity can be reduced if both seasonal patterns can be combined;
- Pipeline (grid) transport turned out to be very suitable and cost-effective for this end user category, if enough volume is demanded either because a significant amount of buildings is connected, and/or because the regional pipeline can be shared with other types of end users with sufficient volumes;
- More research on repurposing the distribution grid for hydrogen and its costs and benefits is required to assess the impact of increasing insulation of buildings and to analyse what transport system adjustment may be needed in dealing with hydrogen flows.

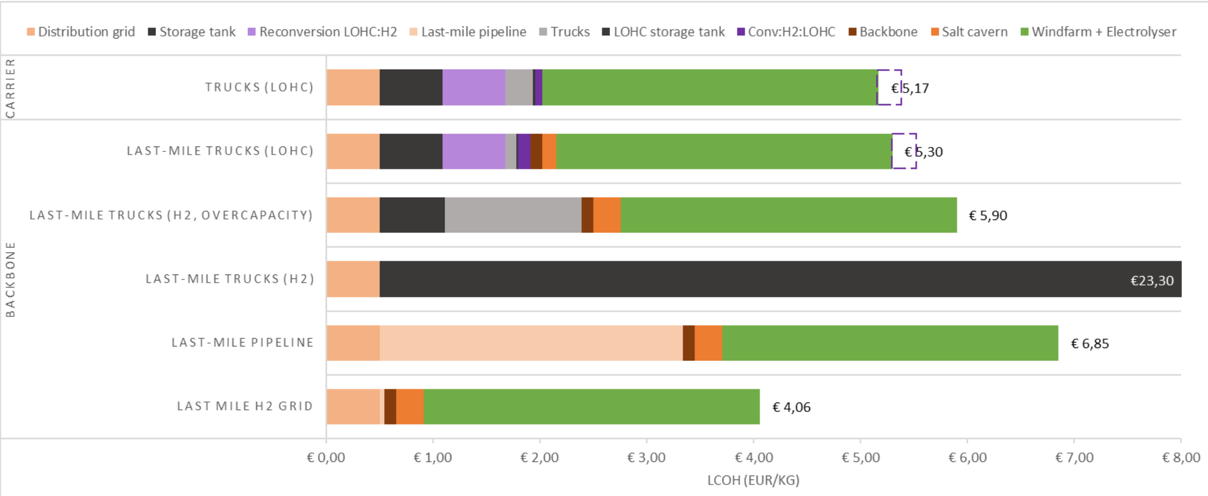


Figure 12 – Overview of the 2030 cost-distributions of built environment value chains

**Chain steps in the opposite direction in order to better compare the impact of the different transport options in the value chains*

Main assumptions: national hydrogen demand: 359 kT/y (43 PJ). LCOE of connected domestic offshore windfarm to electrolyser resulted in 60 EUR/MWh. Heat for LOHC reconversion is considered to be waste heat of 0 EUR/MWh, if these costs would be 25 EUR/MWh, 0.24 EUR/kg costs are added in those chains (see purple dotted boxes). However, heat released during conversion to LOHC may be sold as well. National pipeline costs of 0.11 €/kg of hydrogen are taken into account, based on a general analysis (see section 5.3 in D7A.2 [7]*). For the distribution grid costs 200 EUR/house CAPEX and 150 EUR/house annual OPEX is assumed* [9] [10].

The cost range of green hydrogen applied in the built environment is typically large because its costs strongly are affected by the scale of application especially of the transport system and whether combinations with other hydrogen up-takers can be made (see also Figure 12). Clearly, as Figure 13 shows, hydrogen tax conditions will have a major potential impact on its future economic potential as an energy carrier for the built environment as well.

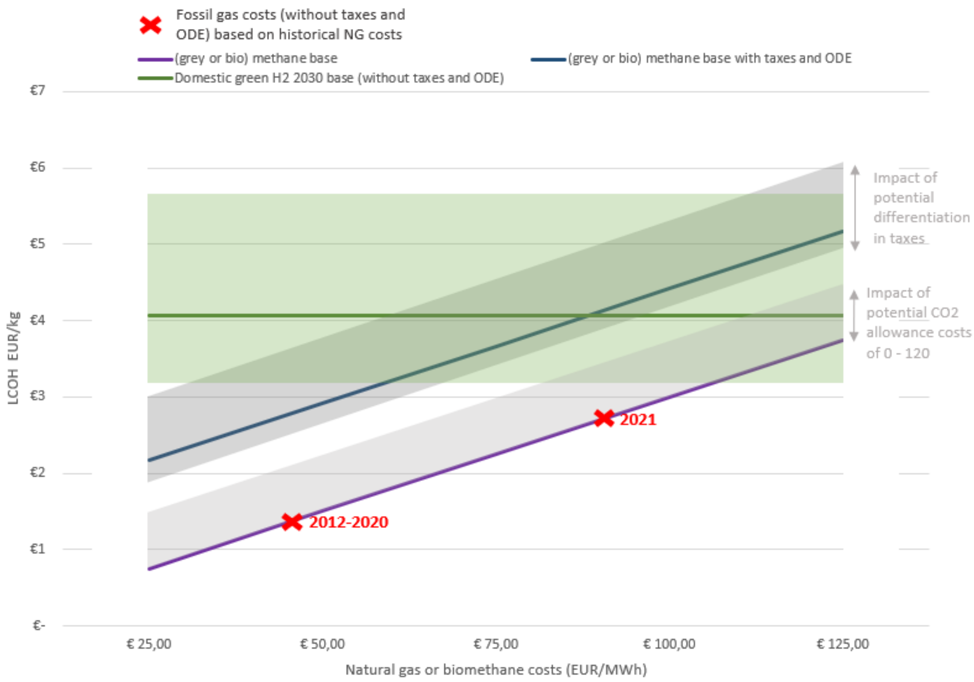


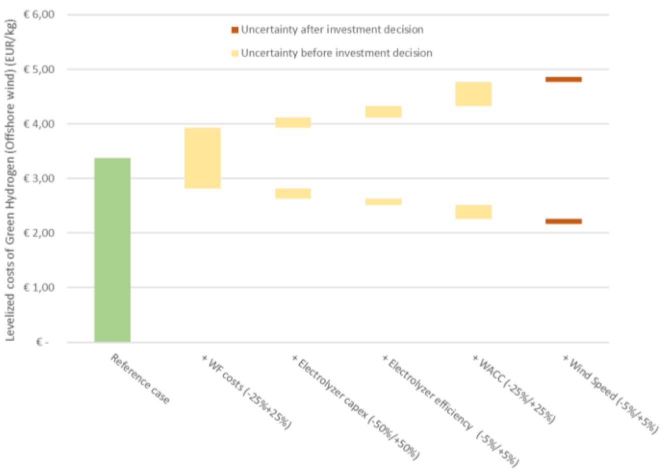
Figure 13 – Cost competitiveness of renewable hydrogen in the built environment. Assumptions: In comparing natural gas with hydrogen, an equivalent amount of energy has been used. This is presented via a hydrogen price equivalent (i.e. the required price for hydrogen to be competitive with natural gas given its price). Both natural gas costs have been shown, i.e. those excluding (purple line) and including taxes and ODE based on 2021 tax values [11] *(grey line). The purple area addresses the impact of a potential CO2 price in the built environment for burning methane (0-120 EUR/ton CO_2) and the grey area the impact of tax differentiation (low: only differentiation in normal taxes without ODE, high: increased taxes of 75% in 2030, according to plans described in the Climate Agreement* [12]*). The levelized costs presented include transport costs to the households. The green areas mark the uncertainty cost ranges of the green hydrogen production cost developments until 2030. The carbon costs of using natural gas are calculated based on the assumption of an emission of 0.203 tCO_2/MWh. The natural gas price of the past decade was some 30 EUR/MWh and transport costs for households some 15 EUR/MWh. Currently, the built environment is not part of the EU Emission Trading Scheme (ETS). However, in the recent RED II amendment a similar emission trading scheme is proposed for this sector.*

Samenvatting

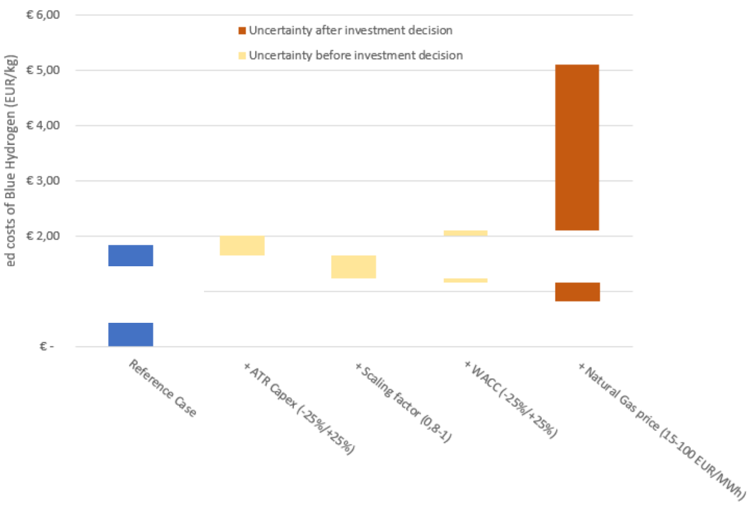
Het streven naar een klimaat-neutraal continent is een van de grootste prioriteiten van de Europese Commissie, die momenteel veel aandacht spendeert aan het zogenaamde 'Fit for 55 pakket', dat zal moeten leiden tot de tussenstap van 55% emissiereductie in 2030 ten opzichte van 1990. De Nederlandse overheid heeft vergelijkbare intenties. Aanvankelijk werd in het Klimaatakkoord gestuurd op 49% emissiereductie in 2030, echter heeft de nieuwe regering in het regeerakkoord laten weten beleidsinstrumenten te willen inzetten die zich richten op 60% reductie. Veelal hebben studies laten zien dat groene moleculen essentieel zijn om een duurzame energie en grondstoftransitie mogelijk te maken. Waterstof, zowel hernieuwbare als met een lage emissie intensiteit, wordt gezien als een belangrijke drager om in deze transitie te voorzien.

In dit rapport zijn voor vijf type eindgebruikers op systematische wijze de genivelleerde waterstofkosten gemodelleerd, voor potentiële waterstofketens in de Nederlandse context. Daarmee geeft het rapport gedetailleerde inzichten in de verdeling van de in 2030 verwachtte kosten over de verschillende ketencomponenten, en worden deze vergeleken met fossiele en andere duurzame alternatieven. Er is grondig aandacht besteed aan onzekere parameters die grote impact kunnen hebben op de uitkomsten, om zo inzicht te geven in de gevoeligheid van de resultaten. Zoals in elke modelleringsstudie moeten de kwantitatieve resultaten geïnterpreteerd worden met de bijbehorende aannames en methoden in het achterhoofd om de juiste conclusies te kunnen trekken. Er is in deze studie specifiek aandacht besteed aan de volgende onderwerpen, gezien deze tot de hoofddoelen behoren: het verkrijgen van inzichten in de meest kritieke kostenaspecten en factoren die bepalen wanneer investeringen kosteneffectief zijn, het identificeren van de impact van de afkomst van de waterstof (binnenlands groen, binnenlands blauw of import) op de keten en het analyseren van de relaties tussen de verschillende waardeketens. Gebaseerd op de uitvoerige analyse en resultaten die in dit rapport zijn beschreven, hebben wij de volgende punten geconcludeerd als belangrijkste inzichten gerelateerd aan de verschillende onderdelen van de waardeketen:

1. **Productie. Er is een grote onzekerheid in de waarden van factoren die bepalend zijn welke afkomst van waterstof het meest competitief zal zijn in 2030;**



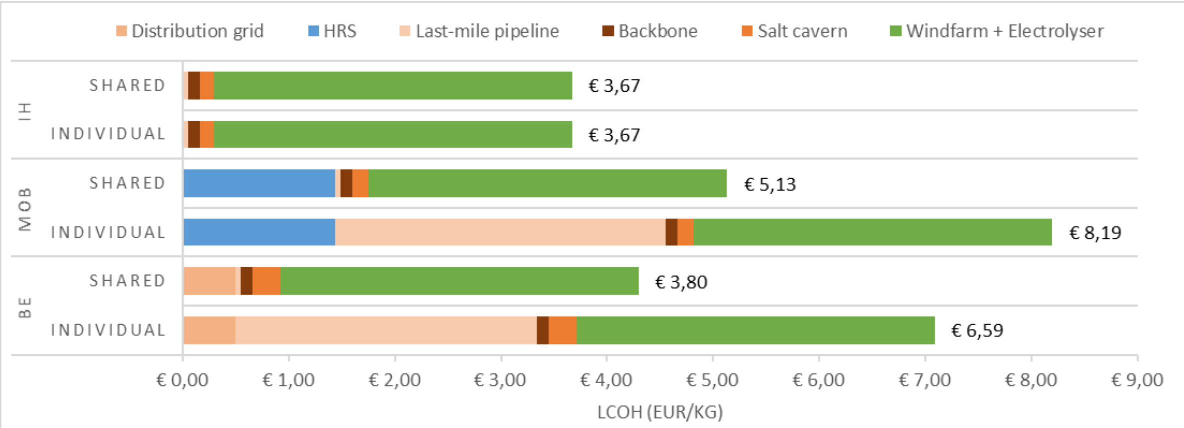
Figuur 14 – Toekomstige kosten van waterstof productie middels wind op zee (Noordzee) in Nederland, 2030. Aannames: Alkaline technologie, CAPEX 450 EUR/kW, jaarlijkse OPEX 2% van CAPEX, efficiëntie 47.6 kWh/kg waterstof, levensduur stacks 60000 vollasturen, WACC 7%, LCOE van direct gekoppeld Nederlands windpark op zee, incl. 100km bekabeling resulteert in 60 EUR/MWh.



Figuur 15 – Toekomstige kosten van blauwe waterstof productie in Nederland, 2030. Aannames: ATR+CCS technologie, CAPEX 1.3 MEUR/MW, jaarlijkse OPEX 4% van CAPEX, capaciteitsfactor 92%, basis schaalfactor 1, Aardgas behoefte 1.2 MJ aardgas/MJ H2 LHV, electriciteitsconsumptie 0.014 kWh/MJ H2 LHV, basis aardgasprijs 25 EUR/MWh, electriciteitsprijs 60 EUR/MWh.

Een significant verschil tussen groene waterstofproductiefabrieken met direct gekoppelde windparken op zee en nieuw geconstrueerde blauwe waterstoffabrieken middels ATR+CCS, is dat de onzekerheid van groen met name zit in de ontwikkeling van de CAPEX, voordat de investeringsbeslissing zal moeten worden genomen, terwijl voor blauw de onzekerheid zit in de OPEX (i.e. de aardgaskosten), welke nog grotendeels onzeker zullen zijn op het moment dat de investeringsbeslissing genomen zal worden.

2. **Transport. Lancerende klanten kunnen gebruikt worden als opstap naar een kosteneffectief transport systeem voor waterstof op een nationaal, regionaal en lokaal schaalniveau;**



Figuur 16 – De kostenreductie door middel van het delen van de investering in een regionale pijpleiding vergeleken dat deze individueel door een eindgebruiker gemaakt moet worden. Aannames: in de individuele ketens is een individuele eindgebruiker (fabriek (IH), waterstofvulpunt (Mob) of waterstofwijk (BE)) met de backbone gekoppeld middels een pijpleiding van 25 km. In de gedeelde ketens worden de kosten van de regionale pijpleiding laten zien, wanneer deze kosten worden verdeeld over de volumes van één van elk van de drie typen eindgebruikers die zich op eenzelfde locatie bevinden.

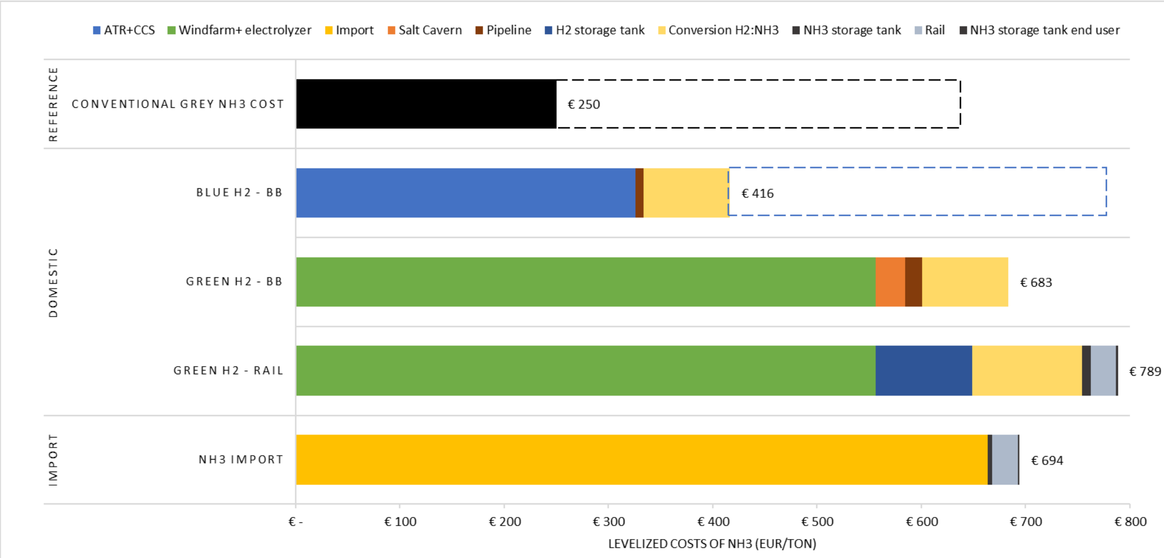
Figuur 16 laat een voorbeeld zien hoe een intersectorale aanpak kan leiden tot voordelen in transportkosten van regionale pijpleidingen voor verschillende type eindgebruikers. In dit voorbeeld kunnen de relatief grote volumes van gedecentraliseerde industrie, die hoge temperatuurwarmte behoeft, helpen om waterstof lokaal beschikbaar te maken voor andere typen eindgebruikers.

3. **Eindgebruikers. Voor alle typen eindgebruikers geldt dat de productiekosten het grootste aandeel vormen van de totale waterstof leveringskosten. Desondanks dienen uiteindelijk elke stap aanwezig te zijn om waterstof op het juiste moment en op de juiste plek beschikbaar te maken. Situationele omstandigheden, technologische details en/of gezamenlijke voordelen tussen eindgebruikers bepalen in grote mate welke opties überhaupt mogelijk zijn en in welke mate deze kosteneffectief zijn. We zullen een kort overzicht geven van de belangrijkste bevindingen per eindgebruiker:**

Waterstof als industriële grondstof: ammoniak voor de kunstmestindustrie

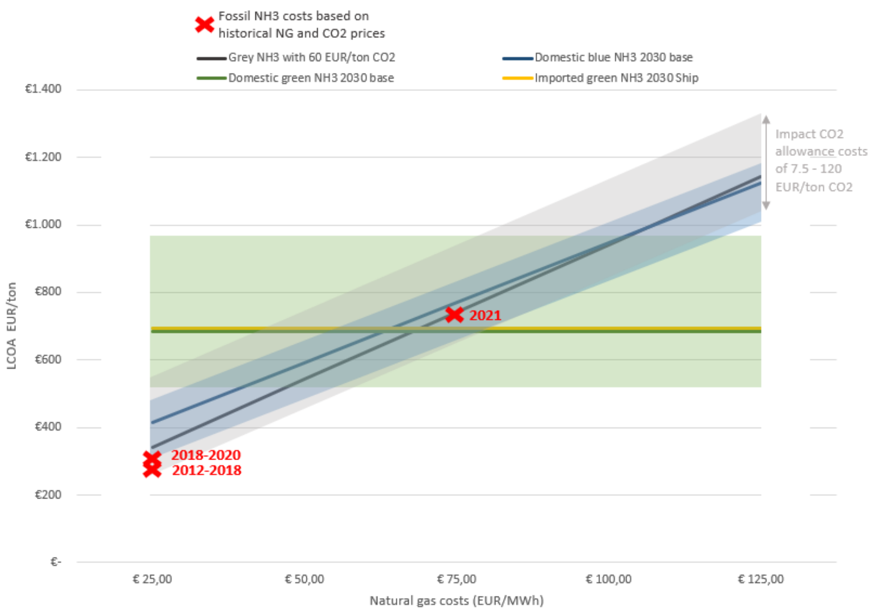
- De benodigde flexibiliteit is een veel bepalende karakteristiek als het gaat om het ontwikkelen en bepalen van de kosten van groene ammoniakketens. Seizoensopslag van gasvormige waterstof in tanks is een erg dure optie, daardoor zijn er drie opties: 1) nationale waterstoftransport met grootschalige opslag in zoutcavernes, 2) het verhogen van de flexibiliteit van het ammoniak synthese proces, 3) meer flexibiliteit creëren aan de productiekant van waterstof (e.g. het combineren met blauwe waterstofproductie en/of import).
- De resultaten laten geen significante verschillen zien tussen de genivelleerde kosten van binnenlandse en geïmporteerde groene ammoniak waardeketens. Binnenlandse ammoniak transport is een voorwaarde voor landinwaartse kunstmestfabrieken om geïmporteerde

ammoniak te kunnen gebruiken[2]. De optie per spoor is beoordeeld in kosten, echter zijn de beschikbaarheid op het spoornet en de veronderstelde veiligheid bezwaren die in de praktijk zwaar blijken te wegen. Oftewel, naast kosten wegen praktische argumenten voor en tegen zeker zo zwaar mee naast kosten, in de vergelijking van ammoniak transportalternatieven zoals vrachtwagens, de binnenvaart en ammoniakpijpleidingen.



Figuur 17 – Resultaten van de 2030 kostenverdelingen voor ammoniak waardeketens.

Belangrijkste aannames: Aardgas prijs 25 EUR/MWh (de gestippelde balken laten de impact van een aardgasprijs van 75 EUR/MWh zien: de grijze ammoniak referentie LCOA wordt dan 650 EUR/ton en de blauwe waterstof ammoniakketen 770 EUR/ton, elektriciteitsprijs van het net 60 EUR/MWh, LCOE van binnenlandse wind op zee direct gekoppeld aan de elektrolyser resulteert in 60 EUR/MWh, groene ammoniak importkosten zijn gebaseerd op de gemiddelde importkosten van ammoniak per schip uit Canada, Australië en Morocco, voor de groene keten per spoor zijn de resultaten getoond waarbij gebruik gemaakt is van flexibele ammoniak conversie.



Figuur 18 – Visualisatie van de impact van de aardgas en CO_2 kosten op de referentie prijs van grijze en blauwe ammoniak. De respectievelijke groene en blauwe vlakken markeren de onzekerheidsmarges gebaseerd op ontwikkelingen in productiekosten tot 2030, het grijze vlak de gevoeligheid voor grijze NH3 kosten op basis van CO2 emissierechten (7.5 EUR/ton laag, 120 EUR/ton hoog). De genivelleerde kosten zijn laten zien op locatie van de eindgebruiker. De referentiekosten van grijze ammoniak zijn berekend met 1.75 ton CO_2/ton NH_3 [1], de kosten voor aardgas en CO_2-rechten zijn in het verleden respectievelijk +- 25 EU/MWh en 5-15 EU/ton CO_2 [2] [3] [4] geweest. In 2021 is echter een

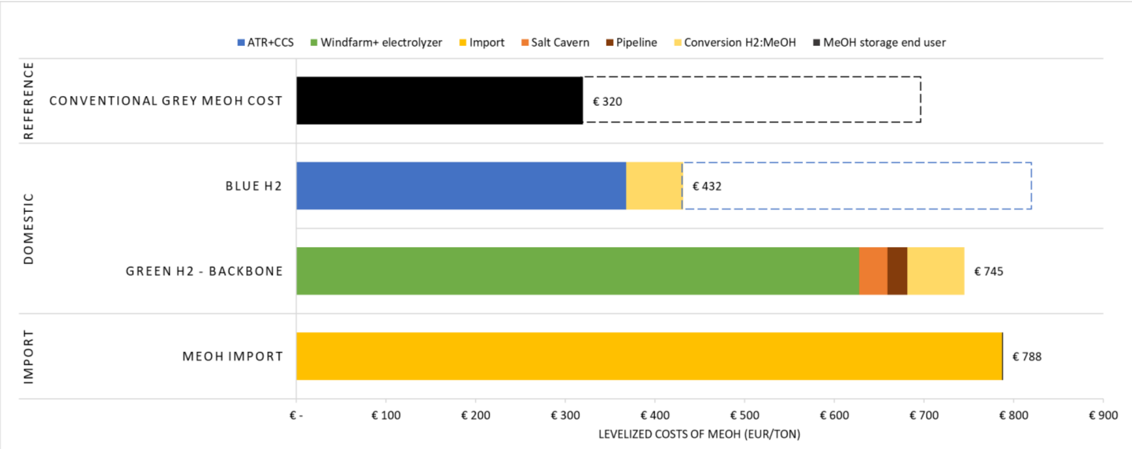
[2] In theorie is het mogelijk om geïmporteerde ammoniak terug te converteren naar waterstof, deze waterstof te transporteren en op locatie van de eindgebruiker weer te converteren naar ammoniak, echter zorgt deze extra conversie-cyclus voor extra kosten en energieverliezen.

scherpe stijging van zowel de Europese gasprijs als CO_2-rechten gezien (sinds de herfst van 2021 was de aardgasprijs tussen 80 en 180 EUR/MWh en kostte emissierechten meer dan 60 EUR/ton CO_2).

De kosten van groene ammoniak berekend in dit rapport (683 €/ton binnenlands, 694 €/ton import) liggen significant hoger dan de traditionele kosten van fossiele ammoniak (250 €/ton). De kosten van aardgas en CO_2-rechten beïnvloeden de competitiviteit van groen versus grijs, terwijl voor blauw alleen de CO_2-rechten impact hebben op de competitiviteit tussen deze, en de grijze route. Om hernieuwbare ammoniak te maken, zijn de enige beschikbare alternatieven via biomethaan (productiekosten van of 50-100 €/MWh [5]) en enkele alternatieven laag in TRL.

Waterstof als industriële grondstof: methanol voor E-brandstoffen

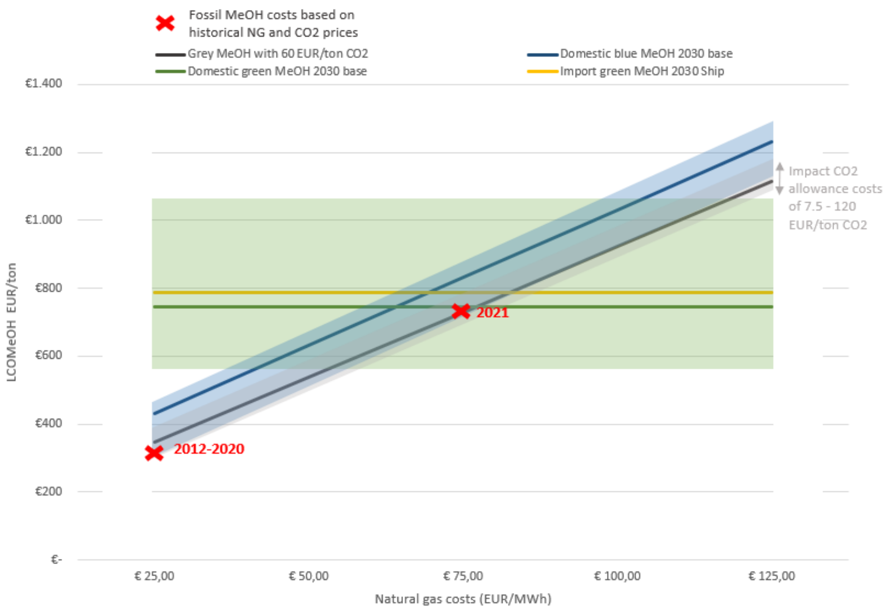
Net zoals werd gezien bij eindgebruikers van ammoniak is ook bij methanol het fluctuerende productiepatroon van grote invloed op de keten, die dus ook hier een mate van flexibiliteit behoeft in de productie, opslag, conversie en/of afname. Een groot voordeel van blauw is dat het realiseren van een stabiele stroom door de keten veel gemakkelijker is, echter is de impact van de aardgaskosten groot.



Figuur 19 – Resultaten van de 2030 kostenverdelingen voor methanol waardeketens.

Belangrijkste aannames: Aardgas prijs 25 EUR/MWh (de gestippelde balken laten de impact van een aardgasprijs van 75 EUR/MWh zien: de grijze methanol referentie LCOM wordt dan 704 EUR/ton en de blauwe waterstof methanolketen 832 EUR/ton, elektriciteitsprijs van het net 60 EUR/MWh, LCOE van binnenlandse wind op zee direct gekoppeld aan de elektrolyser resulteert in 60 EUR/MWh, groene methanol importkosten zijn gebaseerd op de gemiddelde importkosten van methanol per schip uit Canada, Australië en Morocco.

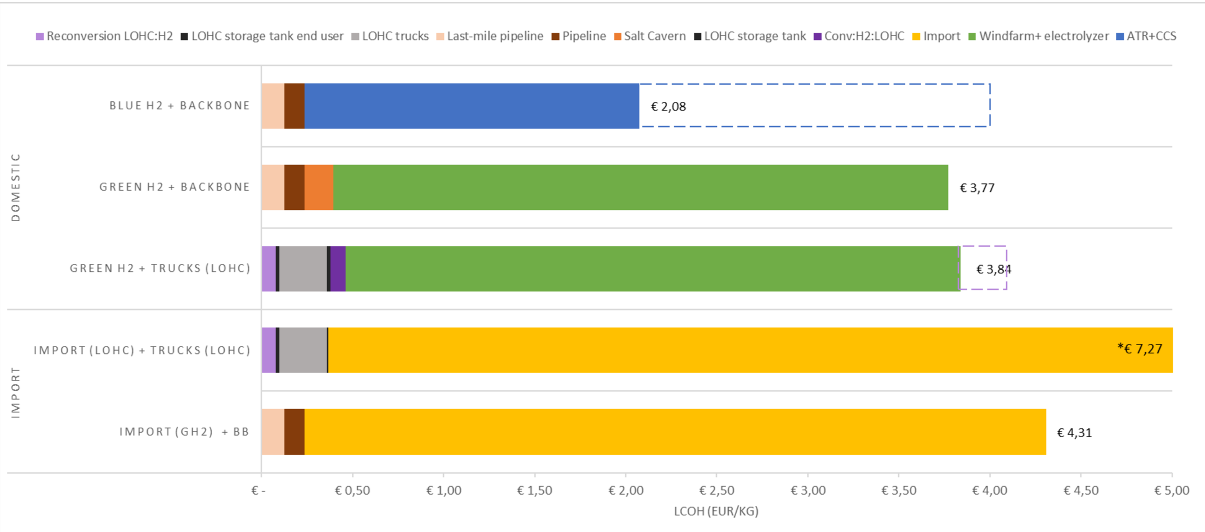
Doordat de impact van de waterstofproductiekosten op het totaal groter is in de methanol casus dan die van ammoniak zijn de onzekerheidsmarges (gebaseerd op de onzekerheid van productiekosten) zowel voor groen als blauw groter. Daarnaast hebben de kosten van CO_2-rechten minder impact op de kosten fossiele methanol, dus moeten deze hoger zijn om groene en blauwe methanol competitief te maken, vergeleken met ammoniak.



Figuur 20 – Visualisatie van de impact van de aardgas en CO_2 kosten op de referentie prijs van grijze en blauwe methanol met duurzame CO_2 die verkregen is uit de lucht. De respectievelijke groene en blauwe vlakken markeren de onzekerheidsmarges gebaseerd op ontwikkelingen in productiekosten tot 2030, het grijze vlak de gevoeligheid voor grijze NH3 kosten op basis van CO2 emissierechten (7.5 EUR/ton laag, 120 EUR/ton hoog). De genivelleerde kosten zijn laten zien op locatie van de eindgebruiker. De referentiekosten van grijze methanol zijn berekend met 0.5 ton CO_2/ton MeOH [1], de kosten voor aardgas en CO_2-rechten zijn in het verleden respectievelijk +- 25 EU/MWh en 5-15 EU/ton CO_2 [2] [3] [4] geweest. In 2021 is echter een scherpe stijging van zowel de Europese gasprijs als CO_2-rechten gezien (sinds de herfst van 2021 was de aardgasprijs tussen 80 en 180 EUR/MWh en kostte emissierechten meer dan 60 EUR/ton CO_2).

Hoge temperatuurwarmte voor gedecentraliseerde industrie

- Omdat dit type eindgebruiker pure (>98%) waterstof vraagt is het importeren van waterstof door middel van dragers minder gunstig dan wanneer de eindgebruiker specifiek vraag heeft naar een drager (e.g. ammoniak of methanol). Conversie is in dit geval geen noodzakelijk onderdeel van de keten.
- De locatie en het vraagvolume van de decentrale fabriek(en) maakt veel uit. In algemene zin geldt: hoe dichter bij de locatie ligt bij een potentiële backbone en des te groter de vraagvolumes, hoe meer kosteneffectief pijpleidingen zijn; en hoe kleiner de volumes en meer afgelegen van andere gebruikers en een potentiële backbone, hoe meer kosteneffectief wegtransport is. Daarbij geldt dat de toepasbaarheid van LOHC vervoer afhangt van de beschikbaarheid en kosten van lokale warmte.

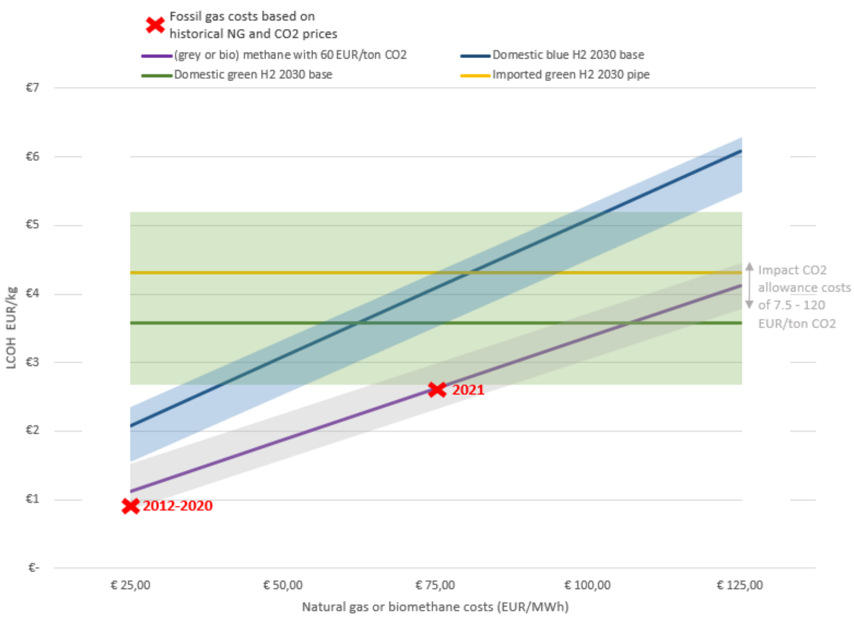


Figuur 21 – Resultaten van de 2030 kostenverdelingen voor decentrale industriële warmte waardeketens.

**keten stappen zijn in de tegenovergestelde richting weergegeven om zo beter de verschillende opties voor transport te kunnen vergelijken*

Belangrijkste aannames: Aardgas prijs 25 EUR/MWh (de gestippelde balken laten de impact van een aardgasprijs van 75 EUR/MWh zien: de blauwe waterstofkosten worden dan 4,08 EUR/kg), elektriciteitsprijs van het net 60 EUR/MWh, LCOE van binnenlandse wind op zee direct gekoppeld aan de elektrolyser resulteert in 60 EUR/MWh, groene waterstof importkosten via LOHC per schip zijn gebaseerd op de gemiddelde importkosten vanuit Canada, Australië en Morocco, de groene waterstof importkosten als gas per pijpleiding is gebaseerd op import uit Morocco als een Europese waterstof backbone beschikbaar zou zijn. Voor de warmtevraag voor LOHC reconversie wordt uitgegaan van restwarmte van 0 EUR/MWh, als deze kosten 25 EUR/MWh zouden zijn, zou deze ketenstap 0.24 EUR/kg duurder worden, daaraan moet toegevoegd worden dat vrijgekomen restwarmte voor LOHC conversie mogelijk verkocht zou kunnen worden. 0.11 €/kg is aangenomen voor de nationale pijpleidingkosten gebaseerd op de analyse in de discussie sectie van dit rapport.

Figure 9 laat zien dat significante waardes nodig zijn voor zowel kosten voor aardgas als emissierechten om groene waterstof goedkoper te maken dan aardgas voor decentrale fabrieken die warmte behoeven. Vergeleken met biomethaan (productiekosten 50-100 €/MWh [5]) zijn de kosten van waterstof hoger (94 €/MWh, laag en hoog 63-141 €/MWh) en de uitdagingen voor transport naar de uiteen gelegen fabrieken groter. Echter, is de beschikbaarheid van biomethaan gelimiteerd en is het daardoor een oplossing die niet op elke locatie, en slechts tot een zeker volume, beschikbaar is.



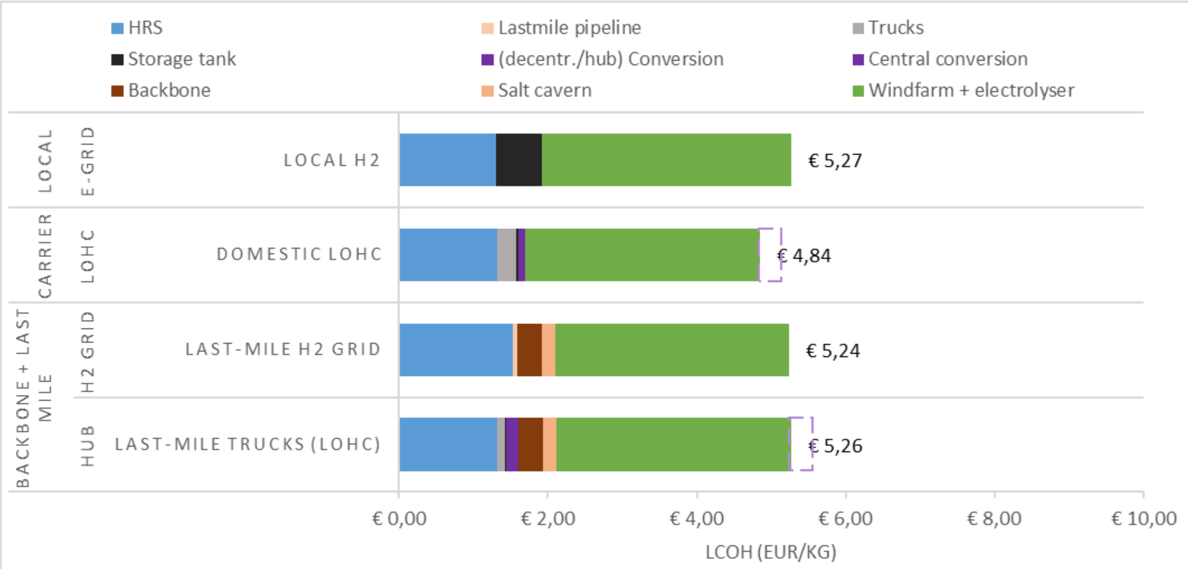
Figuur 22 – Competitiviteit van de waterstofleveringskosten (import, groen en blauwe waterstof) vergeleken met de referentiekosten van dezelfde hoeveelheid energie via aardgas in waterstofkosten-equivalent (=de benodigde waterstofkosten om competitief te zijn met de aardgas + CO_2 kosten van dezelfde energetische hoeveelheid). De genivelleerde kosten zijn laten zien op locatie van de eindgebruiker. Het resp. groene en blauwe vlak laten de onzekerheid zien in productiekosten van groene en blauwe waterstof richting 2030, het paarse vlak laten de onzekerheid zien in emissiekosten van het verbranden van methaan (7.5-120 EUR/ton CO_2). De emissiekosten voor aardgasgebruik zijn berekend met 0.203 ton CO_2/MWh aardgas, de kosten voor aardgas en CO_2-rechten zijn in het verleden respectievelijk +- 25 EU/MWh en 5-15 EU/ton CO_2 [2] [3] [4] geweest. In 2021 is echter een scherpe stijging van zowel de Europese gasprijs als CO_2-rechten gezien (sinds de herfst van 2021 was de aardgasprijs tussen 80 en 180 EUR/MWh en kostte emissierechten meer dan 60 EUR/ton CO_2).

Mobiliteit

Verschillende mobiliteitsketens resulteren in vergelijkbare kostenprognoses. Voor elk type keten, echter, zijn bepaalde situationele karakteristieken benodigd om ze kosteneffectief te ontwikkelen:

- Lokale ketens hebben potentie als een lokaal windpark aanwezig is, seizoensopslag kosteneffectief kan worden voorkomen en op deze locatie vraag van waterstofvoertuigen aanwezig is;
- Binnenlandse LOHC truck ketens hebben centrale conversieplekken nodig (voor ~20+ vulpunten) om schaalvoordelen te halen. Bij de waterstofvulpunten moet lokaal warmte leverbaar zijn om LOHC terug te converteren naar gasvormige waterstof;

- Voordat een waterstofvulpunt waterstof uit een regionaal net geleverd kan krijgen, moet er in deze regio eerst meerdere typen afnemers gevonden worden om dit net tegen de getoonde kosten voor afnemers beschikbaar te maken;
- Om LOHC vrachtwagens te gebruiken voor distributie tussen een backbone en vulpunten, moeten dezelfde schaalvoordelen en lokale warmte beschikbaar zijn voor conversie en reconversie.

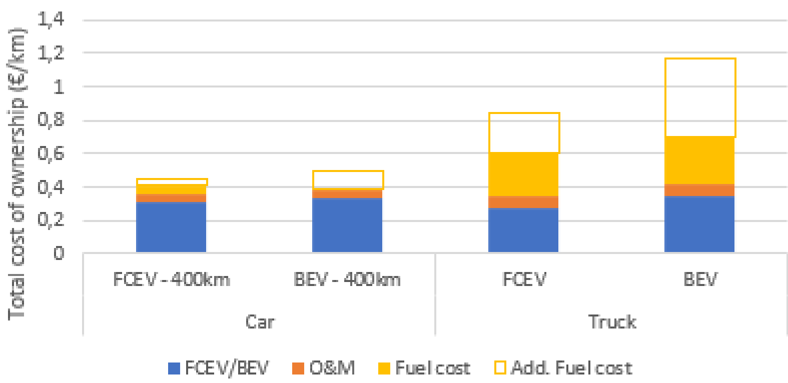


Figuur 23 – Resultaten van de 2030 kostenverdelingen voor mobiliteitsketens met de laagste kosten.

**keten stappen zijn in de tegenovergestelde richting weergegeven om zo beter de verschillende opties voor transport te kunnen vergelijken*

Belangrijkste aannames: 1000 waterstofvulpunten met 400 kg/dag levering, nationale vraag van 141 kT/j, LCOE van binnenlandse wind op zee direct gekoppeld aan de elektrolyser resulteert in 60 EUR/MWh, LCOE lokaal windpark 53 EUR/MWh maar resulteert in lagere bezettingsgraad (0.35 vergeleken met 0.55) dan wind op zee. Voor de warmtevraag voor LOHC reconversie wordt uitgegaan van restwarmte van 0 EUR/MWh, als deze kosten 25 EUR/MWh zouden zijn, zou deze ketenstap 0.24 EUR/kg duurder worden (zie gestippelde balken), daaraan moet toegevoegd worden dat vrijgekomen restwarmte voor LOHC conversie mogelijk verkocht zou kunnen worden. 0.11 €/kg is aangenomen voor de nationale pijpleidingkosten gebaseerd op de analyse in de discussie sectie van dit rapport.

Er is potentie om pure waterstof als brandstof te gebruiken voor lange afstand- en zwaar transport. De brandstofkosten hebben kleinere impact op de totale TCO van lange afstand voertuigen dan zwaar transport voertuigen. Zwaar transport voertuigen gebruiken significant meer brandstof dan kleinere.

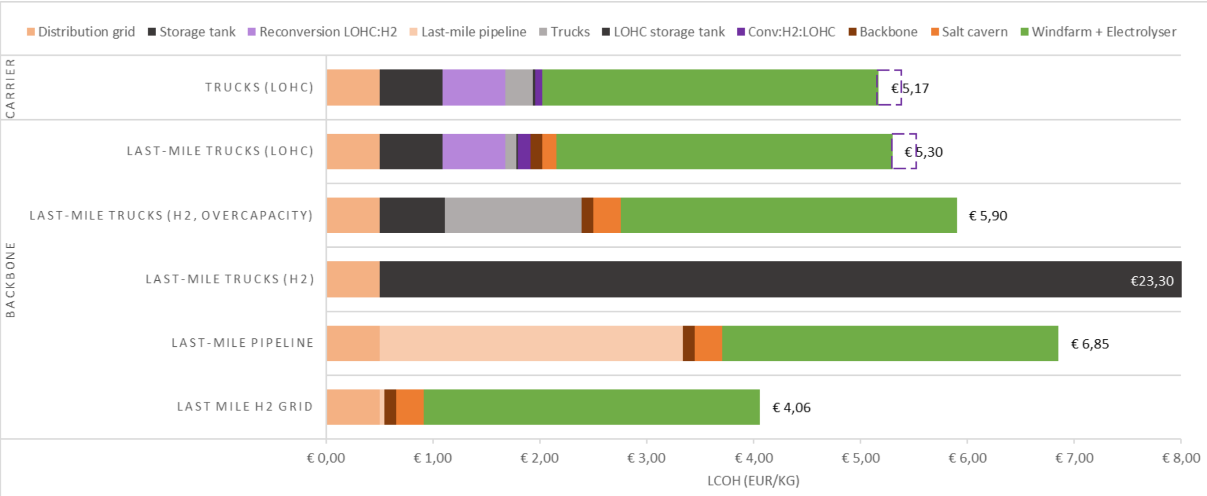


Figuur 24 – Vergelijking tussen toekomstige totale eigenaarskosten van BEVs en FCEVs gebaseerd op [8].

Aannames: personenauto's met range >400km, laadkosten electrische auto's laag: 0.04 EUR/kWh (van eigen opgewekte elektriciteit aan huis) hoog: 0.55 EUR/kWh snellaadkosten excl. Heffingen. Elektrische vrachtwagens 0.2-0.55 EUR/kWh snellaadkosten excl. Heffingen. Waterstoftankkosten 4.8-9.07 EUR/kg. Voor overige aannames zie [8].

Gebouwde omgeving

- De impact van seizoensgebonden warmtevraag van de gebouwde omgeving is groot. Echter, doordat zowel de piek van wind op zee als de warmtevraag in de winter ligt kan de totaal benodigde opslagcapaciteit gereduceerd worden als beide patronen worden gecombineerd;
- Het transport middels (een net van) pijpleidingen is het meest geschikt om met de seizoensgebonden vraag om te gaan, zolang 1) een significante vraagdichtheid van gebouwen aanwezig is of 2) de regionale pijpleidingen gedeeld kunnen worden met een ander type eindgebruiker met grote volumes;
- Meer onderzoek is nodig naar het hergebruiken van het distributienet om te beoordelen wat de mogelijke impact van een gereduceerde gasvraag per gebouw is en de benodigde lokale vraagdichtheid om het hergebruiken van distributienetten zo kosteneffectief mogelijk te maken.

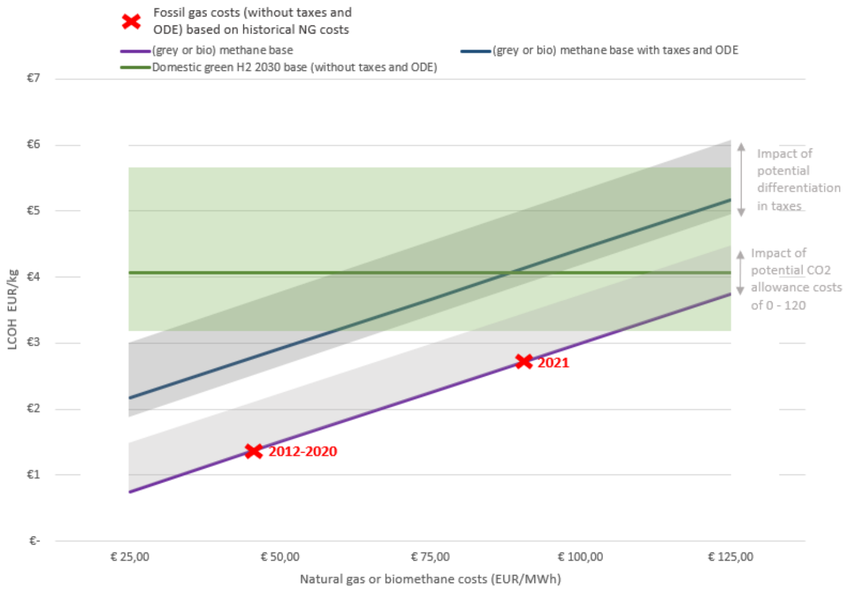


Figuur 25 – Resultaten van de 2030 kostenverdelingen voor waardeketens in de gebouwde omgeving.

**keten stappen zijn in de tegenovergestelde richting weergegeven om zo beter de verschillende opties voor transport te kunnen vergelijken*

Belangrijkste aannames: Nationale vraag van 359 kT/j (43 PJ), LCOE van binnenlandse wind op zee direct gekoppeld aan de elektrolyser resulteert in 60 EUR/MWh. Voor de warmtevraag voor LOHC reconversie wordt uitgegaan van restwarmte van 0 EUR/MWh, als deze kosten 25 EUR/MWh zouden zijn, zou deze ketenstap 0.24 EUR/kg duurder worden (zie gestippelde balken), daaraan moet toegevoegd worden dat vrijgekomen restwarmte voor LOHC conversie mogelijk verkocht zou kunnen worden. 0.11 €/kg is aangenomen voor de nationale pijpleidingkosten gebaseerd op de analyse in de discussie sectie van dit rapport. Voor de distributienetkosten is uit gegaan van 200 EUR/huis CAPEX en 150 EUR/huis jaarlijkse OPEX [9] [10].

De bandbreedte van groene waterstof (gebaseerd op de leverkosten, zie opties in Figuur 26) is relatief groot en hangt met name af van de schaal waarmee waterstof uitgerold zal worden (i.e. of op grote schaal in de gebouwde omgeving; of op grote schaal in andere sectoren met slimme connecties naar de gebouwde omgeving). Eindgebruikers in de gebouwde omgeving zijn al gewend een relatief hoge prijs te betalen voor hun aardgas door heffingen, wat betekend dat differentiatie in heffingen tussen fossiele en duurzame gassen direct al toegepast kan worden zonder de heffingen eerst toe te laten nemen.



Figuur 26 – Competitiviteit van de waterstofleveringskosten in de gebouwde omgeving vergeleken met de referentiekosten van dezelfde hoeveelheid energie via aardgas in waterstofkosten-equivalent (=de benodigde waterstofkosten om competitief te zijn met de aardgas + CO_2 kosten van dezelfde energetische hoeveelheid). De gaskosten zowel exclusief heffingen (paarse lijn) als inclusief heffingen en ODE gebasseerd op 2021 waarden [11] (grijze lijn) zijn laten zien. Het paarse vlak laat de mogelijke impact van CO_2 kosten voor het verbranden van methaan zien (0-120 EUR/ton CO_2) en het grijze vlak de impact van de hoeveelheid differentiatie in heffingen (laag: alleen in normale heffingen excl. ODE, hoog: verhoogde heffingen met 75% in 2030, zoals beoogd in het Klimaatakkoord [12]). De genivelleerde kosten zijn laten zien op locatie van de eindgebruiker. De emissiekosten voor aardgasgebruik zijn berekend met 0.203 ton CO_2/MWh aardgas, de heffingen zijn gebaseerd op actuele waardes [11] en de prognoses om ze toe te laten nemen zoals beschreven in het Klimaatakkoord [12], de kosten voor aardgas en CO_2-rechten zijn in het verleden respectievelijk +- 30 EUR/MWh en transportkosten voor huishoudens van ongeveer 15 EUR/MWh. Hedendaags valt de gebouwde omgeving niet onder het EU emissiehandelssysteem (ETS), maar in de recent voorgestelde RED II aanpassing wordt beoogd een vergelijkbaar systeem in deze sector in te voeren.

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1. Conclusions of the report

Becoming a carbon neutral continent is one of the main political priorities of the European Commission, that is currently spending a lot of attention in establishing the set of required legislations, known as the Fit for 55 package, to move towards the in-between goal of 55% emission reduction compared to 1990 in 2030. Similar intentions are made by the Dutch government, that initially aimed for 49% emission reduction in 2030, but the new government decided to target with its policies to achieve 60%. Many studies showed the need for green molecules to fulfil the energy and material demands in a sustainable manner. Hydrogen, renewable and/or low carbon, is foreseen as one of the important carriers to fulfil this transition.

In this study, levelized costs of potential hydrogen value chains, for five types of end-uses are modelled in the Dutch context in a systematic way. The study gives detailed insights in the foreseen 2030 cost breakdowns and compares the costs with the existing, and foreseen sustainable alternatives to give insights in their potentials and drawbacks. Broad attention is paid to the most impactful parameters that are uncertain, in order identify their sensitivities on the results. As in every modelling study, the quantitative results should be evaluated with sharp notice on the assumptions used, to fully understand them and to gather the correct insights. Related to the main aims of this study, specific attention is paid to the following aspects: to obtain insights in the most critical costs and determinants for acceptable business cases, to identify the impact of different hydrogen sources (domestic green, domestic blue or import) and to analyse the relations between the different value chains. Based on the results and analysis performed in this report, we conclude the following key insights related to the value chain:

1. Production: there is a large uncertainty range in the dominant factors that will determine what source of hydrogen will become most competitive;
2. Transport: launching customers could be used as steppingstone towards a cost effective transport system for hydrogen;
3. End-users: in all type of end uses, production costs represent the largest share in the total supply costs. However, in the end no single value chain step can be missed to make hydrogen available at the right place and time. Situational aspects, technological details and/or mutual benefits of combinations between end-users greatly determine what options are available and cost effective.

First, it is seen that several parameters cause large uncertainty in the most cost-effective carbon neutral hydrogen source in the future. Comparing domestic green hydrogen production via combined tenders and newly constructed blue hydrogen production plants, a very important difference is that 2.30 of the 2.50 €/kg cost uncertainty range of the green hydrogen business case (considering that the windfarm and electrolyser are part of the same project, i.e. combinedly tendered) lays in uncertainties that can be dealt with before the investment decision is made (e.g. technological innovation, WACC, see Figure 29), while 3.30 of the 4.30 €/kg cost uncertainty range for blue hydrogen relates to the natural gas price developments which is only known up to a certain extend at the moment when the investment decision has to be made (see Figure 30). The developments of the European natural gas prices that are seen since the autumn of 2021 show the large unpredictability that should be dealt with. The expected costs of import calculated for 2030 (4.50-6.70 €/kg) lay higher than the domestic produced (3.38 €/kg for green and 1.85 €/kg for blue) routes. However, the chance that if import routes may become cost competitive in the future, is a risk for investors in domestic capacities. If green hydrogen capacities are already deployed, they can still produce under the market price due to their low marginal costs (still, as long as the windfarm and electrolyser as a single project is assumed, and electricity does not have to be purchased on the electricity market). It remains uncertain if this is the case for possible blue hydrogen production investments, as this fully depends on the natural gas price. In our results (see also D7B.3 'Import analysis report') represented for 2030, it is seen that especially for end uses demanding green hydrogen related chemicals, such as ammonia or methanol, import routes of those carriers (695 and 787 €/ton respectively) can be established comparable in costs compared to the domestic green ammonia and methanol value chain (695 and 786 €/ton respectively).

Secondly, obviously cost effective transportation availability is a requirement to connect producers and consumers. Independent of the transport costs, accessible pipeline infrastructure has some advantages for end users over carrier transport, such as that no investments in reconversion installations have to be made at end-user locations, lower dependence on fuel price developments affecting the costs of transport by trucks and trains, and no need for situational criteria (such as the availability of local heat for LOHC reconversion, or rail and station availability for ammonia transport by rail). The disadvantage is that a minimum requirement of volumes is needed in the beginning to allow the investments that must be made to develop and reuse the infrastructure, therefore launching customers are essential. For the largest hydrogen consumers, such as large ammonia and methanol industries, it is seen that the demand volumes are that large that individual pipeline transport chains can be developed cost effectively (see Figure 34 and Figure 37). This potential role of launching customer for national infrastructure of the large chemical industrial end-users can be lost if they choose for the route of import of ammonia and methanol instead of domestically produced (green or blue) hydrogen production (although it should be considered that there are other large scale central industries not included in the scope of this study that could become launching customers). For smaller types of end users, such as distributed industries that require high temperature heat, refuelling stations and the built environment, a large amount of consumers would be required to make national transport via pipelines cost effective. Hence, the large industries could become launching customers to make national hydrogen pipeline infrastructure assessable for other end users. Similarly, distributed industrial plants requiring high temperature heat could accelerate a local demand for hydrogen that could unlock investment potential of local hydrogen grids that are accessible for end users with smaller volumes, such as refuelling stations and (parts of) the built environment. Hence, for pipeline transport enough volumes is a precondition. It is seen that LOHC transport could be cost effective for the industrial heat and mobility sector, under the preconditions that cheap assessable heat is available for the reconversion of LOHC, and the conversion to LOHC is done at a central plant to gain the required economies of scale. Carrier and local chains are discussed to have potential to develop HRS before local hydrogen grids could become available. On the contrary, hydrogen in the built environment can only be made cost effectively available when a national and local pipeline network, including large scale storage of hydrogen, is established. The role of launching customer for local infrastructure of the distributed industries is lost if they choose to obtain hydrogen via LOHC trucks instead of locally (reused) pipelines.

Thirdly, looking from the perspective of the different types of end users, it is seen that in most cases the levelized production costs have the largest impact on the total levelized costs of supply. Therefore, it is expected that innovations and support incentives on the production cost side will have the most impact in reducing the overall supply chain costs and therefore the business case of a specific end user to decide using hydrogen. In the small volume, distributed type of end uses (i.e. mobility and built environment) it is seen that the last mile transport could have significant impact on the total supply costs as well. Moreover, taxes and excises have a large impact on the price that consumers have to pay in those two types of end-uses. Finally, in these two end uses customer preferences (e.g. willingness to invest in their homes, driving range, refuelling time) and other cost factors beyond the fuel (i.e. hydrogen) costs will play a big role (e.g. insulation required, costs boilers and heat pumps, costs vehicles, batteries and fuel cells). Therefore, in those two types of end uses a more broad perspective than the supply costs should be considered as well, to assess its applicability and competitivity. For the ammonia, methanol and high temperature heat end uses, the levelized production costs are the major driver of competitiveness, and moreover, sustainable or carbon neutral alternatives besides hydrogen are limited: in most cases only biomethane, that is available in limited volumes and some technologies in the very early stages of technology maturity.

To sum up, firstly the production costs, that have the most significant contribution to the total supply costs all the end uses, are the most uncertain. The choice whether to support domestic green, domestic blue and/or import routes is a political one, but if support is desired it should focus on the primary uncertainty of the source: Policies that would decrease the barrier of the relatively large investments involved by this green domestic route can help to start early deployment that enables the projected cost reductions of this technology. For blue domestic hydrogen, low cost availability of methane is a crucial aspect of the cost effectiveness of decarbonization via this route, which has become a lot more uncertain due to the developments since the autumn of 2021. Finally, for import the most important aspect is that there is enough offtake for green hydrogen to develop supply routes. Besides support to the production elements of the chains, it should being mentioned that no production of hydrogen will be deployed as long as not every other element of the chains is in place to transport, store and offtake the hydrogen. Therefore, a look from a broader value chain perspective is essential, instead of limiting the view to the production stage. Secondly, the means of transport chosen by certain end users might impact the potential supply costs of other end users, as certain end users might contribute as launching customers for investments in infrastructure that can be shared among multiple users. With regards to development of transport infrastructure, a cross sectoral approach is required as there is seen that specific types of end uses could unlock a potential for others. Especially when hydrogen is foreseen to be used in parts of the built environment, a widely accessible hydrogen pipeline network, nationally and locally, is required.

Furthermore, based on the results and limitations of this study, two specific directions for further research and innovation are recommended. First, with regards to technological innovation we recommend to focus on the production and conversion technologies. Especially for green hydrogen, a lot of cost reduction potential can be achieved by decreasing the technology costs and improving efficiencies. Secondly, it is seen that sometimes gaseous tank storage costs could include a significant share of the costs, for example in the green domestic ammonia rail chain, at the HRS or in more local chains. If large share of hydrogen is produced via a variable producing source, a higher technical and economic feasibility of flexible conversion (for example to ammonia or methanol) could lead to a better optimization of the total chain costs. The second direction for further research lays in the mutual dependencies of multiple actors decisions within the chain, as there is seen that this could hugely impact the hydrogen supply costs as well. Further research should dive deeper into the specific details of those dependencies and could investigate for specific cases how different types of actors could collaborate and benefit from each other to maximize the value achieved when hydrogen supply chains are being developed.

2. Introduction

The European Fit for 55 package signifies again the urgency of keeping global average temperature increase below 1.5 C, or at least well below 2.0 C, and amplifies the role of the EU in speeding up the roll-out of renewable energy sources (RES) and introducing hydrogen in the energy system. A particular challenge resulting from the introduction of intermittent RES is to match supply and demand, a challenge becoming more tangible every year. Another challenge is to create sustainable alternatives for fossil oil and gas that can provide comparable levels of energy security and affordability. The implementation of sustainable alternatives, such as hydrogen and hydrogen-based carriers - the main topic of this report - will clearly strongly affect the current energy value chain: new energy carriers need to somehow fit in with the existing energy value chain while increasing significantly in volumes and capacity.

Currently, hydrogen is almost exclusively produced and consumed in specific chemical and other industrial processes and a few mobility use-cases only, but not generally accessible for other sectors. Recognising that carbon neutral hydrogen is one of the few options to deliver large volumes of green energy molecules for those end uses that for various reasons need molecules rather than electrons as feedstock or energy carriers, the issue is how hydrogen can also be made available to other sectors that are currently used to rely on fossil energy molecules. Developing such broader hydrogen accessibility can be realized by creating new hydrogen value chains. In doing so, what parts of the existing energy value chain can still be used in such new hydrogen systems is an important issue to consider in trying to find the most-cost effective ways to provide a green, safe, reliable, sufficiently flexible and affordable supply of hydrogen for various end-users.

The main characteristics of an upcoming national hydrogen economy – e.g. preliminary based on ‘green’ or ‘blue’ hydrogen; typically having an import- or export-focus of supply; or with a prime purpose of the transport and storage system for hydrogen either to be used as gas or liquid or rather to support the electricity system – will obviously strongly depend on the strategies countries choose.

The Dutch hydrogen strategy is somewhat mixed in that respect.

There is significant potential for offshore wind energy, and its green power production is likely to cover part of the rapidly increasing demand for green power both as such and as a source for generating the green hydrogen needed. It, however, becomes increasingly clear that domestically produced green power volumes are grossly insufficient to cover all future domestic green energy demand, especially when energy demand for feedstock is included such as for bunker fuels and chemicals (e.g., kerosine, fertilizers). In the case of the Netherlands imports will therefore have to be an important additional future source of carbon-neutral hydrogen.

The Netherlands also has large opportunities for domestic ‘blue’ hydrogen production due to the large offshore CCS potential, existing offshore transport infrastructure and (gray) hydrogen production capacities, but so far, however, no explicit goals for this option have been mentioned in the Dutch (or for tat matter European) hydrogen strategies. Rather ‘green’ hydrogen seems to be the prime policy goal, even if it is often recognized that blue hydrogen will (have to) play an (at least) transitional role in developing a carbon neutral hydrogen system.

With regard to transport and storage of hydrogen, several comparative studies have been carried out assessing which means of transport and storage are the most suitable ones given the distances, volumes and end use purposes of future hydrogen uptake. In doing so, some aspects have received less attention so far. One example is the purity of the hydrogen along the chain: e.g. some types of transport, storage and end use are not compatible with hydrogen at the same (extremely high) purities along the entire value chain. Also the pros and cons of different carriers with regard to value chain consistency of pressure, storage and flexibility demands should be assessed more extensively for proper cost assessment of and decision-making on specific value chain compositions. Finally little attention has so far been given in hydrogen analyses to the possible impact on value chain costs if the hydrogen transport and/or storage demand of various end users is combined, especially if time profiles of demand of individual end users do differ.

2.1 Aim of the report

In this report the main focus will be on the cost assessment and NPV break-even values of the entire hydrogen value chain by analyzing five specific hydrogen end use categories individually and combined. The generic definition of a value chain used in this study is the range of activities that brings a product from its source to an end-use, whereby value is added during every activity distinguished: production/conversion, transport, storage, and implementation. Our definition of value chain or levelized costs therefore covers all value chain components. In doing so it remains essential to realize that towards energy value can essentially only be created by: covering distance; conversion to a different carrier; and bridging different time profiles between supply and demand e.g. via storage or enhancing flexibility.

In most of the literature on hydrogen economics costs are assessed per value chain component without due recognition to how such costs may be affected by the conditions of the rest of the value chain, and the transport and storage part in particular. The logic of this approach is that in actual practice most investors in the hydrogen economy focus their investment on one value chain component only, e.g. just hydrogen production, or hydrogen transport, or storage, or some specific implementation. In fact investment often then again is only focused on a specific part of that value chain component only, e.g. just the production of electrolysers (or parts of them) or the construction of fuelling tanks, etc. In other words, in practice investment is just typically organized to cover small value chain elements only, facing the issue if positive NPVs can be realised assuming the rest of the value chain works out well. However, for a virtually new energy system such as the hydrogen economy the latter assumption cannot always be taken for granted. The NPV for just one element may look fine, but may fall apart if one would include the other elements of the overall value chain into the picture, or vice versa. That is why we will focus on the costs of the entire value chain rather than on the NPV of just components of that chain.

That is also why including the complete concrete value chains conditions including transport and designated end-uses into the analyses, can put the assessment of the cost effectiveness of various investment options in the right overall socio-economic perspective. In doing so one also will have to consider: the end-use conditions, expected volumes and scale of transport and storage, demand profiles, location-specific circumstances with respect to grids and storage options, related hydrogen quality requirements, or options to smartly combine end users. That way one creates a more comprehensive and realistic economic and societal perspective on the future feasibility of hydrogen. This is important not only to be able to make the right choices in policy decision making towards enhancing the introduction of hydrogen, but also in assessing the feasibility and risks of private investment in elements of the future hydrogen value chain.

Hence, the innovative character of this report is in the systematic value chain component-based cost comparison of a range of five new hydrogen-based complete value chains generating information on the costs and break-even NPVs that apply to such complete value chains. To the best of our knowledge, a comparable systematic investigation of various hydrogen potential value chain costs - also explicitly including the choice between 'blue' and 'green', the role of transport, gas quality issues, the impact of combined end uses, and the option of imports - has not been carried out before, in any case in the context of the Netherlands energy system.

The research activities can be distinguished in:

- Examining for the key parts of the value chain (production, conversion, transport, storage, various applications) the costs and the main other determinants for an acceptable business case.
- Identifying what difference it makes whether the hydrogen is produced domestically or imported (from regions outside Europe).
- Analysing the complementary and conflicting aspects of various hydrogen-based value chains.

In doing so, the focus will be on: large-scale applications in industrial feedstock for fertilizer and E-fuels, high-temperature heating, hydrogen refuelling stations for mobility, and heating for the built environment.

The value chain analysis is preceded by an extensive literature overview (see D7A.1 'Hydrogen Value Chain literature review') of the existing techno-economic knowledge on hydrogen value chains and their components. Especially the most recent developments in these value chain elements have been covered to provide a starting point for the subsequent analysis.

2.2 Approach

The value chains' cost-effectiveness analysis will be carried out with the help of a so-called Value Chain Model (VCM). In order to be able to determine the cost optimisation aimed for, this model specifies the required capacity, investment levels, and hydrogen volumes for each element of the value chain considered. For this purpose, a calculation mode has been developed to be able to better analyse various pathways and parameter sensitivities. In modelling value chains, the volumes and costs of hydrogen in the various stages of the value chain will be identified to also provide detailed insight in the economic and technical implications of introducing specific value chain components. The latter can typically be of use for: spatial planning, capacity planning, and feasibility studies regarding hydrogen value chain elements.

3. Hydrogen value chain analysis

3.1 Market dynamics

Currently hydrogen is primary used as feedstock in the chemical and oil industry, e.g., in fertilizer, methanol and refineries. Hydrogen may, however, also be an attractive decarbonization option for many other use sectors that currently use fossil oil and gas. The decarbonisation of these sectors via hydrogen – or hydrogen-based carriers - will likely generate next new dynamics in existing and new energy markets.

Substantial new hydrogen demand will require new supply capacity and supply modes, but different modes will face different unit costs. Such costs will not only depend on the technology chosen and intermittency of production methods, but will also vary with specific quality and infrastructure requirements for the applications and with the availability and costs of options to meet all these requirements including flexibility options.

Eventually various end users are likely to use carbon neutral hydrogen, but in different shapes ranging from pure hydrogen in gaseous form or liquified and with different purity levels to derived (syn)gases and liquids such as ammonia and methanol. All energy carriers will have their own marketplace, but due to conversion options these markets will be coupled and interactive, which may complicate modelling their market behaviour. Because all these markets also share their dependence on the availability of transport and storage options, this may further complicate modeling their functioning.

In appendix E 'Market Dynamics' it is analyzed what issues can form an obstacle for the emergence and development of hydrogen-based markets, and suggests ways forward (see Figure 27).

The first issue addressed is to bring together suppliers and consumers at an immature market place, because suppliers, consumers and infrastructure operators will have different time scales on which they can act and their decisions influence each other directly. The actual information on supply and demand are very uncertain in the beginning and therefore there is spoken of and chicken-egg problem. Therefore, a clear governance structure is required that facilitates mutual commitment between producers, consumers, transport and storage service providers to align their timing towards the development of a fully functioning market.

The second issue is how hydrogen carriers are distributed amongst sectors and based on what criteria this is determined. Sectors that are willing to pay a high price for the hydrogen does not necessarily lead to the most effective emission reductions per unit of energy from a holistic view on decarbonization options. Especially as long as the available supply of renewable molecules remains limited, governmental interference is required in the emerging hydrogen market to reach the largest environmental impact in the short and/or long term, for each kilogram of hydrogen used.

The third issue are the uncertainty in four that are related to infrastructure development on a system level: the molecule of choice (e.g. hydrogen, ammonia, methanol, syngas) for the carrier and/or traded commodity function, decisions about transport modalities, how is dealt with storage and flexibility over time and the degree in which private companies or industrial clusters decide to be self-sufficient. A start with relatively low risks, is to facilitate the development of local hydrogen markets with infrastructure for hydrogen (carriers) at locations that are the most promising.

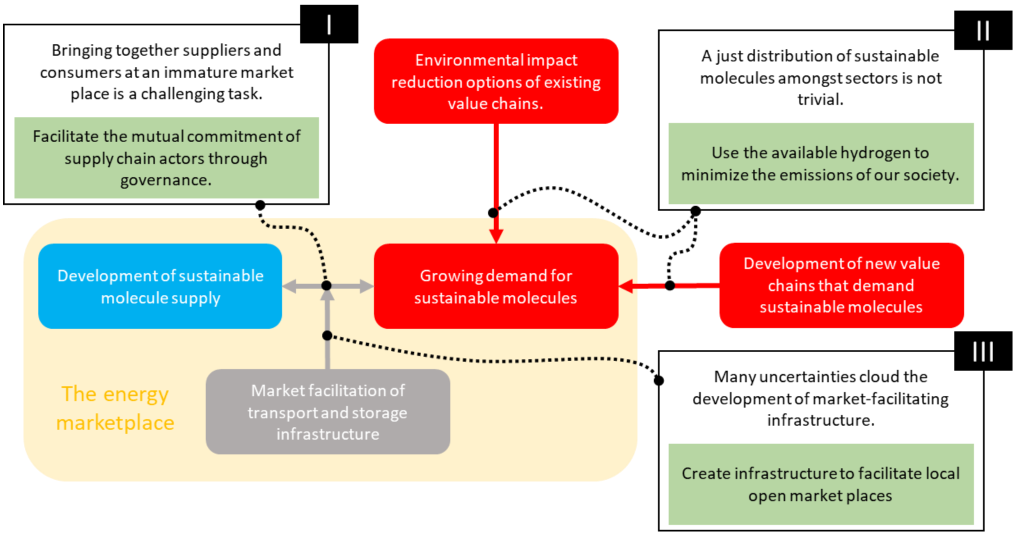


Figure 27 – Schematic summary of the findings in the hydrogen market dynamic analysis (Appendix E), including the three derived issues and solutions (I, II and III)

The framework, issues and solutions retrieved from the market dynamics analysis can be used to see the value chains and the computed outcomes in the light of the (new) energy market places that are expected to evolve. Although the framework and its analysis focusses on the role of hydrogen (related) molecules and therefore limits the complexity of the full energy sector, understanding this particular part contributes to the understanding of the system as a whole.

3.2 Model

To analyse the various future value chains that have been distinguished in this report, a model has been designed using a variety of cost-functions and employing a broad database of technical and financial parameters for validation. Because the combinations of value chain elements differ between the value chains considered, a modular approach has been used to simulate the different sequences and combinations per value chain. These modules, each representing a specific chain element, are broadly classified in hydrogen: production, transport, storage, and carrier-conversion. The exact calculations per chain element and its assumptions are explained in greater detail in Appendix A.

The model can be characterised as a quantitative calculation model, i.e. calculating capital and operational costs of value chain elements via a bottom-up approach. It requires hydrogen or hydrogen carrier volumes as input for determining the costs per chain element to: produce, transport, store, or convert such volume. These volumes will be derived from market demand prognoses. So, the model does not predict or calculates future demand volumes, but instead uses such data to estimate the costs of different value chains for specific end-uses.

The costs resulted from the model are represented as levelized hydrogen (or ammonia, or methanol in those specific markets) delivery costs at the end user. The levelized costs include the investments, fixed and variable operational costs, discounted over time by the WACC, covering both the costs of equity and the expected rate of returns given the projected project time. In other words, the levelized costs can be used to identify the average net present costs of a product (e.g. an unit of energy, fuel or feedstock in this study) that are required for a positive investment decision.

Besides the comparison between different types of hydrogen value chains, the supply costs are compared with (equally sustainable) alternatives, in order to gain insights in the competitiveness of the analysed chains for specific type of end uses. In Appendix C example NPV's are shown what could happen to the business cases if, due to uncertainties in the market or the availability of cheaper alternatives, higher or lower revenues are received than the levelized costs.

The specific assumptions related to individual end use sections are discussed in those specific sections. The general model assumptions are described below:

- The model assumes a fixed demand for every type of end use. The model does not include the impact of price elasticity and has not the purpose to do so. A general demand projection is used to indicate the expected costs to develop the value chain. For the ammonia and feedstock end uses, this demand is based on the size of one typical plant. For the other end uses, this is based on a projected demand of the sector and an amount of locations is used to represent the distributiveness and individual customer demand sizes of consumers in these type of end uses.
- The costs represented in the model are projections for 2030. The cost data is received from the 'HyDelta Database' provided by WP7B. A project lifetime of 20 years and WACC of 0.07 is used to calculate the levelized costs and Net Present Value (NPV).
- The prices of commodities used are considered being fixed in this study. A natural gas price of 25 €/MWh, electricity price of 60 €/MWh, a diesel price of 1.35 €/litre, a water price of 1.68 €/m^3, a CO_2 allowance price of 60 €/ton and a low temperature heat price of 0 €/MWh. As these prices are uncertain by developments in those markets, the impact of those prices on the total costs are assessed and if significant results are taken into account in the discussion of the outcomes.
  A heat price of 0 €/MWh is noticeable. This heat price is used for heat required for the Direct Air Capture (DAC) and LOHC reconversion. In case of the methanol chains including DAC, waste heat from the electrolyser can be used and the option of LOHC transport is perceived only applicable when waste heat is available locally, as otherwise 1) (in case when hydrogen or electricity is used) around 25% of the delivered energy content at the destination is required for reconversion which makes the chain 33% more expensive, or 2) natural gas has to be used to generate the heat which contradicts the purpose of using hydrogen.
- Repurposed natural gas pipelines are assumed to be available in order to calculate the pipeline transport costs.
  The location of storage is important to consider. As a calculation model is used, the location of the storage is determined by the set-up of the chains. The model includes variable production patterns (in the case of offshore wind) and consumption patterns (related to the end user). This fluctuating pattern remains in the chain until a storage is located, which balances the hourly variable input to a stable output flow. The storage represents the so-called 'decoupling points' in the supply chain: storage 1 in Figure 28 represents the decoupling of the supply driven variability, and storage 2 in Figure 28 represents the decoupling of the demand driven variability. In other words, the model takes the hourly flows and required flexibility of the chain elements into account for the pre-defined chains, but does not include a hourly flow and capacity optimization to determine the optimal capacity and operation planning.

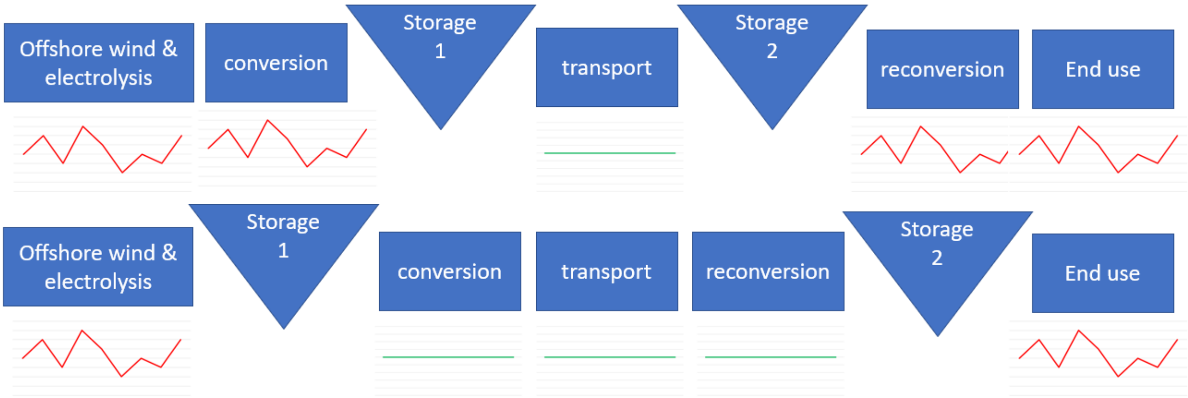


Figure 28 – Visual representation of the impact of the position of storage on the flow variability throughout the chain

- Individual end use cases are calculated. For the smaller end uses, large scale production and national pipeline transport are used. For the local transport, both options of an individual pipeline are shown, or an indicative costs of a local hydrogen grid based on the existing natural gas grid costs.

4. Hydrogen sources for a Dutch hydrogen economy

4.1 Green hydrogen production

Offshore wind capacity is expected to become the largest domestic source of renewable energy in the Netherlands to satisfy potential future green hydrogen demand (apart from imports). In the Value Chain Model (VCM) used in this study the windfarm capacity required to meet (part of the) hydrogen demand will be calculated on the basis of on the one hand the yearly national demand for green hydrogen, and the applicable wind profiles on the other hand. In the analysis, the green hydrogen production costs are derived of off-grid windfarms that are directly connected to the electrolysers. By combining the costs of a dedicated windfarm, cabling and electrolysers into one chain element, the levelized chain-based costs of hydrogen can be derived. This chain-based approach therefore implies that relatively high levels of initial capital expenses are required, but that by comparison the operational expenses during the course of the project will be lower. Because there is no need to buy electricity from the open power market in this setting, it also can avoid future power market uncertainties. However, because offshore wind energy production and especially electrolyser technology are still in the earlier stages of technological development and promises of the learning curve is large when production capacities would be widely deployed, the ranges of predicted costs of green hydrogen are still quite significant (see also Figure 29). In Figure 29 an overview of the most impactful uncertainty factors are given. The uncertainty ranges of the factors of the technological developments are based on the HyDelta supply chain technology database (low is no technical improvement, base is expected 2030 value, high is more technical improvement than expected) and presented cumulatively. For the WACC, an indicative range of 25% is taken, resulting in a low WACC of 5.25 and high WACC of 8.75. The uncertainty factor of windspeeds is based on windy and windless years.

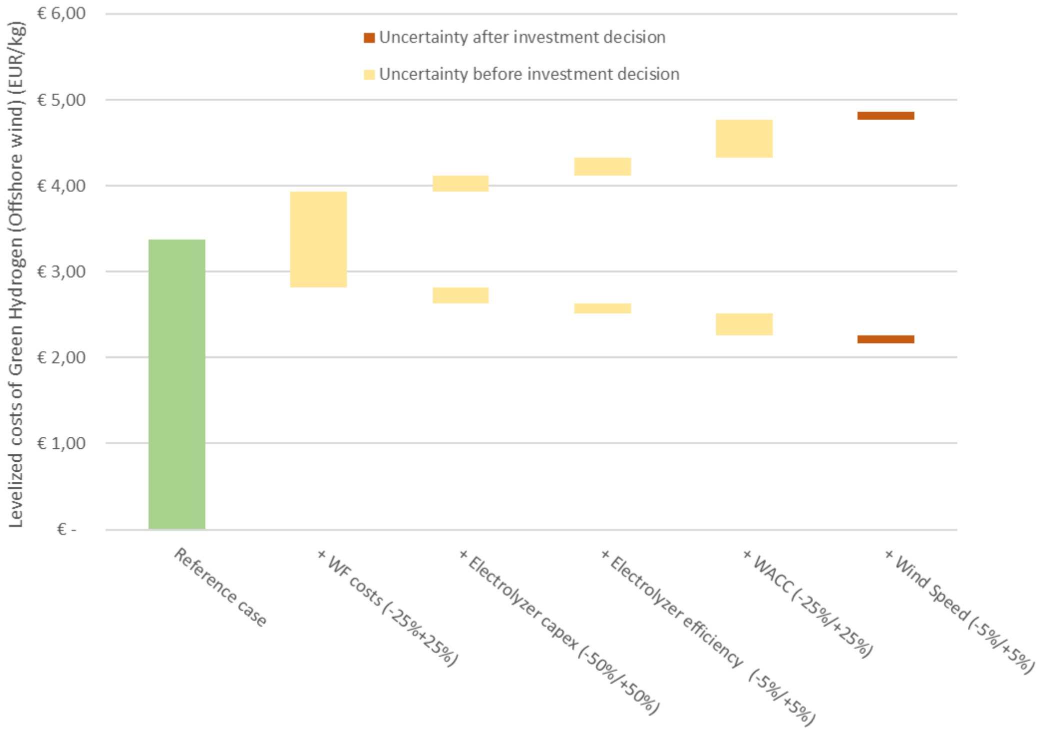


Figure 29 - Future cost of green hydrogen production via offshore wind (North Sea) in the Netherlands, 2030

Assumptions: Alkaline technology, CAPEX 450: EUR/kW, scaling factor: 0.9, annual OPEX: 2% of CAPEX, efficiency: 47.6 kWh/kg of hydrogen, stack lifetime: 60000 FLH, WACC: 7%, Dedicated Dutch offshore wind farm LCOE incl. 100km cabling: 60 EUR/MWh.

Electrolyser technology costs are projected to significantly decline in the coming decade due to upscaling and learning effects, and this also goes for offshore wind technology. However, there are still factors that may cause a surge of costs (materials or resources). Figure 29 shows that uncertainties about the costs of offshore wind capacities are responsible for a large share of the cost range of green hydrogen. Also, the financing costs represented by the WACC (Weighted Average Cost of Capital) seriously affect uncertainties around the business case of green hydrogen projects. Uncertainties about costs are not restricted to those that hold at the point of investment, there are also parameters affecting the business case of green hydrogen production once the project has started, like the wind speed over future year. In this case, where a dedicated off-grid offshore windfarm is connected to the electrolyser, the electricity costs are not subject to the market prices and therefore not a considerable factor of uncertainty.

The cost-price of hydrogen will also depend on the number of operating hours per annum of the electrolyser and therefore also on the capacity of the electrolyser relative to the capacity of the connected windfarm. If the electrolyser capacity is small relative to that of the connected windfarm the electrolyser will annually run a large number of full load hours so that the capex investment can be divided over a relatively large volume of hydrogen produced. De backdrop of such a case, however, is that there will be a relatively large number of moments that the excess of wind capacity needs to be curtailed (at least in the direct-connection approach). If instead the electrolyser capacity almost equals that of the windfarm, the number of full load hours will be less but also the need to curtail wind. To raise electrolyser efficiency, the capacity to handle a more fluctuating production pattern can be helpful, but the technical capabilities to cope with ramp-up/ramp-down rates may come at an additional cost (for more detailed information, see Appendix A).

4.2 Blue hydrogen production

Conventional hydrogen production is based primarily on the reforming of natural gas (CH4) to H2 and CO2 by Steam Methane Reforming (SMR). The CO2 is currently typically emitted directly into the atmosphere, which makes the hydrogen 'grey', but once the CO2 is captured and permanently stored the hydrogen is classified as low-carbon or 'blue'. During the latter process there is still some emission of CO2, dependent on what places the CO2 is captured during the process. If CO2 is only separated from the high-pressure synthesis gas stream up to around 60% of the total emissions can be reduced. If CO2 can also be captured from the diluted furnace flue gas, around 90% of total emissions can be captured. However, capturing CO2 by this second step is significantly more expensive than the first step [8]. Moreover, as methane (natural gas) is still used as a resource there are still some minor emissions in the upstream process. In general, blue hydrogen is considered as a temporary pathway towards decreasing CO2 emissions in the energy system.

In this report Auto Thermal Reforming (ATR) is considered to be the most suitable blue hydrogen production technology for new production capacities being established. This is because it has a high capture rate (94%) at lower costs than SMR [8] and can be operated with (green) electricity input. ATR is not on the same high Technical Readiness Level (TRL) as SMR is, but current projects are developing to install facilities on the large scale [13].

Cost of hydrogen via blue hydrogen production were projected lower than those of green hydrogen before the autumn of 2021, but strongly depend on the used natural gas price, as that is the main resource. There is a significantly lower dependency on electricity prices, as electricity is mostly only used to maintain the operational pressure and temperature. To maintain a low carbon emission profile the used electricity needs, however, to be free of CO2 emissions as well.

As long as there is no national CO2 network, the production of 'blue' hydrogen is rather location specific due to the need to connect with a usually large-scale storage facility for CO2. In the Dutch energy system, offshore natural gas fields are the most suitable potential locations for long-term storage and therefore blue hydrogen production facilities are most logically located close to shore.

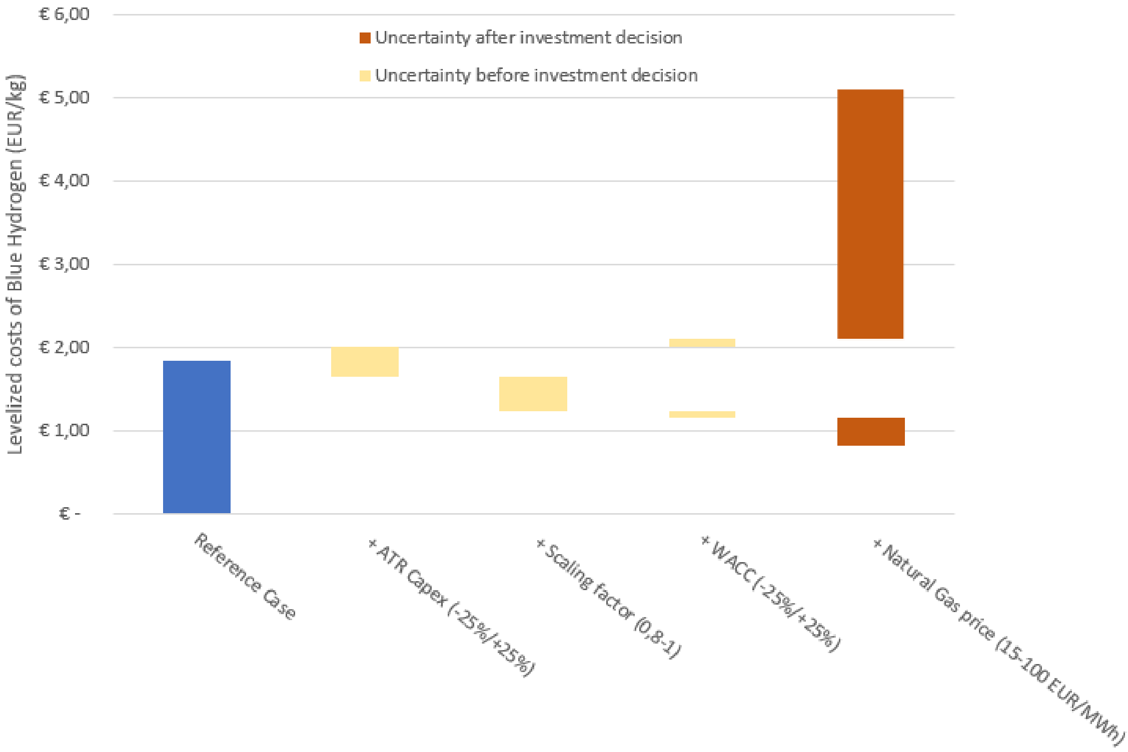


Figure 30 - Future cost of blue hydrogen production in the Netherlands, 2030.

Assumptions: ATR+CCS technology, CAPEX 1.3 MEUR/MW, annual OPEX: 4% of CAPEX, capacity factor: 92%, base scaling factor: 1, Natural gas feed 1.2 MJ NG/MJ H2 LHV, Power consumption: 0.014 kWh/MJ H2 LHV, base natural gas price: 25 EUR/MWh, electricity price: 60 EUR/MWh.

The cost of blue hydrogen production via ATR is not yet at the level of industrial production scale, unlike costs based on the currently regular Steam Methane Reforming technology to producing grey hydrogen from natural gas. Therefore uncertainty ranges of ATR technology costs are considered for both its Capex and its scaling factor, as cost implications of both are not proven yet in practice. From the financing costs perspective the variation in WACC also has been considered. The effects of all these uncertainty ranges are presented in Figure 30. The uncertainty ranges of the factors of the technological developments are based on the HyDelta supply chain technology database (low is no technical improvement, base is expected 2030 value, high is more technical improvement than expected). For the WACC, an indicative range of 25% is taken, resulting in a low WACC of 5.25 and high WACC of 8.75. A natural gas price of 15 €/MWh is perceived as low and 100 €/MWh as high. The sensitivities show that still the most significant parameter in the sensitivity analysis of 'blue' hydrogen production costs is the natural gas price which may remain subject to high uncertainty in the future. Providing tools just to reduce the price risk of this parameter could already seriously help in developing more robust 'blue' hydrogen supply profiles.

4.3 Import of hydrogen (carriers)

Import costs are derived from the HyDelta deliverable 7B 'Comparison of different carrier import chains'. The cost represent the total costs of supplying hydrogen via a specific location and carrier to the harbour of Rotterdam. The pipeline option is only perceived as applicable for locations that are located relatively closely to the Netherlands.

Table 1 - Import costs derived from HyDelta workpackage 7B. In our reference case the Average is used.

Name	Unit	Australia	Argentina	Canada	Morocco	Iceland	Saudi Arabia	Oman	United Kingdom	Average
Specific H2 supply costs via NH3	*€/t H2*	4267	4256	5080	4507	6919	5371	4472	4037	4864
Specific H2 supply costs via LH2		6557	5968	6230	5613	7797	7107	7899	7212	6798
Specific H2 supply costs via LOHC		5818	5839	8275	4930	11767	4766	6452	7654	6938
Specific H2 supply costs via MeOH		4542	4623	5560	4801	7721	5533	5763	6013	5570
Specific H2 supply costs via Pipeline (low)					2530	4723			3401	3551
Specific H2 supply costs via Pipeline (high)					4470	6663			5341	5491
Specific NH3 supply costs	*€/t NH3*	582	581	704	618	975	743	789	809	725
Specific MeOH supply costs	*€/t MeOH*	621	633	765	658	1070	760	792	828	766

5. Hydrogen Value chains for specific use-cases

Hydrogen is applicable in a vast number of end-uses, which makes it an interesting energy carrier for the future. To develop towards a system where industries or utilities can use hydrogen for their processes wherever it is desired, sufficient production, transport and storage facilities need to be installed to be able to meet the hydrogen demand at the right place, volume and time. An indication of how these hydrogen value chains can take form in the future is derived for different end-uses:

- Industrial feedstock
- Industrial Heating
- Mobility
- Built Environment

By identifying the costs, volumes and technological challenges necessary to make hydrogen available for these end-uses we contribute to a better-informed decision making process on designing future hydrogen value chains.

The various hydrogen end-use sectors differ significantly on their characteristics, among which their demand volume at end-use locations. Using carbon-neutral hydrogen directly at end-use-cases where significant CO_2 emission can effectively be avoided, like industrial feedstock or heating, can stimulate scaling advantages and the roll-out of hydrogen production and infrastructure. Still, within the value chains for large-scale end-uses there are several variations in design, as will be elaborated in the respective sections below.

For value chains with smaller demand volumes it seems reasonable to assume that they can use established hydrogen infrastructure (instead of assuming that separate infrastructure and production assets need to be installed for each (small) end-use location). If a value chain is designed to use such 'shared' infrastructure assets, this requires a distinction for some value chain elements (assets) between a 'national (or regional) scale' (shared) and a 'local scale' (dedicated). This implies for the analysis that costs for industrial feedstock and heating (typically 'national scale') are based on dedicated infrastructure, i.e. just for their respective end-use. For mobility and built environment ('local scale'), it, instead, means that they have the option to use a backbone, large-scale green hydrogen supplies, or import facility, while these options are not solely dedicated for their end-uses.

The value in this dual approach is to show the unlocking potential for smaller end-uses of sharing some assets, while the feasibility of dedicated value chains can also be analysed, namely for the larger-scale industrial end-uses.

The demand volume levels used in the techno-economic analysis in determining end-use costs are estimated on the basis of current demand volumes together with existing projections. It should be mentioned though that future demand volumes are highly uncertain both per sector and at the national scale. In an earlier literature review multiple predictions of national hydrogen usage have been assembled (Figure 31). Demand projections per will be elaborated below.

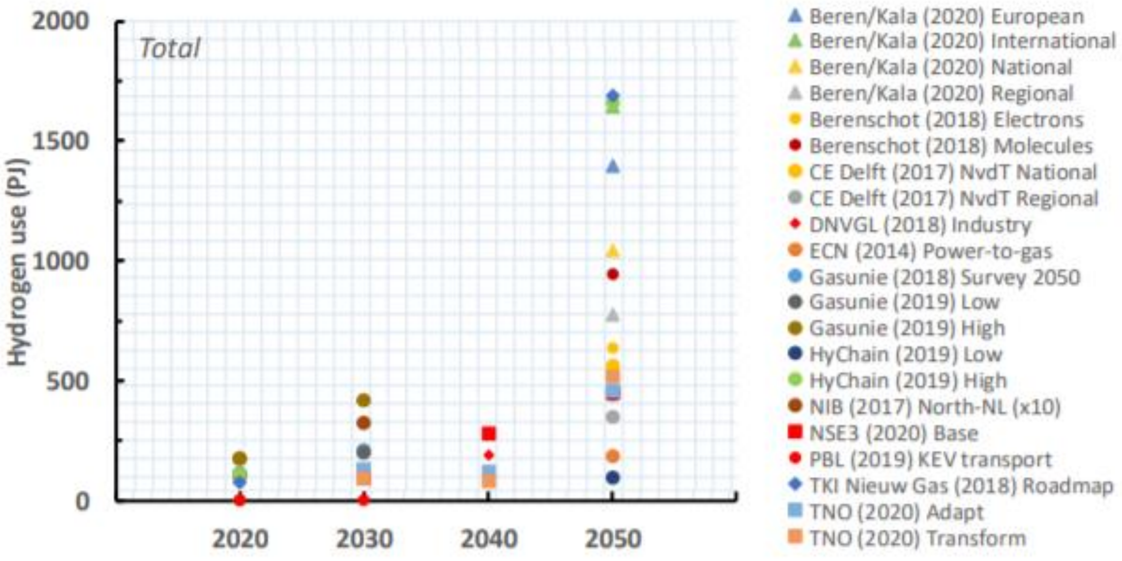


Figure 31 - Demand estimates of future hydrogen use in the Netherlands [14].

To put these volumes in perspective, the existing Dutch (fossil) hydrogen production is estimated around 100-110 PJ pure hydrogen per year [15], of which the production represents around 10% of the Dutch natural gas consumption [16]. Due to the potential replacement of traditional energy carriers by pure clean hydrogen, such as in heavy duty transport and for production of synthetic fuels, the demand for clean hydrogen might rise in the future, according to some of the scenario studies overviewed in Figure 31. If the demand for clean hydrogen will increase rapidly, a lot of offshore wind will be required to produce those hydrogen domestically via the green pathway. Table 2 gives an indication of what capacities of domestic offshore wind are required to produce the volumes of clean hydrogen. Those numbers can be assessed in the perspective of the 38 to 72 GW of offshore wind that are projected by the government to be required in 2050 [17], which is projected for both electrons and molecules instead of hydrogen only. Hence, if the demand for hydrogen will rise significantly, it seems unsurmountable that multiple types of sources (e.g. green, blue and/or import) of clean hydrogen are required. In the next section, the potential sources and chains are discussed more thoroughly for every type of end user.

Table 2 – Indicative table of the required offshore wind capacities to produce the hydrogen demand volumes (assumptions: 47.6 kWh/kg of H2, 15MW wind turbines with a load factor of 0.55 and spatial use of 2.7 km²)

PJ (H2)	kT (H2)	GW (wind)	Share Dutch North Sea		PJ (H2)	kT (H2)	GW (wind)	Share Dutch North Sea
100	833	8	3%		900	7501	74	24%
200	1667	16	5%		1000	8334	82	26%
300	2500	25	8%		1100	9168	90	29%
400	3334	33	10%		1200	10001	98	31%
500	4167	41	13%		1300	10834	106	34%
600	5001	49	16%		1400	11668	115	37%
700	5834	57	18%		1500	12501	123	39%

800	6667	65	21%		1600	13335	131	42%

4.1 Industrial feedstock

4.1.1 Industrial feedstock: Fertilizer industry

End-use description

Dutch fertilizer production facilities are concentrated in two industrial clusters located in Zeeland and Limburg. By their large, centralized demand for natural gas acting both as a resource and energy source (heat), these regions are interesting potential demand hubs to scale up hydrogen technology. The chemical clusters in the regions use hydrogen to produce ammonia, which is used as input for various types of fertilizer, but that is also transported from these clusters to other, smaller, chemical industries [18]. Domestic transport of ammonia occurs currently via rail or ship.

Making the ammonia production process more sustainable will have a direct impact on the production process because its carbon emissions are directly related to the feedstock and energy uptake. Except from using carbon neutral hydrogen there are just a few alternatives to decarbonise, to the extent that the feedstock requires molecular building blocks (H_2 and N_2) to produce NH_3. Using green gas instead of natural gas is considered carbon neutral under the right conditions, but requires immense green gas supplies to feed both the energy requirements and the molecular usage of the process. Other alternatives, like electro-chemical ammonia synthesis still has a low Technical Readiness Level (TRL) [19].

Replacing the input of natural gas directly by green hydrogen avoids the step of natural gas reforming and its emissions, but also excludes the production of CO_2 to be used further downstream in some of the fertilizer production processes (e.g., UREA) (See appendix D, Figure 103). Realizing a sustainable, alternative CO_2 source for these specific products is outside the scope of this research, as it requires specific industrial process analyses. When green hydrogen is used as the input for the industrial site, (energy consuming) process steps such as NG-reforming or CO_2 removal can be avoided if hydrogen is directly fed into the NH_3 synthesis process. This process, however, still requires power input to maintain the required temperature and pressure for the NH_3 synthesis (Haber-Bosch process).

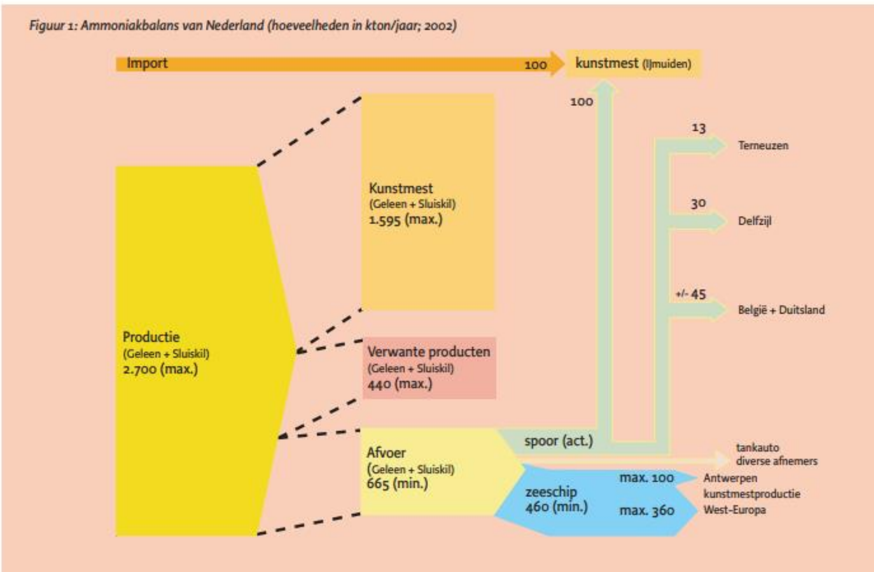


Figure 32 - Indicational Ammonia supply and demand in the Netherlands in 2002 [18]. The fertilizer plant in Ijmuiden has been decommissioned in 2010.

Alternatively, the CO_2 emission which is normally emitted at the fertilizer production site can be captured earlier in the value chain, by producing blue hydrogen at a suiting location and transporting the H_2 to the fertilizer plant site. Lastly, the NH_3 conversion process can also take place earlier in the value chain, e.g., internationally as a carrier or directly after the electrolysis process, which provides the end-use location with green NH_3 as a resource. In this section, we analyse the carbon neutral alternatives for NH_3 feedstock.

Demand volume and pattern

The world-wide fertilizer market has grown massively in the past century, but stabilized somewhat in the last decades [20] [21]. It is expected that future use of fertilizer will not grow that immensely in the coming decade, because of the increasing restrictions on the use of nitrogen in agriculture due to its negative impact on biodiversity and soil fertility. In our analysis, we assume a similar production volume of NH_3 in the considered domestic fertilizer production facilities.

Table 3 - End-use characteristics for fertilizer production [3]

End-use	NH3 production volume (kton/year)	NH3 feedstock volume input (kton)	Required Hydrogen eq. (kton)	Operation hours (hours)	Demand pattern
YARA Sluiskil	1662	1047	178	8000	constant
OCI Nitrogen	1081	511	87	8000	constant

Value chain description

Concerning the option to use clean hydrogen as an input-resource for fertilizer and the corresponding market characteristics, some potential value chains for this end-use have been designed. Compared to importing green NH3, the data on a national hydrogen transport system and on domestic hydrogen production without a hydrogen transport infrastructure give insight in what is the most cost-effective approach to realize new value chains.

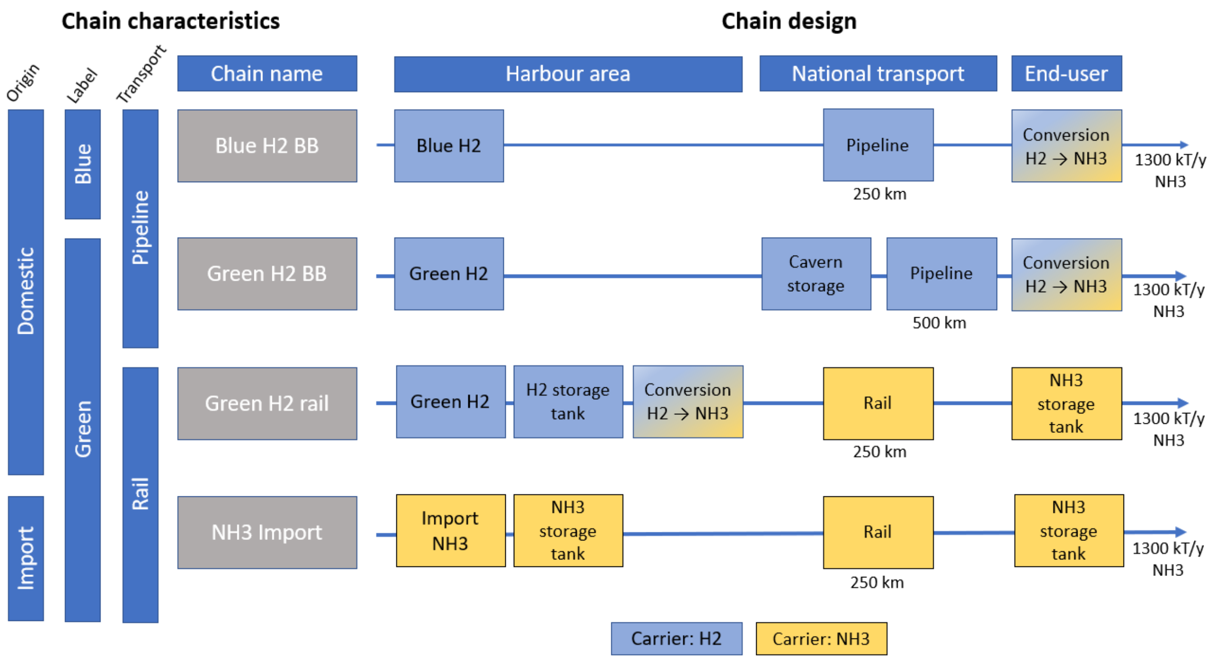


Figure 33 – Overview of ammonia chain compositions considered.

Note: the difference in distance is due to the required transportation from the salt cavern location to Limburg, while the other chains consider transport from Rotterdam area to Limburg. See Appendix D for a geographical representation of the chains.

Results

Cost decompositions of the various value chains for industrial feedstock reveal a couple of insights.

The cost of ammonia is mainly determined by the production costs of hydrogen. As the production costs of hydrogen mainly depend on the costs of its conversion technology and of its (renewable) energy source, these are also the main factors affecting the costs of NH_3 supply for industrial feedstock purposes. When the costs of the energy source get lower, the cost of NH_3 will decrease rapidly as well. Therefore, in the case if a natural gas price of 25 €/MWh is considered, the low cost of blue hydrogen production returns the lowest value chain costs in total. This characteristic is comparable to what can be observed in the traditional production process of NH_3 and fertilizer, where the natural gas price is the main cost component for NH_3 production. The range of uncertainty of the levelized costs of ammonia at the end-use location is depicted in Figure 34 (greater detail in Appendix D). In this figure the parameters with the most cost impact are (simultaneously) varied showing that there is still quite some uncertainty towards future cost developments. For import based value chains, the cost variation strongly depends on from which country the imports take place, whereas domestic green and blue hydrogen production costs strongly depend on windfarm-Capex and the natural gas price, respectively.

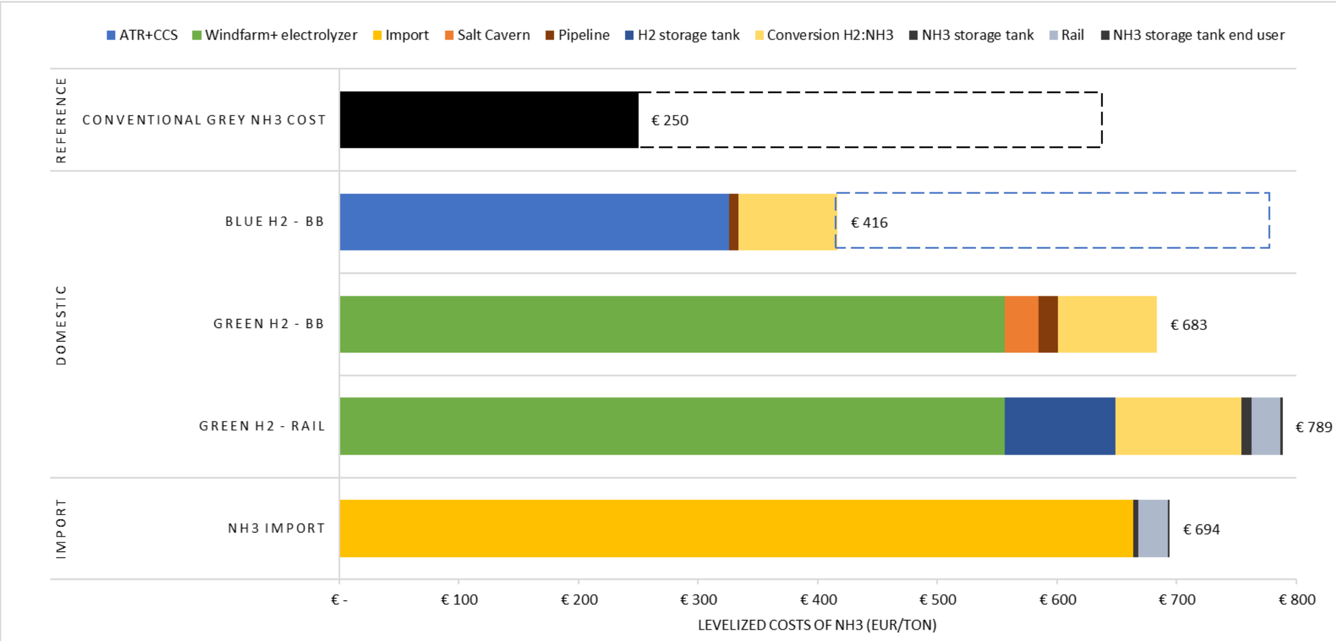


Figure 34 - Results of 2030 cost decompositions for ammonia value chains.

Main assumptions: natural gas price: 25 EUR/MWh (dotted bars show the impact of a natural gas price of 75 EUR/MWh: grey reference LCOA increases to 650 EUR/ton and blue H2 BB to 770 EUR/ton), electricity grid price: 60 EUR/MWh, LCOE of connected domestic offshore windfarm to electrolyser: 60 EUR/MWh, green NH3 import costs include the average import costs by ship from Canada, Australia and Morocco, for the Green H2 Rail chain results of flexible conversion operation mode are presented, which partially follows the offshore wind pattern.

The impact of access to large-scale hydrogen storage for green hydrogen production can be significant. Due to the seasonal wind profile the hydrogen supply fluctuates over the course of a year while the production of NH_3 is aimed to be constant as much as possible to maintain the required high temperature and pressure in the production process. When local hydrogen storage is required to sustain such a constant NH_3 production process but is at the same time not easy to find, the cost of storage (H_2 buffer) may increase to undue proportions (theoretically over 6 weeks of storage are needed to maintain production). This can be avoided if one has access to (large-scale) hydrogen storage in salt-caverns via the hydrogen backbone, that can economically store hydrogen at the scale required. As blue hydrogen is considered to have a constant production profile, it is assumed that storage fees for this type of hydrogen are negligible.

Alternatively, the NH_3 conversion plant can be designed such that it can cope with seasonally fluctuating production volumes by directly following the production pattern of the electrolyser (and therefore windfarm). When one assumes that one can operate multiple NH_3 conversion trains, and optimize process operations with the most effective H_2 - NH_3 production ratio, less local storage will be necessary. If under such conditions only ½-week of hydrogen storage would be required and the remaining (mainly seasonal) storage will be done in ammonia tanks, this would reduce costs significantly. For more detailed technical and economic implications of a flexible ammonia train set up, further research might be required.

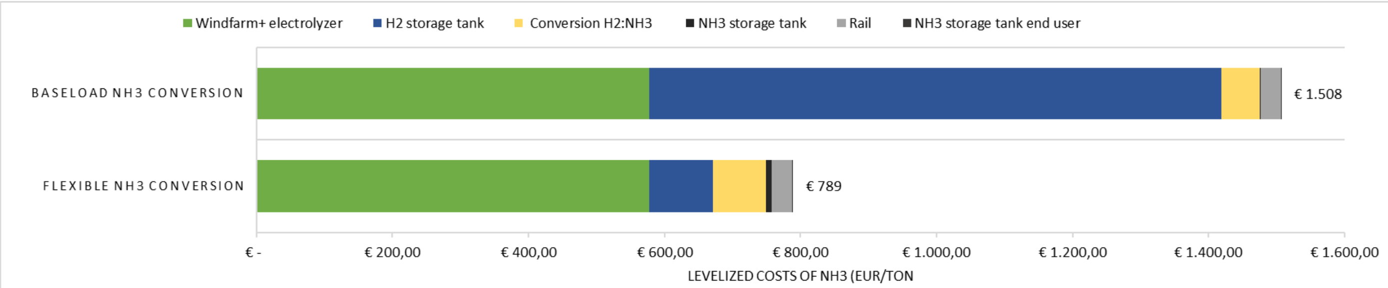


Figure 35 - NH_3 levelized costs decomposition for the 'Green H2 Rail' chain, considering baseload and flexible operation of the conversion stage.

Assumptions: Baseload: the NH_3 synthesis process needs a constant H2 production flow (also when there is less wind in the year). Flexible: the synthesis process is designed to be able to cope with seasonality, and requires only 1 week storage.

For green NH_3 value chains, large-scale imports of NH_3 may be able to compete with the domestic production of green NH_3. Because imports of NH3 does not require local H_2 storage or domestic transport, and because NH_3 instead can usually relatively easily be stored locally, imports of NH3 can avoid quite some cost in the value chain. Only when there is the availability of a hydrogen backbone, the green hydrogen can cost-effectively be transported and stored domestically at large volumes, bringing down value chain cost of green NH_3 production. In that case domestic green NH_3 production is likely to be competitive with import of NH_3.

To satisfy NH_3 demand for inland locations, rail transport is required to transport large volumes of NH_3 to the required destinations. Cost-wise this transport does not represent the largest share of costs for NH_3 supply, but it may have a significant impact on rail capacity, safety and risks. In fact, when the NH_3 end-use location is inaccessible via shipping, costs of hydrogen supplied via pipelines is more cost efficient for the assessed volumes. However, the difference in cost are relatively small compared to the production costs of the chains. It is expected that other aspects of rail transport, such as capacity, acceptance and/or safety issues may shift the preference to a backbone-supplied value chain. On the other hand, for imported ammonia in terms of costs and efficiency it makes no sense to reconvert the imported ammonia to hydrogen, transport the hydrogen via pipelines and convert the hydrogen, again, to ammonia. Hence, for imported ammonia rail transport might be a preferable option, or – although not considered by this report – the option of ammonia transport by pipelines could be explored if imported volumes turn out to be significant.

To conclude, as long as the natural gas prices remain under 50 €/MWh, blue hydrogen is a cost-attractive source of hydrogen for NH_3 in industrial feedstock because of two main reasons. First, the (still) relatively low cost of blue hydrogen production makes it easier to close the currently existing gap between the existing market price for NH_3 and its carbon-neutral alternative. Second, it can also maintain a constant level of production thus avoiding large hydrogen storage requirements. 'Import' and 'Green NH_3 with a backbone' therefore follow as sensible carbon neutral alternatives of NH_3 value chains. When there is no backbone available, domestic production of NH_3 is only possible when: NH_3 synthesis takes place close to the source of hydrogen; the synthesis process can be designed to cope with fluctuating green hydrogen production; and over one hundred rail tank cars daily transporting NH_3 is a feasible option. If not, the latter transport problem can partially be avoided when there is access to river transport so that the required volumes can be transported via daily smaller LPG tanks, or weekly medium scale tankers.

Competitiveness

The costs of carbon neutral NH_3 production via carbon neutral H_2 value chains are still high compared to the fossil alternative (red cross on the left of Figure 36). The cost difference can be covered either by making the fossil alternative more expensive (e.g., via CO_2 taxation), or by finding ways to reduce costs for the carbon neutral alternative (e.g. via learning curve effects, subsidies, or up scaling).

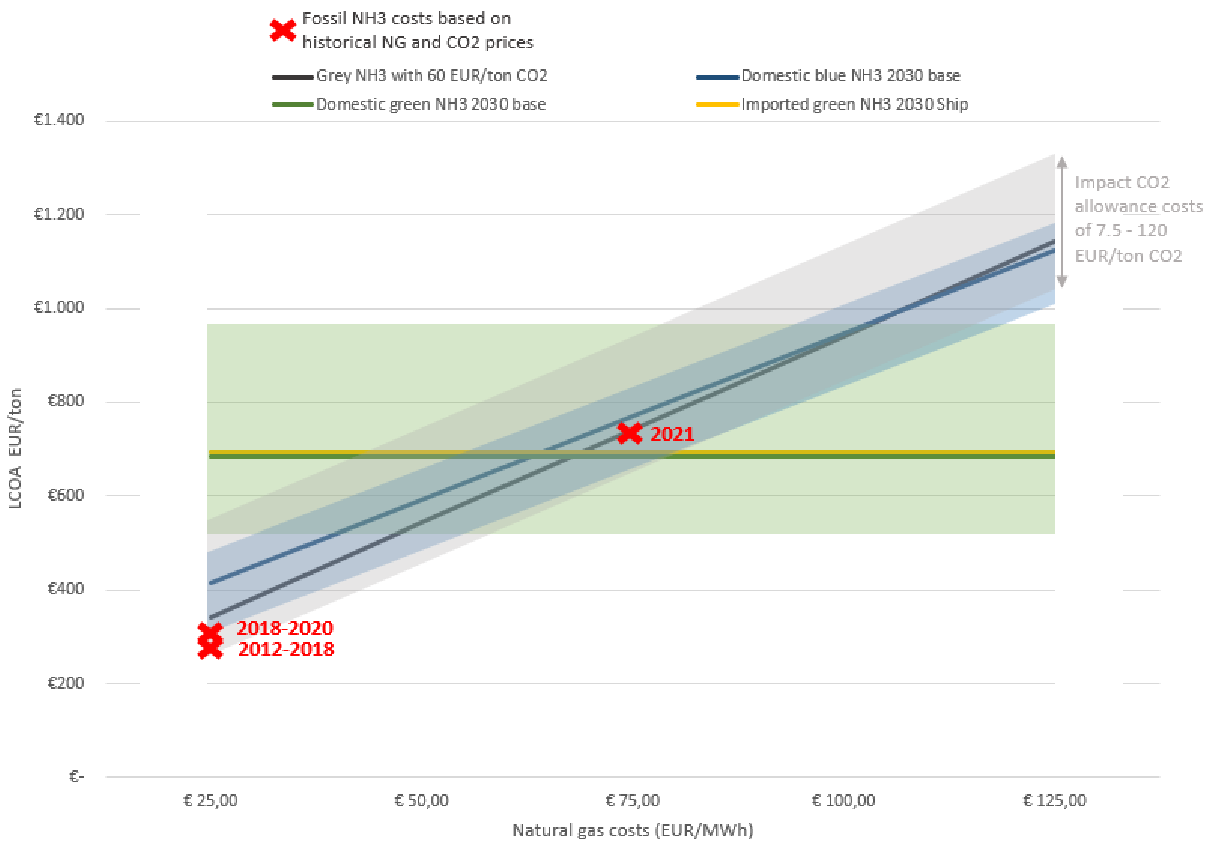


Figure 36 - Visualization of the impact of the natural gas and CO2 prices on the reference price of NH_3 and on carbon-neutral NH_3 produced from blue hydrogen. The resp. green and blue areas mark the uncertainty cost ranges of the green and blue hydrogen production cost developments until 2030; the grey area represents the uncertainty in fossil NH3 costs based on the CO2 allowance price (7.5 EUR/ton low, 120 EUR/ton high). The levelized costs presented include transport to end-use site. The reference costs of NH3 are calculated using 1.75-ton CO_2/ton NH_3 [1], the natural gas and CO_2 prices of the past decade have been, resp. some 25 EU/MWh and 5-15 EU/ton CO_2 [2] [3] [4]. However, in 2021 a sharp increase of both European natural gas and carbon emission allowance prices is seen (since the autumn of 2021 the natural gas price rose to 80-180 EUR/MWh and the allowance price to 60-90 EUR/ton CO_2).

A high price of natural gas (>75 EU/MWh) makes green NH_3 (import or domestic) competitive with (the reference case of) grey NH_3. In that respect, the developments in the European gas market are of great impact on the competitiveness of green hydrogen if they turn out to be permanent. Moreover, the rising CO_2 allowance prices impact the competitiveness as well, although less strongly than the natural gas price. Since the cost price of blue hydrogen also depends on natural gas prices, green NH_3 can already compete with blue NH3 at natural gas prices of around 60 €/MWh. As far as green NH3 cost reduction options is considered, the results suggest that incentives reducing the costs of RES will be among the most effective ways to lower levelized costs of green NH_3..

4.1.2 Industrial Feedstock: Methanol production for E-Fuels

Another end-use currently considered that would possibly need significant volumes of carbon neutral hydrogen in the (near) future, is (green) methanol for E-fuels. Also fuels based on green carbon combined with green hydrogen may be used in the future in hard-to-abate industrial and transport activities. While still directly emitting CO_2, the use of the latter green fuel alternatives for fossil-based fuels can still be a major mitigation step forward.

Demand volumes

The used volume of transport fuels in the Netherlands is quite significant, mainly due to the presence of large international logistical hubs such as Amsterdam Schiphol Airport, the Port of Rotterdam and other seaports. Currently, about 1200 PJ/y is used in national and international transport fuels, of which about 800 PJ/y is used for international transport. It is projected that the latter can grow to 960 PJ [22]. Covering all this demand by domestic production is impossible to achieve, and therefore import of energy will keep being necessary. In this study we analyse the case of a methanol demand location, with slightly smaller demand than a typical traditional methanol plant (1-1.7Mt/y [23]), by comparing different potential value chains for this volume. In the Netherlands, most of the refineries are located in the Rotterdam harbour area, therefore, this location is used for the analysis.

Table 4 – End-use characteristics for E-fuel production

End-use	MeOH Demand volume (PJ/year)	Required Hydrogen eq. (PJ/y)	Required Hydrogen (kton/y)	Operation hours (hours)	Purity input.	Demand pattern
E-fuel	100	120	900	8000	98%	constant

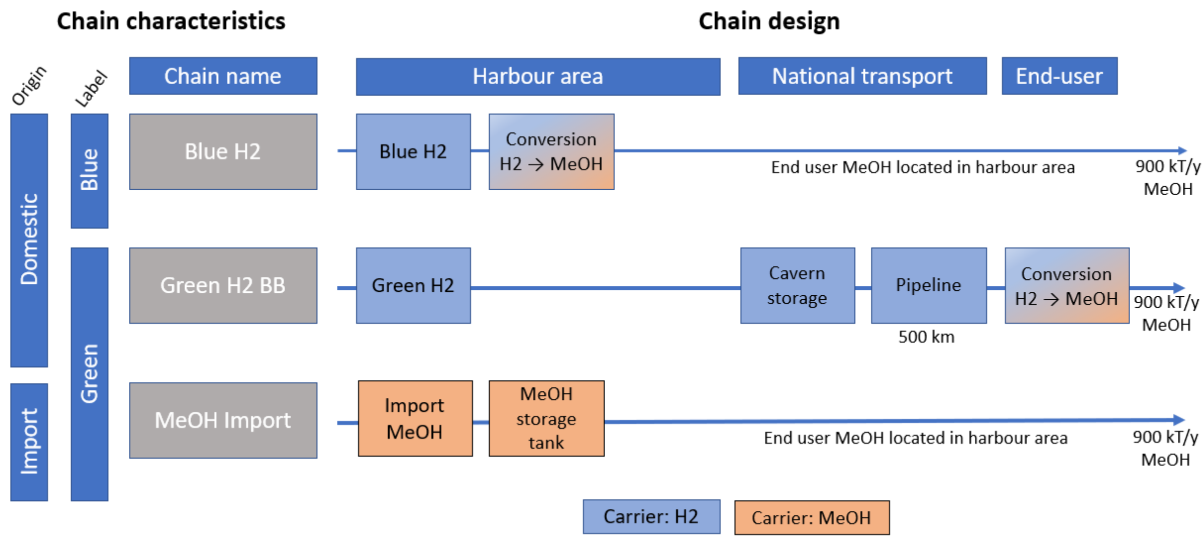


Figure 37 – Overview of the methanol chain compositions considered.

Note: In the case of blue H2 and imported MeOH, no transportation is considered as the end user is located at the Rotterdam harbour area, where the blue hydrogen and imported methanol is located as well. For the domestic green case, cavern storage is required to store the seasonal fluctuations in offshore wind generation. See Appendix D for a geographical representation of the chains.

Results of methanol chains

In analysing potential methanol value chains it has been assumed that the E-Fuel production takes place close to the site of import or production of hydrogen. This makes that the value chains are more concise and do not encompass a lot of different value chain elements before methanol enters the E-

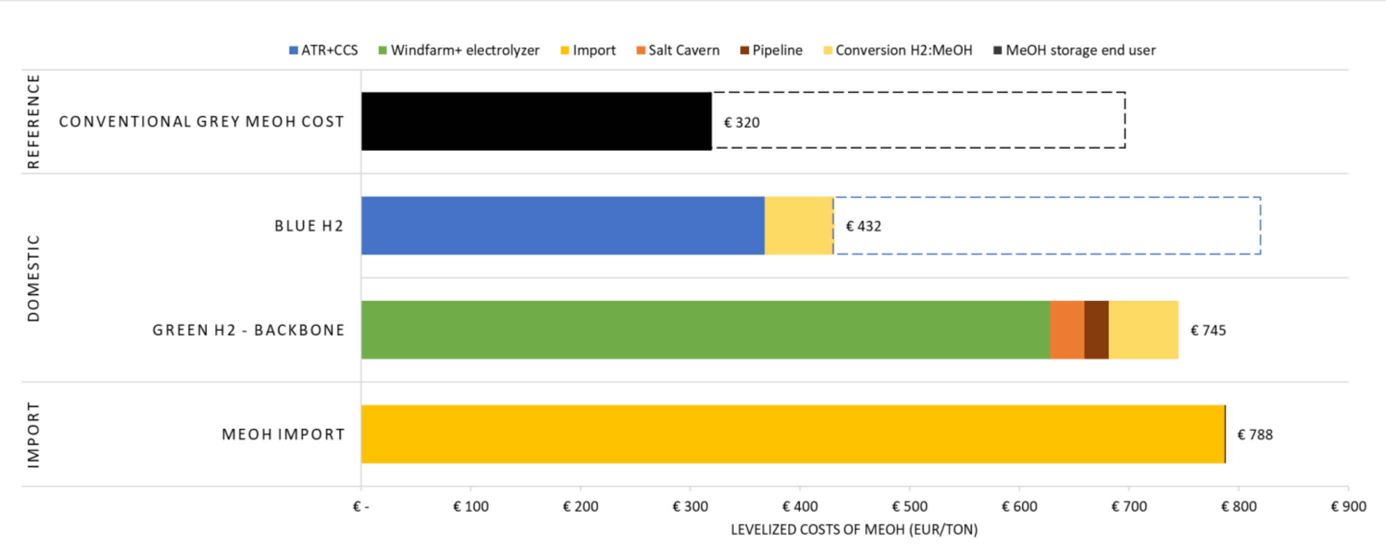


Figure 38 - Results of 2030 cost decompositions for methanol value chains.

Main assumptions: natural gas price: 25 EUR/MWh (dotted bars show impact of a natural gas price of 75 EUR/MWh: grey reference LCOM increases to 704 EUR/ton and blue H2 to 832 EUR/ton), electricity grid price: 60 EUR/MWh, LCOE of connected domestic offshore windfarm to electrolyser resulted in 60 EUR/MWh, green MeOH import costs include the average import costs by ship from Canada, Australia and Morocco.

fuel production process. The costs at the end-use gate of methanol based on blue hydrogen can be the lowest of all alternatives, but also vary the most due to their strong dependence on feedstock prices of their main input (i.e. the price of natural gas). The costs for transport in these chain is neglectable as production and consumption takes place at the same location, potentially even in the same plant. The cost levels of methanol based on import versus domestic production of green electricity are comparable, and are both quite sensitive to the uncertainties of the costs of RES (Renewable Energy Source). For the production of methanol based on green hydrogen, costs have to be considered for large-scale cavern storage, which is required to balance power production fluctuations of offshore wind (approx. 3 caverns for the capacity considered, max. required volume 21 kton (7.8 kton per cavern)).

Competitiveness

Carbon free methanol is not competitive with fossil methanol yet if one considers the low gas prices of the past decades (25 €/MWh). As methanol is traded on a competitive world-wide market, it is typically produced on a large scale at places where the resource natural gas is relatively cheap. Fluctuations in the market price are mainly due to the market price of natural gas (the main resource), or to market interruptions such as upstream temporary shut-downs of large suppliers of methanol [24]. The relatively low cost levels of the conventional methanol market make it difficult for sustainable methanol to compete without financial or other support. Moreover, it is seen that the CO_2 allowance costs have smaller impact on the competitiveness with low carbon alternatives than the ammonia market, as there are less emissions involved per ton of methanol produced. Comparable to the ammonia results, the green (import or domestic) value chains become competitive with the blue value chains at a natural gas price of around 60 €/MWh. Therefore, also in this sector developments in natural gas prices will greatly impact the competitiveness between blue and green.

If the reference case is used but the costs of biomethane (50-100 €/MWh [5]) are used as feedstock to produce bio-methanol, the methanol costs will result in 512-896 €/ton of MeOH, which are in the same range of the green hydrogen based methanol value chains (domestic and import). Although the volumes of biomethane needed to meet the enormous demand for E-fuels of the future would require a huge amount of biomass availability, which might be perceived as unrealistic to harvest them in a sustainable manner.

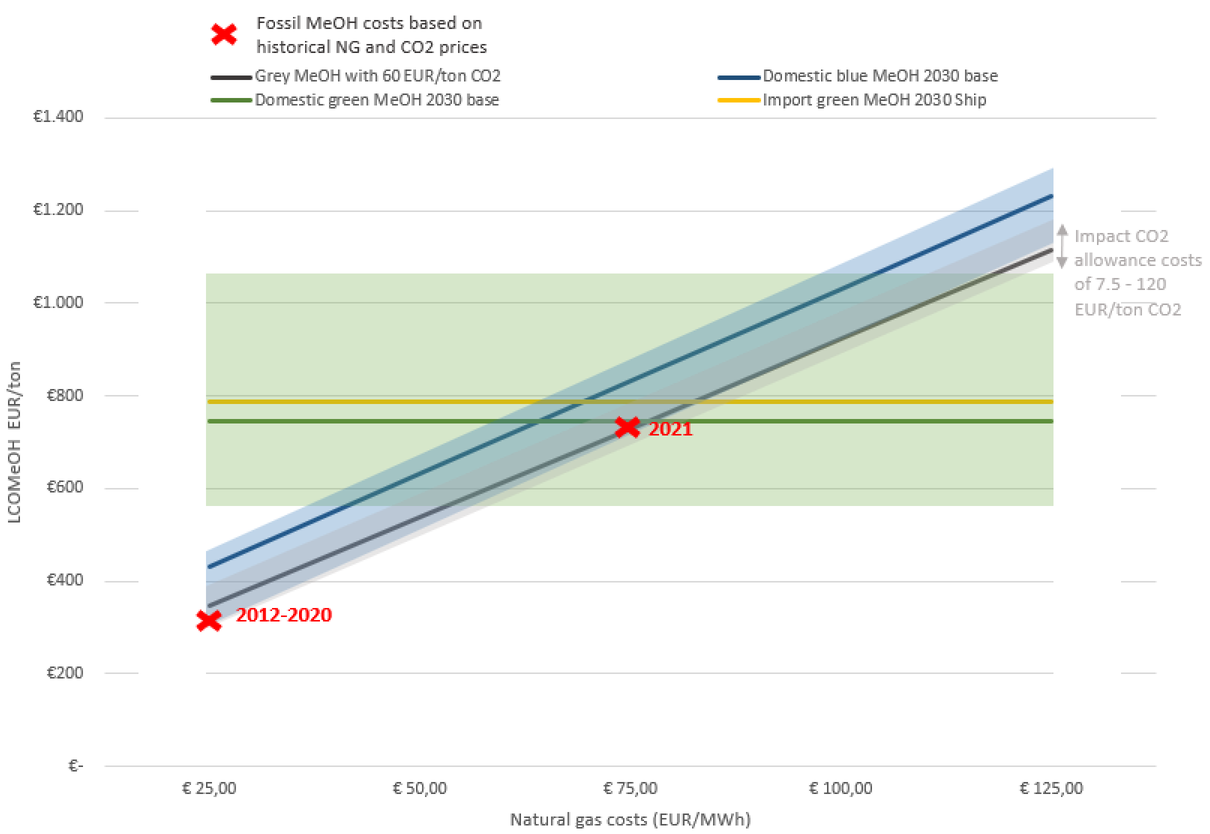


Figure 39 – Visualization of the impact of the natural gas and CO2 price on the reference price of MeOH and on carbon-neutral MeOH produced from blue hydrogen and sustainable CO2 extracted from the air. The resp. green and blue areas mark the uncertainty cost ranges of the green and blue hydrogen production cost developments until 2030; the grey area represents the uncertainty range of fossil MeOH costs depending on the CO2 allowance price (7.5 EUR/ton low, 120 EUR/ton high). The levelized costs presented include transport to end-use site. The reference costs of MeOH are calculated using 0.5-ton CO_2/ton MeOH [6], the natural gas price and the CO_2 price of the past decade have been used, respectively, +- 25 EU/MWh and 5-15 EU/ton CO_2 [2] [3] [4]. However, in 2021 a sharp increase of both European natural gas and carbon emission allowance prices is seen (since the autumn of 2021, the natural gas price rose to 80-180 EUR/MWh and the carbon allowance price to more than 60 EUR/ton CO2).

4.2 Decentralized high-temperature industrial heating

Chain description

A second hydrogen end-use sector of interest relates to those industrial activities that require high temperature heat (HTH, >600 °C), as there are little to no valid alternatives for conventional natural gas fired heating other than using renewable fuels, such as clean hydrogen or biomethane; electrification, for instance, is not considered as no viable option for >200 °C heat demand with the available technologies according to the Dutch Cluster 6 [25]. Quite some decentralized, 'Cluster 6'[3] industrial sites (e.g. ceramic, cement, glass) need high temperature heat for their processes, and currently generally use natural gas for this. One of the sustainable heating alternatives is to use green gas or hydrogen assuming required quality and volumes can be achieved. If all natural gas currently nationally used for industrial HTH in cluster 6 would be replaced by hydrogen, the required hydrogen volume would boil down to some 359 kt H_2/y.

Hydrogen quality requirements

Hydrogen for HTH-industries would for technical reasons most likely not require very high purity levels, as blended hydrogen streams in natural gas are not included of the scope of the designed value chains, we use a 98% purity level of the supplied hydrogen. It should be mentioned, however, that the use of other fuel gases needed when hydrogen is used (air or oxygen) may raise NO_x emissions. It therefore may be necessary from an environmental perspective to analyse per process type this impact as well as what impact impurities in the hydrogen gas may have on emission levels [26].

Demand volume and pattern

The potential HTH hydrogen demand volumes of the five Netherlands' industrial clusters (Fig. 18) can be calculated in a quite straightforward way. As far as the scattered cluster 6 HTH activities is concerned, estimating their possible future hydrogen demand is more difficult because it requires location- and process-specific assessment whether hydrogen is a feasible option to decarbonize. The current demand for natural gas for HTH gives in any case a fairly solid insight in the bandwidth of heating demand levels for this sector (see Figure 40), the more so since the demand for THT is quite constant. To stay at the safe side in estimating potential THT hydrogen demand, the following conservative assumption has been made with respect to the week/weekend demand profile (see Figure 42).

[3] As the five largest industrial centers of the Netherlands are referred to as the five clusters, the other, more secluded, large factories combined are referred to as 'cluster 6' industries.

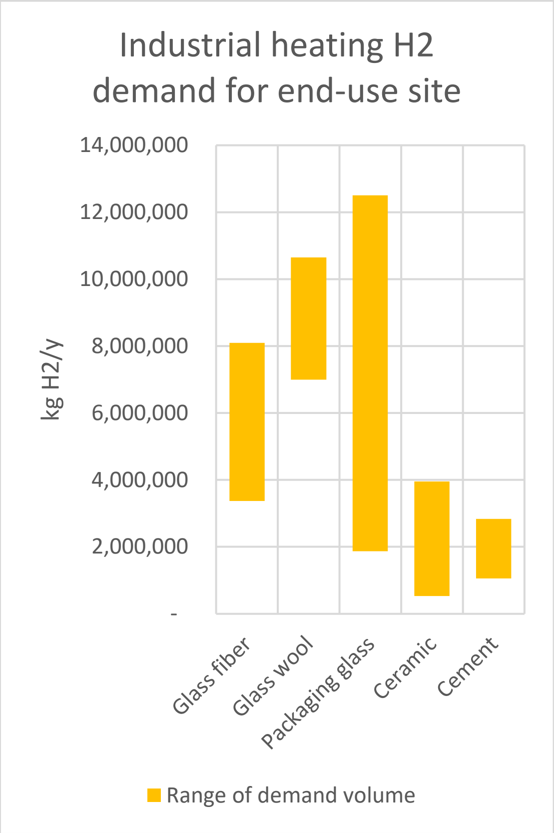


Figure 40 - Ranges of potential hydrogen uptake estimates for some HTH industries, based on existing Natural Gas demand [69].

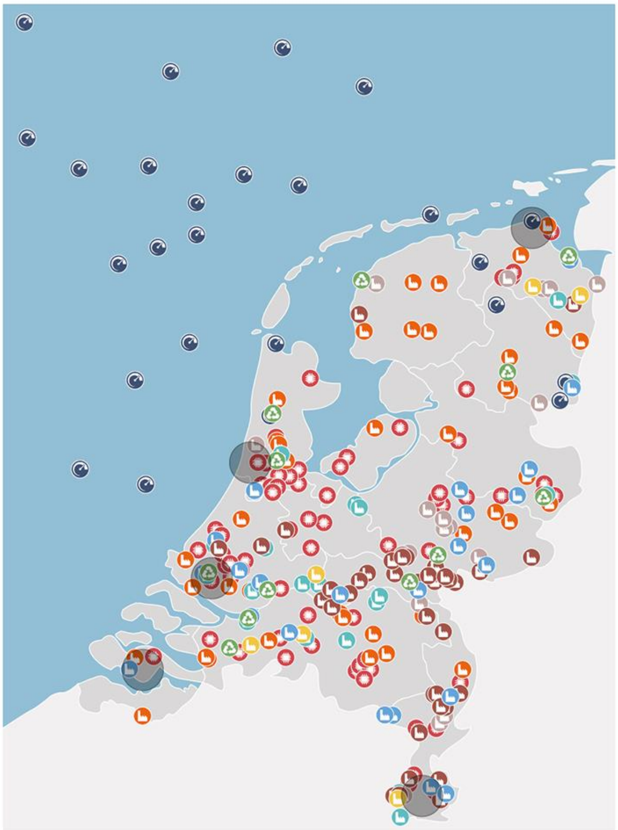


Figure 41 - Decentralized cluster 6 industry spread over the country [25].

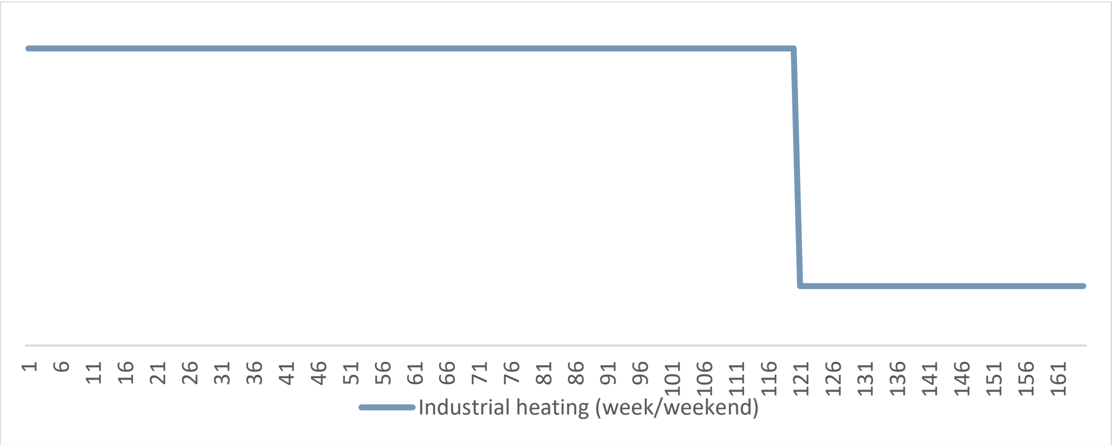


Figure 42 - Normalized hourly hydrogen demand pattern for a representative industrial HTH site.

Why it can sometimes be complex to assess if hydrogen for HTH is feasible can be illustrated with the help of an example. Industrial burning with the help of methane in the ceramic sector is currently also used to enhance the product quality. Whether or not the same quality can be achieved if instead hydrogen is used is currently researched, for example by DNV GL (not published yet). As was mentioned already, also the emittance of NO_x when burning hydrogen with air as an oxygen input can be an environmental issue, although using instead oxy-fuel burners (pure oxygen input) may provide a solution for this.[4]

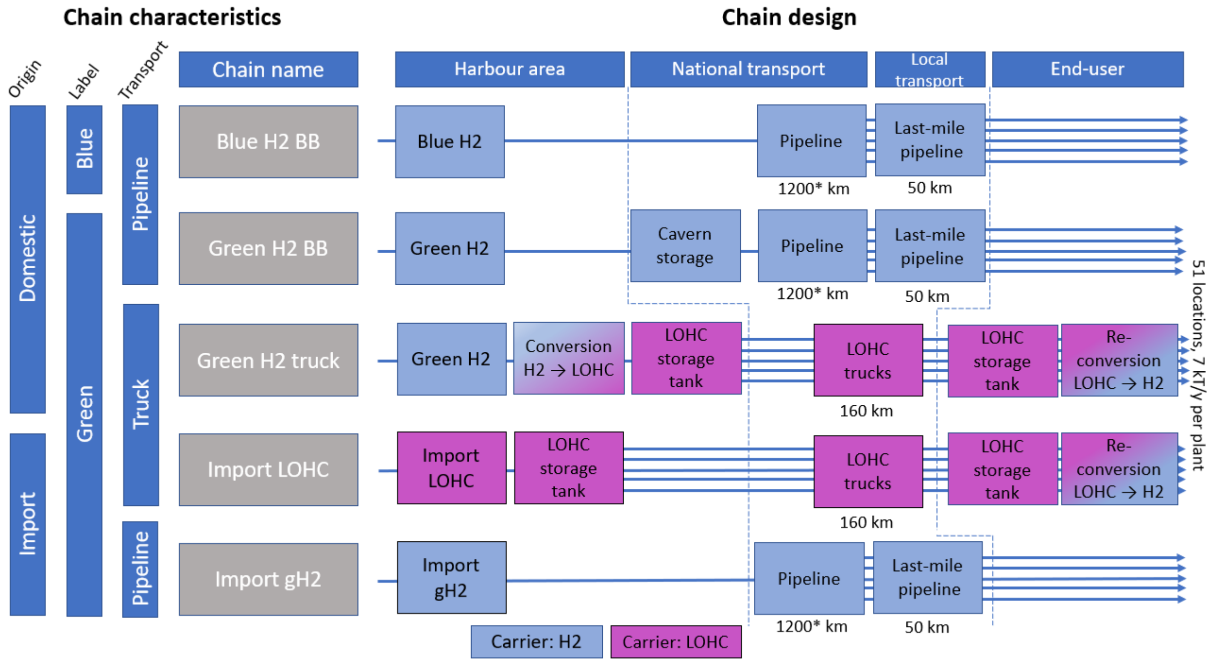


Figure 43 – Overview of the high-temperature industrial heating chain compositions considered.

*Note: *For the national pipeline transport, a pipeline length of the proposed backbone is used and costs of 0.11 €/kg of hydrogen are taken into account based on a general analysis presented in the discussion section. The 160 km of LOHC trucks means that an average distance of 160 km has to be bridged with transport from the central point of production. For pipelines connecting the end user with the backbone 50 km is assumed. See Appendix D for a geographical representation of the chains.*

The availability of transport options can create another bottleneck for the replacement of natural gas for HTH purposes by hydrogen, especially for industrial sites that are not centralized and need large volumes of hydrogen. Such sites may not be connected to the backbone (at least initially), so that a last-mile dedicated transport solution needs to be developed guaranteeing that the hydrogen will be available at the right time, quality and place. This is the more challenging, if also hydrogen storage is needed locally guaranteeing a constant production process. Inland transport could then be facilitated via H_2(-carrier) trucks or barges (If imported hydrogen would be used, it is probably better in such cases not to reconvert it before entering the site). For all these reasons in the analysis of this study a clear distinction has been made between transport used for hydrogen from domestic sources and from imports, and between a last-mile transport via a pipeline, truck with carrier, or trucks with hydrogen.

[4] Using pure oxygen instead of air, (~80% N_2) in a hydrogen burner, can avoid the emittance of NO_x

Results - Industrial Heating

Comparing the outcomes of the chains, as shown in Figure 44, similar differences in domestic green and blue production costs are seen as in the ammonia and methanol chains. With regards to the import of LOHC, costs are significantly higher than the domestic produced chains, hence for industrial heating in 2030 the domestic produced hydrogen chains are more competitive than the import chains. However, gaseous hydrogen import via pipelines is seen as a more cost effective option. With regards to the transport costs, the routes via pipelines or LOHC trucks seem not to differ that significant in costs, mainly also because transport costs have a minor contribution in the total levelized costs of supply. The cost benefit of LOHC is especially seen in the storage costs using this carrier, while the pipelines are better in terms of transport costs. It should be considered that the LOHC reconversion requires installations, and therefore additional investments, at the end user. Moreover, it is unknown if waste heat of specific plants can be used for the LOHC reconversion. If additional costs for heat used in the reconversion process are required cost would increase (e.g. heat costs of 25 €/MWh would increase the costs of 0.24 €/kg).

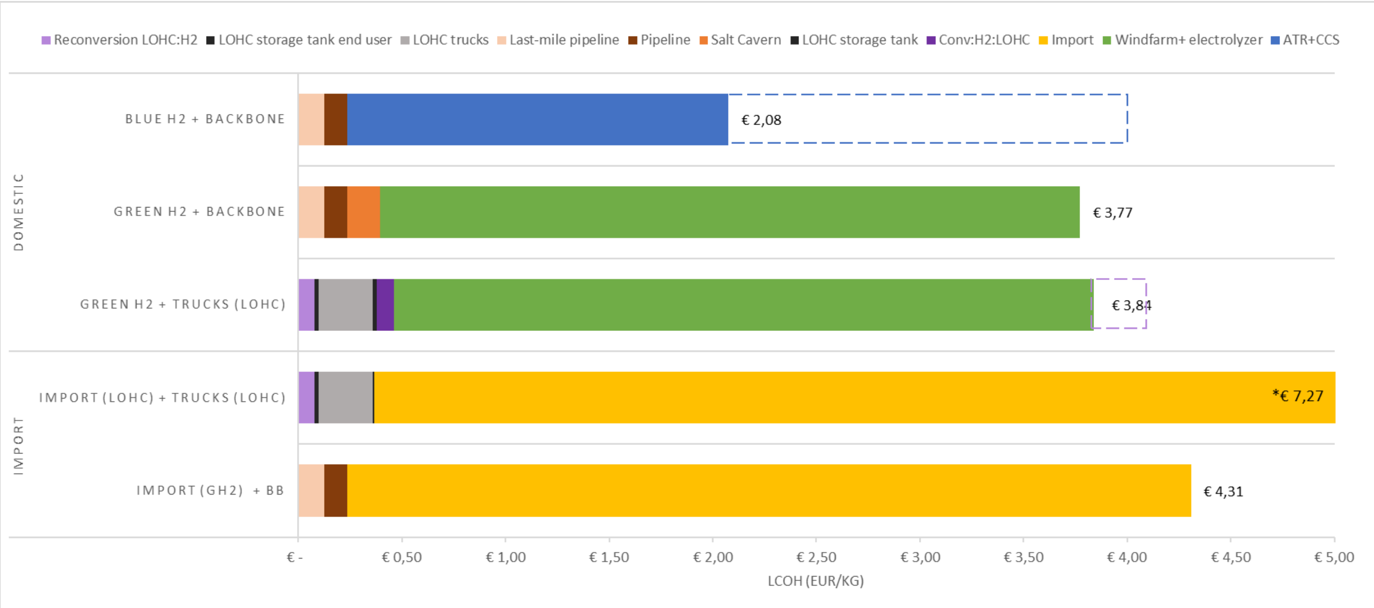


Figure 44 - Results of 2030 cost decompositions for industrial heating value chains.*

**chain steps in the opposite direction in order to better compare the impact of the different transport options in the value chains*

Main assumptions: natural gas price: 25 EUR/MWh (dotted bars show the impact of a natural gas price of 75 EUR/MWh: Blue H2 value chain costs increase to 4.08 EUR/kg), electricity grid price: 60 EUR/MWh, LCOE of connected domestic offshore windfarm to electrolyser resulted in 60 EUR/MWh, green hydrogen import costs via LOHC include the average import costs by ship from Canada, Australia and Morocco, the green gaseous hydrogen import costs assumes the import costs from Morocco by pipeline, if an European Hydrogen Backbone would be available. Heat for LOHC reconversion is considered to be waste heat of 0 EUR/MWh. If these costs for heat would be 25 EUR/MWh, additional 0.24 EUR/kg costs are added in those chains. However, released heat during conversion to LOHC can potentially be sold as well. For national pipeline costs, 0.11 €/kg of hydrogen has been used, which is based on a general analysis presented in the discussion section.

The cost effectiveness of the means of transport are a result of the location of the plant. For example, if a plant is located near the backbone, last mile pipeline costs are reduced significantly. While, if a relatively small plant is located far away from the backbone, and relatively not that far from the harbour, the option of LOHC transport could become more preferable. In the sensitivity analysis, the impact of location and demand size on the costs of the chain options are analysed in greater detail.

Sensitivity analysis

Given the variety in industrial HTH demand volumes between sites, the analysis needs to include how this may affect hydrogen levelized costs, i.e. including the costs of its transport to the end user. Lower demand volumes per site could be expected to lead to higher transport costs per unit of volume. Yet we found that compared to the base case of site-specific hydrogen demand (7 kton hydrogen/year), transport costs of sites facing demand between 2 and 20 kton hydrogen per annum did not lead to seriously different levelized costs at location at similar transport distances (Figure 45).

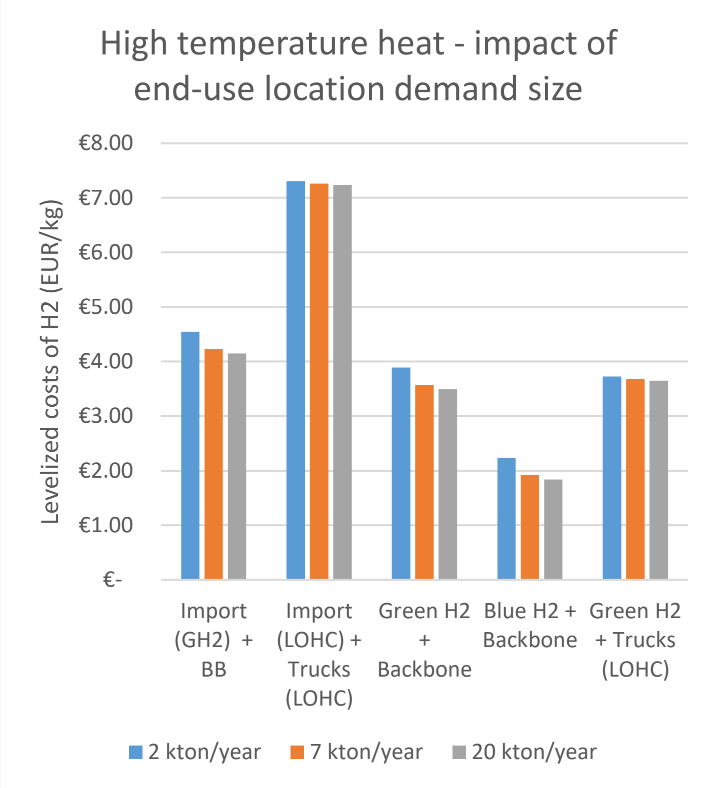


Figure 45 - Levelized costs of hydrogen at end-use location for the minimum, base and maximum hydrogen end-use demand levels.

As can be concluded from Figure 46, costs for most industrial HTH volumes and distances are the lowest for pipeline transport. When distance increases and volumes decrease below 2 kton per year, it could be feasible to consider using liquid organic hydrogen carriers (LOHC) trucks for transport. However, such a small, decentralized, singular HTH site is very rare in the Netherlands, so this option, although sometimes optimal on paper, remains rather theoretical. The alternative, gaseous H_2 transport by truck, is generally not economically feasible for the same range of volumes. For various demand volumes in a certain range of distances reuse of pipelines is more cost effective than transport via trucks (approx. 5-9 kton and 80-200 km.), but of course only under the site-specific condition that such

Yearly demand volume (kton H2/year)

Distance (km)	1.000.000	3.000.000	5.000.000	7.000.000	9.000.000	11.000.000	13.000.000	15.000.000	17.000.000	19.000.000
20	'GH2 truck'	'pipe'	'pipe'	'pipe'	'pipe'	'pipe'	'pipe'	'pipe'	'pipe'	'pipe'
40	'LOHC truck'	'pipe'	'pipe'	'pipe'	'pipe'	'pipe'	'pipe'	'pipe'	'pipe'	'pipe'
60	'LOHC truck'	'LOHC truck'	'pipe'	'pipe'	'pipe'	'pipe'	'pipe'	'pipe'	'pipe'	'pipe'
80	'LOHC truck'	'LOHC truck'	'LOHC truck'	'pipe'	'pipe'	'pipe'	'pipe'	'pipe'	'pipe'	'pipe'
100	'LOHC truck'	'LOHC truck'	'LOHC truck'	'pipe'	'pipe'	'pipe'	'pipe'	'pipe'	'pipe'	'pipe'
120	'LOHC truck'	'LOHC truck'	'LOHC truck'	'LOHC truck'	'pipe'	'pipe'	'pipe'	'pipe'	'pipe'	'pipe'
140	'LOHC truck'	'LOHC truck'	'LOHC truck'	'LOHC truck'	'pipe'	'pipe'	'pipe'	'pipe'	'pipe'	'pipe'
160	'LOHC truck'	'LOHC truck'	'LOHC truck'	'LOHC truck'	'pipe'	'pipe'	'pipe'	'pipe'	'pipe'	'pipe'
180	'LOHC truck'	'LOHC truck'	'LOHC truck'	'LOHC truck'	'LOHC truck'	'pipe'	'pipe'	'pipe'	'pipe'	'pipe'
200	'LOHC truck'	'LOHC truck'	'LOHC truck'	'LOHC truck'	'LOHC truck'	'pipe'	'pipe'	'pipe'	'pipe'	'pipe'
220	'LOHC truck'	'LOHC truck'	'LOHC truck'	'LOHC truck'	'LOHC truck'	'pipe'	'pipe'	'pipe'	'pipe'	'pipe'
240	'LOHC truck'	'LOHC truck'	'LOHC truck'	'LOHC truck'	'LOHC truck'	'pipe'	'pipe'	'pipe'	'pipe'	'pipe'
260	'LOHC truck'	'LOHC truck'	'LOHC truck'	'LOHC truck'	'LOHC truck'	'pipe'	'pipe'	'pipe'	'pipe'	'pipe'
280	'LOHC truck'	'LOHC truck'	'LOHC truck'	'LOHC truck'	'LOHC truck'	'pipe'	'pipe'	'pipe'	'pipe'	'pipe'
300	'LOHC truck'	'LOHC truck'	'LOHC truck'	'LOHC truck'	'LOHC truck'	'LOHC truck'	'pipe'	'pipe'	'pipe'	'pipe'

Legend
<0,2 €/kg
0,2 - 0,4 €/kg
0,4 - 0,6 €/kg
0,6 - 0,8 €/kg
>0,8 €/kg

Figure 46 - Least-cost alternative per distance and volume for the alternatives: Gaseous H_2 truck, LOHC-truck, and new pipeline.

pipelines are available. It should be mentioned in this respect that reuse of pipelines does require some refurbishment of compressors and technical applications for hydrogen transport, and therefore costs. The transport costs per individual user of a grid will almost proportionally decline the more the grid will also be used by others, which is another site-specific factor. So in practice introducing hydrogen in, for instance, a specific built environment or decentral located industrial sites will typically be determined by the site-specific availability of nearby local grid connections and easy grid use combinations with multiple other end-use(r)s that are also willing to convert their energy demand to hydrogen.

A special case is when hydrogen demand concerns long distance and low-volumes, while pipeline connections are not easy. In such cases the use of LOHC trucks can be the most effective transport mode, especially if at the point of destination industrial heat is available to reconvert the LOHC to H_2. In such cases the number of trips and trucks needed to transport the required LOHC volumes will in practice also strongly depend on factors like distance to end-use locations and storages[5].

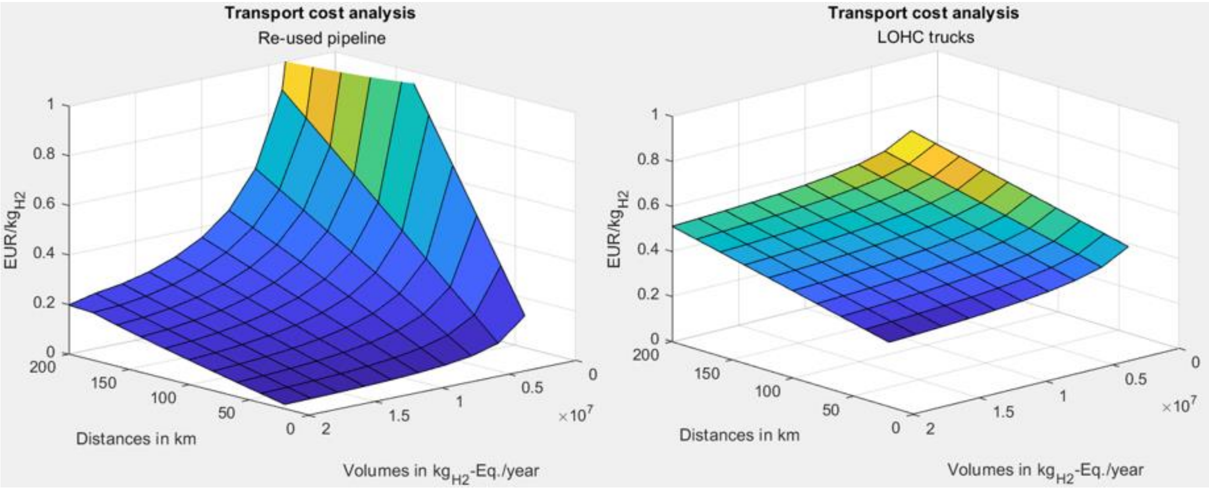


Figure 47 – Impact of distance and volumes on transport costs.

The volumes are presented in kilograms of hydrogen equivalents transported towards a single location per year (for example $2*10^7$ kg equals 20 kT). Assumptions: transport to 51 locations, existing pipeline diameter is 0.21 meter (based on Dutch regional natural gas transport grid). LOHC truck transport costs include costs for conversion and reconversion per location, heat for LOHC reconversion is considered to be waste heat of 0 EUR/MWh, if these costs for heat would be 25 EUR/MWh, additional 0.24 EUR/kg costs are added in those chains, however released heat during conversion to LOHC can potentially be sold as well.

Note: the transport costs for LOHC trucks presented in this figure could be reduced with 0.10 €/kg if conversion for all 51 locations will be done centrally at one location, due to economies of scale in the conversion costs. As described in Figure 43, central conversion is assumed in the costs presented in Figure 44.

To conclude: the use of hydrogen for decarbonising industrial heating is challenging but promising if only because of a lack of alternatives for greening. The typical characteristics of the use-case - a relatively constant demand profiles, large demand volumes and often decentralized locations - make it challenging to organize getting hydrogen in sufficient quantities to the right location. The potential volume of national yearly demand for hydrogen for generating high temperature heat (completely replacing the current use of natural gas) can be estimated at some 360 kt H_2. Such volume would, however, only apply, *if* all end-uses can effectively be supplied with hydrogen via the existing transport system. Our value chain analysis shows that there is no general best mode of H_2 transport of hydrogen for industrial heating, but that use-case specific characteristics define the most cost-effective options. In general, based on volume and distance, pipeline transport is the most logical option, but for smaller

[5] To illustrate, at 150 km. and 1 kton H_2 per year, about 1-2 trucks per day would be required, whereas 3 and 12 trucks per day would be needed for medium-scale (5 kton H_2 per year) and large-scale (20 kton H_2 per year) industrial heating demand. These numbers are not optimized for the best possible routing but do use the trucks for multiple hydrogen demanding locations to minimize idle time of truck use.

industrial heat and longer distance use-cases LOHC transport can be a legitimate option as well, especially if costs of storage of LOHC and the availability of local rest-heat are also taken into account.

Competitiveness

Making hydrogen able to compete with natural gas as a fuel for HTH can basically be achieved via similar measures as hold for industrial feedstock, such as a significant CO_2 penalty or raising the natural gas price via taxation. However, one has to be aware that for some sites using green methane rather than hydrogen for HTH may be the preferred option for technical and economic reasons, especially since domestically produced volumes of green methane may well be sufficient for such cases. To compare the outcomes of the analysed value chains with the costs of using biomethane for HTH, Figure 48 can be used: using the existing Guarantee of Origin price to 'proof' the green origin of the methane, an additional certificate costs of 10 €/MWh (range of 5-15 €/MWh from [27]) could be added to the natural gas price. However, the price of those certificates are based on a voluntary willingness-to-pay of consumers to state that they are 'green'. The actual biomethane production costs are estimated in a range of 50-100 €/MWh [5].

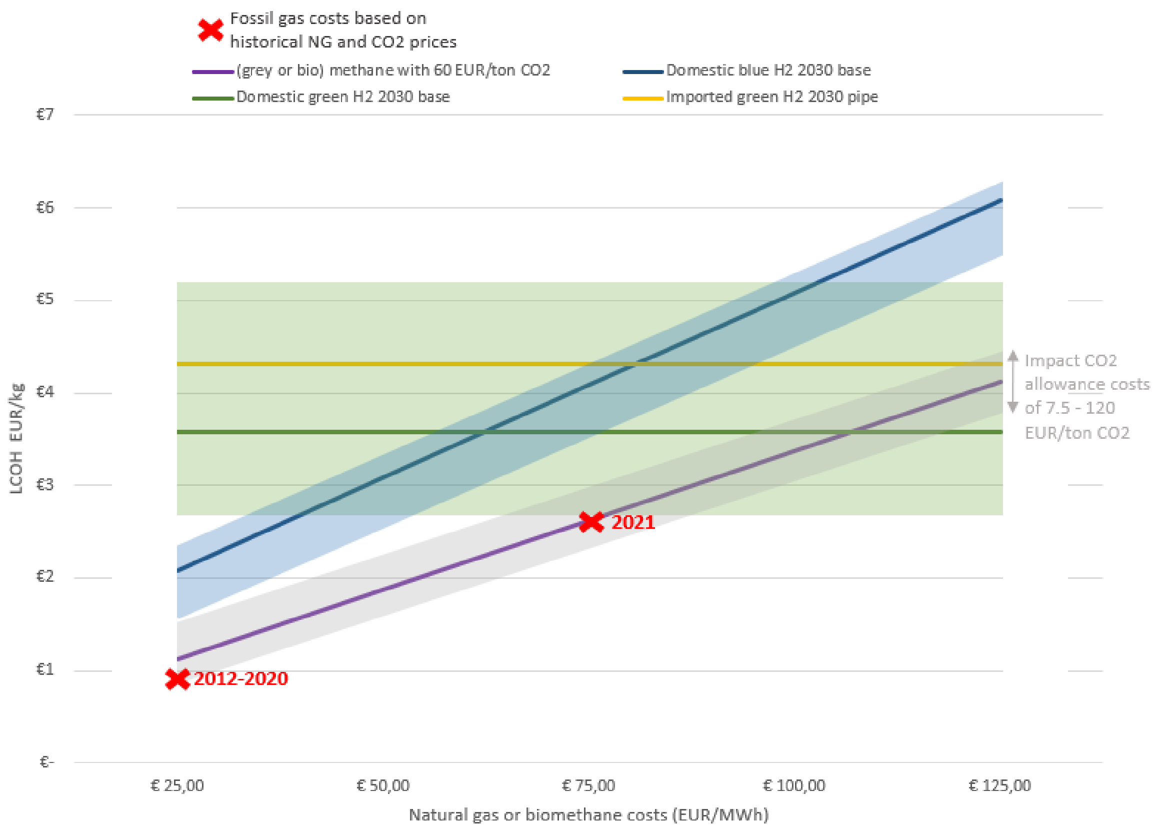


Figure 48 – Hydrogen supply costs (import, green and blue H_2) compared to the reference costs of natural gas. In comparing natural gas with hydrogen, an equivalent amount of energy has been used. This is presented via a hydrogen price equivalent (i.e. the required price for hydrogen to be competitive with natural gas given its price and allowances for polluting CO_2). The respective green and blue areas mark the uncertainty ranges of the green and blue hydrogen production costs until 2030; the grey area represents the cost range of burning methane depending on the CO2 allowance price (7.5 EUR/ton low, 120 EUR/ton high). The levelized costs presented include transport costs to the end-use site. The carbon costs of using natural gas are calculated using 0.203 ton CO_2/MWh of natural gas; the natural gas and CO_2 prices of the past decade have been used: respectively, +- 25 EU/MWh and 5-15 EU/ton CO_2 [2] [3] [4]. However, in 2021 a sharp increase of both European natural gas and carbon prices took place (since the autumn of 2021, the natural gas price rose to 80-180 EUR/MWh and the carbon allowance price to over 60 EUR/ton CO2).

For green hydrogen to be competitive with blue alternatives (or natural gas combined with a CO_2 penalty), the CO_2 price needs to be significantly higher than the current (early 2022) default of 80

€/tCO_2 which is similar to approx. 12 €/MWh natural gas premium. It is important to note that our modelling suggests that if the 80 €/CO_2 default would be combined with a natural gas price of 90 €/MWh and higher, the base case of green domestic hydrogen domestic would become competitive (see Figure 48).

4.3 Mobility

Chain description

In this third potential hydrogen application case, mobility, it will specifically be focused on pure compressed hydrogen used for FCEV applications. In April 2021, 269 FCEVs were registered on the road in the Netherlands and seven hydrogen refuelling stations (HRS) were counted [28]. Given these small numbers it still is very difficult to say how the actual demand volumes of this end-use sector may evolve towards 2030. This will anyhow depend on economic and technical developments in BEV- and FCEV-technology, both in passenger cars, trucks and other types of vehicles. Customer preferences and developments in supporting policies can, however, also have a decisive impact.

Table 5 – HRS specifications developed by the Hydrogen Mobility Ireland group [29] Note: in our study a hydrogen purity of 99.97% is assumed based on the ISO14687-2019 standards.

Metric	Unit	Extra Small	Small	Medium	Large	Industrial
HRS capacity	Kg/day	80	200	400	1,000	5,000
Number of refuelling positions		1	1	2	4	4
Refueling per hour per position		2.5	6	6	10	3
Max refuels per hour/day		2.5/20	6/40	12/80	40/180	N/A
Passenger cars served per station		100	400	800	1,600	N/A
Delivery Pressure	Bar	350	350	350	350	350
Dispensing pressure	Bar	700	700	350/700	350/700	350
Speed of 700 bar fill	mins	<5	<5	<5	<5	N/A
Speed of 350 bar fill	mins	N/A	N/A	10	10	20
Hardware redundancy factor		Single train	Single train	N+1	N+1	N+1
Hydrogen purity	%	99.999	99.999	99.999	99.999	99.999
Target station reliability/availability	%	98	>99	>99	>99	>99
Access		Public	Public	Public	Public	Private

Demand level, pattern and requirements

In this study, hydrogen demand volumes are based on the projections for 2030 as stated in the Dutch Climate Agreement, resulting in 141 kT of hydrogen per year, to serve 300,000 FCEVs [30]. Numbers and characteristics of future HRS typically depend on policy and business decisions (based on projected regional market demand, etc.). To illustrate, future HRS station specifications from the European Hydrogen Mobility project are shown Table 5. In this project an average HRS capacity of 400 kg/day has been assumed which leads to a projected national number of 966 HRS each demanding 146,000 kg of hydrogen annually.

Figure 49 illustrates the hourly demand pattern that is used to represent fluctuations of demand at the HRS during the day. For the sake of simplicity, all hydrogen is assumed to be dispensed at 700 bar, requiring storage at 950 bar as a difference in pressure is needed for dispensing. It should being mentioned that most heavy-duty vehicles currently on the road or in development are designed to be fuelled by hydrogen pressurized up to 350 bars, which requires a slightly different configuration of the HRS, compared to the 700 bar vehicles. The quality of the hydrogen is purified to specifications required by fuel cells, i.e., 99.97% purity based on ISO14687-2019 standards.

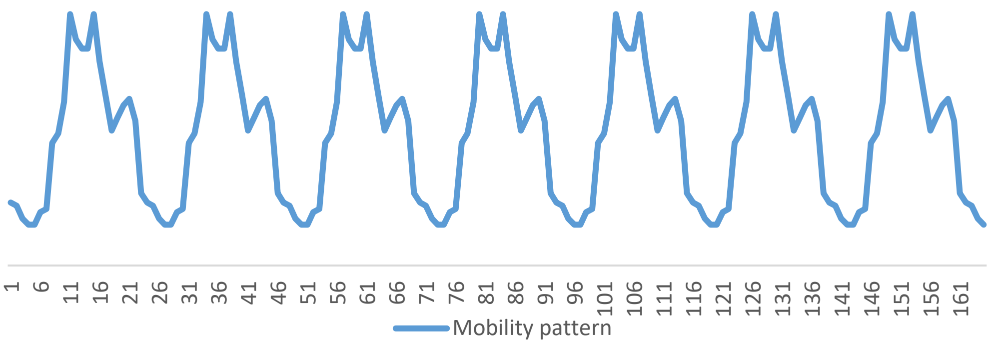


Figure 49 – Normalised hourly pattern of an HRS during one week

Mobility chain designs

There are many potential chain options to supply HRS with hydrogen. In this study, three main directions are investigated. In doing so the focus was on the transport infrastructure between the production site and the HRS, instead of also taking the different hydrogen production modes (e.g., green domestic, blue domestic and green import) into account, because hydrogen production mode costs for mobility do not differ from such costs for other destinations discussed above. The only exception is the addition of a local green hydrogen chain, which is perceived as more feasible in this use-case since last-mile transport and purification costs can be avoided. For HRS the infrastructure conditions instead differ a lot compared to the previously analysed end-uses, because: hydrogen volumes are significantly lower; the number of end-use locations is significantly higher; and the hydrogen requires higher pressure and purity (although in most cases compression and purification is done at the HRS itself, so in this cases it will not affect the chain upstream).

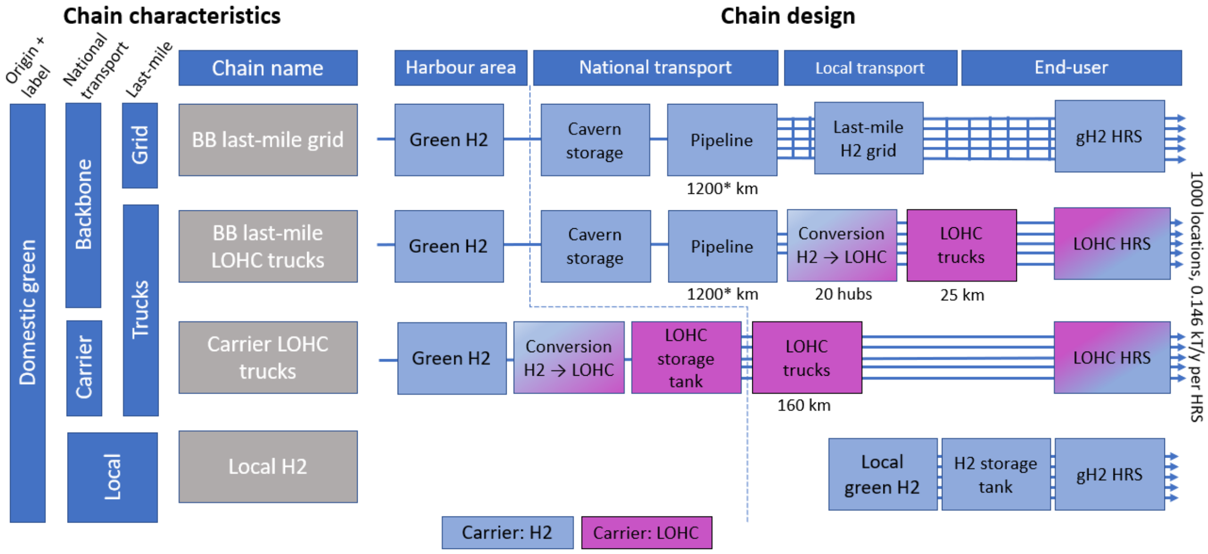


Figure 50 – Overview of the mobility chain compositions considered.

*Note: Only the main chains are presented in the figure, the other chains of which results are presented are variations on these chains. *For the national pipeline transport, a pipeline length of the proposed backbone is used and costs of 0.11 €/kg of hydrogen are taken into account based on a general analysis presented in the discussion section. The 160 km of LOHC trucks means that an average distance of 160 km has to be bridged with transport from the central point of production. For pipelines connecting the end user with the backbone 25 km is assumed. The HRS consists of tank storage, eventual reconversion, compression and purification installations. The local chain assumes connection to a local windfarm and includes additional tank storage capacity. See Appendix D for a geographical representation of the chains.*

Mobility results

In comparing the overall supply costs of the 'best' options of the three supply chain directions, it became clear that the levelized costs levels are close to each other. The promising local value chain/decentralised production option has been chosen to be discussed more thoroughly. In this option it has been assumed that 3.65 days of additional storage is needed above the 3.85 days of storage included in the HRS in every chain (see Appendix A chapter 1.3). If this additional storage could be prevented the overall costs will drop from 5.27 to 4.68 euro/kg hydrogen. Moreover, if the HRS is located in places where large volumes of local renewable electricity is produced and demand is low, there could be early business cases (i.e., before hydrogen infrastructure is developed) to the extent that also congestion management services could be provided (a topic for further research).

The chains transporting hydrogen by way of a LOHC have a storage cost advantage at the HRS (see costs 'Domestic carrier' and 'Last-mile trucks (LOHC)'), because tank storage costs of LOHC are significantly lower than of gaseous hydrogen. However, if somehow the storage capacity of gaseous tanks can be reduced or even limited at the HRS, costs of a local hydrogen chain could be reduced with 0.61 euro/kg assuming a local hydrogen grid with similar volumes and costs as the natural gas regional grids. Further research, more detailed on the HRS designs, should investigate to what degree both the LOHC delivery and grid connected HRS could benefit in storage costs exactly.

Another point of attention with respect to the LOHC-option is that the conversion of LOHC towards gaseous hydrogen requires heat. Industrial areas with relatively cheap waste heat could therefore be good locations fur such refuelling facilities, but may also typically be places where potential hydrogen pipelines could be shared amongst different end-users and therefore be an attractive transport option for gaseous hydrogen. If no waste heat for LOHC-conversion is available, additional costs for heat demand should be included and obviously the sustainability of the heat source should be part of the discussion (just as the availability of fuels to move the LOHC trucks). For the purpose of an indication: if the cost of heat for LOHC reconversion would be 25 €/MWh, the cost of reconversion would rise with 0.24 €/kg of hydrogen.

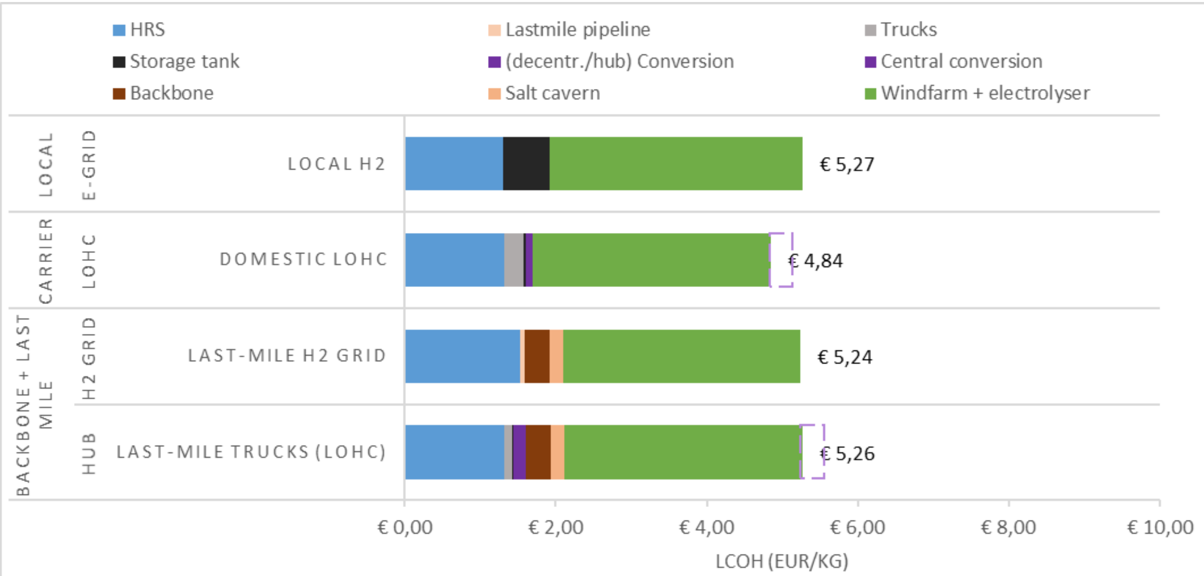


Figure 51 – Overview cost-distributions of the lowest cost value chain options for mobility.

**chain steps in the opposite direction in order to better compare the impact of the different transport options in the value chains*

**Chain steps have been presented in the opposite direction as in the other cases in order to better show the impact of the different transport options on value chain costs*

Main assumptions: 1000 HRS delivering 400 kg/day, the assumed demand pattern results in a 50% HRS utilization rate, national demand: 141 kT/y. LCOE of domestic offshore windfarm connected to electrolyser: 60 EUR/MWh, LCOE of local onshore windfarm: 53 EUR/MWh, but having a lower utilization (0.35 compared to 0.55) than offshore generation. Heat for LOHC reconversion is considered to be waste heat of 0 EUR/MWh. If costs for heat would be 25 EUR/MWh, 0.24 EUR/kg costs has to be added (see purple dotted boxes). However, heat released during conversion to LOHC can potentially be sold as well. National pipeline costs of 0.11 €/kg of hydrogen are taken into account based on a general analysis presented in the discussion section.

Results Backbone and last-mile chains

In backbone-based hydrogen transport chains, hydrogen is: produced with electricity from offshore wind, nationally transported via the backbone, and stored in pipelines and salt caverns. Such chains may subsequently differ in the last-mile mode bringing the hydrogen from the backbone towards the HRS, which is either based on a hub, or on a dedicated last-mile pipeline or a connection to a potential hydrogen distribution grid.

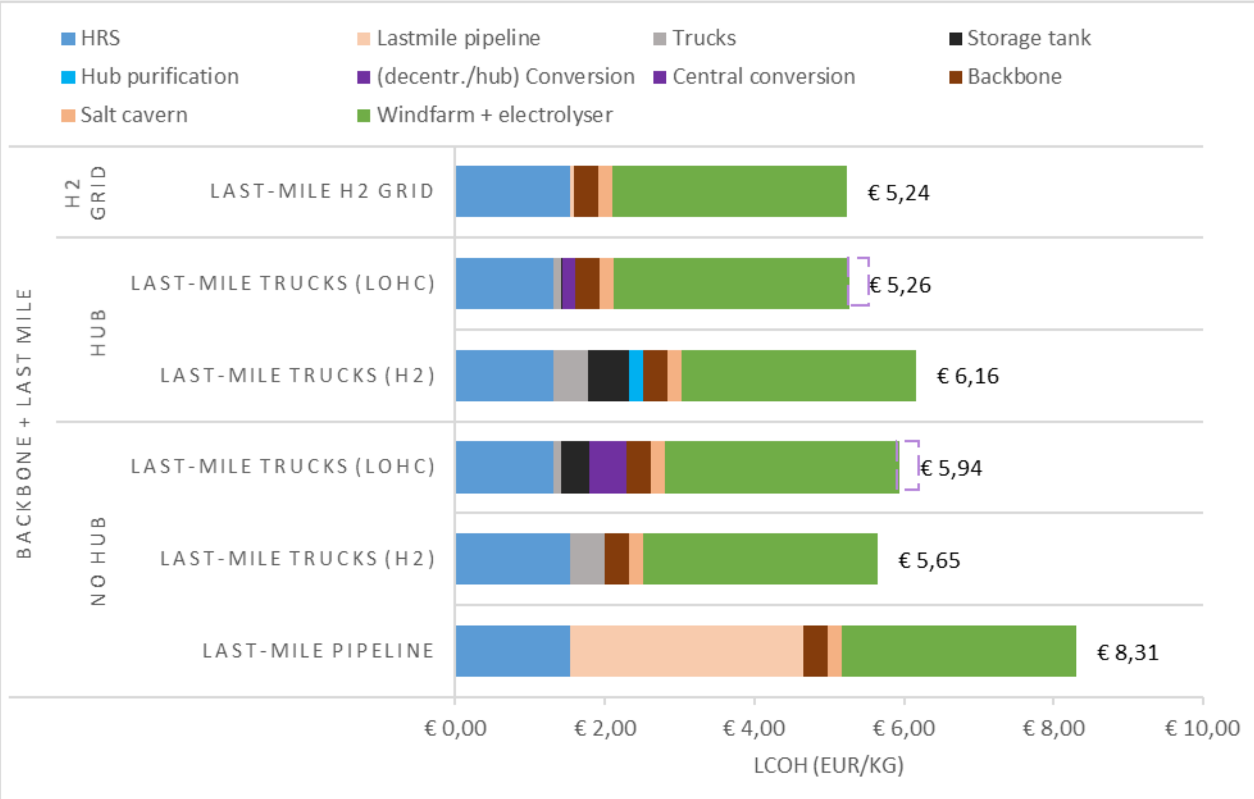


Figure 52 – Overview cost distributions of mobility chains via a national hydrogen backbone.

**chain steps in the opposite direction in order to better compare the impact of the different transport options in the value chains*

Main assumptions: 1000 HRS delivering 400 kg/day, the assumed demand pattern results in 50% HRS utilization rate, national demand of 141 kT/y. LCOE of connected domestic offshore windfarm to electrolyser resulted in 60 EUR/MWh. Heat for LOHC reconversion is considered to be waste heat of 0 EUR/MWh, if these costs for heat would be 25 EUR/MWh, additional 0.24 EUR/kg costs are added in those chains (see purple dotted boxes), however released heat during conversion to LOHC can potentially be sold as well.

Results show that using a hub for last-mile gaseous hydrogen truck transport is less cost effective than not using hubs (hydrogen levelized cost price of 5.65 vs 6.16 euro/kg), while for LOHC trucks hubs instead result in significantly lower costs (5.94 vs 5.26 euro/kg). Using a hub means that in case of gH2 trucks hydrogen is purified for 50 HRS at the backbone exit, instead of purifying hydrogen locally at each HRS. However, for gH2 truck transport the hub option leads to additional storage costs of purified hydrogen at the hub, while such storage is not required without hubs, because then trucks can be filled directly from the national pipeline system. A hub for LOHC trucks means that conversion of gH2 to LOHC is performed for, again, 50 HRS instead of for each HRS individually. Since LOHC storage is required in both with and without a hub, and the economies of scale of LOHC plants are significant (conversion costs are 0.49 €/kg of hydrogen for a single HRS and 0.19 €/kg if combined in a hub for 50 HRS), this explains why the hub option with LOHC turns out to be more cost effective option.

Constructing dedicated pipelines from the backbone to the generally widely spread HRS locations will typically result in high transport costs due to the relatively small demand volumes per HRS and large investment costs of pipelines. That is why it seems logical that such dedicated grid investment will typically only be made if it can serve (various) other end uses than HRS as well. Site-specific optimal solutions therefore are likely to become the standard, but are difficult to model in a generic way. If existing regional 40 bar natural gas grids can be used to be converted into local hydrogen grids levelized hydrogen costs per kg obviously will get lower, and, again, the more so to the extent that one succeeds in serving multiple types of consumers. The latter option would, however, require that all users connected to that grid are prepared to convert towards using hydrogen.

Hydrogen carrier-based transport and storage chains

In the following we will focus on the levelized costs of transport chains based on hydrogen carriers, both LH2 and LOHC, assuming that the hydrogen is imported via carriers as well. In general the LOHC chains are more cost effective than the LH2 chains (see Figure 53). However, specific advantages of LH2 chains (compared to LOHC) can be that less truck transport flows are required (60 trucks making average 1.75 trips/day compared to 90 trucks with average 2.5 trips/day), and no heat is required for reconversion of the carrier to hydrogen on the HRS. On the other hand, LH2 chains have to deal with hydrogen boiling-off and relatively high electricity consumption during conversion and storage of the liquid hydrogen.

The costs of production and transport required for import of both LOHC and LH2 are relatively high compared to the projected domestic costs. The economic viability of these chains therefore strongly depends on future cost reductions.

Important factors determining the costs of the domestic LOHC chain option are that:

1. waste heat or another low-cost heat source should be available near the HRS;
2. the central conversion plants costs can benefit from economies of scale. At a large scale hydrogen can be converted to LOHC for 0.09 euro/kg (see figure); for 50 HRS (of the assumed size) this cost could be 0.15 euro/kg, but for plants serving less than 25 HRS, costs raise to a level of 0.47 euro/kg;
3. the distance from the landing point should preferable be limited. The currently used distance in the analysis, 150 km, resulted in transport costs of 0.26 euro/kg. For locations nearby harbours or hydrogen production locations, this cost could, however, be reduced towards 0.11 euro/kg (namely in the case of a 25 km distance).

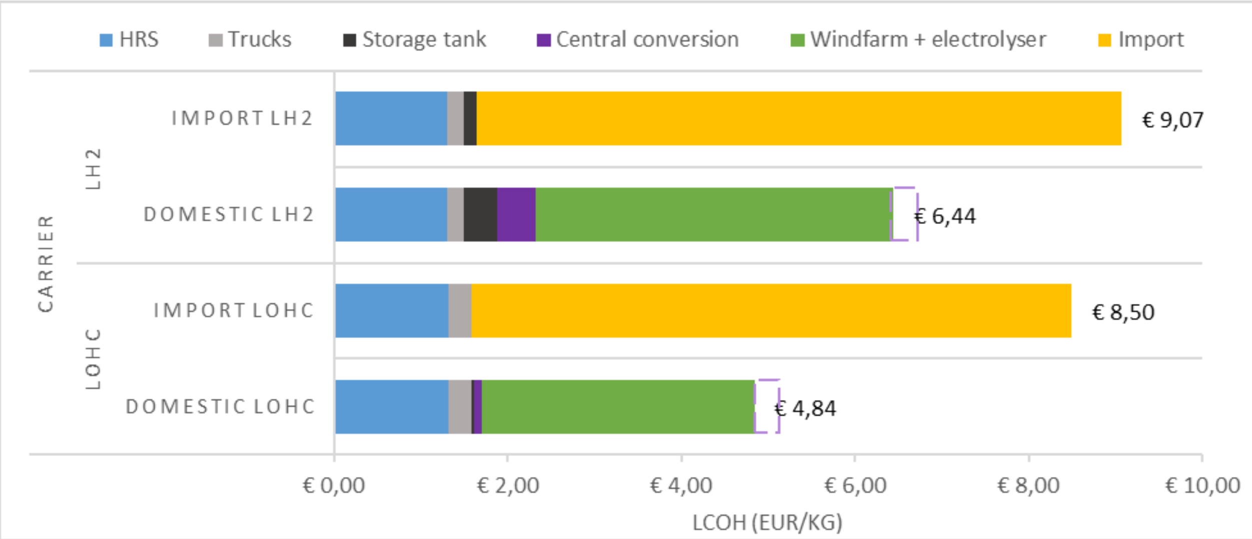


Figure 53 – Overview of cost distributions of mobility chains using hydrogen carriers for national transport and storage.

**chain steps in the opposite direction in order to better compare the impact of the different transport options in the value chains*

Main assumptions: 1000 HRS delivering 400 kg/day, the assumed demand pattern results in 50% HRS utilization rate, national demand of 141 kT/y. LCOE of connected domestic offshore windfarm to electrolyser resulted in 60 EUR/MWh, green hydrogen import costs via LOHC and LH2 include the average import costs by ship from Canada, Australia and Morocco. Heat for LOHC reconversion is considered to be waste heat of 0 EUR/MWh, if these costs for heat would be 25 EUR/MWh, additional 0.24 EUR/kg costs are added in those chains (see purple dotted boxes), however released heat during conversion to LOHC can potentially be sold as well.

Results local chains

In local chains, hydrogen is assumed to be locally produced near the HRS by the combination of a local wind farm and electrolyser. The assumed average demand of a single HRS requires a 2.3 MW wind turbine and electrolyser in order to produce enough hydrogen during the assumed 3081 full load hours of onshore wind turbines in the Netherlands. The main advantages of this option are that transportation costs could be avoided and also that the purity of the hydrogen is not lost during transportation. Moreover, the local chain does not depend on the availability of national hydrogen infrastructure.

However, due to the seasonal fluctuations and uncertainty in wind electricity generation, sufficient storage should be in place to supply hydrogen at the HRS when there is demand. If the capacity of such storage would be created by gaseous hydrogen tanks, 33 tanks of 500 kg should be installed at every single HRS, representing 41 hydrogen uptake days (i.e., 11% of annual demand) of storage capacity in order to deal with the seasonal fluctuations in local wind production. This would result in the massive storage costs of 6.71 euro/kg of hydrogen. Fortunately there are multiple ways to lower storage requirements, by: 1) installing more generation capacity and/or curtailing electricity at specific moments; 2) connecting to a hydrogen or electricity grid; or 3) converting the hydrogen locally towards LOHC enabling to store larger volumes more cost effectively. Because option 3) still results in relatively high costs (>6 euro/kg due to the limited scaling benefits), and because the case of a connection to a hydrogen grid has been analysed already above, we will only show indicative costs of the case in which a local renewable energy source can be used to produce hydrogen for the HRS (and 3.6 days of additional gaseous hydrogen storage tanks are assumed to be sufficient to guarantee supply by storing fluctuations of mostly half a week).

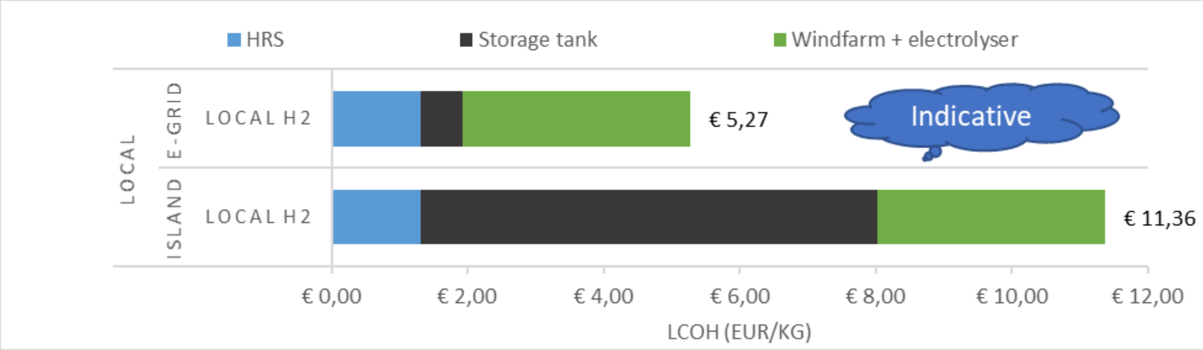


Figure 54 – Overview cost distributions of local mobility chains

**chain steps in the opposite direction in order to better compare the impact of the different transport options in the value chains*

Main assumptions: 1000 HRS delivering 400 kg/day, the assumed demand pattern results in 50% HRS utilization rate. LCOE of connected domestic offshore windfarm to electrolyser resulted in 60 EUR/MWh, LCOE local onshore windfarm 53 EUR/MWh but resulting in lower utilization (0.35 compared to 0.55) than offshore generation. Island assumes that seasonal storage in hydrogen tanks is applied, E-grid assumes that only a share of the local electricity is used to produce hydrogen for mobility, in this case 3.6 days of additional storage is considered as sufficient: further (specific) research should analyse the specific impact on the required storage and utilization of the electrolyser.

Sensitivity analysis & discussion

Three types of sensitivities in mobility chains have been assessed:

- the impact of different sizes of HRS;
- the costs of just suppling hydrogen to the HRS, so not including those of storage, compression and purification at the HRS; and
- the potential of specific early supply chains and HRS developments.

To analyse the impact of HRS size on what is the optimal transport chain, five different HRS sizes are used (See Table 5), namely 50 kg/day (very small), 200kg/day, 400 kg/day (considered as average), 1000 kg/day and 5000 kg/day (industrial). The annual national hydrogen demand in the sensitivity analyses stays the same, namely 146kT per year, so that, with the smallest HRS size 8000 HRS would be required to meet the national demand, and with the largest HRS only 80 HRS.

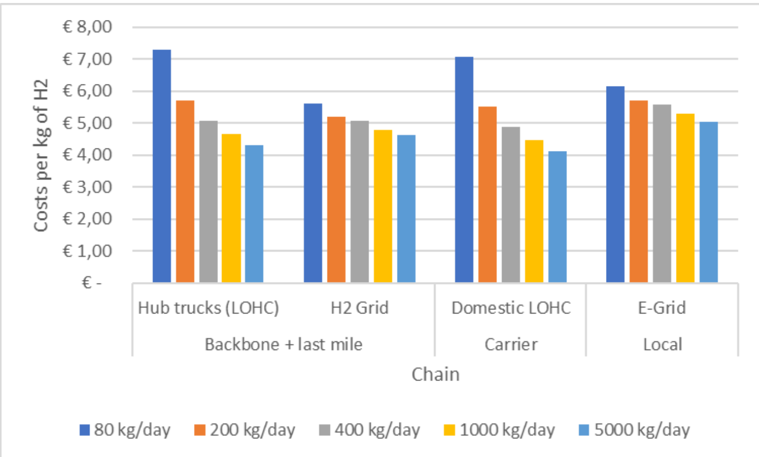


Figure 55 – Sensitivity of HRS size on the most cost-effective mobility value chains.

The cost impact of the HRS sizes on chain optimality is shown in Figure 55. It shows that in all the chains cost reductions result if the HRS size increases, mainly due to scaling advantages in the HRS itself. The largest cost impact is in the chains using LOHC. In the LOHC hub case, no significant changes in costs did show up for conversion, storage and transport via trucks. The cost reductions are mainly impacted by LOHC reconversion, LOHC storage and purification; especially the LOHC reconversion and LOHC storage increase significantly for this small scale, due to the relatively large economies of scale of those technologies. At the industrial HRS even using LOHC storage for the local chain could become an option from a cost perspective, due to the reduced conversion and reconversion costs of LOHC as result of economies of scale. However, as the scale is significant, much more local generation would be required (>28MW). The costs of the gH2 supplied HRS reduce less than the LOHC supplied HRS, because there are only cost reductions in the purification equipment. For gH2 tanks, only a relatively small cost increase is seen for the smallest scale HRS, but for the other HRS sizes costs remain the same.

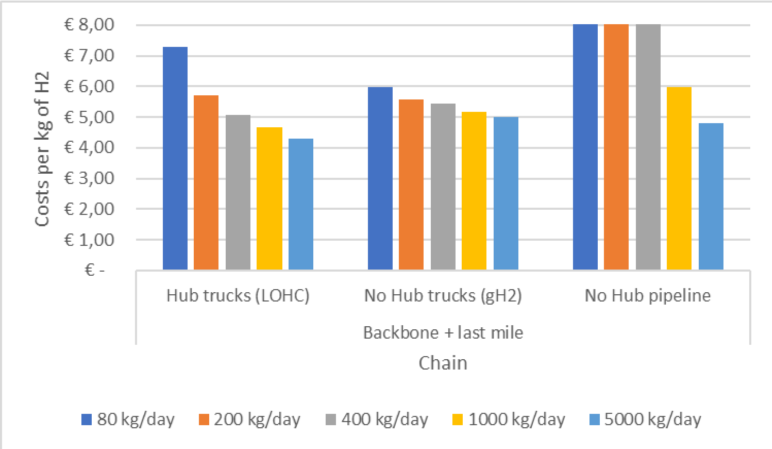


Figure 56 - Sensitivity of HRS size in comparison with gH2 trucks and dedicated pipeline connections.

Due to the lower cost effectiveness of the LOHC last mile option for small-scale HRS, gaseous last mile transport via trucks becomes more attractive for these cases. For the larger industrial HRS supplying volumes of 5000 kg/day, dedicated (re-used) pipelines instead become an option depending from the length of the pipeline and the option to re-use (parts) of the pipeline. The smaller the length and the larger the share that can be reused, the lower the costs of this option are. In Figure 56, the various costs are put in perspective, including costs for a case of a 25 km reused pipeline.

The above results illustrate that HRS costs have a strong impact on competitiveness of the various chains. The LOHC HRS have a cost advantage because 'liquid' hydrogen carrier can be stored relatively cheaply (several cents against the 60 cents for storage in gaseous hydrogen tanks). So, the volume of storage required at the HRS combined with the balanced engineering of: storage, optional reconversion, purification and compression can have a large impact on hydrogen levelized costs. Put it differently, only looking at the costs of hydrogen supply to the HRS gives quite another view on costs, as has been represented in Figure 57. This perspective tells us that if storage volumes of gaseous hydrogen needed on HRS sites could be reduced - for example thanks to a connection with a pipeline system or the application of smart delivery strategies with trucks - the potential of these chains will improve significantly.

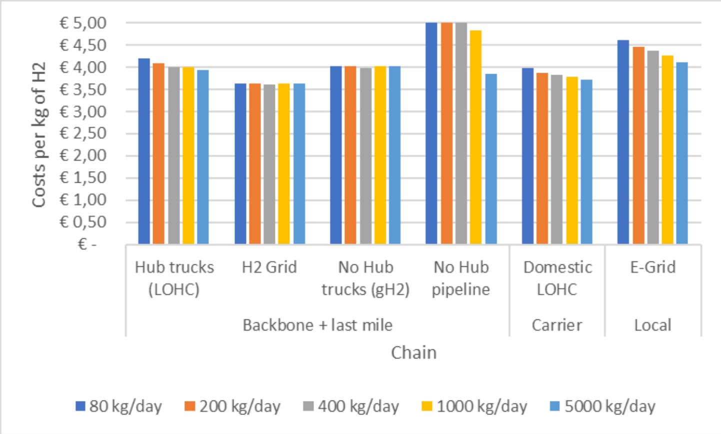


Figure 57 – Overview of levelized costs of hydrogen supply to HRSs with different sizes, including reconversion costs for LOHC

The chains discussed so far all relate to situations in which large hydrogen infrastructure (national pipeline and storage) already exists. For that reason also a perspective is given on early hydrogen value chains for mobility in which a national hydrogen backbone will not be part of the options but the outcomes of the local chains will not differ. Figure 58 shows the costs of such early domestic LOHC value chains compared to the costs of the local value chains. The first bar represents a value chain for a single HRS, resulting in relatively high costs for conversion into LOHC due to the relatively small conversion unit size (146 tonnes of hydrogen per year, relating to a HRS delivering 400 kg/day). If this unit can be used for a combined set of 20 average sized HRSs (representing an annual demand of 2920 tonnes of hydrogen per year), central conversion into LOHC becomes already a lot more cost attractive. This is similar in Figure 58 where it is shown that if the same annual demand (2920 tonnes) is distributed over two large industrial transport hubs (for example a harbour and a train station), economies of scale will reduce the HRS costs significantly. By comparing the domestic LOHC chain costs with those associated with HRS coupled to local electricity and hydrogen power plants, it is clear that the LOHC chains can be relatively cost effective for average- to large-scale HRS, and the local chains for small- to average-sized HRSs.

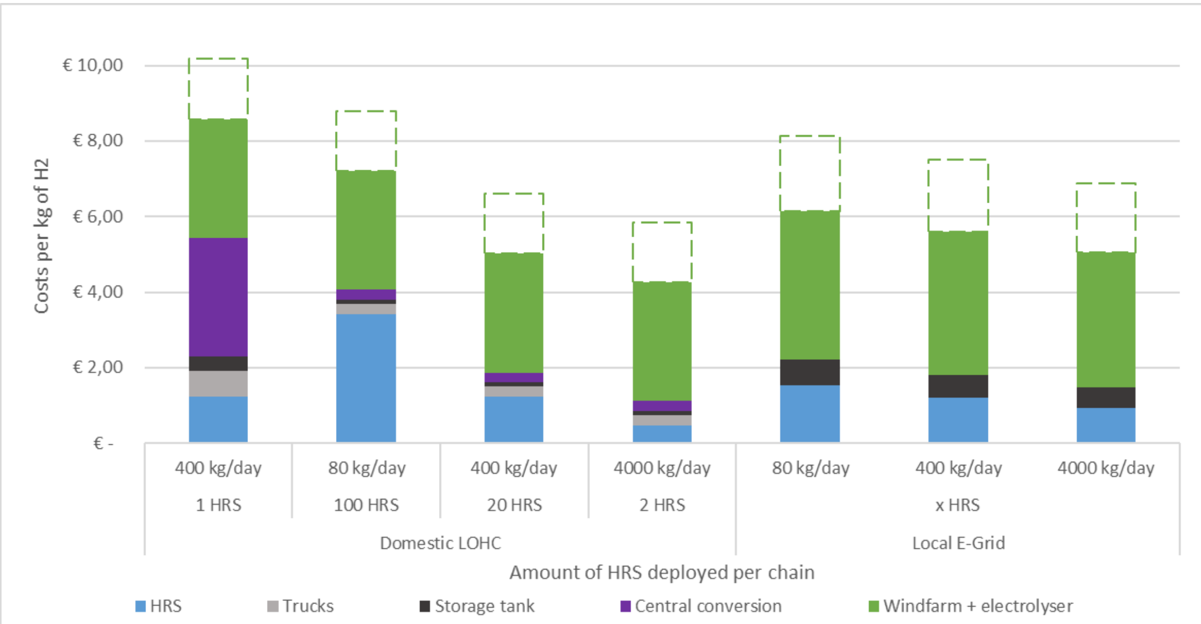


Figure 58 – Overview of costs of early mobility value chains, dependent on the annual demand and HRS size.

Note: since the green production cost assumptions are based on 2030, the dotted green bars show the impact of today's costs (similar assumptions as the highest green cost presented in Figure 29).

Comparison with sustainable alternative

We will now compare the TCO of long-range FCEV and BEVs for both personal cars and trucks, by using the outcomes of the LCOH of this study. There is a hydrogen focused market segment of private consumers or business users (e.g. taxis) demanding for cars with a driving range of at least 400 km, also because for vehicles with shorter ranges (e.g. 250 km) the battery costs will be that low that fuel cell electric vehicles are not able to compete.

Figure 59 compares the future total costs of ownership of FCEV and BEVC for two types of vehicles: personal cars and heavy-trucks. As a lot of external factors are included in the competitiveness of hydrogen used for mobility, and this is not the focus of the report, the IEA approach [8] and data is used to calculate and compare the TCO. In this analysis, the price values are adapted to align the data with the HyDelta report and adapted to the Dutch situation, for instance, charging at costs about 23 €/kWh and fast charging along the highway is a lot more expensive [31][6].

For the FCEV the lower boundary hydrogen fuel price is 4.8 EUR/kg and the higher boundary fuel price 9.07 EUR/kg. For the battery electric cars a lower boundary of 0.04 EUR/kWh is used, representing a case of recharging at home including own generated electricity; for the higher boundary the current average fast charging tariff is used minus the existing electricity taxes, which results in a figure of 0.55 EUR/kWh[7]. Figure 59 shows that the main costs in the TCO are due to the fuel cell and battery costs, which are projected to be comparable in the future for long-range cars [8]. Comparing the costs of fuel, BEVs could have an advantage when relatively cheap electricity can be used charging the BEV at home.

FCEV seems relatively more interesting for heavy-duty long-haul segments (trucks and intercity buses), since energy consumption per kilometre tends to be largest for large vehicles used over long distances. So, fuel costs generally make up a greater share of total costs for heavier vehicles and vehicles with high utilisation (reflected in the figure). For trucks we assumed similar hydrogen fuel prices as for cars, and for electric trucks only fast charging prices are used (0.2 EUR/kWh low and 0.55 EUR/kWh high, excl. taxes) as trucks should be back on the road again as soon as possible. The result of the increased impact of fuel prices is that heavy-duty FCEVs tend to be more competitive against BEVs than personal cars, although this can be different depending on the (uncertain) future hydrogen and fast charging prices. FCEVs could in general be competitive against BEVs in heavy-duty applications if hydrogen could be delivered at less than 6.4 EUR/kg, although the exact hydrogen price at which they become competitive depends on overall annual mileage and other operational characteristics (e.g. HRS network utilisations, price development in capex cost). Moreover, another metric to use for TCOs for trucks could be in terms of €/ton/km or €/m^3/km of freight, instead of €/km [32]. Another often mentioned advantage of fuel cell electric trucks should also be taken into account, namely that more volumes and/or weight of freight could be transported per km due to the lower sp. atial requirements and weight of hydrogen tanks and fuel cells as compared to the large batteries. Also here technological development could alter this perspective.

[6] IEA price of 12 USD/kWh for electricity and 5 USD/kg for hydrogen. HyDelta assumptions are 0.23-0.55 EUR/kWh for electricity and 4.8-9.07 EUR/kg for hydrogen. An exchange rate of 0.89 USD/EUR is applied.

[7] In the Nethelands 0.60 EUR/kWh is the average price paid for fast charging; 0.25 EUR/kWh is the lower and 0.79 EUR/kWh the upper boundary [https://incharge.vattenfall.nl/laadpaal-en-opladen/wat-kost-snelladen].

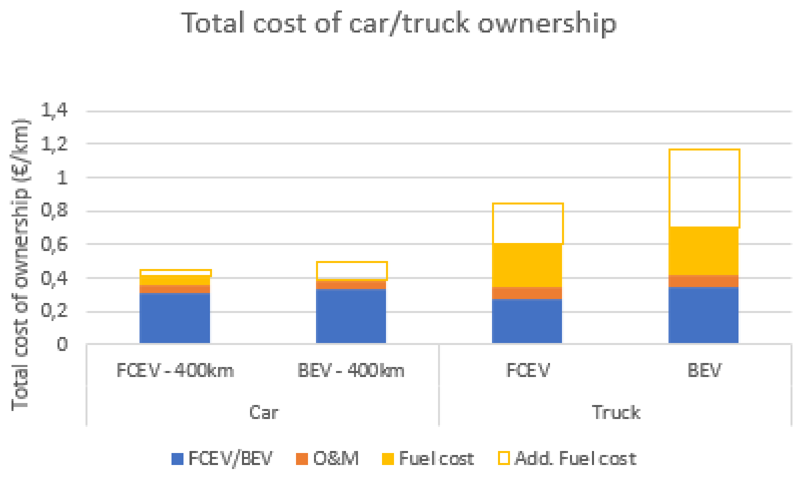


Figure 59 – Future Total cost of ownership comparison of BEV & FCEV based on [8].

Assumptions: cars with range >400km, charging costs FCEV car low: 0.04 EUR/kWh (self-generated electricity at home) high: 0.55 EUR/kWh fast charging costs excl. taxes. FCEV truck 0.2-0.55 EUR/kWh fast charging costs excl. taxes. Hydrogen fuelling costs 4.8-9.07 EUR/kg. For remaining assumptions see [8].

4.4 Built environment

Chain description

Compared to the hydrogen end-uses discussed above, considerably more uncertainty applies in the built environment about if and to what degree hydrogen may be demanded in the future. In the Dutch climate agreement, it is foreseen that no or barely no hydrogen will be used in the built environment before 2030 [12]. Even with respect to the more distant future there is discussion as to what degree the built environment will use renewable gases, as all-electric and heat grids are also considered suitable future options in a lot of areas. According to the outcomes of the 'Start analysis for natural gas free neighbourhoods' of PBL: heat grids generally would be the most applicable option in larger cities and villages; electric options where the electricity grid has enough capacity; and renewable gases in the more rural areas with relatively older, less insulated houses, a less dense population of houses and low electricity grid capacities. Moreover, even if it would be known how much renewable gases are to be used in the built environment, it still is an open question what the share of biomethane vs renewable hydrogen would be, and to what degree one will use hybrid heat pumps or existing/hydrogen boilers.

Demand level, pattern and requirements

Since this study focuses on hydrogen costs by 2030, and only little demand for hydrogen in the built environment is expected before 2030, it is hard to make demand assumptions. The 'Grid of the future' study [33] (Dutch: Net van de Toekomst) scenario's resulted in an annual hydrogen demand of 18-166 PJ in 2050. Another study, II3050 [34], which actualised the projections of 'Grid of the future' as one of the tasks described in the Climate Agreement, resulted in demand projections of hydrogen in the built environment of 0-54 PJ annually in 2050. In this analysis yet we assumed a national demand of 359kT (or 43 PJ). This volume will only somewhat affect national storage costs and requirement; for production and national pipeline transport costs the volumes mentioned are simply too small to have any serious impact. For the regional distribution of the demand, we assume built environment hydrogen application scales of a neighbourhood (some 560 houses) [5], or the size of a typical early demonstration project. In the sensitivity analysis attention will be paid to hydrogen delivery at a gas receiving station (Dutch: 'gasontvangststation' (GOS)) scale, which represents approximately 10,000 houses.

The demand profile of the built environment is characterized by a strong seasonal pattern, unlike the previously discussed end-use applications. In summer, gas in the built environment is almost only required for hot water, while on cold winter days the demand is much higher as a lot of energy is required to heat the house. Figure 60 shows the pattern that is used for the whole season, retrieved from the Energy Transition Model from Quintel. It is assumed that 83% of the annual gas demand is required for space heating and 17% for hot water [35]. The pressure of the hydrogen used in the built environment is low (<8 bars, mostly between 0-1 bars) and the purity demanded 98% [5].

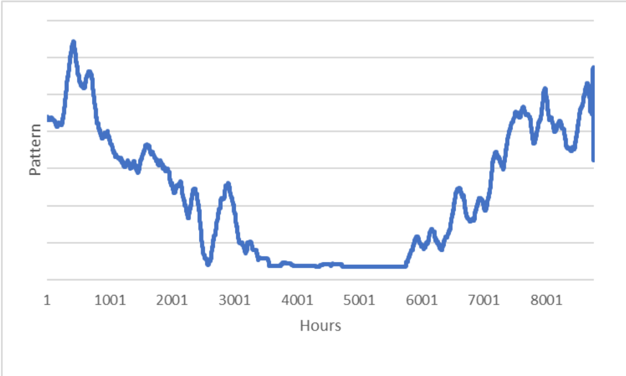


Figure 60 – Demand pattern of the built environment (in this figure hourly data is smoothened by a weekly average)

Built environment chain designs

In the built environment chains, again multiple types of chains are analysed and mutually compared.

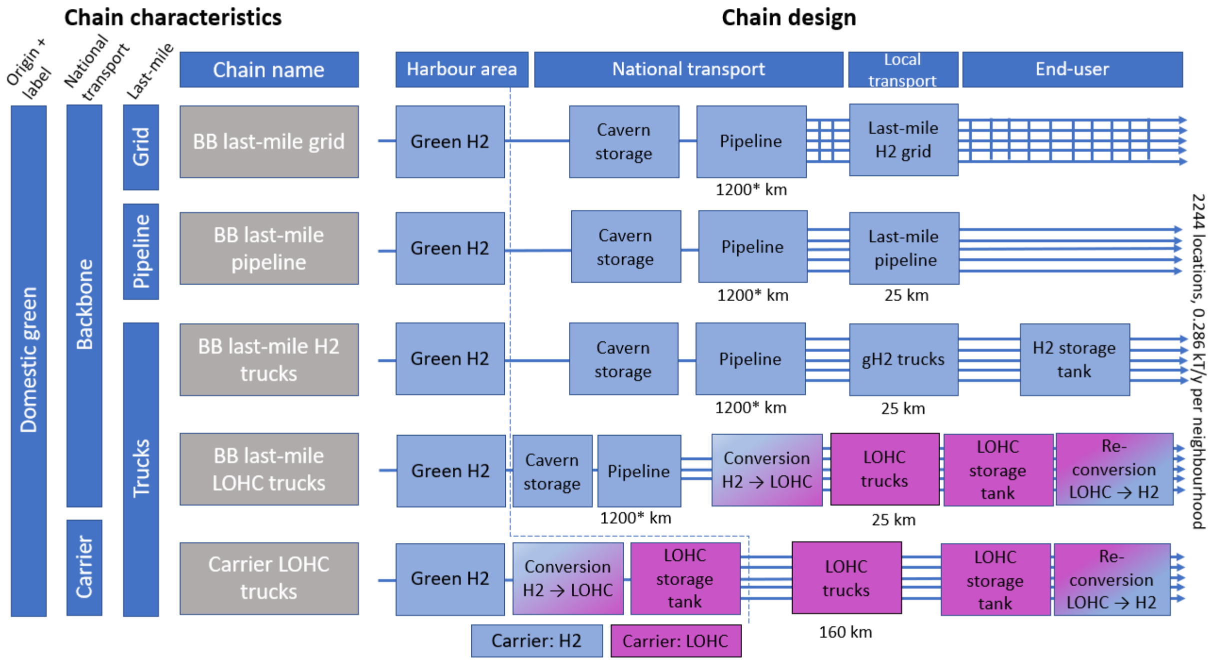


Figure 61 – Overview of the built environment chain compositions (incl. those without large scale grid repurpose) considered.

*Note: *For the national pipeline transport, a pipeline length of the proposed backbone is used and costs of 0.11 €/kg of hydrogen are taken into account based on a general analysis presented in the discussion section. The 160 km of LOHC trucks means that an average distance of 160 km has to be bridged with transport from the central point of production. For pipelines connecting the end user with the backbone 25 km is assumed. At the end of each chain, additional costs are calculated for the repurposed distribution grid, connecting the buildings with the point in the neighbourhood or local grid where the hydrogen is injected. See Appendix D for a geographical representation of the chains.*

Most chains (the upper four in Figure 62) are assumed to use the national hydrogen pipeline infrastructure (i.e. backbone), but with different last-mile transport options, namely: gaseous hydrogen trucks, LOHC trucks, and pipeline transport. The last chain (bottom one of Figure 62) assumes LOHC trucks driving through the country to supply the neighbourhoods.

Built environment results

Figure 62 shows the LCOH outcomes of the different chains. First, it should be noticed that for LOHC trucks a distance of 150 km is assumed for national transport; for last mile transport from the backbone to the neighbourhood a distance of 25 km is assumed. Dependent on the exact location of the neighbourhood, the transport costs of both options may vary with the actual distances. In options with truck transport significant costs for storage apply because of the seasonality in demand vs a stable supply needed. Because storage costs of LOHC are relatively modest, their margin are modest compared to those of gaseous hydrogen storage tank costs in chains with last mile gaseous hydrogen trucks (>18 EUR/kg). Storage costs can be limited by storing in salt caverns instead of locally, but this would require more than twice the amount of trucks to deal with the higher demand in the winter (see 'Last-mile trucks (H2 overcapacity)' in Figure 62). In the chains with LOHC trucks, relatively significant costs are due to reconversion since the capacity for this is also scaled on the high winter volumes. Because reconverting LOHC requires heat, demand for it will be relatively high during winter and small during summer, so that suitability of this type of storage may become questionable: this would cost another 1200 kWh of heat per house annually plus 26 or 154 kWh of fuels annually for the LOHC trucks to deliver at 25 or 150 km., respectively.

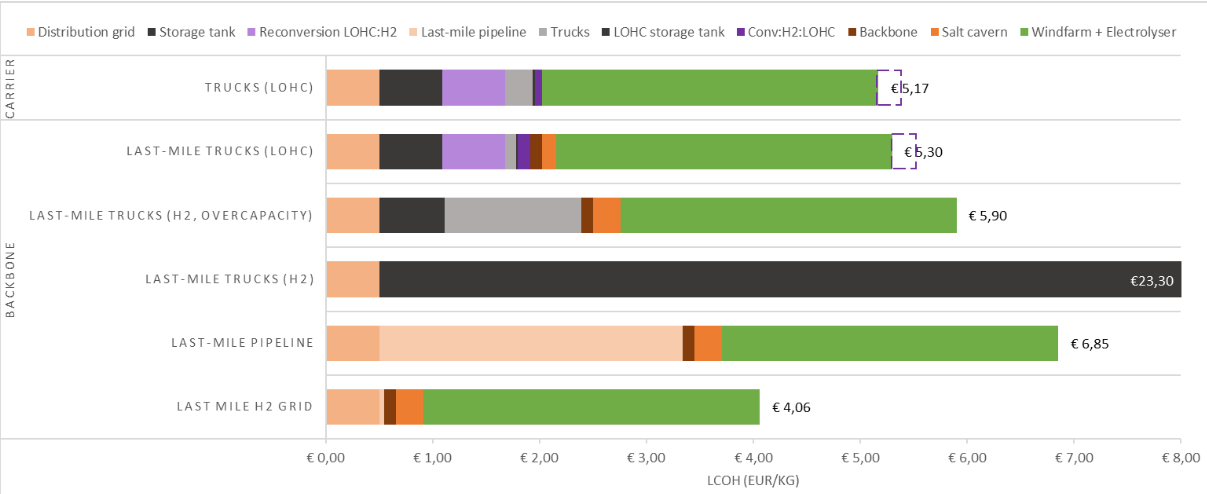


Figure 62 – Overview of the cost-distributions of the built environment value chains.

**chain steps in the opposite direction in order to better compare the impact of the different transport options in the value chains*

Main assumptions: national hydrogen demand: 359 kT/y (43 PJ). LCOE of connected domestic offshore windfarm to electrolyser resulted in 60 EUR/MWh. Heat for LOHC reconversion is considered to be waste heat of 0 EUR/MWh, if these costs would be 25 EUR/MWh, 0.24 EUR/kg costs are added in those chains (see purple dotted boxes). However, heat released during conversion to LOHC may be sold as well. National pipeline costs of 0.11 €/kg of hydrogen are taken into account, based on a general analysis (see section 5.3 in D7A.2 [7]). For the distribution grid costs 200 EUR/house CAPEX and 150 EUR/house annual OPEX is assumed [9] [10].

The chains using pipelines as last mile transport option are assumed to store volume fluctuations from offshore generation and demand in the caverns. However, connecting one single neighbourhood to the backbone over a distance of 25 km is relatively expensive. If the distance between the neighbourhood and backbone is lower than 5 km, the pipeline option would still outcompete the other last mile options for a similar distance (with total supply costs of around 4 euro per kg). If the last mile transport volumes increase (e.g. larger neighbourhoods, more neighbourhoods, or demand combining with other (large) end-users), the pipeline option becomes significantly more attractive. This is shown by the 'last-mile H2 grid' option which assumes that a local hydrogen grid could be used at similar costs as the existing natural gas grids. In the sensitivity analysis more attention will be spend on the cost reductions of the various chains by increasing the volumes of the neighbourhood or the part of the local grid that is converted towards hydrogen.

Another point of attention is the storage volume required in the different chains. Figure 63 shows the differences in storage capacity needed between chains that separate the storage requirements to balance the intermittent offshore wind capacity and the (seasonal) fluctuating demand for heat on the one hand, and chains that combine both fluctuations in one storage facility on the other hand. This is because offshore wind capacity produces most during winter when also demand is highest, so that production and demand patterns align with each other on a seasonal interval. Now, if storages are separated, one storage facility at the supply side is built to store offshore produced wind in the winter to create a stable supply during the whole year. In addition, another storage facility at the demand side is created facing most demand during the winter, so that a large buffer must be created in the summer to supply the peak demand during winter. Both storage capacities together – at the supply and demand side - exceed the single storage capacity required if both seasonal patterns can be aligned in a single storage facility.

Figure 63 also shows that the seasonal storage required to balance the demand fluctuations in the built environment (grey bar) is larger than to balance the fluctuations in the offshore wind production pattern (orange bar). To balance the total seasonality in the demand profile in the neighbourhood of tanks, a very large number of tanks would be required: 110 gaseous hydrogen tanks of 500 kg. or one large LOHC storage tank at every neighbourhood (of 560 houses).

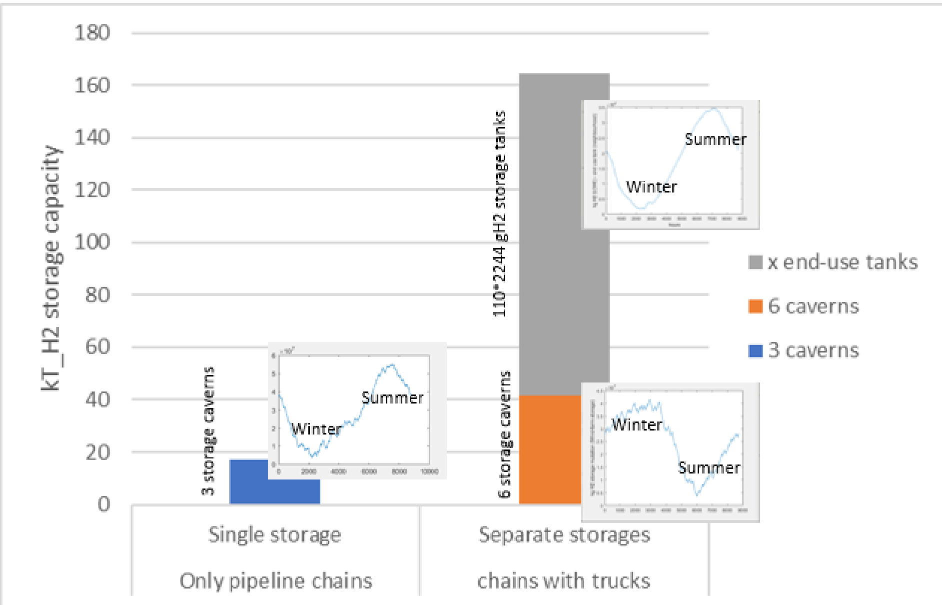


Figure 63 – Difference in required storage capacity by separating and combining the supply and demand pattern

Sensitivity analysis & discussion

The costs presented above were calculated for neighbourhoods of around 560 houses switching from natural gas to renewable hydrogen. In the sensitivity analysis, the impact of converting larger areas and of hybrid heat pump demand patterns is analysed.

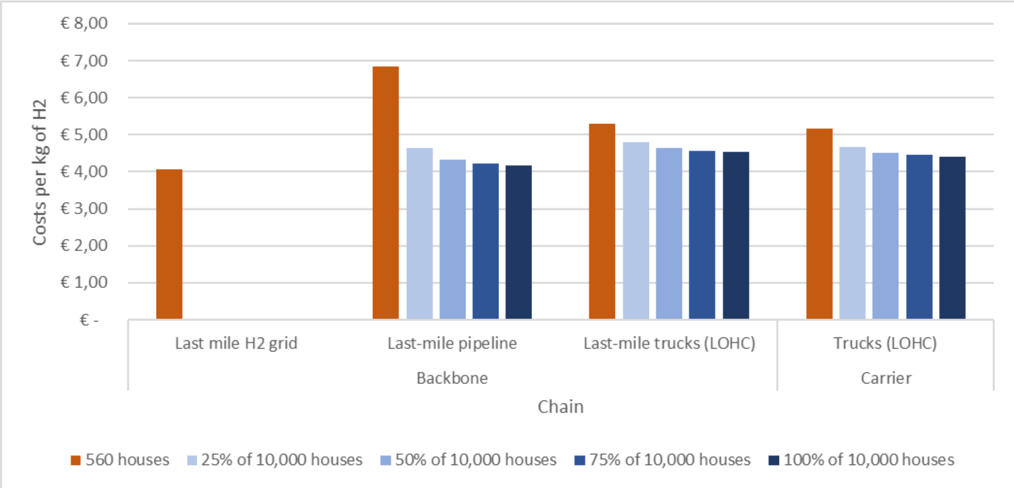


Figure 64 – Sensitivity of demand volumes for the different chains

In our cost assessment of larger-scale future introduction of renewable gases in the built environment, we will first focus on local grid delivery costs of hydrogen towards completely converted households. In doing so, an average number of 10,000 households per gas receiving station is assumed, which obviously can differ in practice. Figure 64 shows the difference in delivery costs between when a single neighbourhood is converted (i.e. 560 houses only, see red bar) or instead the whole hinterland of a gas receiving station (i.e. 10,000 houses, see dark blue bar). In general, costs of reused pipelines can be shared amongst much larger volumes in case of last mile pipeline scenarios, which would make them almost negligible for distances of e.g. 25 km. For the chains including LOHC, cost reductions are typically seen in the storage and reconversion sites near the gas receiving stations. However, issues with organising the required waste heat and fuel to operate all trucks will become increasingly severe as hydrogen flows get more significant. Also the cost impact was assessed of less houses being connected to the gas grid, e.g. because heating alternatives are chosen such as all-electric or heat grids. Figure 64 shows that then no significant differences in delivery costs apply if demand for gases decreases by 75, 50 or even 25%: in all these cases reusing a dedicated pipeline remained the most cost-effective option.

Next, the effect of hybrid heat pumps (HHP) on the delivery chain costs is assessed. Obviously the HHP option depends a lot on future developments of electricity and gas prices and electricity grid capacity. How will costs and chain design factors look like when HHPs rather than hydrogen boilers will be used? Figure 65 shows a projection of such a case by using input data from the Energy Transition Model of Quintel thereby assuming a cut off coefficient of performance (COP) for space heating of 2.6. This results in 64% of energy for space heating being electric and 36% gas [36] and an overall 53% reduction of gas demand by households while demand fluctuations will increase.

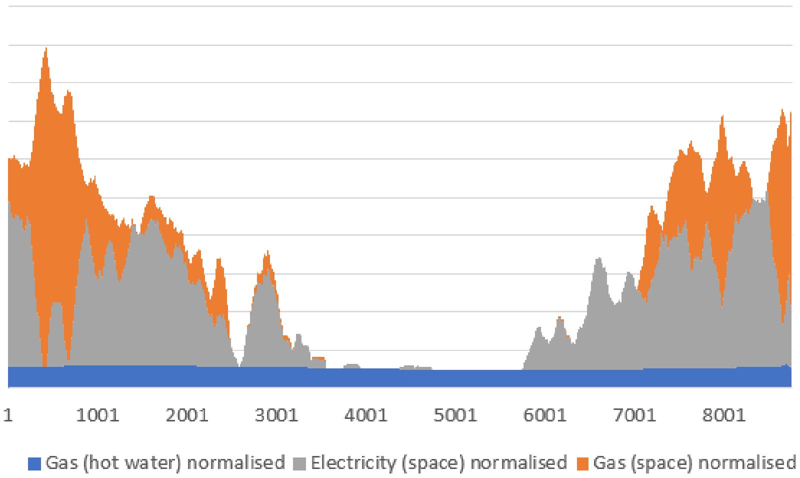


Figure 65 – Household energy demand shares when using a hybrid heat pump

The simulated increased seasonality of hydrogen demand and lower gas demand volumes do impact the costs of the hydrogen supply chains (including last mile pipelines). These costs will increase just as other connections do transporting smaller volumes. However, if pipelines use can be shared with other end-users with large volumes, individual user costs may come down significantly (see costs of last mile hydrogen grid in Figure 66). The costs of seasonal storage in gaseous hydrogen storage tanks are still very high, and therefore not represented in the figure. If an overcapacity of gaseous hydrogen trucks is used to supply during winter, this requires six times more trucks (compare the 3 times more trucks that were required in the initial case of the built environment demand pattern of hydrogen boilers). The costs of the LOHC chains mainly increase by the doubling of costs of reconversion and storage equipment required at the neighbourhoods or gas receiving stations.

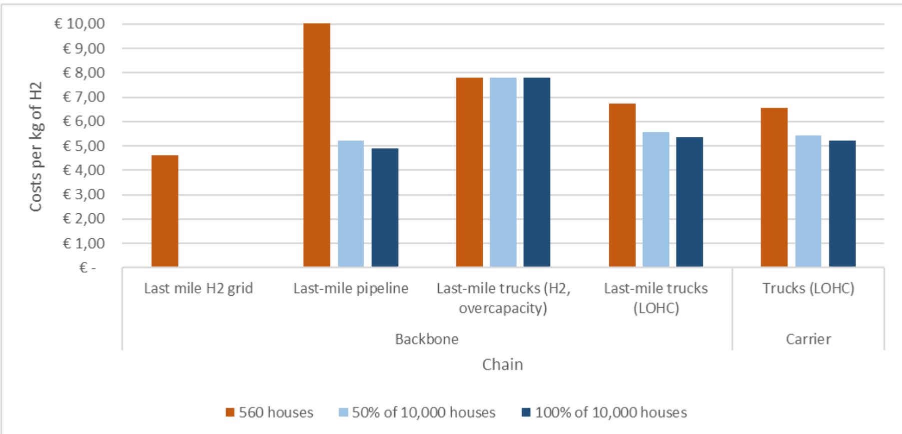


Figure 66 - Sensitivity of using the HHP demand pattern for the different chains

In previous figure the impact of using HHP on the total chain costs was assessed. A first specific aspect that should be taken into account are the impact on the distribution grid costs if less hydrogen is used per house. Typically, it is seen that similar grid repurposing and annual costs have to be made, as the number of end users (and so the share of the grid that has to be repurposed) stays the same. However, less hydrogen is transported via the distribution grid so those costs have to be divided over less volumes, which causes a rise of the distribution grid costs per kg of hydrogen. Figure 67 shows an indicative cost impact of both insulation and the use of HHP. It should be mentioned that currently only indicative costs of repurposing the distribution grids is available [9] and that the costs taken are only distributed over houses [10], while a large part of the demand in distribution grids could be filled by other types of buildings. Hence, it is reasonable that the distribution grid costs per kg of hydrogen will increase if the consumers will reduce their hydrogen consumption (e.g. via insulation or HHPs), however the actual result of this costs should be investigated in greater detail.

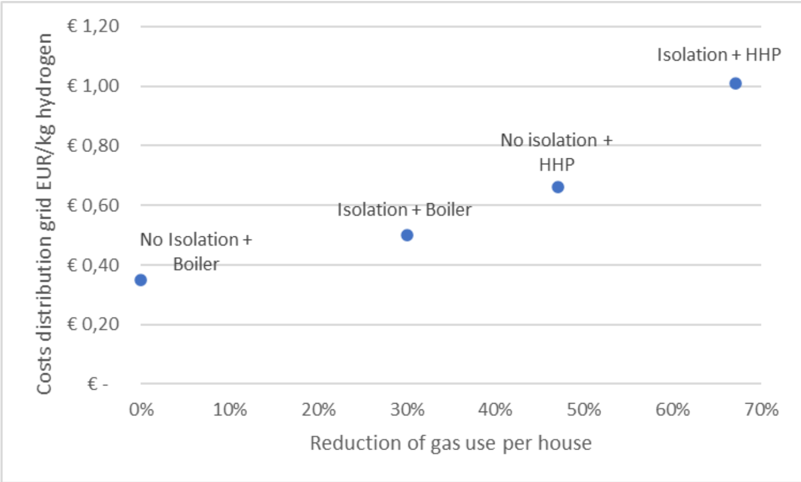


Figure 67 – Indicative impact of reduction in gas consumption of end users on the distribution grid costs.

Assumptions: annual gas demand per house: No isolation + boiler 1340 m³ of natural gas, 410 kg of hydrogen, Isolation + boiler 932 m³ of natural gas, 286 kg of hydrogen, No isolation + HHP 710 m³ of natural gas, 218 kg of hydrogen, Isolation + HHP 438 m³ of natural gas, 134 kg of hydrogen [10] [36]. For the distribution grid costs, 200 EUR/house CAPEX and 150 EUR/house annual OPEX is assumed [9] [10]. Note: the costs of repurposing the distribution grid are indicative but the best publicly available yet, further research is required here.

Figure 68 shows the impact of HHP on the required storage capacities. It should be mentioned upfront that total storage capacity demand for the HHP built environment (BE) scenario is just 47% of demand in a scenario with dedicated gas boilers. Despite these lower volumes, still more storage capacity is required in the offshore wind and HHP profile than in the offshore and initial H2 boiler profile. This is because the time profiles of offshore wind and HHP are less aligned primarily due to the stronger seasonality of the HHP pattern. However, still more storage capacity is required when the storage capacity is divided in one facility dealing with supply- and another with demand-fluctuations.

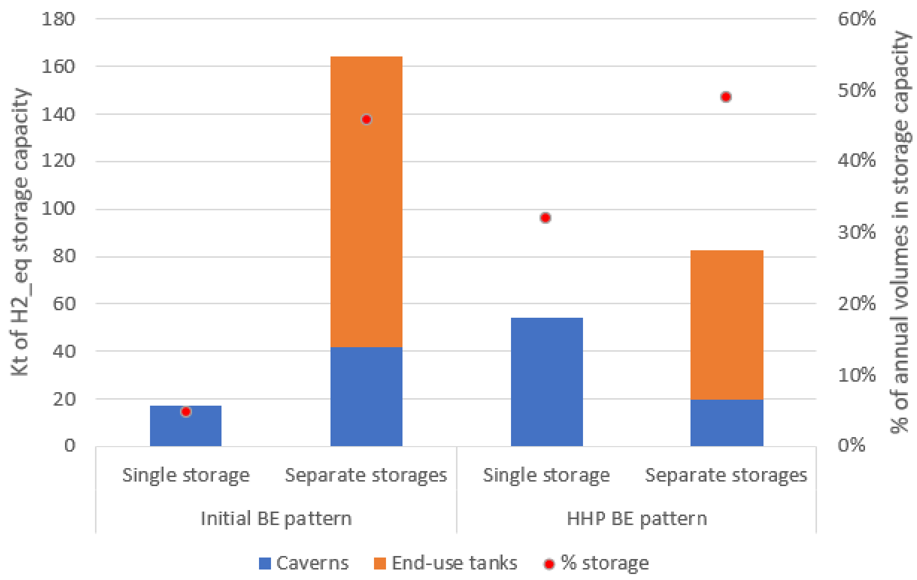


Figure 68 – Impact HHP demand pattern on the required storage capacities

Competitiveness with sustainable alternative

The competitiveness of introducing hydrogen in the built environment is very much dependent on site-specific conditions. Because essentially energy has no value unless it is delivered in the right form, at the right time and at the right place, conversion, storage and transportation conditions of the full energy system will determine if, where and when hydrogen in the built environment pays off. Assessing this requires a dynamic and spatial analysis of electricity and hydrogen markets to determine if and at which moments (in the case of hybrid heat pumps) hydrogen will be more competitive than electric alternatives. In the 'Start analysis for natural gas free neighbourhoods' of PBL [12], it is, for instance, shown that in the Netherlands there are many places where all electric or heating grids would be relatively too expensive options because: the electricity grid has low capacity; houses are poorly insulated; and/or the density of buildings is too low to deploy a heat grid economically. In these cases renewable gas such as hydrogen seems the most cost-effective long-term option. In the following we will focus on such cases.

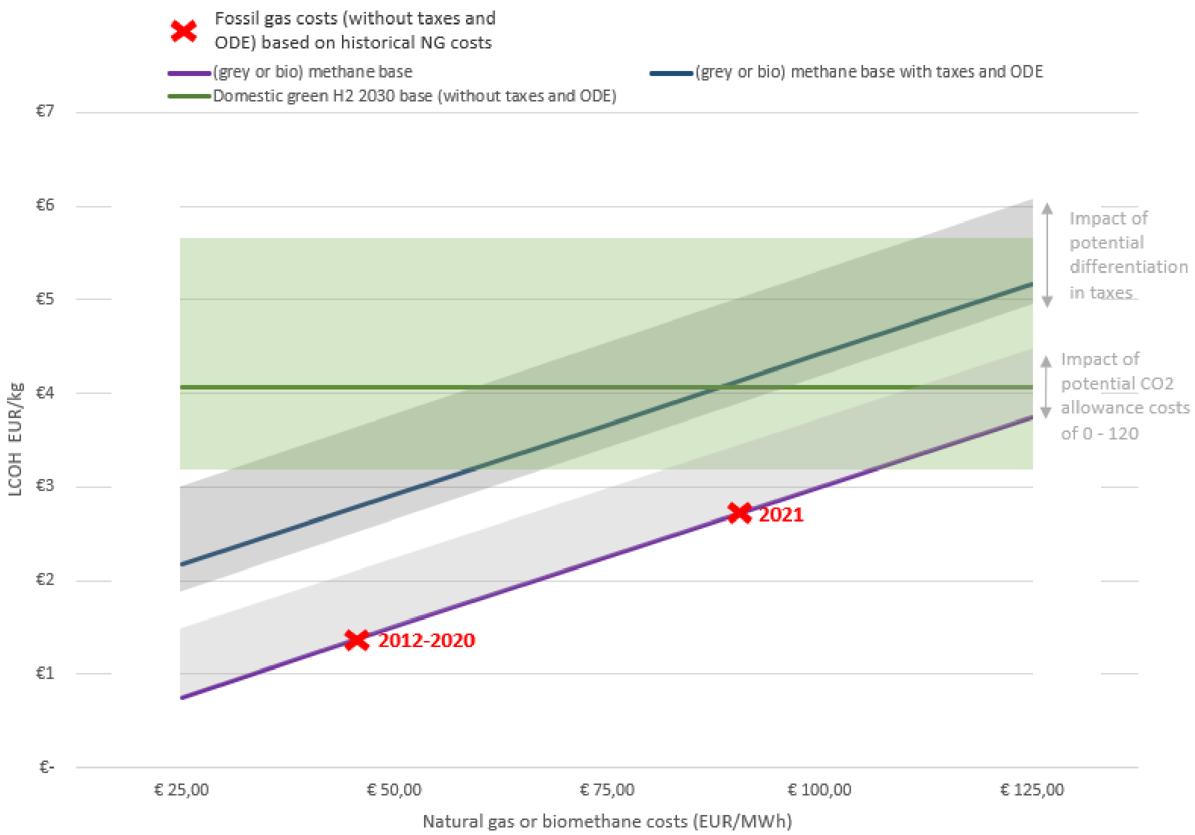


Figure 69 – Cost competitiveness of renewable hydrogen in the built environment. Assumptions: In comparing natural gas with hydrogen, an equivalent amount of energy has been used. This is presented via a hydrogen price equivalent (i.e. the required price for hydrogen to be competitive with natural gas given its price). Both natural gas costs have been shown, i.e. those excluding (purple line) and including taxes and ODE based on 2021 tax values [11] (grey line). The purple area addresses the impact of a potential CO2 price in the built environment for burning methane (0-120 EUR/ton CO_2) and the grey area the impact of tax differentiation (low: only differentiation in normal taxes without ODE, high: increased taxes of 75% in 2030, according to plans described in the Climate Agreement [12]). The levelized costs presented include transport costs to the households. The green areas mark the uncertainty cost ranges of the green hydrogen production cost developments until 2030. The carbon costs of using natural gas are calculated based on the assumption of an emission of 0.203 tCO_2/MWh. The natural gas price of the past decade was some 30 EUR/MWh and transport costs for households some 15 EUR/MWh. Currently, the built environment is not part of the EU Emission Trading Scheme (ETS). However, in the recent RED II amendment a similar emission trading scheme is proposed for this sector.

Figure 69 shows the bandwidth of green hydrogen costs found in this study (except from the chains with significantly higher costs that have been disregarded). The x-axis shows potential methane prices of biomethane or natural gas. Currently, the sustainable origin of methane can be proven by Guarantees of Origin (GoO), which were traded in the Netherlands in the 2021 price range of some 10-20 EUR/MWh [37], although such levels do not fully cover the gap between biomethane and natural gas production costs. Costs of biomethane range between 50 and 100 EUR/MWh [5], whereas costs of green hydrogen retrieved from this study averaged at 87 EUR/MWh with a bandwidth of 59-119 EUR/MWh (see also section 4.1). These data suggest costs of hydrogen to be higher than of biomethane, but this may obviously change in time and subject to situational characteristics, such as availability of biomass or renewable electricity.

Comparing the current costs of using green hydrogen with those of natural gas (still the energy source of 95% of the existing heating demand in the built environment) shows that the 'traditional' costs of using natural gas (<25 EUR/MWh) were significantly lower than of using renewable hydrogen against current prices. However, the excessive rise of natural gas prices since mid-2021 have changed this picture a lot, just as CO_2 prices do (albeit to a less significant degree). Next to these factors future tax moves may have a further decisive impact on the competitiveness of green hydrogen vs fossil alternatives (see also the Dutch Climate Agreement on this).

5 Discussion

In the previous section value chains for specific type of end users are analysed in great detail. In this section, the results will be discussed based on four topics: the insights with regards to the market dynamics of the hydrogen value chains; the business cases and financial incentives required to make hydrogen value chains economically viable; reflections based on the practical roll out of hydrogen value chains; and limitations and directions for further research.

5.1 Market dynamics and competitiveness hydrogen value chains

Developing future value chains for a hydrogen economy is challenging if only because of the multiple chain actors involved, all with their own perspectives and interactions between different value chains. Moreover, virtually all hydrogen value chain elements still are in their early stages therefore still facing many unknown factors and risks from a business case perspective. In Appendix E 'Market Dynamics' the potential future markets and their interactions have been analysed, and three ways towards future development of existing energy carrier markets were presented:

1. Facilitate the mutual commitment of supply chain actors through governance
2. Use the available hydrogen to minimize emissions
3. Create infrastructure to facilitate local open market places

The stakeholders of all chain elements of the complete value chain need to make investment decisions to decarbonize and to develop their new business model. To diminish their risks in doing so, it is important to have the best information and to start early collaboration and governance in decarbonising the complete value chain. Techno-economic modelling as used in this analysis can help in projecting capacities and related costs aiding stakeholders in decision-making on what to focus on in preparing for the future, but there will always remain significant uncertainties around all kinds of parameters paralysing investment. Reducing such uncertainties by e.g. policymakers and/or research therefore remains essential for progress.

By focusing on (potential) hydrogen or hydrogen-carrier end use cases that have a significant decarbonizing potential, this study tries to concentrate on value chains that are expected to matter most to reach mitigation targets on the medium run. Large industrial feedstock markets, for instance, such as the fertilizer and E-fuel industry, operate on world-wide markets and require yearly hundreds if not thousands of kilotons of hydrogen (or NH_3) to maintain production levels while having little other alternatives to decarbonize than introducing carbon neutral hydrogen. Local plants with high-temperature heat demand are another category with few decarbonisation alternatives other than carbon neutral hydrogen. Lastly, categories with similar issues of hard-to-abate and not-easy-to-otherwise decarbonise local energy demand and therefore with significant hydrogen potential, are heavy-duty mobility (trucks, buses. long-distance cars, shipping, trains and aviation) and older type of buildings in the built environment, which are very expensive to insulate to the level needed to use heat pumps.

The chicken-egg problem hydrogen development is facing is sustained if there is no clear and timely development in all factors - supply, accessible infrastructure, or demand – relevant for hydrogen or hydrogen-carriers. Producers want to know if and how much demand for hydrogen or specific carriers there will be in the future, transport companies want to know where hydrogen will be produced and consumed and end-users do not know when clean hydrogen will become available as option to decarbonize their processes. By thoroughly analysing separate value chain designs by combining supply, infrastructure and demand, this research provides stakeholders with insight in the (potential future) economics of dedicated value chains. The development of these value chains provide insights in the required infrastructure options for the development of a liquid, mature and open hydrogen market.

5.2 Business case reflections and financial incentives

Next to the analysis of hydrogen value chains themselves, the costs of hydrogen as an energy carrier (or feedstock) have been compared to those of (existing) alternatives to put the value chain analysis results in perspective. To decarbonize the end-use chains considered various incentives can be introduced.

Firstly, the ones with the greatest impact on the value chain costs are represented in Table 6. This is because the analysis shows that the largest share of hydrogen value chains' costs is typically due to the production chain element and reduction of the costs of the most sensible parameters would have the greatest impact on the production costs. Financial incentives to lower hydrogen production costs will therefore be relatively effective in enhancing its introduction, but incentives will more generally be most effective when sustaining a structurally better business case (instead of only improving the business case as long as the financial incentive lasts).

Table 6 - Costs and incentives for H2 production.

Costs of production				**Incentives**	
	Uncertain parameters	**Sensitive parameters**		**Potential financial incentive**	**Potential policy incentives**
Green Hydrogen	• Wind farm costs • WACC • Wind speeds • Electrolyzer stack lifetime	• Wind farm capex • WACC		Financial incentives for structural windfarm capex reduction, financial risk reduction for investors.	Research in windfarm capex reduction, increasing knowledge on new technological concept also reduces financial risks.
Blue Hydrogen	• ATR (Large-scale) Capex • CCS Capex • WACC • Natural Gas price	• Natural Gas • Scaling effects of ATR+CCS technology		Reduce the price, or the uncertainty of the price, of natural gas when CCS is used.	Analyse specifically which technological parts of blue hydrogen are subject to economies of scale.
Import	Country specific: • WACC • RES costs	• WACC • RES costs		*HyDelta deliverable WP 7B*	

Secondly, another consideration in financial incentives is the 'stacked value' of those incentives. Actually, the required investments to repurpose the natural gas pipeline grids for hydrogen are independent of the volumes that will be transported by the pipelines, as long as capacity stays sufficient. This means that each euro of financial support in these investments can benefit multiple types of end users to receive the hydrogen against lower costs.

Thirdly, it should be considered that every part of the chain should be in place before hydrogen can really be deployed. For example, a lot of financial support can be given to the production stage of the clean hydrogen, but if there is no transport and storage infrastructure, or the technology to set up chains with LOHC is not developed far enough, the hydrogen cannot be brought to customers at the right place at the right time and therefore will not come off the ground. Hence, although probably decreasing production costs could have the largest impact on the total value chain costs and an euro spend on repurposing pipeline infrastructure will benefit the costs for a lot of potential customers, in the end it is most important that support measures ensure that every desired part of the value chain is being developed in one or another way.

5.3 Practical implications for the roll out of hydrogen value chains

In this section it will be reflected on what information the modelling outcomes provide that can be useful in the development of hydrogen value chains. Moreover, there is reflected, with the outcomes and some additional calculations, to understand how the considered chains may benefit from being developed in parallel.

Potential of value chains being developed individually

In this report hydrogen value chains have been analysed for multiple end-users covering: ammonia, methanol, high-temperature industrial heat, fuel cell electric mobility, and the built environment. For the truly large industrial sites using (and often producing) large volumes of ammonia and methanol, economies of scale often are already that large that just one large hydrogen production plant or pipeline could already be deployed economically when that plant would switch to renewable (or carbon neutral) hydrogen. Obviously for such big players it will be hard to step over from 0 to 100% renewable hydrogen just like that, but in such a transition their location, often typically in clusters with other large industrial plants, is likely to be supportive in reaching the volumes required to deploy new value chains. For more distributed end-users, like most of the other value chain types analysed, all kinds of factors, but especially transportation towards the end-users. may be more of a challenge.

Due to the relatively large hydrogen demand volumes in distributed industrial heating plants, a dedicated delivery chain with LOHC trucks and related conversion and reconversion can often be set up relatively cost effectively. Moreover, the waste heat from the plant could potentially be used for reconversion of LOHC. However, in these chains the hydrogen option will mostly have to be compete with (low-priced) natural gas (prices of autumn of 2021) and biomethane (that can just be transported via the existing pipelines). Another point of attention is the (potentially high) costs of the required transport flows of trucks and whether investments in local LCOH reconversion plants and storage capacity may become superfluous because at some point in time gaseous hydrogen could become assessable via a (reused) pipeline grid.

In the mobility end-use the comparable option of LCOH truck chains have been investigated. The advantage in this type of end-use is that the price of the sustainable and fossil alternatives for long-distance or heavy-duty transport may be higher than those of industrial heat. Moreover, the volumes are lower, requiring less trucks to transport the volumes. However, multiple HRSs should be deployed to achieve the required economies of scale for LCOH conversion, and a disadvantage (in terms of mitigation) is that for reconversion heat is required. Therefore, the less cost-efficient gaseous hydrogen trucks can sometimes be feasible as well. Moreover, introducing just local electricity grid connected value chains in mobility were found to be sometimes quite promising and deserving further investigation, the more so since they provide options that can be deployed independent from other hydrogen value chains or value chain end users.

The results of the built environment value chains instead showed the opposite, namely that developing hydrogen value chains independent of other types of end-users will almost always become quite expensive or unfeasible because of other reasons. Due to the large storage capacity required to deal with seasonal fluctuations, local storage may face high costs and spatial requirement issues in case of gaseous hydrogen storage in tanks, or, in cases of LOHC storage, high levels of heat demand at times when much heat is demanded from houses. Hence, in such cases both national transport connections and relatively large-scale storage may be required which may only be economically feasible if significant hydrogen volumes use this infrastructure. The challenge will therefore then be to organize end users such that they provide the critical mass of hydrogen demand for heating their homes and/or other end uses that investment in the necessary infrastructure pays off nicely. Public authorities and distribution companies may be helpful in organizing such demand volumes.

Now that the potential of developing hydrogen value chains for each type of end use has been discussed, we will focus on the opportunities to combine infrastructure for multiple end users on both a local and national scale.

Combining end users for national and last-mile transport options

For all the types of end users, hydrogen value chains including national pipeline infrastructure were considered. If pipelines are reused, the costs of reusing this infrastructure will be independent on the volumes that are transported through this pipeline system (as the pipelines are already there, so no choices can be made with regards to sizing etc.). Therefore, the more users and volumes are connected to this national grid, the relatively lower the costs of transportation per kg. This is represented in Figure 70. The figure illustrates the mutual benefits of users of the grid, when the amount of users increase. On the other hand, the figure shows that significant volumes are required to increase the cost efficiency of the means of transport. Similar to the HyWay27 study [38], it is assumed that 1000 km are reused pipelines and 200 km are new pipelines with the same diameter as the existing pipelines (0.91 meter). The figure show the indicative levelized costs of transport based on the annual volumes transported. A typical issue is that volumes of clean hydrogen are currently low and expected to increase over time. This means that volumes can be relatively low after the investment in national pipeline infrastructure is made, and increase over time. The longer it takes for these volumes to develop, the higher the levelized costs will become.

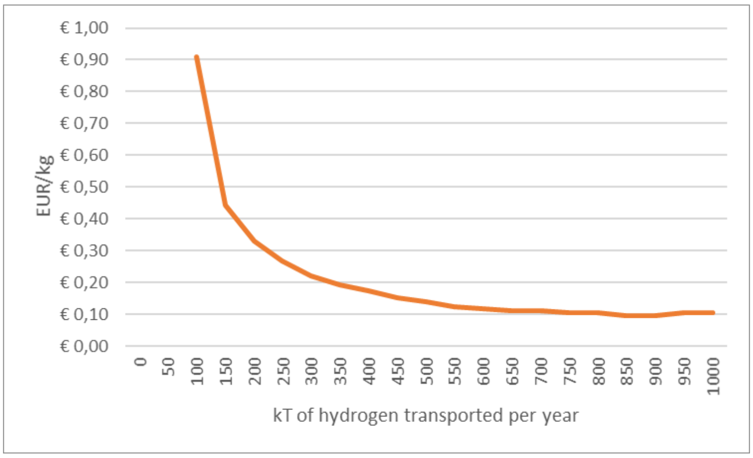


Figure 70 – Indicative impact national volumes on national reused pipeline levelized costs of transport.

Assumptions: two times 500 km reused pipeline, 200 km new pipeline, both diameter of 0.91 meter (see pipeline function in Appendix A for calculation methodology)

In the analyses of the separate end users, it became clear that pipeline transport costs were often likely to be quite significant per unit transported if the chain-related transported volumes were rather low, as often would be the case. This result obviously will change if somehow transport demand and its time profiles of different end use categories can be combined. This can in practice, for instance, be achieved by locally clustering industrial users, sets of local neighbourhoods and one or several HRSs. To show how costs are affected if such a cluster is subsequently connected with a potential hydrogen backbone, pipeline costs for both reused and new pipelines are shown for differing distances and volumes in Figure 71. It shows that for a cluster located 10 km from the backbone, hydrogen can be made available for cluster end users against a price below 10 cents per kg if demand represents >1.5 kT/y and a an existing pipeline is reused, or >4 kT if a new pipeline has to be be constructed. If the cluster is located further away from the backbone, for example 50 km., at least 4 kT/y of hydrogen demand is required to be able to transport these volumes against a price of less than 10 cents per kg.

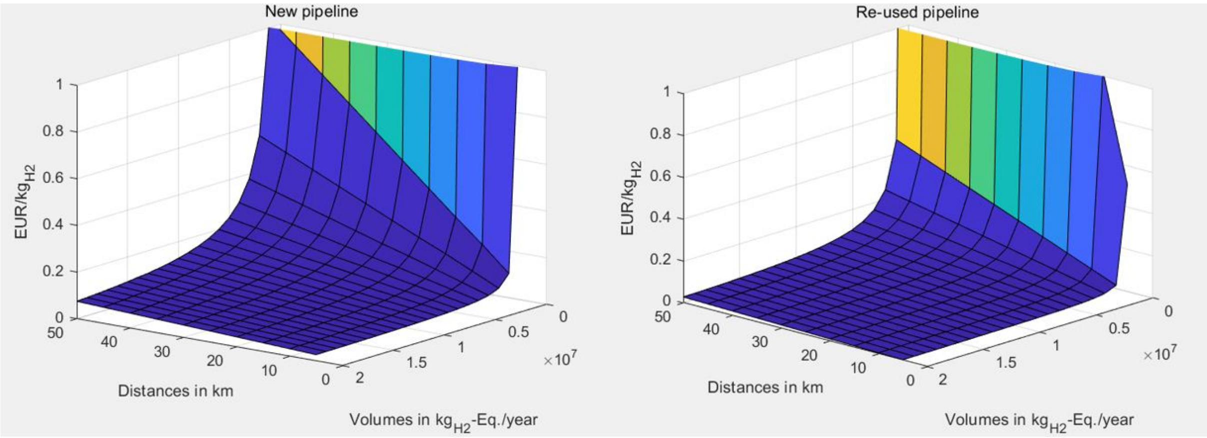


Figure 71 – Last mile levelized hydrogen costs of transport by pipelines.

X-axis: distance in km, Y-axis: levelized costs of hydrogen transport in €/kg, Z-axis: the annual transported volumes ($0.1*10^7$-$2*10^7$ kg equals 1-20 kT of hydrogen).

In Table 7 the estimated annual hydrogen demand volumes per type of end user distinguished in this study are shown. This reveals that expected hydrogen demand volumes of already average, but certainly large industrial plants, or of multiple smaller plants could work as true hydrogen uptake accelerator for a specific region. If one such a larger plant is connected via such a pipeline, nearly located neighbourhoods and/or new HRSs can also easily be connected relatively cost effectively as well. Even if such a larger plant is not present at a certain location, a serious cluster of houses, other buildings or smaller plants could also act as a similar precursor of sufficient economies of scale of local hydrogen pipeline transport capacity. This option of local collective pipeline end users seems rather promising and would deserve serious policy attention as one of the key alternative routes to speed up and scale up the introduction of significant mitigation via a broader introduction of hydrogen.

Table 7 – Annual demand volumes per type of end user (and for indicational purposes the energy equivalent in natural gas)

Potential users local pipeline	Annual H2 demand (kT)	NG energy equivalent (m^3)
1000 houses (HHP)	0.134 kT	437,864 m^3
1000 houses (H2 boiler)	0.286 kT	934,547 m^3
HRS (400kg/day)	0.146 kT	477,077 m^3
HRS (5000kg/day)	1.825 kT	5,963,456 m^3
Industrial plant (small)	2 kT	6,535,294 m^3
Industrial plant (average)	7 kT	22,873,529 m^3
Industrial plant (large)	20 kT	65,352,941 m^3

Figure 72 shows the impact on the last mile transport costs of sharing a last mile pipeline towards a region by multiple types of end users. In this case (25 km) costs of reusing a pipeline for an industrial consumer are already very low. However, in isolation the hydrogen demand volumes of one HRS or one neighbourhood would probably be too low to start reusing existing pipelines for hydrogen on a sound economic basis. The figure below shows that if there is an industrial user in the area starting to use hydrogen, other initially (much) smaller end users categories could benefit by joining against relatively low costs of connecting. A similar effect can potentially be seen for the distribution grid costs if one or multiple large heat consumers, connected at the distribution grid, will move towards hydrogen. Further research, specially focussing on this topic, is required to identify the potential impact of different types of local users (e.g. large buildings, shopping centres, small industry) on the end user costs of repurposing distribution grids towards hydrogen.

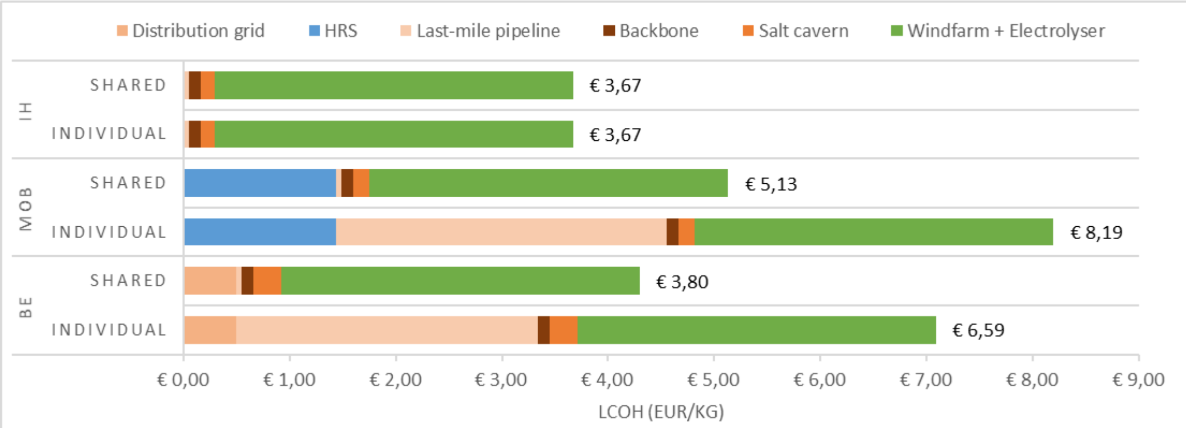
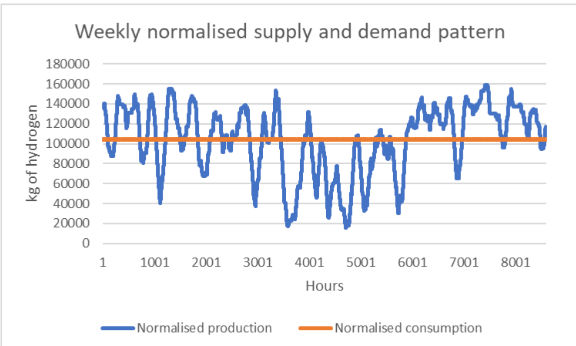


Figure 72 – Cost reduction of sharing last mile (regional) pipelines compared to using individual pipeline infrastructure per end use. Assumptions: in the individual chains a single end user (industrial plant (IH), HRS (Mob) or neighbourhood (BE)) is connected to the last-mile pipeline of 25 km connecting the end user with the backbone. If that pipeline can be shared among the one of each three types of end users, the pipeline costs are based on the consumption volumes of those three end users together.

Combining different end user patterns in one national storage facility

Just like sharing the use of a pipeline system, can storage capacity be shared amongst different end use applications as well. In the analysis of the built environment end use, it was observed that the seasonal demand pattern of the built environment partly matched with that of the offshore wind electricity production. So, less storage capacity was needed than if annual demand would have been stable. Adding the built environment to the mix of hydrogen users will therefore reduce the total storage capacity required, as least assuming electricity supply from offshore wind. This case can be illustrated with the help of Figure 73 in which industrial feedstock, industrial heating, and mobility demand patterns have been combined. The blue line (Figure 73a) shows the variation in supply by the offshore wind production, which is lower during summer than in the winter. If the demand is stable during the year (orange line in Figure 73a) the storage is filled during winter and released during summer (see Figure 73b). In this case 15 caverns would be required if there would be a national annual demand of 1000kT of hydrogen from the different sectors, representing capacity to store 11.6% of the annual demand.



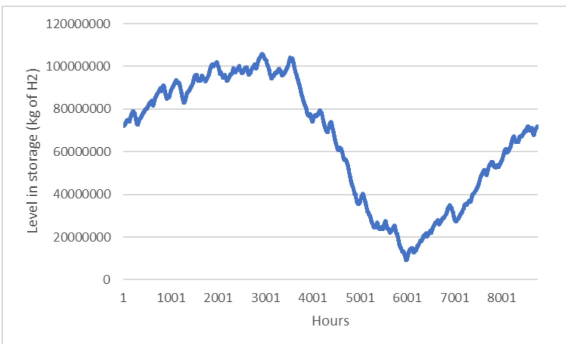


Figure 73 – Stable demand: Weekly normalised supply and demand pattern (a) and storage level during the year (b)

If starting from that case now 400 kT of hydrogen demand from the built environment (use of hydrogen boilers) would be added, the storage requirement will change. Now, the combined demand pattern of storage capacity is not stable anymore over the year; instead there is more hydrogen demanded and produced during winter (see orange line Figure 74a). In Figure 74b it is shown that there is in fact not one seasonal storage cycle anymore, but various cycles each with shorter durations are created by relatively colder and warmer weeks/months and/or relatively more and less windy weeks/months. The counterintuitive simulation result shows that although the hypothetical national demand increased from 1000 to 1400 kT, yet less storage capacity is required, namely 11 (instead of 15) caverns, representing a storage capacity of only 6.1% (instead of 11.6%) of annual demand.

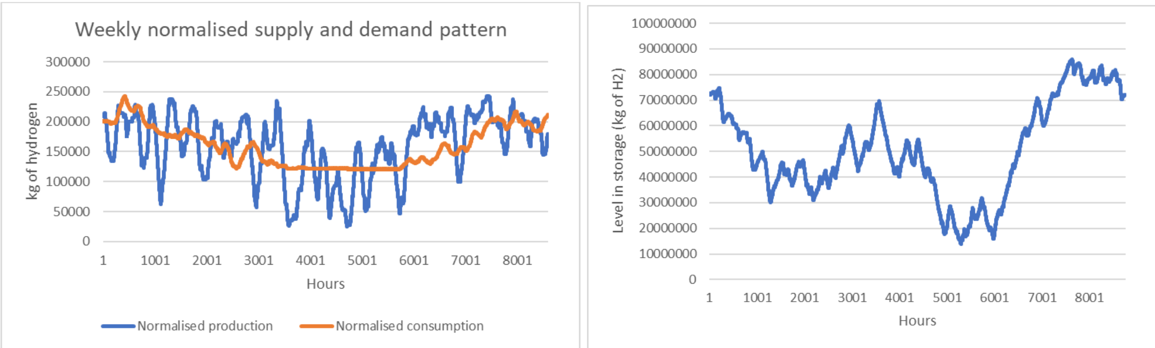


Figure 74 – BE demand: Weekly normalised supply and demand pattern (a) and storage level during the year (b)

In our earlier analysis similar results did show up. For instance it was shown before that the most optimal case of national storage capacity needed would be reached (compared to the storage capacity needed if there would only be end users with stable demand) if 26% of national hydrogen demand would come from the built environment (in case of boilers). This would reduce the required national storage capacity by 53%. In case of hydrogen demand according to the HHP pattern, having 19% of the national demand being built environment resulted in the lowest storage capacity (35% less than if there would have been only stable demand). So, adding hydrogen demand to the overall national demand for hydrogen carries ceteris paribus the non-trivial bonus of needing substantially less storage capacity than otherwise!

This does not imply that hydrogen demand from the built environment is the only way to reduce the national storage capacity needed to balance the hydrogen market. Balancing hydrogen seasonality in supply can also be achieved by adding solar power to the supply profile, or by additional blue hydrogen supply during summer. However, it does say that matching the right shares of supply sources with the expected demand types could reduce the required storage capacity significantly. Hence, sharing storage capacity, beyond the fact that it may help to secure supply by downtimes of certain suppliers, can be most beneficial when specific sources and end users can be combined balancing their individual fluctuations.

Implications of results for the developments of infrastructure

Based on the analysis in this study, recommendations can be provided for the development of hydrogen transport infrastructure in practice:

1. Users with relatively large volumes, so called 'launching customers' can accelerate the development of both national and local cost efficient transport infrastructure;
2. The right mix of sources that matches the demand profiles could reduce the storage capacity requirements significantly;

3. Hydrogen transport and storage by carriers can be used for domestic transportation and storage purposes in the initial phase of development or in specific situations. However, especially when the carriers are used for transport and storage purposes only (e.g. liquid hydrogen and LOHC), the additional energy requirements should be taken into account (see Figure 75).

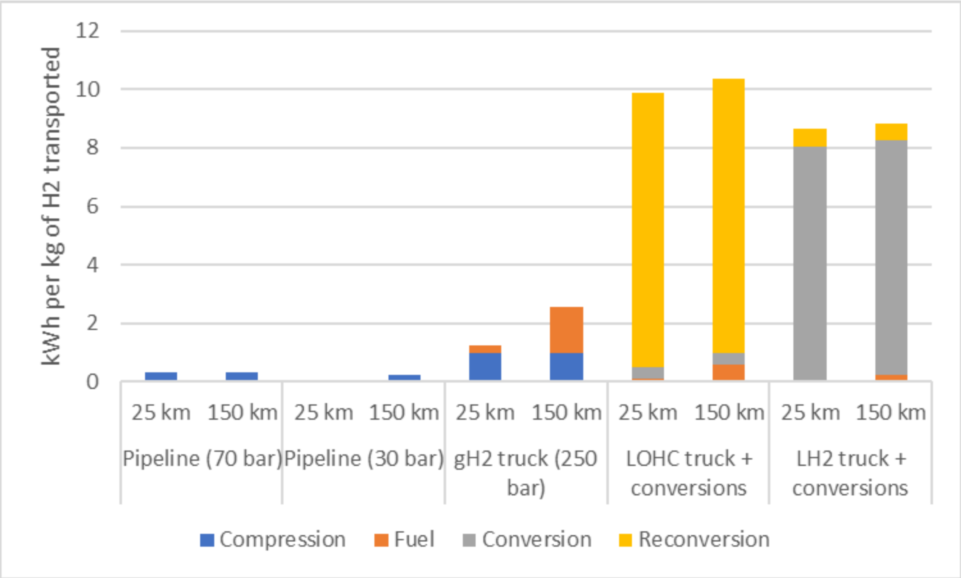


Figure 75 – Energy consumption required for the transportation of one kg of hydrogen (equals 33,3 kWh) Note: during conversion of hydrogen to LOHC 8 kWh of heat is released.

5.4 Limitations and further research

During the analysis and discussion of outcomes, several aspects of our study are discussed that should be taken into account when drawing conclusions. In this section, the main limitations of the study are summarized as follows:

- The study is designed to analyse value chains of different end user types in a generic Dutch context, in order to structurally compare and analyse the specific characteristics that should be taken into account for the development of those value chains. The results of this study should be seen in this perspective. In practice, and also highlighted in the discussion of our results, it is seen that sectors and end users are not that strictly separatable and a lot of situational characteristics could impact the costs. For example: different type of end users are currently connected to the same infrastructure and national legislation is in place how the costs of that infrastructure are distributed among the end users. Moreover, every region will have its own specific characteristics, which could lead to other insights.
- This study specifically focusses on value chains for hydrogen and insights specifically gained based on this scope, as this was the focus and scope of the research. The relation with other energy carriers and markets is taken into account if applicable during the discussion of the results and in Appendix E. Obviously, hydrogen value chains will in any case be part of the greater energy system, which should be taken into account when interpreting the results.
- The designs of the chains are based on fully renewable and low carbon (>95%) options. It should be noted that in the short term other hydrogen value chains are available partially reducing the emissions. Some typical options often discussed are blending hydrogen in existing natural gas grids, reusing CO_2 from other processes instead of retrieving it from Direct Air Capture, or partial capture of CO_2 (e.g. 60%) for the production of 'low carbon' hydrogen.

- With regards to the domestic green and blue production costs the following should be considered: for green hydrogen production a dedicated offshore windfarm is used to generate electricity for the electrolyser. In reality a lot of different designs are possible, for example that part of the generated electricity can be sold to the grid, or potentially (dependent on the legal requirements for green hydrogen production) even that grid electricity is used to produce hydrogen. All those options could result in different LCOH, but are considered to be out of scope for this report. With regards to blue hydrogen production it should be taken into account that in this study blue hydrogen is produced via newly constructed ATR+CCS plants, while multiple options are available as well, such as applying CCS on existing SMR plants.
- In this study 1% buffer stock is assumed for the storage, additional to potential supply and demand fluctuations. Specific operational characteristics and the risks taken to run out of stock will determine the actual storage capacity that is installed at specific locations. Especially gaseous hydrogen tank storage, usually representing 0.35-0.60 €/kg of hydrogen for 1% buffer stock, reduction or increase if this buffer stock could significantly impact the chain costs.
- The HRS design, local characteristics and its operational strategy a specific topic, but do impact the value chains of hydrogen delivered to road transport. In this study, a general HRS design is taken, however, in practice characteristics as storage capacity, compression capacity, delivery pressure and local production can be optimized based on situational characteristics, such as HRS utilization and availability of local RES. A lot of research in technologies, operational strategies and optimizations of HRS and their chains is going on and still developments are made, therefore the HRS costs in this study should be seen as the rough, indicative costs but could differ in specific cases or innovations in the future.

Based on the results and limitations of our study. We want to highlight several topics of further research that would be of interest:

- As discussed, the production costs of green hydrogen are of large impact in the value chains assessed. Moreover, the potential development in costs due to 1) technological innovation (in both electrolyser and RES-based power generation); and 2) large scale deployment projected; by literature has a major impact on the cost effectiveness of the green value chains. Besides deployment, also research that could reduce the costs in this part of the chain would be most effective to make green hydrogen value chains more competitive, for all type of end users.
- In our research we only took reuse of existing natural gas pipelines into account. Further, more detailed research should specify to what the impact of repurposing existing capacities and infrastructure of the Dutch industry (e.g. at existing ammonia and methanol plants, capturing CO_2 from existing hydrogen production facilities) could be on the preferred future value chains, also taking to long term perspective into account.
- In order to move towards fully decarbonized value chains, as analysed in this study, 'in between' steps could be considered when developing the clean hydrogen value chains, such as chains reusing emitted and captured CO_2 instead of the currently relatively expensive DAC technology. Further research should focus on identifying the most potential directions, such that: 1) Investments made for those 'in-between' steps have long term value and are preferably not temporal; 2) The 'in-between' steps do not create a lock-in for moving towards a fully decarbonized chain.
- Local HRS chains turned out to have potential to supply hydrogen against competitive costs, but more specific research is required in the optimizations of available RES and HRS design. Especially at places where hydrogen demand for mobility is expected and the electricity grid is

congested often, potentially local electrolysers, besides batteries, can be used to help stabilizing the grid[8].

- The hydrogen value chains turn out to have the well-known chicken-egg problem and in this study it is seen that there is potential for mutual benefits between end users, including dependencies on so called 'launching customers' that could make infrastructure investments more cost effective. Future research should focus on the impact and strategy of different types of end users and chain stakeholders to make effective combined investment decisions to develop cost effective chains. Additionally, the required political incentives and legislative frameworks should be explored.
- Not a lot of publicly available studies have investigated the costs of converting distribution grids to hydrogen. The report of Kiwa [9] provides a lot of information about repurposing the distribution grids, however, authors describe the cost information as indicative. Still, this information is used in studies about hydrogen for heating houses [10] [39]. As we discussed that the hydrogen delivery costs of repurposing distribution grids depend on the density of hydrogen used by a specific grid, further research should focus on the impact of potential decrease of gas use due to insulation or hybrid heating systems and combinations of local end user types (e.g. houses, shopping centres, local industries) that may benefit the costs of hydrogen distribution to local customers. This information might be crucial to optimize decisions when making local district heat transition plans.

[8] It should be noted that the potential of this option could be limited by the requirements of additionality and options to proof hydrogen greenness, set by the EU Commission.

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Appendix A - Cost functions

The HyDelta Value Chain model is a quantitative calculation model that includes a set of multiple cost functions to calculate levelized costs and Net Present Values of a large variety of hydrogen value chains that can be designed. A wrapper function is used to pick the right cost functions of all chain elements involved in the right sequence for the chains that were predefined in this study. This set of chains can be extended easily. The cost functions are designed such that the output of the first cost function can be used as input for the second cost function and so on. The wrapper starts at the end user characteristics that should be met, and based on these characteristic the chain elements are calculate in the opposite direction of the flow of hydrogen, ending at the production or import stage. A schematic overview of the wrapper function is shown in Figure 76. The main inputs for the model are the demand volumes, transport distances and the end user characteristics that the chain aims for. The parameters and cost data are stored in a central database that is accessed by the different cost functions.

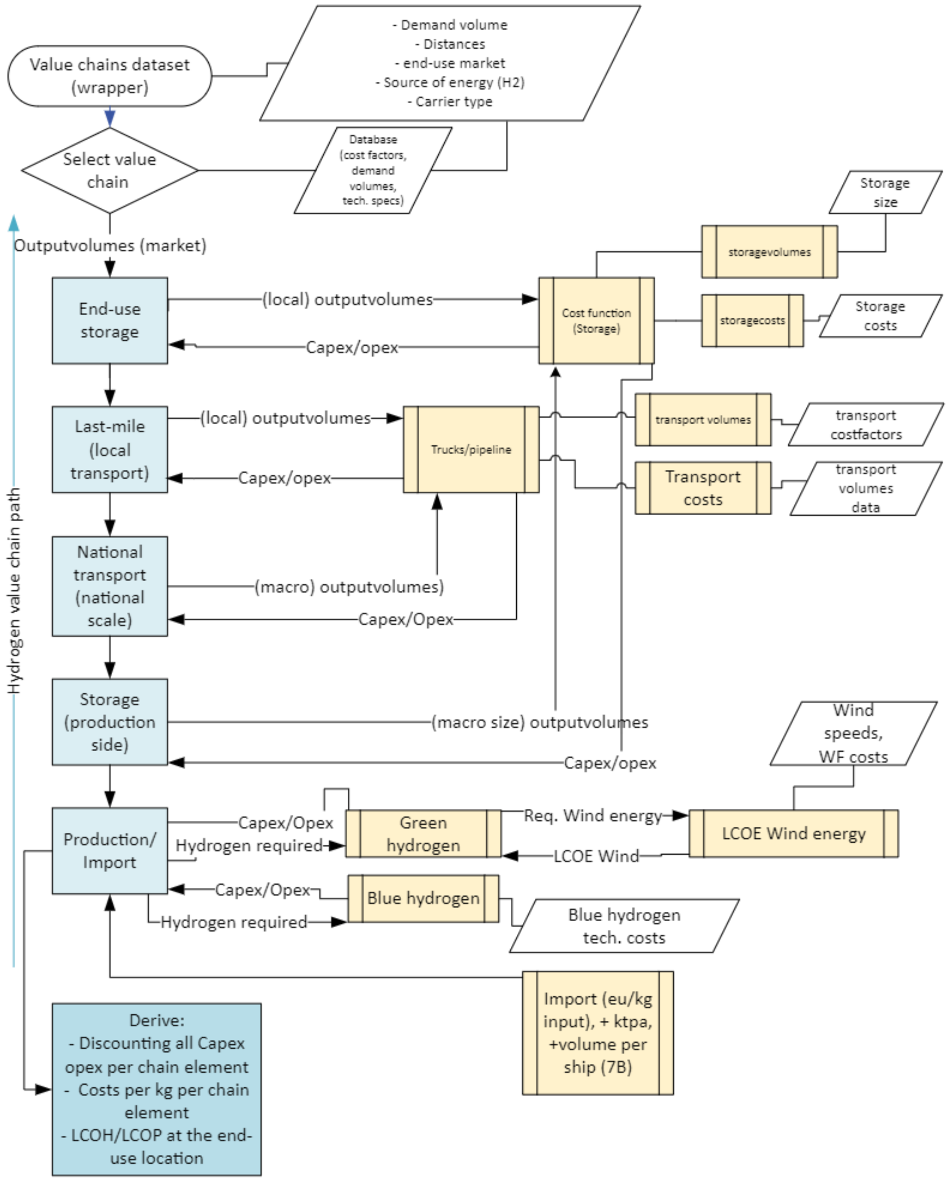


Figure 76 – Schematic overview of the value chain model wrapper and connection to the cost functions and database

1.1 Offshore wind energy

Wind profile

The used wind-profile was taken from the Royal Netherlands Meteorological Institute (KNMI) Wind Atlas database with actual mast data. The wind-profile was examined for three wind areas for the years of 2014 – 2018. Important to note is that year-on-year deviations in the period of 2014-2018 were in the order of 4 to 5% (see Figure 77). Based on this, the profile of 2018 was chosen as this year displayed a more stabilized average annual windspeed. K5 is taken as the reference wind-speed.

Data was taken for a mast height of 150m at an hourly resolution, and converted to power by applying the power curve of an assumed future wind turbine technology. With this dataset, the impact of seasonality and fluctuating wind speed input for hydrogen production can be taken into account.

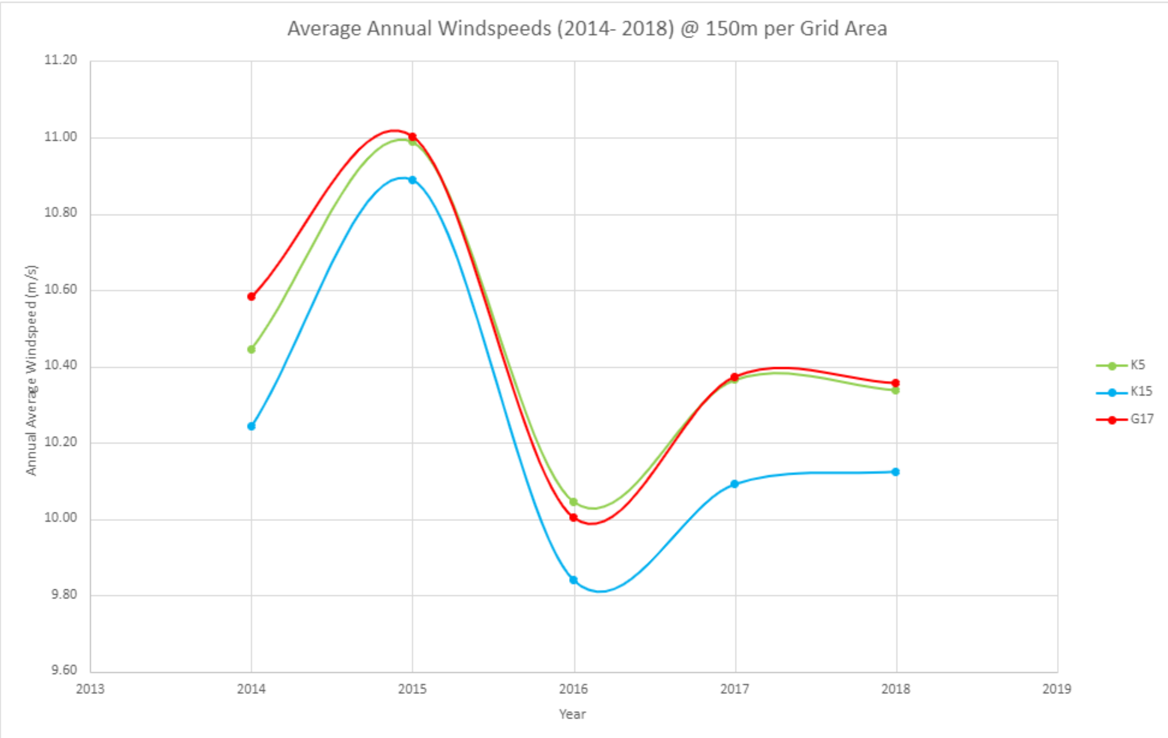


Figure 77- Average windspeeds over multiple years, an average hourly wind pattern over these years is used to calculate energy production quantities in the model.

Measured KNMI location	Average wind speed at 150m in 2018
53.7 – 3.33 (K5 area)	10.34
53.24 – 3.99 (K15 area)	10.12
54.05 – 5.4 (G17 area)	10.36

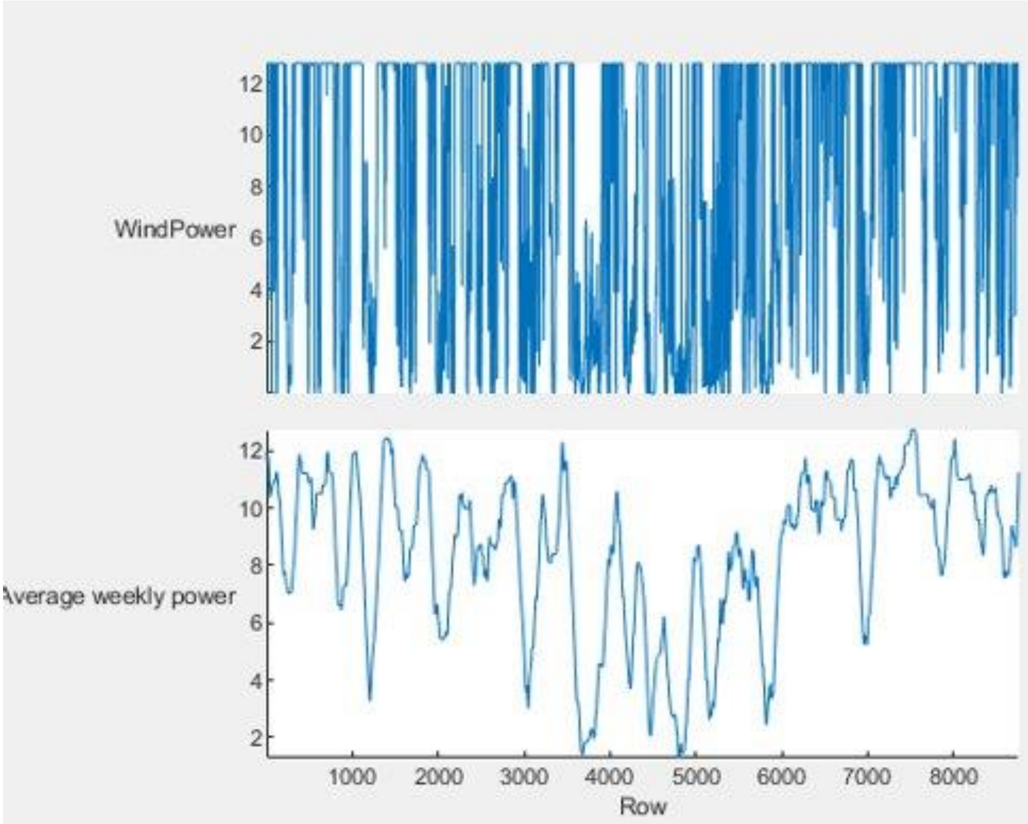


Figure 78 – Wind power pattern of K5 in 2018 used as reference pattern in the analysis

Turbine technology

Offshore wind technology is developing rapidly over the last decade, and is expected to improve the coming decade as well. In a recent TKI Wind op Zee study, the uncertainties and learning curves for offshore wind technologies are analysed and quantified for the years 2020 to 2030.

When upscaling present wind turbine technology to 2025, 2030 and beyond, the approach of Bulder et al. on potential cost reductions for offshore wind energy is followed (B.H. Bulder, 2021).

- Wind turbines will continue to increase in nominal power, the assumption is that in 2025 it will be possible to build a wind turbine with a rotor diameter of 250 m with a nominal power of 15 MW
- By 2030, it is assumed that a wind turbine with a nominal power of 20 MW with a rotor diameter of approximately 290 m will be feasible

The key parameters of these technologies considered in the report are summarized in the table below.

Table 8 – Key parameters of wind turbine and their expected development in the future

Wind turbine		2020	2025	2030
P_{nom}	MW	10	15	20
D_{rotor}	M	193	250	290
H_{hub}[1]	M	126.5	155	175
Rotor PD	W/m²	342	306	303
RPM_{min}	RPM	3.5	2.7	2.3
RPM_{max}	RPM	8.4	6.5	5.6

Economic lifetime		20	25	30
Farm area	km²	125	67	100
Yield	TWh/Y	3.5407	4.7775	9.4704
Capacity factor		0.539	0.543	0.541
Farm efficiency		0.913	0.875	0.876
Availability		0.974	0.974	0.976

Due to the ongoing developments in turbine technology, the nature of the true power curve for the turbine, the power curve, was obtained by using the key parameters highlighted above, by upscaling the parabolic fit for the Siemens Gamesa 7MW, and by calculating a range of values for the rated windspeed and confirming the value with TKI wind op zee (B.H. Bulder, 2021). The actual curve fit equation is:

$$Power = (Turbine_{cap}/10.25^{3.33}) \times W^{3.33} - 45 \sin\varphi$$

$$\varphi = 0.743172 \times W - 1.33434$$

Where, W is the wind speed in m/s and $Turbine_{cap}$ is the turbine capacity in MW. The equation is valid for wind speed $2.5 \leq W \leq 10$ and provides the power in kW. When the power is below the cut-in speeds (below 2.5) or above the cut-out speed above 28 m/s the power produced is dropped to zero. For $10 \leq W \leq 28$ the power is 15 or 20 MW.

		2020 (10 MW)	2025 (15 MW)	2030 (20 MW)
# of wind turbines		75	67	100
Pnom of wind farm	[MW]	750	1005	2000
Distance to shore	[km]	70	70	70
Distance to grid	[km]	100	100	100
year		2020	2025	2030
WACC[3]	[%]	3.80	3.88	3.88
Single turbine	[M€]/turbine	7.41	13.05	19.02
Support structure	[M€]/turbine	4.97	8.50	11.38
Electricity total	[M€]	735.97	926.83	1766.74
Project fixed cost	[M€]	45.00	60.30	120.00
Installation total	[M€]	110.31	131.39	205.75
Total Capex	[M€]	1819.8	2563.0	5132.4
Total Opex	[M€]/year	63.90	70.59	107.96
Yield	[TWh]/year	3.5407	4.7775	9.4704
LCoE 2020	[€/MWh]	**55.2**	**48.7**	**42.3**

Figure 79 - Cost developments for windturbine technology [40]

The cost factors for a 15 and 20 MW turbine were categorized into the cost of a single turbine, support structure costs, array costs, fixed costs, installation costs. The CAPEX of the turbines was calculated by using the formula below:

$$Capex_{Turbines} = (Turbine_{capex} + Supportingstructure_{capex}) * num_{turbines}$$

Array costs for the windfarm depend on the windfarm capacity:

$$Capex_{Arraycosts} = (Array_{costfactor} + Projectcostfacto + Installation_{costfactor}) * Capacity_{WF}$$

OPEX of the windfarm is determined by multiplying the maintenance cost factor by the capex of the turbines:

$$Opex_{fix} = Maintenance_{costfactor} * Capex_{Turbines}$$

Cabling

The windfarm capacity in the model is 2 – 4 GW while a distance to shore of 100km was considered for the cabling length utilizing a DC transmission mode. The cabling costs in the model has been set at 0.85 M€/MW. This cost is contrasted to assumptions from other studies in the figure below.

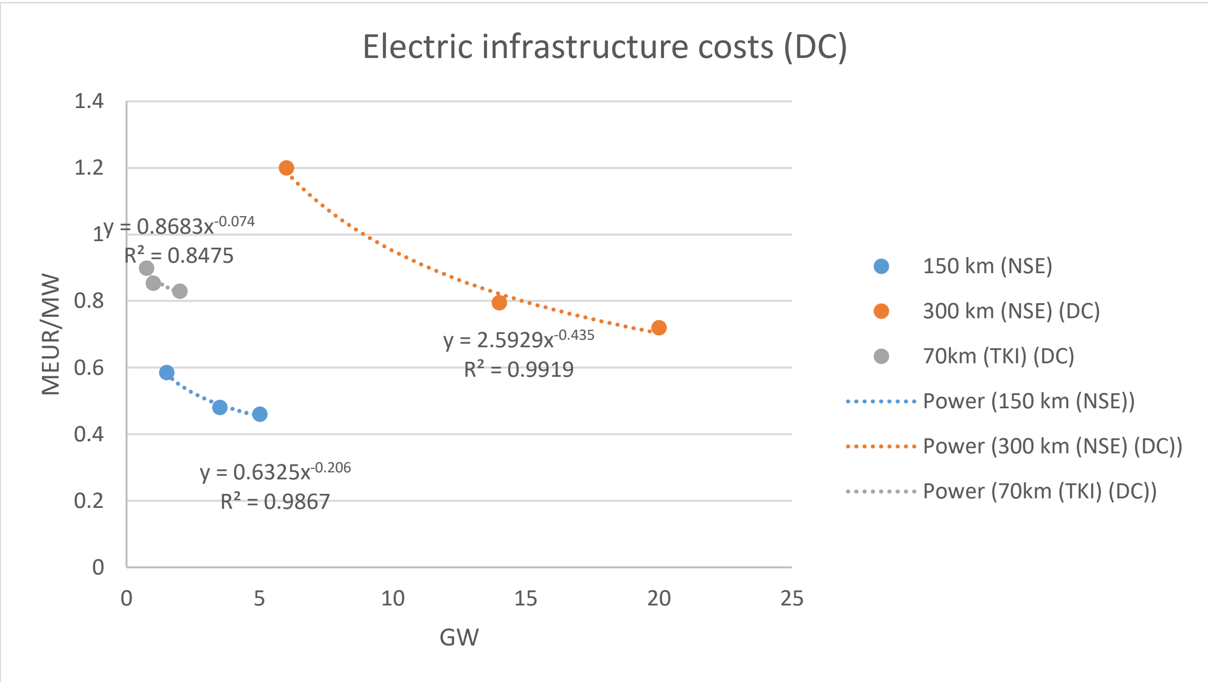


Figure 80 – Overview electric infrastructure costs according to different sources

Studies by TKI show that for a substation-to-shore cabling distance of 70km, the M€/MW ratio is substantially high for the applicable cabling capacities with a small range in variation. In the NSE studies - for a 150 km cabling distance - this value shows a prominent decrease in the cabling costs range with a higher variation. For a 300km cabling distance there is a higher variability in electric infrastructure costs depending on the power handling capacity of the cable.

It can be seen that increases in cabling capacity play a considerable role in reducing the infrastructure costs, this could be due to the effect of economies of scale. The magnitude of this reduction is emphasized with increasing cabling distances from the shore.

1.2 Green hydrogen production

Electrolyser technology

There are two main families for electrolysers: Alkaline and PEM (proton exchange membrane).

Alkaline electrolysers utilize an alkaline electrolyte such as potassium hydroxide (KOH). The technology is considered to be reliable and competitive. In the case of a cold start, Alkaline electrolysers require up to 20 min to be operational. For power-to-gas, the start-up should ideally be instantaneous in order not to lose electricity when there is surplus production. To bypass this limitation, isolating the electrolyser to maintain the temperature above 30°C may allow a start in a few seconds. The elements that wear are the membranes and the electrodes that must be regularly revised. Depending on the size of the installation, the type of operation (continuous or not) or other parameters, the lifetime of a unit varies between 50,000 and 90,000 h. Alkaline electrolysers have a long experience in optimizing performance (materials used, efficiency, lifetime and cost). The power range available (up to several mega-watts) allows it to be used for the exploration phase of power-to-gas technology [41].

With PEM electrolysers a membrane coated with a catalyst separates the anode from the cathode. The decomposition reactions of the water occur at the anode. The core of the PEM electrolyser is the PEM membrane made from precious metals such as platinum, iridium and ruthenium. Degrading elements are the membrane and the catalysts. The advantage of PEM electrolysers lies in their short starting times (<10s). A PEM electrolyser has an advantage over alkaline electrolysers in terms of raw material usage as well its smaller footprint [41]. The more complex structure than the alkaline electrolysis and some specific components (membrane and catalysts) make the PEM electrolyser still expensive. This technology is relatively recent compared to alkaline electrolysis, but has a high potential to improving performance in terms of overall efficiency and reducing cost [41].

Since the 2030 cost data projected lower costs for the alkaline technology than PEM, alkaline electrolysers are considered in the assumptions used to calculate the main outcomes of the model. There is a direct connection between the windfarm and the electrolyser, hence hydrogen production follows the wind profile.

The capacity of the electrolyser is calculated through the required yearly demand of hydrogen at the next step in the value chain. If there are considered losses in hydrogen during the transport of hydrogen to the end-use, the required hydrogen volume at the beginning of the transport chain element is higher than the demand of hydrogen at the point of end-use.

$$Capex_{electrolyzer} = CF_{electrolyzer} * Capacity_{electrolyzer}^{SF}$$

$$Opex, var_{electrolyzer} = E_{costs} * E_{required}$$

$$Opex, fix_{electrolyzer} = Opex_{fix} * Capex_{electrolyzer}$$

Sensitivities

The Levelized cost for the production of green hydrogen is bound to several factors that can have a significant effect on its final cost in the market. Windfarm costs, electrolyser CAPEX, electrolyser efficiency, WACC and windfarm lifetime are parameters that have varying degrees of impact on determining the levelized cost of green hydrogen production. The magnitude of these parameters and their effect on the market is defined in the figure below, each with varying degrees of impact.

Among the various parameters, windfarm costs have the highest impact in affecting hydrogen prices. A ±25% change in windfarm costs has the potential to impact LCOH costs by ±15%. Other foreseeable effects on the LCOE of offshore wind farms are higher transmission cost due to the fact that most wind farms will be built further from shore, the near shore sites have almost been exhausted already [40]. In order to improve the business case of offshore wind farms, reducing CAPEX, especially for the sites far from the coast is important.

With regard to WACC, ±25% change can affect the prices within a ±10% range. As stated earlier, the higher the discount rate the larger the uncertainty and sensitivity parameters affecting project activities. Hence it is a parameter that can have a high impact on affecting the cost of hydrogen production.

±5% changes in electrolyser efficiency can lead to a ±5% change in the LCOH. The efficiency of an electrolyser is defined as the ratio of the higher heating value of hydrogen (HHV, in kWh per kg) to energy consumed by the electrolyte per kg of hydrogen. At present, typical electrolysis efficiency ranges between 70 and 75%. The efficiency of electrolysis is expected to increase in the future. This projection is based on many factors such as current density, electricity costs, capital costs, etc. In this case study, the efficiency is maintained at 70% for the power-to-gas facilities in 2030, a typical value that is predominantly found in the electrolysis market now. The efficiency calculations for post 2040 are calculated for higher efficiency since efficiency is likely to increase in the future.

The main cost contributor for a power-to-gas plant is the electrolyser CAPEX with a cost range of 800 – 3000 €/kW in 2017, depending on the power and technology, PEM being still more expensive than alkaline. However, with the extension of power-to-gas technology, a decrease in prices is to be expected from about 1.5 million euros in 2017 to 0.55 in 2030 for a 1 MW PEM electrolyser [41].

The lifetime of operation for windfarms is also shown to play an important role, ±25% changes is expected to have a cost impact within a range of -4% to 6%. Based on a study commissioned by TKI Wind-op-Zee and carried out by TNO and BLIX consultancy, increasing the design life of a windfarm by ten years up to 40 years is the most promising innovation with largest cost reducing impact, lowering the LCOE with -7.6% [40]. The reason for this large impact is the fact that with relatively low costs increases (=< 10%) the total generated yield increases by 40%. However, this upside is highly dependent on the assumed WACC with diminishing returns at increased WACC.

1.3 Storage

The storage function is a generic function that can be used to calculate the storage costs at different parts of hydrogen value chains. The following characteristics are taken as main input to calculate the storage costs: the type of storage used, the annual volumes flowing through the chain and the variation in input and output the storage has to deal with. In this manner, the storage function is used to calculate storage costs for the following types of storages:

- Compressed gaseous hydrogen stored in salt caverns (<180 bar)
- Compressed gaseous hydrogen stored in tanks (250 bar)
- Liquid hydrogen stored in tanks
- Liquid organic hydrogen carriers stored in tanks
- Ammonia stored in tanks
- Methanol stored in tanks

Methodology used for cost calculation

This is done in three steps: first, the stored volumes are determined on an hourly basis. Second, the amount of storage units is determined. Thirdly, the costs are calculated. The following paragraph will describe these steps in greater detail.

Based on the location of the storage within the pre-determined value chain, the storage is required to buffer against variations in input and output. Examples of variation could be intermittent input of hydrogen based on flexible production dependent on windspeeds or due to arrivals of ships at the import terminal. Variation in output could be caused by demand patterns, such as seasonal demand differences for gas to heat buildings and refueling behavior of consumers at tank stations. These variations are represented by an 'input pattern' and 'output pattern' that represent the share of the annual volume that enters and/or exits the storage every hour. Based on these patterns and the annual volume, for every hour the cumulated storage mutation is calculated via the function below.

$$cum.stor.mutation_t[kg] = cum.stor.mutation_{t-1}[kg] + input_t[kg] - output_t[kg]\ \forall t \in T$$

In all storages, there is an additional buffer perceived of 1% of the annual volumes (equals storing 365*0.01=3.65 days of demand) flowing through the storage. This is perceived enough for variation in input and output caused by trucks which are usually travelling multiple times per day and therefore causing very minor variations. Further, the minimum value of the cumulative storage mutation is taken as starting level of the storage, in order to compute the actual hourly storage levels (see function below).

$$storagelevel_t[kg] = cum.stor.mutation_t[kg] - startvolume[kg] + buffervolume[kg]\ \forall t \in T$$

The maximum hourly storage level is used to size the storage facility to the required scale. Based on a minimum and maximum possible size for every storage unit (e.g., a cavern or specific type of tank), there can be determined how much storage units are needed in the storage facility. If the minimum size of a storage unit is larger than the actual storage capacity required, the minimum size storage unit has to be purchased (as smaller is perceived not feasible), this could lead to high storage costs. For example, if very low storage capacity is required but there is chosen to analyze to store these volumes in salt caverns, there has to be opened a relatively large salt cavern facility for small storage demand and therefore costs will be high due to the oversized storage facility. However, in the analyzed chains this is barely the case as there is tried to select the most promising chain set-ups. If there is more storage capacity required than the maximum capacity of one unit, multiple units are needed and the size of each unit is determined based on the minimum feasible size to meet the required capacity.

The amount of storage units () and the size of each unit (will determine the CAPEX of the storage facility (). The base size () and costs () of the storage facility are based on a standard storage facility with one storage unit and the scaling factor () is used to represent the economies of scale for the whole storage facility.

$$CAPEX[€] = basecosts[€](\frac{N * Size\_unit[kg]}{basesize[kg]})^{scalingfactor}$$

The fixed annual operational costs are determined as percentage on the initial investment costs. The variable costs differ per storage technology that is used, however commonly include electricity costs for compression of hydrogen or cooling the liquids in the storage facility.

Storage cost comparison

In this section an overview of the storage capacities will be provided, followed by an overview of the costs. Starting with the required storage capacities, it has already been mentioned that the required amount of storage capacity depends on the variation of hourly inputs and outputs the storage has to deal with. In the model, multiple hourly patterns are used to indicate the storage capacity required at certain locations within the chain. In Figure 81 the impacts of those patterns on the storage capacity requirements are shown.

This is done by two measures indicating the similar thing: the percentage of the annual volumes and the days of storage. The percentage of annual volumes indicates that if 1000 kg of hydrogen is demanded annually, and if the storage capacity required to deal with the fluctuations would be 10 kg, the storage capacity as percentage of the annual volumes would be 1% (10/1000=0.01). The days of storage represents the amount of days that the full storage capacity could deliver the average daily demand, until the storage would be empty (so in the example this will be 10/(1000/365)=3.65 days, or if the percentage of the annual volumes is known already, it will be 0.01*365=3.65 days).

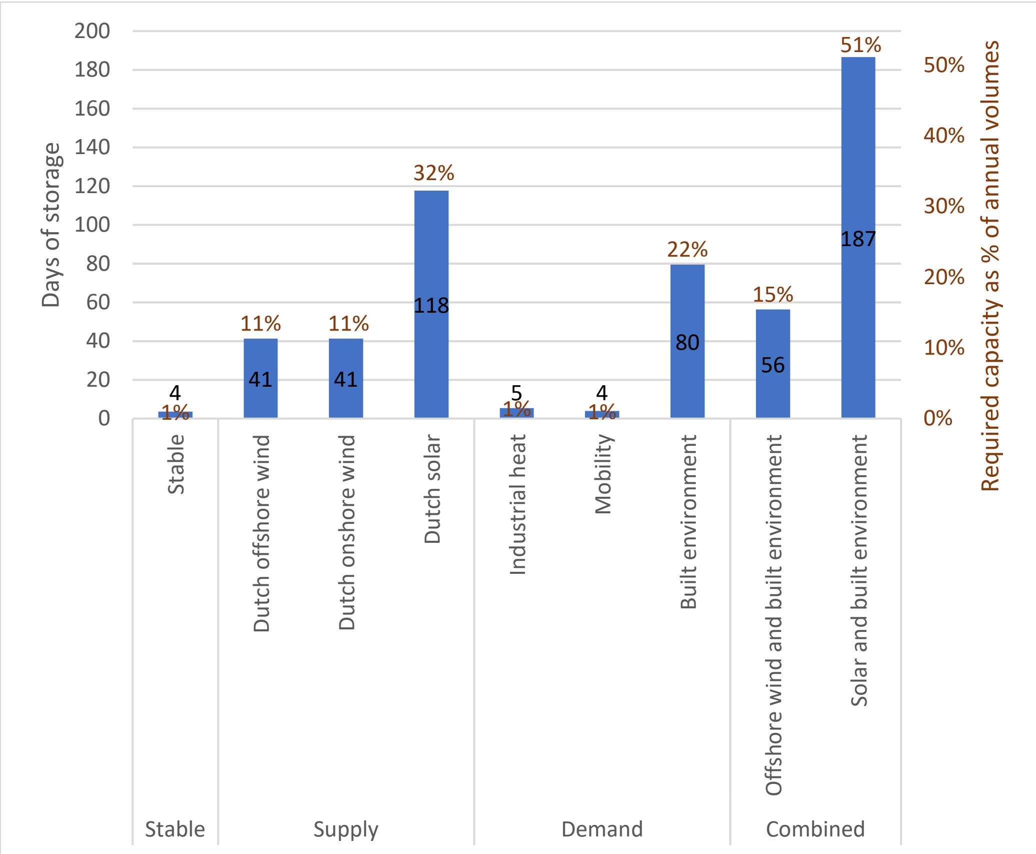


Figure 81 – Impact of the supply and demand patterns on the required storage capacity

First, the impact of a stable supply and demand pattern is shown. A stable supply pattern is used for the blue hydrogen production, for the transportation modules, and on the demand side for the demand of industrial feedstock. Here, as the hourly input and output patterns are stable and equal, the storage capacity is only determined on 1% buffer volume of the annual volumes (representing 3,65 days) which is perceived as enough for these processes that barely includes fluctuations. Secondly, several specific supply patterns are used for Dutch offshore wind (5782 full load hours), Dutch onshore wind (3081 full load hours) and illustratively the impact of Dutch solar (891 full load hours) is added to the graph. It is seen that although the difference in full load hours between onshore and onshore wind, the impact on the storage capacity is comparable, as the seasonal differences seem to be quite comparable. Indicatively (since not included in one of the chains), the pattern for Dutch solar shows a larger seasonal difference in winter and summer production, leading to a required storage capacity of 32% of the annual volumes (i.e., 118 days). Thirdly, specific demand patterns are included for industrial heating, mobility and built environment. The mobility demand pattern includes hourly fluctuations during the day which do not lead to substantial additional storage capacity besides the buffer (approximately 0.2 days additional capacity). A similar insight is seen for the weekly pattern of industrial heat processes (approximately 1.77 days additional capacity), only seasonal fluctuations, such as the demand in the built environment will substantially increase the storage requirements (approximately 76 days). Combining the seasonal variation in supply and demand could reduce the required storage capacity significantly. A large reduction is seen when patterns are combined that both have relatively high supply and demand in winter, and relatively low supply and demand in summer. For example, offshore wind and the built environment require respectively 41 and 80 days of storage individually, and those patterns combined in one storage unit requires 56 days of storage. On the other hand, if patterns with relatively low supply and high demand in winter, and relatively high supply and low demand in summer are combined, the mutual gains of adding them in one single storage plant are almost zero. For example, solar and the built environment require respectively 118 and 80 days of storage individually, while combining these patterns in one storage would even lead to 187 days of required storage capacity.

In Figure 82 insights in the storage costs are provided for small scale (A and B) and large scale (C and D), a stable supply and demand (A and C) and a seasonal demand pattern (B and D). The levelized costs in this graph are solely based on the storage costs, while in the perspective of the full chain these costs are always going hand in hand with potential additional conversion and reconversion costs and or higher or lower transport costs. For example, if a storage should deal with variation in supply, the conversion capacity should also be scaled to deal with the maximum hourly flow volume resulting in a lower utilization that may involve the levelized costs of conversion as well. Another point depends on the carrier that is required by the end user: if an end user demands ammonia, this type of storage might be applicable. However, as reconversion of ammonia towards hydrogen is very expensive, especially on a small scale, the relatively low costs of ammonia storage in tanks this might not be an economic option in most chains. Hence, these costs are the raw storage costs of hydrogen equivalents as result of the storage function and individually cannot be used to compare what the most cost effective type of storage is, as this depends on very chain or situational specific aspects. Having made this first note, several things can be concluded from the figures:

- Storage costs in most cases, especially when applied on large scale, are relatively low and will not have the largest impact on the chain costs. However, some exemptions will be discussed in next points;
- Gaseous hydrogen storage in tanks is relatively expensive in most cases and could have significant impact on the overall levelized costs of hydrogen. Especially if seasonal storage is required, gaseous hydrogen storage costs in tanks are going through the roof;
- The storage costs of the smallest volumes are mainly impacted by the assumed smallest applicable size of storage unit (tank or cavern). Obviously, as storage caverns are very large, this option requires the largest scale to become cost effective, based on storage costs only;
- Liquid hydrogen storage is significantly less cost effective for seasonal storage, as due to hydrogen is lost due to boil-off. This does not even consider that more hydrogen should be produced and processed upstream if a full chain perspective would have been considered;
- For hydrogen stored with carriers (in our scope LOHC, NH_3 and MeOH) it should be considered that if those carriers are used for storage purposes only (i.e. incl. conversion and reconversion on site), an additional storage facility should be in place to store the carrier (respectively MCH, N_2 and CO_2) during moments that less hydrogen is stored.

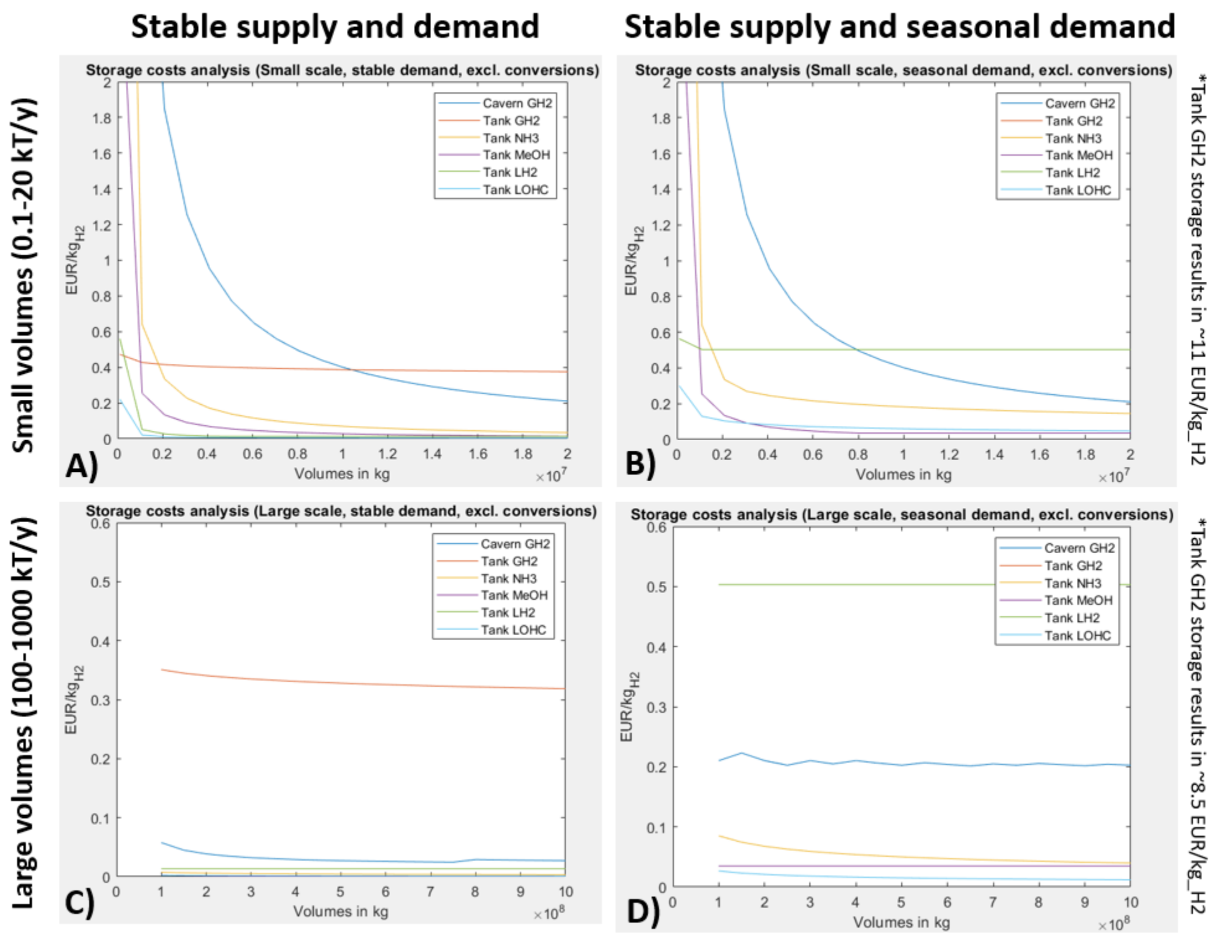


Figure 82 – Overview of raw levelized storage costs of hydrogen equivalents excluding conversions

1.4 Transport

In order to calculate the transport costs transporting specific volumes of a certain type of carrier over a given distance, different modules are used for each type of transport. This is because the principles of calculating transport costs for pipelines, trucks, trains and barges differ a lot between these means of transport. Although, still those functions, except the pipeline function, are developed in such a manner that similar modules can be used to calculate transport costs using different carriers. For example, the truck function is used to calculate costs for gaseous hydrogen, liquid hydrogen and LOHC truck transport costs, but if cost data for NH3 trucks is included, the module can be used to calculate these costs as well. Currently, the modules are used to calculate the following transport costs:

- Gaseous hydrogen transport by pipelines;
- Compressed gaseous hydrogen transport by trucks (250 bar);
- Liquid hydrogen transport by trucks;
- Liquid organic hydrogen carrier transport by trucks;
- Ammonia transport by ammonia rail cars;
- Indicative: LOHC transport by container barges.

1.4.1 Pipeline

The hydrogen transport costs by pipeline are calculated by performing the following steps: 1) determine the required diameter based on the volumes and pressure drop 2) calculate the pipeline costs 3) calculate the compressor costs 4) if re-use if applicable, choose whether re-using or constructing a new pipeline is more cost effective.

The main input for calculating the pipeline transport costs are the volumes that need to be transported, the distance and eventually the diameter of an existing pipeline. The required diameter of the pipeline is calculated based on the functions presented below [42]. The volumes are the annual volumes in kilograms demanded by the next supply chain stage. A multiplier is used to scale the pipeline at the max capacity that flows through the pipelines. In our study a multiplier of 1.1 is assumed. The units of the variables in the formulas are shown between square brackets.

$$Volumetric\_flow\_rate\left[\frac{m^3}{s}\right] = \frac{\frac{volumes[kg/y]}{8760} * multiplier}{H_2\_density\left[\frac{kg}{m^3}\right] * 3600}$$

$$Pipeline\ diameter[m] = \sqrt{\frac{volumetric\_flow\_rate\left[\frac{m^3}{s}\right]}{H_2\_speed\left[\frac{m}{s}\right]} * 4/\pi}$$

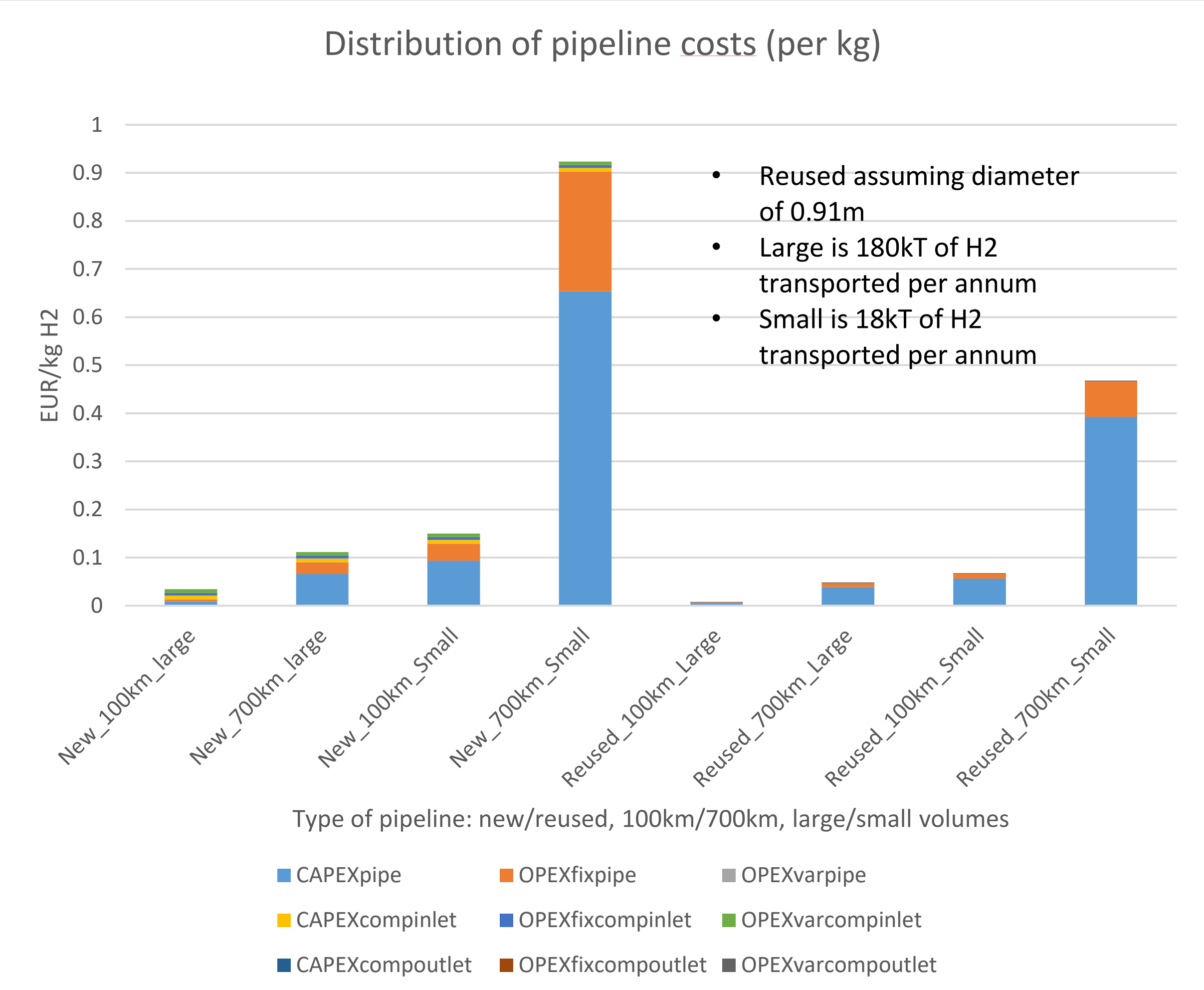
The pipeline function assumes that hydrogen enters the pipeline at 30 bars (outlet pressure electrolysers, and based on the proposed hydrogen backbone specs [43]), and should be delivered at a minimum of 30 bars. A maximum inlet pressure of 70 bars is assumed, which will be used for new constructed pipelines, while for reused pipelines the inlet hydrogen is only compressed towards higher pressure levels if this is required to transport the volumes through the existing diameter. Moreover, the pressure within the pipelines should not drop below 10 bars and the maximum velocity is set conservatively on 20 m/s [42] [44] [45], however, more recent studies, such as executed in HyDelta WP1E suggest that speeds of 50 m/s could be possible which would increase the volumes that could be flowing through the same diameter sized pipelines. A pressure drop module of TNO is used that is based on the Darcy Weisbach and Colebrook-White equation principles, using the hydrogen molecular weight of 2 g/mol, an average temperature of 10 degree Celsius, dynamic viscosity of 0.0000086 Pa·s and a surface roughness of 0.00005 meters. In this manner, there is determined how much compressor capacity is required (at the inlet and/or outlet of the pipe) at its costs are calculated (see section 1.6.1).

The costs of the pipeline are based on the diameter. Multiple functions can be found in literature to calculate the costs of hydrogen pipelines. In this study, the cost curve based on ACER [46] is used, that was validated to be used on and offshore in the Dutch context by ECN [47]. For reused pipelines is assumed that the pipeline investment costs for repurposing are 30% of the new costs, based on estimations of the European Hydrogen Backbone study [48].

Using the above described methodology, both costs for new and reused pipelines are calculated within the pipeline function and the most cost effective option is chosen. This usually results that reused pipelines are chosen, if applicable (if the required diameter is large enough to transport the demanded volumes). Only in very extreme situations where very small volumes are demanded and a very large diameter of the existing pipeline is available, will result in a more cost-effective option to choose for a small new pipeline instead of repurposing the large existing pipeline. As mentioned, this is only the case under very extreme conditions and therefore not seen in the analysed chains or sensitivities.

Insights in pipeline costs

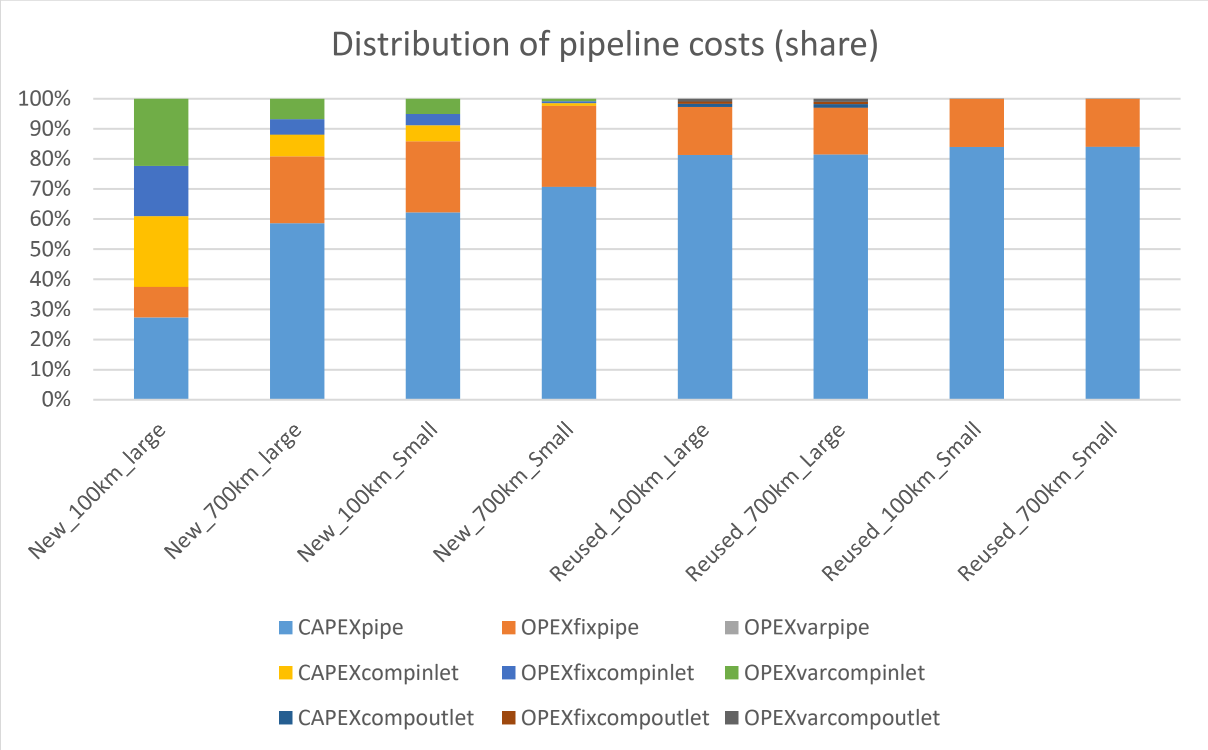
In the figure below the impact of the volumes and distance on the pipeline costs are shown. Pipeline transport is known for its significant economies of scale: if enough volumes are transported, the costs are very low but at a certain point the transport costs per kg of hydrogen could increase significantly. This is seen in the example figure below, for a distance of 700km and annual volumes of 18kT the costs per kg are significantly higher than the other three examples which are relatively cost efficient. The point at which pipeline transport costs significantly rise really depends on the ratio between the transported volumes and the distance: the longer the distance, the larger volumes are required to make the pipeline a cost-effective mode of transportation.



	New_100km_large	New_700km_large	New_100km_Small	New_700km_Small	Reused_100km_Large	Reused_700km_Large	Reused_100km_Small	Reused_700km_Small
Transportcosts/kg [EUR]	0,03	0,11	0,15	0,92	0,01	0,05	0,07	0,47
Diameter [m]	0,365	0,445	0,1354	0,1954	0,91	0,91	0,91	0,91
Pressure inlet [bar]	70	70	70	70	30	30	30	30
Pressure outlet [bar]	58	32	47	45	29,7	28,2	30	30

Figure 83 – Cost distribution of the pipeline function for reuse/new, 100km/700km and small/large volume pipelines.

In Figure 84 below, the distribution of the pipeline costs are shown for multiple volumes and distances. As result of the pipeline function used, in most cases the costs mainly contain the pipeline CAPEX, especially in the case of the reused pipelines, where in the presented examples barely additional compression was required. The compression costs took the largest share for short new pipelines with large volumes. In this case the pipeline costs per kilogram are relatively low due to the large volumes and the short distance compared to the other examples. When the distance is relatively long and the pressure drop increases beyond the accepted boundaries there are two ways to deal with this: increase the pipeline diameter or add additional compressor capacity. In Figure 84 only costs are shown if the first option is chosen. If the second option would have been chosen, the compressor costs would have had a more significant share of the total costs in the cases with 700 km new pipelines, depending on how often times in-between compressor capacity would have been added.



	New_100km_large	New_700km_large	New_100km_Small	New_700km_Small	Reused_100km_Large	Reused_700km_Large	Reused_100km_Small	Reused_700km_Small
Transportcosts/kg [EUR]	0,03	0,11	0,15	0,92	0,01	0,05	0,07	0,47
Diameter [m]	0,365	0,445	0,1354	0,1954	0,91	0,91	0,91	0,91
Pressure inlet [bar]	70	70	70	70	30	30	30	30
Pressure outlet [bar]	58	32	47	45	29,7	28,2	30	30

Figure 84 – Cost distribution represented as share within the total pipeline costs for different volumes and distances

1.4.2 Trucks

The truck transport costs are calculated by the following performed steps: 1) determine the amount of trips that a truck could drive annually for every arc, 2) determine the amount of trucks annually required at every arc, 3) calculate the CAPEX and OPEXfix of the total truck fleet required and 4) calculate the annual OPEXvar based on fuel and labour costs. For gaseous hydrogen transport trucks, additional costs for compression from 30 to 250 bars are added.

The annual amount of trips that a truck could drive for every arc are determined via the formula presented below. The total available time is calculated by the yearly amount of days times the average hours per day a truck drives based on Reuß [43] (75% annual utilization corresponding to 18 hours per day). The time that one trips takes is twice (back and forth) the average driving and loading time.

$$trips_i = \frac{365 * utilization[\frac{h}{d}]}{2 * (\frac{distance_i[km]}{drivingspeed\left[\frac{km}{h}\right]} + loadingtime[h])} \; \forall i \in I$$

The amount of trucks required per arc in a specific year is calculated by the formula presented below. For each year and at each arc, an annual transported volume is demanded. The total transport capacity (i.e. amount of trucks), depends on the volumes each truck can carry per trip and the amount of trips each truck can drive per year. Here, the amount of trucks required per arc can still be an real (i.e. float) number, because it is assumed that if for example at two arcs a half truck is required, one truck can be shared between those arcs (i.e. the truck is used 50% of the time at arc A and 50% of the time at arc B).

$$trucks_{i,t} = \frac{annual\_volume_{i,t}[kg]}{capacitytruck[kg] * trips_i} \forall i \in I, \forall t \in T$$

The CAPEX and OPEXfix are calculated for the total truck fleet required at all the arcs combined. Here, the sum of the trucks required at the arcs is conversed to a ceiling number, as it is perceived as not possible to purchase a half truck. A 'truck' is distinguished in two components: the truck cab (similar for all the types of carriers) and the trailer (designed to transport a specific carrier), both having different lifetimes. The module is designed to purchase the right amount of truck cabs and trailers each year to meet the required amount of trucks in each year in the total fleet. The fixed OPEX are based on the actual number of truck cabs and trailers within the fleet.

The variable OPEX are based on fuel and labour costs. The calculation methodology of the fuel costs for each arc in each year is shown in the formula below. Simplified, the costs are derived by the total driven distance by the truck fleet times the fuel price per kilometre. In the model the trucks are fuelled with diesel (0.35 litre per km when driving 70 km/h on average, and 1.35 euro/litre diesel) to compute the costs. However, within this calculation methodology other fuels (e.g. hydrogen) could have been implemented as well. The underlying relation between the average driving speed, weight of trucks and its loads and the fuel consumption per km should be considered, as it is not included within the model's calculations (yet).

$$fuel\_costs_{i,t}[€] = 2 * distance_i[km] * trucks_{i,t} * trips_i * fuelconsumption[\frac{unit}{km}] * fuel\_price\left[\frac{€}{unit}\right] \forall i \in I, \forall t \in T$$

The wage costs for each year at each arc are derived by multiplying the total driving time of trucks by the assumed wage of the drivers.

$$wage\_costs_{i,t}[€] = trucks_{i,t} * 365 * utilization\left[\frac{h}{d}\right] * driverwage\left[\frac{€}{h}\right] \quad \forall i \in I, \forall t \in T$$

The variable OPEX per year can be calculated by the sum of the fuel costs per arc and the sum of the wage costs per arc, as shown in the formula below.

$$variable\_opex_t[€] = \sum_{i=1}^{I} fuel\_costs_{i,t}\,[€] + \sum_{i=1}^{I} wage\_costs_{i,t}\,[€] \quad \forall t \in T$$

Insights in truck costs

Figure 85 shows the distribution of the levelized costs for truck transport for an annual demand of 5 kT and distance of 50 km. The blue parts of the bars show the costs of the trucks, the green parts of the bars the fuel and labour costs, the grey parts of the bars the compression costs, the red part of the bars the conversion costs and the yellow part of the bars the reconversion costs. The figure makes clear that for the LOHC and LH2 trucks the conversion costs take a large share of the total transport costs, especially for LH2 truck transport. The truck, fuel and labour costs are significantly lower compared to the gaseous hydrogen trucks, because carrier trucks can carry way more hydrogen per trip (1800 and 4300 kg per trip compared to 670 kg per trip for gH2) and therefore less trucks, fuel and personnel is needed to transport the same volumes. Compression involves relatively small share of the costs of the trucks that transport gaseous hydrogen, while fuel and wage costs are most significant there. If FCEV trucks would have been used to transport the hydrogen instead of diesel trucks, and it is assumed that the costs of truck cabs would rise from 160.000 euro's to 270.000 euro's [49] [50] and 7.8 MJ of hydrogen per km is used [8] (equalling 0.065 kg of hydrogen). The transport costs via gaseous hydrogen will decrease 1 cent per kg if hydrogen fuel costs of 5 euro's per kg are used, or rise with 2-

3 cents if hydrogen fuel costs of 9 euro's per kg are used. The transport costs by LOHC and LH2 trucks will be impacted even less, as truck and fuel costs do contribute very slightly to the levelized transport costs.

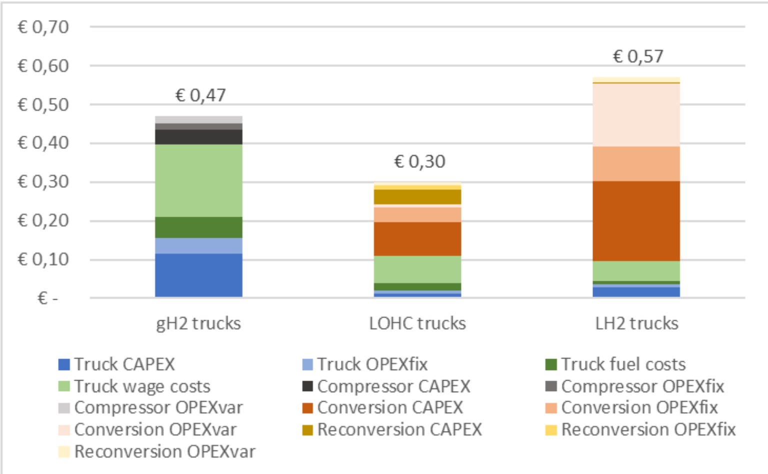


Figure 85 – Distribution of the truck transport costs for 5kT per year over a distance of 50km

In Figure 86 the impact of transport distance and volumes per demand location are shown on the truck transport costs. For gaseous trucks it is seen that the volume does not impact the levelized transport costs a lot: more trucks, fuels and personnel is required, but this increases equally to the additional volumes that have to be transported. For the LOHC and LH2 trucks the levelized costs of transport decrease if the volumes per demand location increase, due to the economies of scale of the conversion and reconversion installations. The costs of truck transport increase if the distance increases, as each truck can drive less trips per year (i.e. less volumes per truck can be transported per year) and more fuel and wage costs have to be paid per kg of hydrogen transported. The impact of increased distance on the levelized transport costs is the largest for trucks transporting gaseous hydrogen, as the truck, fuel and wage costs represent the largest share of the total transport costs. For trucks transporting LH2 the impact of distance on costs is the lowest, as the wage and fuel costs have the least share on the total transport costs. This means that the longer the distance the more competitive LH2 trucks will be become compared the alternatives, but also the transported volumes determine the actual tipping point.

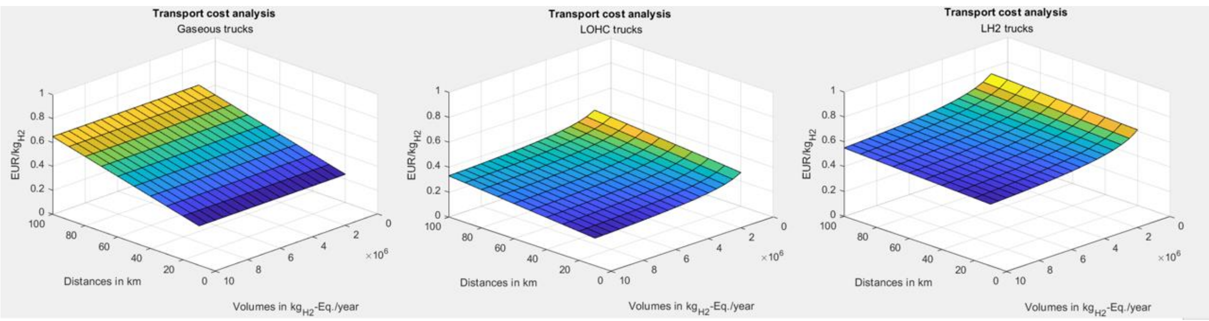


Figure 86 – Overview of the impact of distance and volumes on the truck transport costs (trucks shared among 50 locations)

Figure 86 shows the costs of truck transport when trucks can be shared among different arcs (in this case 50 locations). If trucks are purchased on one dedicate route, the impact of the truck costs could be significant if an additional truck has to be purchased that is barely used. For example if 4kT of hydrogen can be transported by one LH2 truck per year but the demand is 4.1kT of hydrogen per year, two LH2 trucks are required (due to the assumption that no 1.05 truck can be purchased) but one of them is barely used. This causes the 'waves' that are shown in Figure 87. In reality projects are not expected to purchase a truck if it is known that they are utilized for a low percentage.

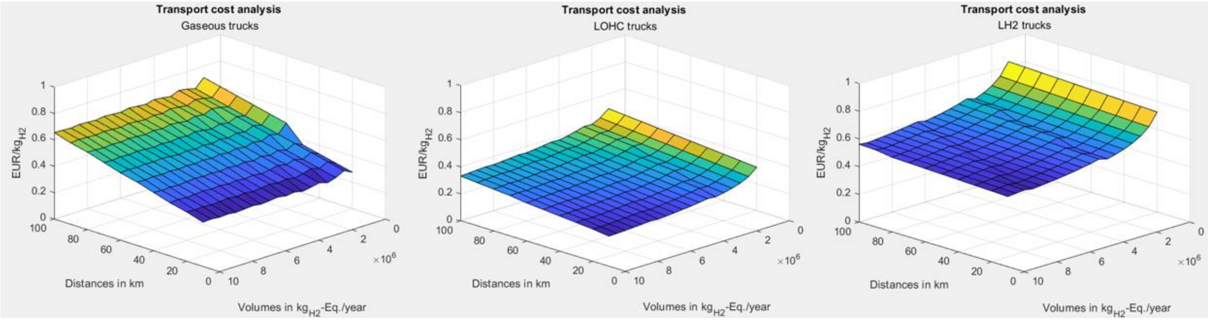


Figure 87 – Overview of the impact of distance and volumes on the truck transport costs (trucks shared among 1 location)

1.4.3 Rail

The methodology to compute the rail transport costs is comparable to the truck transport cost methodology, except for some differences. The major assumption used is that a freight transport company is used to transport the goods. Hence, the total investments in the railways and locomotives are not taken into account, but there is invested in specific rail transport cars (RTCs) and freight and loading costs are paid for transportation of the rail cars by trains [51]. Similar steps are taken as the truck transport module: 1) the amount of required trips per year is defined, 2) the amount of railcars required, 3) the CAPEX and fixed OPEX are calculated based on the required RTC fleet and 4) the variable OPEX are calculated.

First, the annual amount of trips per RTC is defined. An important aspect to determine the amount of trips that a railcar can make, is the departure of available trains. The actual availability of the Dutch railway capacity is beyond the scope of this study. In this study we will only do calculates that do identify the impact of train flows that are required for specific volumes of hydrogen carriers (i.e. ammonia) transported. However, for the sake of determining the amount of required railcars, it is required to make an assumption about the departure of trains, as it is an unavoidable aspect of making use of a railway system that departure times have to be considered. In this study it is assumed that there is one moment per day that railcars can depart. Based on the assumptions used: 32 hours for loading and unloading each trip cycle [51] and a speed of 80 km/h [52] this means that if the travelling distance would be 640 km, one trip would exactly take 24 hours (32/2+640/80=16+8=24) and so one cycle (back and forth) would take two days. Based on the cycle time and the annual operation time of RTCs based on their utilization, the amount of trips per RTC per year can be calculated. For the costs of rail transport, this tipping point should be considered, since the amount of trips per RTC is reduced by 50% if a one way trip can not be made in one day (and so the investments in RTCs will be doubled). Although, under our assumptions trains will have enough time to travel through the Netherlands in one day. Probably more important is the assumption how often freights can depart: if freights cannot depart every day, but once in two days, also double amount of RTCs would be required to transport the same volumes. Therefore, we will spend attention on the impact of this on the rail transport costs at the end of this section.

When the annual amount of trips per RTC is calculated, the amount of required RTCs per year per arc can be determined via the formula below.

$$RTCs_{i,t} = \frac{annual\_volume_{i,t}[kg]}{capacityRTC[kg] * trips_i} \forall i \in I, \forall t \in T$$

The CAPEX and fixed OPEX of the RTC fleet are computed in a similar way as the trucks, just based on investment costs of RTCs and annual fixed OPEX as percentage of the total investment costs of the fleet. Also here, it is considered that no investment in half RTCs can be made, hence, the number of RTCs should be an integer number.

The variable costs of rail transport are the tariffs paid for both tonnes-kilometres of freight transported and the loading and unloading costs at the stations, these tariffs include the costs for fuels, rail and station utilization etc. The tariffs are based on the average liquid freight transport costs per ton-kilometre and the average costs per ton of loaded and unloaded liquid freight at departure and arrival station in the Netherlands in 2020 [53]. For the freight tariff, this means that the weight of the RTC itself should be paid twice per trip (back and forth), and the weight of the freight only once (the RTCs go back unloaded). The weights should be divided by 1000 as the tariffs are in tonnes.

$$freight\_costs_{i,t}[€] = (distance_i[km] * RTCs_{i,t} * trips_i) * \frac{2 * RTCweight[kg] + loadweight[kg]}{1000} * freighttariff[€/ton/km] \ \forall i \in I, \forall t \in T$$

The costs for loading and unloading for every arc in every year, are based on the tariff per tonnes that includes both loading and unloading, and only has to be paid for the load of the freight itself.

$$loading\_costs_{i,t}[€] = (RTCs_{i,t} * trips_i) * \frac{loadweight[kg]}{1000} * loadingtariff[€/ton] \ \forall i \in I, \forall t \in T$$

The total variable OPEX per year is the sum of the freight costs of all arcs and the loading costs of all arcs.

$$variable\_opex_t[€] = \sum_{i=1}^{I} freight\_costs_{i,t}\,[€] + \sum_{i=1}^{I} loading\_costs_{i,t}\,[€] \quad \forall t \in T$$

Insights in rail costs

In Figure 88 the levelized transport costs (in hydrogen equivalents) are shown for ammonia trains over a distance of 250 km and annual volumes of 234 kT of hydrogen (1300 kT of ammonia). The costs of conversion and reconversion are not included in these costs, as – on the contrary of the LH2 and LOHC trucks – the ammonia rail function is only used in chains when ammonia is the end product. In other words, conversion is required and reconversion not, in all cases, while for LOHC and LH2 trucks this was not the case. Using ammonia trains for transport of hydrogen itself will have relatively large (re)conversion costs (see conversion chapter). The transport costs under the assumption of trains departing every day are 0.12 euro per kg of hydrogen and the freight and loading tariffs represent the largest share of the costs. As discussed in previous paragraph, if it is assumed that trains only depart once per two days, double the amount of RTCs are required to transport the same volumes per year: the RTC CAPEX and fixed OPEX per kg of hydrogen are doubled. If the trains would only depart once per three days, a similar increase in the RTC CAPEX and

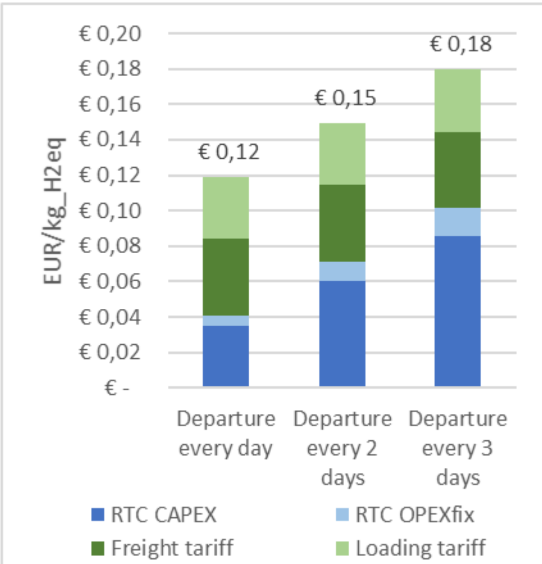


Figure 88 – Levelized costs of hydrogen equivalents transport by ammonia trains (234kT H2_eq per year over 250 km)

fixed OPEX is seen, resulting that the share of the RTC costs becomes larger than the freight and loading tariffs.

In Figure 89 the impact of volume and distance on the levelized transport costs of hydrogen equivalents by ammonia trains is shown, for distances between 100 and 800 km and volumes between 83 kT and and 283 kT of hydrogen equivalents per year (corresponding 460 and 1570 kT of ammonia). The impact of volumes on the levelized costs per kilogram is comparable to the gaseous hydrogen trucks: more RTCs have to be purchased, more tariffs are paid but this increases linearly with the volumes so in terms of costs per kg. If the distance increases, the costs for loading remain the same, but the costs paid for the freight tariffs will rise. The costs for the RTCs will remain the same, as independent of the distance RTCs can be used once per day due to the departure of trains. However, between 600 and 700 km a shift is seen, as due to the increased travelling time of this distance the cycling time of one trip exceeds one day. Hence, at this point more RTCs have to be purchased and the costs increase.

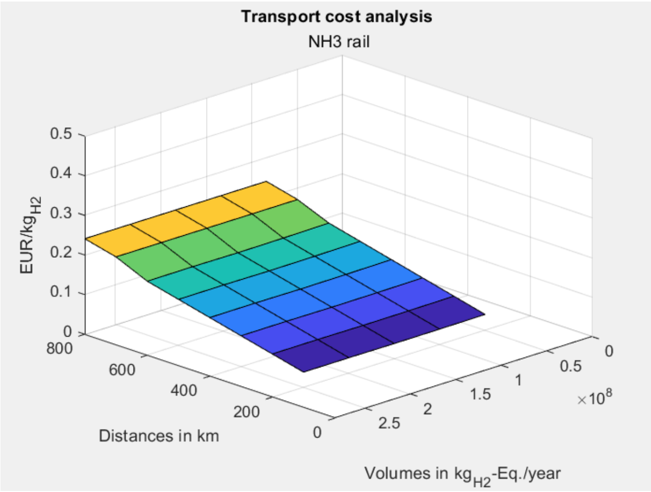


Figure 89 – Overview impact of distance and volume on rail transport costs

1.5 Conversion

The function used to compute the conversion costs is also a generic conversion function that can be used for multiple conversion technologies (see Table 9), based on the 'input carrier' and 'output carrier' that is stated as input variable of the function.

Table 9 – Overview of conversions and reconversions that are included in the conversion function

Conversion data available in conversion function					
Input carrier	**Conversion**	**Output carrier**	**Input carrier**	**Reconversion**	**Output carrier**
H2	Liquefaction	LH2	LH2	Evaporation	H2
H2	Hydrogenation	LOHC	LOHC	Dehydrogenation	H2
H2	Ammonia synthesis	NH3	NH3	Ammonia dissocation	H2
H2	Methanol synthesis	MeOH	MeOH	Methanol reforming	H2

The conversion costs are calculated simply starting with the CAPEX, followed by the fixed OPEX and finally the variable costs. The methodology to calculate the variable costs might differ per conversion technology, dependent on the additional resources that are required and the inclusion of these costs in the assumed conversion plant costs.

First, as input of the function a maximum hourly volume could be given to determine the required size of the plant. For example if LOHC tanks are used to store the variable renewable produced hydrogen, then the hydrogenation plant cannot be scaled on baseload production, but should be able to convert the maximum hourly output of the electrolyser towards LOHC. Hence, based on the analysed chain, the function scales the conversion plant on a maximum hourly volume that is given (maximum hourly volume is translated to the maximum annual volume, if plant would operate at maximum capacity), or determines the maximum hourly volume based on the baseload utilization of the plant. The CAPEX of the conversion plant is calculated according to the function presented below. The annual fixed OPEX are based on a percentage of the initial investment costs.

$$CAPEX\_conversion_i = basesizecosts[€/ton/day] * (\frac{maxvolume_i[kg/year]/1000/365}{baseload\_utilizationrate})^{scalingfactor} \forall i \in I$$

The variable costs depend on the type of conversion that is used. Methanol synthesis is the exception as it is assumed that CO_2 required to make the methanol is obtained via Direct Air Capture (DAC). The CAPEX, fixed OPEX and variable OPEX (based on electricity and heat) of the DAC to obtain the CO_2 required to produce the methanol are added to the CAPEX, fixed OPEX and variable OPEX of the methanol synthesis plant. For the ammonia synthesis, plant cost assumptions are used that include the Air Separation Unit (ASU) already to obtain the required amount of N_2, so in therefore no additional costs for the ASU are calculated separately.

For all conversions variable costs consists of electricity costs, heat costs and water costs, based on the consumption per kg of the 'output carrier' conversed. If no electricity, heat or water is used for a specific conversion, the consumption of that resource is 0, so no costs are added. For required heat (only used for the DAC for methanol synthesis, and dehydrogenation of LOHC) costs of 0 are assumed. For the DAC usually the waste heat of the electrolyser or SMR process can be used. And so for the waste heat produced by hydrogenation and the heat required for dehydrogenation no revenues and/or costs are assumed, although the availability of waste heat is taken into account as prerequisite to use LOHC as carrier in a cost-effective and sustainable manner.

Insights in conversion costs

Figure 90 shows the cost resulted for the conversion and reconversions. Figure 90a and b shows the conversion and reconversion costs for relatively small volumes and Figure 90c and d for relatively large volumes. All costs and volumes are translated to hydrogen equivalents to make the conversion costs equally comparable to each other (a kg of ammonia contains 0.18 kg hydrogen and a kg of methanol contains 0.2 kg hydrogen). In the presented costs it is assumed that the plants use baseload production. Comparing the costs shown in the figures, some aspects of the conversion technologies are recognized:

- Ammonia synthesis and dehydrogenation involve the largest economies of scale among the conversion and reconversion technologies;
- Ammonia dissociation is the most expensive conversion technology;
- For conversion and reconversion of ammonia and methanol, reconversion costs are higher than conversion costs, while for liquid hydrogen and LOHC this is the opposite;
- Liquification of hydrogen is significantly more expensive than evaporation of hydrogen, while for hydrogenation and dehydrogenation these differences are less significant;
- For both large and small volumes, the combined conversion and reconversion costs are the lowest for LOHC, followed by methanol on the second place. Both could involve additional

costs for heat. If a natural gas (or other heat source) price of 25 EUR/MWh is used for the heat required during these processes the following costs would have been added to both processes:

- 0.23 EUR/kg of hydrogen equivalents would have been added during the dehydrogenation process (although potentially revenues can be gained during the conversion process when heat is released);
- 0.24 EUR/kg of hydrogen equivalents would have been added during the methanol synthesis process, due to the heat requirements for the Direct Air Capture process;
- Similarly, ammonia dissociation becomes 0.13 EUR more expensive per kg of hydrogen extracted from the NH3.

Hence, this would significantly impact the costs of these processes. Adding costs for heat would almost close the cost gap between the combined costs of liquid hydrogen conversion and reconversion and those for LOHC.

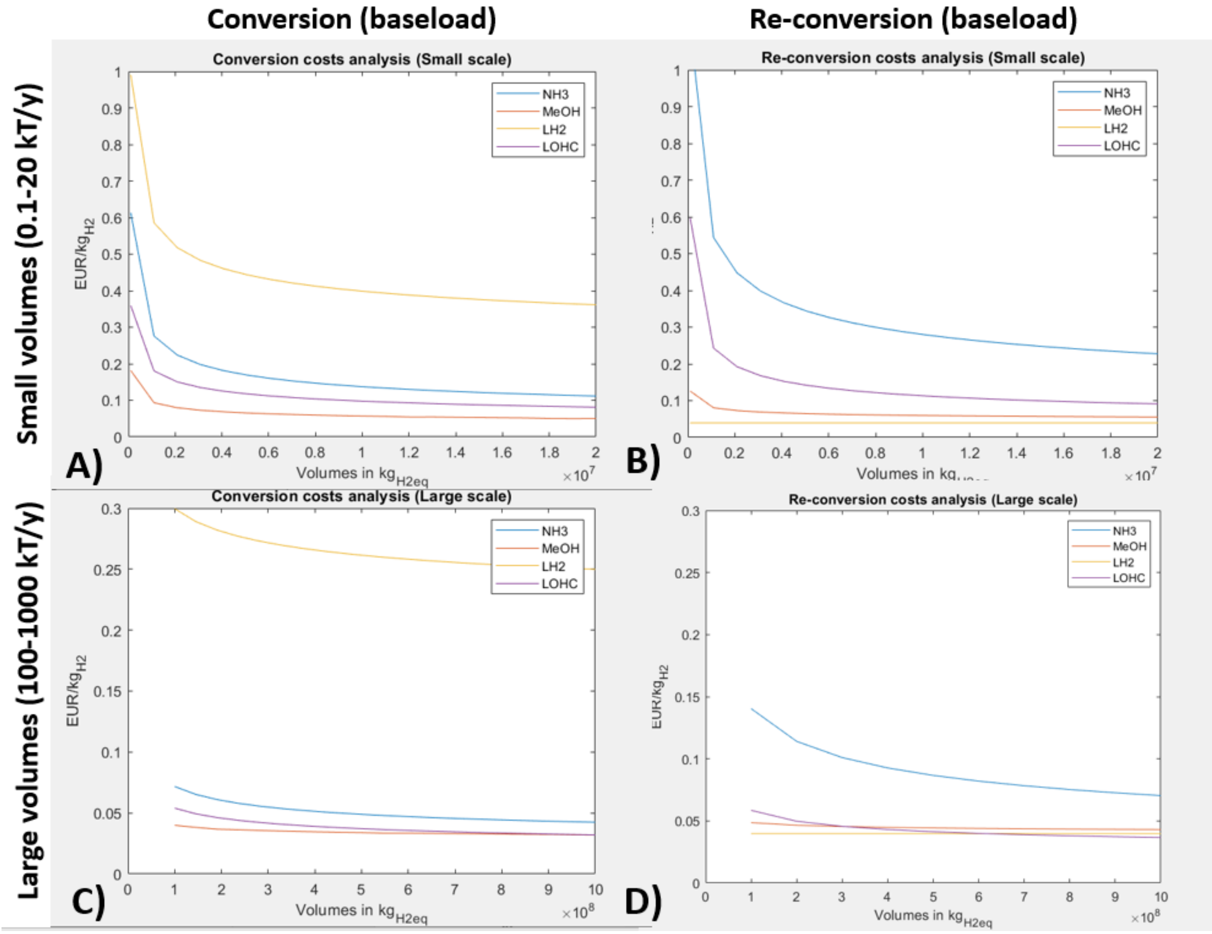


Figure 90 – Overview of levelized baseload conversion and re-conversion costs in hydrogen equivalents

1.6 Compression and purification

1.6.1 Compression cost function

To calculate the compression costs, first the required power of the compressors is calculated, followed by the compressor CAPEX, fixed OPEX and variable OPEX based on the electricity used.

The input of the compressor function are the maximum hourly mass flow rate per location in kg (), the annual volumes per location (in kg) that have to be compressed, the inlet pressure and the desired outlet pressure. The investments in the compressor capacity are based on the compressor power (in kW) that has to be installed. The required compressor power is calculated via the function presented below [54] [55].

$$P_i[kW] = \frac{Q_i}{3600} \times \frac{Z \times T \times R}{M_{H_2} \times \eta_{comp}} \times \frac{N_\gamma}{\gamma - 1} \times \left[\left(\frac{P_{out}}{P_{in}} \right)^{\frac{\gamma-1}{N_\gamma}} - 1 \right] \forall i \in I$$

where:

Q_i the maximum flow rate (in kg per hour) of hydrogen that has to be compressed on location i
P_{in} the inlet pressure of the compressor (suction),
P_{out} the outlet pressure of the compressor (discharge),
Z the hydrogen compressibility factor,
N the number of compressor stages (1),
T the inlet temperature of the compressor (278 K),
γ the diatomic constant factor (1.4),
M_{H2} the molecular mass of hydrogen (2.0158 g/mol),
η_{comp} the compressor efficiency ratio (here taken as 90%),
R the universal constant of ideal gas (8.314 J K-1 mol-1).

The annual fixed OPEX are calculated as percentage of the initial investment cost and the variable OPEX are based on the electricity used to compress the hydrogen. The utilization is based on the difference between the maximum hourly mass flow rate () and the average hourly mass flow rate. Moreover, electricity lost due to efficiency losses.

$$OPEXvar\_compression_{i,t}[€] = P_i[kW] * \frac{(Q_i[kg] * 8760)}{annual\_volume_{i,t}[kg]} * electricity\_price[\frac{€}{kWh}] * DTE \; \forall i \in I, \forall t \in T$$

where:

P_i the compressor power at location i in kW,
Q_i the maximum flow rate (in kg per hour) of hydrogen that has to be compressed on location i,
DTE the Driver Thermal Efficiency (90%).

1.6.2 Combined compression and purification

The costs for purification depend a lot on the gas mixture that has to be purified, the required purity and the scale of purification. Therefore, a lot of different cost functions and information is available within the literature [56] [57] [58] [59] [60] [61] [62]. To obtain the right cost and technical data that would fit for the purpose of the purification function in our model, namely for the purification at the HRS to fuel cell quality, a commercial technology developer specialized in compression and purification of hydrogen for mobility purposes was contacted to obtain valid data. The data obtained is applicable for a combined purification and compression installation.

The data and cost function that is used, assumes that inlet hydrogen with a purity of 98% (based on the proposed backbone specs [43]) comes in at a pressure between 30 and 50 bars. The purified hydrogen derived has a purity of 99.97% (based on ISO 14687 specifications) and a pressure between 300 and 500 bars, in our model we assumed 350 bars. The cost calculations performed are similar to the conversion cost calculations described in chapter 1.5 and are based on the specific investments, scaling factor, lifetime, operations and maintenance costs and electricity consumption costs.

Insights in compression and purification costs

Figure 91 shows the compression costs per kilogram of hydrogen compressed, depending on its inlet and outlet pressure. Generally, the higher the outletpressure/inletpressure ratio, the higher the compression costs (as well the CAPEX, fixed OPEX and electricity costs) are as more power is required to compress the hydrogen. For example as 70/30=2.33 is lower than 30/10=3 or 950/350=2.71, the compression costs to compress hydrogen from 10 to 30 bar are higher. The compression demand relates to the potential compression requirements in the model scenario's:

- 10 to 30 bar relates to the exit point of a transmission pipeline with a very high pressure drop (mostly this is way lower);
- 30 to 70 bar is the compression required at the start of new (high pressure) pipelines;
- 30 to 200 bar is the required compression for storing hydrogen in gaseous hydrogen tanks;
- 30 to 250 bar is the required compression for gaseous hydrogen transport by trucks;
- 350 to 950 bar is the required additional compression at the HRS after the combined purification and compression step;
- 30 to 950 bar is the required compression if purification is performed at another location than the HRS.

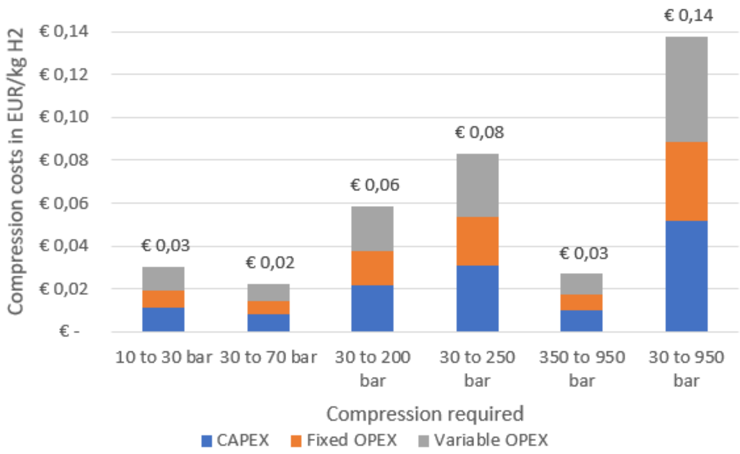


Figure 91 – Insights in compression costs

In Figure 92 the impact of volume on the combined purification and compression cost function is shown. The smallest volume represented in the figure (146.000 kg per year) represents the average size of the consumption of one HRS, while the maximum volume shown in the figure (7.3 kT per year) represents the volume assumed for a purification hub of 50 average size tank stations.

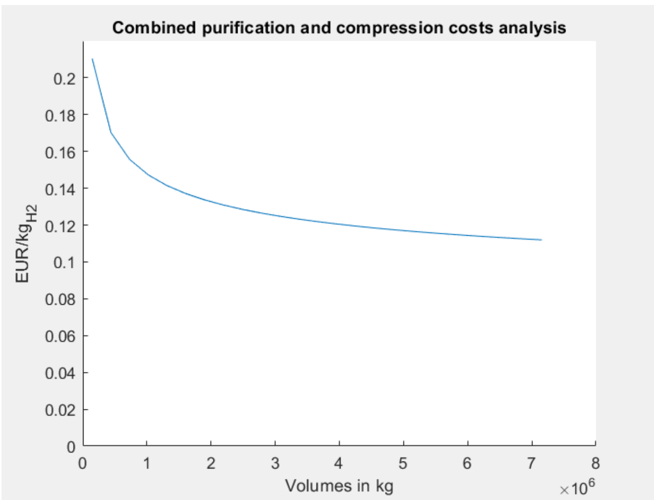


Figure 92 – Combined purification and compression costs depending on its scale in annual volumes

1.7 Financial

In every function, the annual CAPEX, fixed OPEX and variable OPEX are calculated, representing the cash flows over the projects lifetime. The project lifetime used is 20 years. The lifetimes of the assets included through the value chains have large differences, for example truck caps last 8 years and new pipelines (more than) 40 years. We used a linear depreciation methodology to determine the remaining value at the end of the project lifetime to be able to compare the costs equally. Otherwise trucks transport would have been cheaper if a project life of 24 years would have been assumed (exactly three truck investments could be utilized), compared to 20 years (the truck investments of the third truck would have been utilized for 50%).

The cost of capital is the rate that a company/consortium is expected to pay on average to all its security holders to finance its activities. The WACC is commonly referred to as the firm's cost of capital. Importantly, it is dictated by the external market and not by management. Applying a single sector or even firm specific costs of capital for a pool of activities can lead to an over/underestimation of the financial risks perceived by the market. However, little is known about how financial investors are valorising the risk profile, and thus the cost of capital, of these new kinds of value chains comprising of multiple assets and stakeholders.

An 7% discount rate is considered which reflects the large uncertainty and sensitivity parameters of the project activities.

Below, two generic functions are presented to calculate the Net Present Value (NPV) and the Levelized Costs of Energy (LCOE). represents the years as set of the total project lifetime . represents the discount rate. In this study we used the WACC as discount rate to include both the required return of investors and the impact of the present value of future cash flows in the cost calculations. The NPV indicates the current value of all future cash flows generated by a project, including both the capital and operational costs. The Levelized Costs of Energy is an indicator for the price of energy required for a project where the revenues would equal the costs, including a return that has to be made on the investments.

$$NPV = \sum_{t=1}^{T} \frac{Cashflow_t}{(1+r)^t}$$

$$LCOE = \frac{\sum_{t=1}^{T} \frac{Total\_costs_t}{(1+r)^t}}{\sum_{t=1}^{T} \frac{Energy\_output_t}{(1+r)^t}}$$

These generic functions are used to calculate the LCOP and NPV for every chain, and being able to get insights in the cost distribution of the LCOP. The formula below shows how the Net Present Costs for a specific chain element n (e.g. hydrogen production, or truck transport) are calculated for the set N of all chain elements that are included in a specific chain.

$$NPC_n = \sum_{t=1}^{T} \frac{CAPEX_{n,t} + OPEXfix_{n,t} + OPEXvar_{n,t}}{(1+WACC)^t} \forall n \in N$$

The Levelized Cost of Product (LCOP) or Levelized Product Cost (LC) is a similar indicator as the LCOE, except the only difference that the terminology is changed to comply with the scope of the value chains analysed in this study, which includes beyond energy also feedstock products (e.g. ammonia and methanol) and cover the full production and supply costs instead of the production costs only. The formula below shows the calculation of the LCOP for the full chain (of all elements are summed). If the share of the cost of a single element in the total LCOP can be calculated to divide this single by the total output volumes of the chain. And if the levelized cost of an individual chain element is wanted to be calculated (for example in the separate chain cost element analysis performed in this appendix), the can be divided by the output volumes of that specific chain element.

$$LCOP = \frac{\sum_{n=1}^{N} NPC_n}{\sum_{t=1}^{T} \frac{Volumes_t}{(1+WACC)^t}}$$

The NPV of a chain is calculated by the formula presented below. The cashflow of each year is calculated by summing the revenues of all chain elements in that specific year and extract the total annual costs of that specific year. The sum of the Present Values (PV) in each year gives the Net Present Value at the end of the project lifetime. The revenues applied in the model are based on the levelized costs of the alternative, which could be another green option or an grey option including its carbon costs.

$$NPV = \sum_{t=1}^{T} \frac{\sum_{n=1}^{N} Revenues_{n,t} - \sum_{n=1}^{N}(CAPEX_{n,t} + OPEXfix_{n,t} + OPEXvar_{n,t})}{(1+WACC)^t}$$

1.8 Import

The import costs of the model are retrieved from the Import Model that is used in HyDelta Workpackage 7B to calculate the hydrogen (carrier) import costs. The import costs include the costs per volume of hydrogen or carrier that is imported to the harbour of Rotterdam, or entering the national Dutch hydrogen pipeline system if import of gaseous hydrogen via pipelines is used.

The only calculations performed are that in the general scenarios import costs of a specific carrier are based on the average import costs from multiple countries: Canada, Australia and Morocco. The average is taken as it is perceived that not all the hydrogen can be purchased from the most cost effective location, as in reality multiple importing countries will demand for the most cost efficient import routes which could drive up the costs. The average taken is assumed to give an estimation of the actual future price, that is subject to a dynamic global market.

The model can import LOHC, Liquid hydrogen, ammonia, methanol and gaseous hydrogen from some specific locations where international pipeline connections could potentially be established. To limit the amount of content in the graphs of the main report, only the most cost effective import routes are shown. For ammonia and methanol end-uses, it turned out to be most cost efficient route was to import it via the same carrier as is demanded as feedstock. For the end-uses that demand gaseous hydrogen import via gaseous hydrogen turned out to be most cost effective, however, under the precondition that a large scale European hydrogen backbone is available. Without considering that option, import and inland transport via LOHC was found to be the most cost effective route. Therefore, these options are considered and shown in the figures in the main report.

Appendix B – Model validation

The value chain model (VCM) used to calculate the results shown in this report is developed with great carefulness. During the process of modelling, each function was tested and outcomes were compared with values seen in earlier derived literature. Moreover, discussions have taken place with the colleagues working on HyDelta 7A and 7B to align the calculation methodologies as much as possible and to compare outcomes on discrepancies.

Besides this extensive process of model development, an external validation process has taken place with modellers from the consortium partners that were not involved in the HyDelta project. They tested the model based on two validation methodologies:

1. The outcomes of the HyDelta Value Chain models are compared with the outcomes of the DNV value chain model (ExplEnergy tool), by using – as much as the model allows – the similar input data;
2. The HyDelta value chain model is runned with extreme demand values to check if the expected scaling took place.

The outcomes of both validation methodologies are discussed in this appendix.

1.1 Validation based on outcome comparison with DNV model

The defined methodology was to put the same input data, from the HyDelta 7B datasheets, in the DNV model to compare the outcomes of both the HyDelta Value Chain model and the DNV model. There was chosen to focus at the ammonia and distributed high temperature heating value chains, because these chains included a lot of functions that were also included in chains of other end users.

Some particular functions could not be validated using this methodology, as the DNV model did not support calculations for ammonia transport by rail, methanol synthesis using DAC and LOHC truck transport.

1.1.1 Validation of ammonia value chain results

The ammonia value chain was validated with the support of a DNV internal model[9] which has capability to assess several value chains based on various input parameters and with dedicated outputs (e.g., cost of energy).

For this specific case, the following two ammonia value chains were validated:

- Domestic green ammonia transported via pipelines, *specific value chain name: NH3.B {'Domestic', 'H2', 'Green', 'NH3', 'Pipeline', 'NH3'}*
- Domestic blue ammonia transported via pipelines, *specific value chain name: NH3.C {'Domestic', 'H2', 'Blue', 'NH3', 'Pipeline', 'NH3'}*

Domestic green ammonia value chain

See Figure 93 for a visualization of the validation outcome based on the domestic green ammonia value chain. Overall, the discrepancy between the final cost value retrieved from the HyDelta model (37 EUR/GJ) and from the DNV model (33.4 EUR/GJ) resulted in 10% between the two model outcomes. Considering that both modelling engines are not exact replicates, and the input parameters could not exactly be mimicked, the outcome still suggests that the HyDelta model is trustworthy. The costs allocated to the electrolyser and the windfarm displayed the largest discrepancy.

[9] ExplEnergy

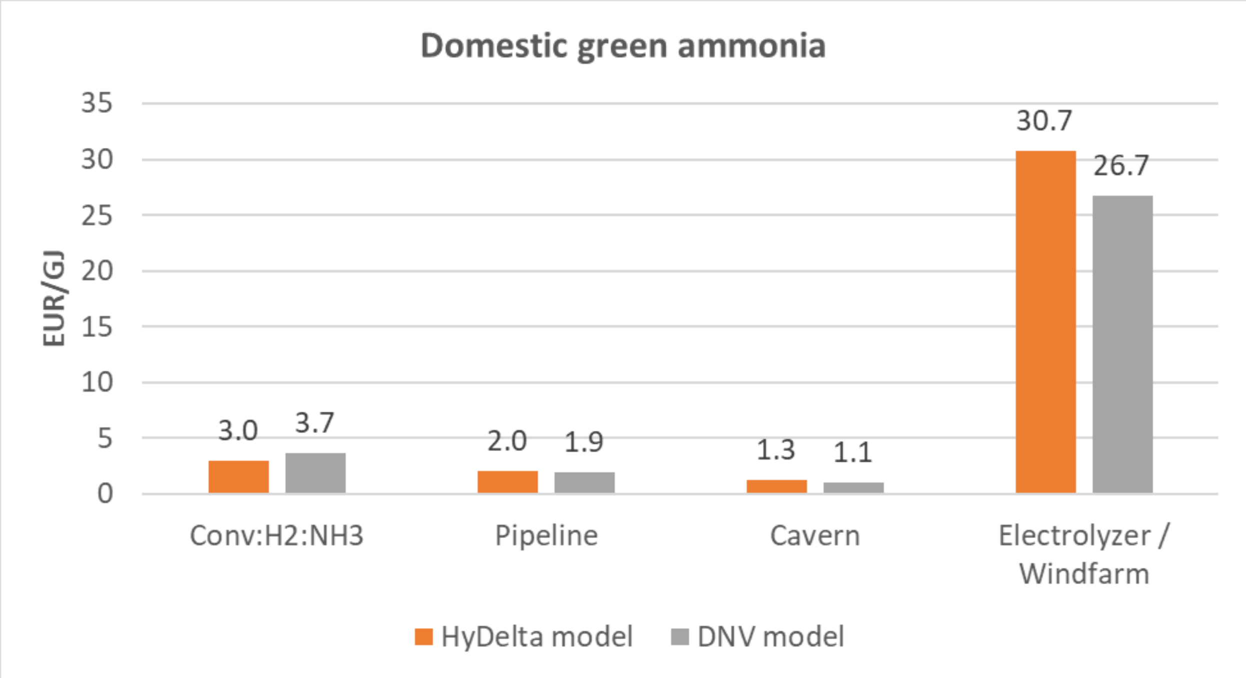


Figure 93 – Validation of the domestic green ammonia value chain based on the DNV model.

Domestic blue ammonia value chain

See Figure 94 for a visualization of the validation outcome based on the domestic blue ammonia value chain. Overall, the discrepancy between the final cost value retrieved from the HyDelta model (20.2 EUR/GJ) and from the DNV model (18.8 EUR/GJ) resulted in 7% between the two model outcomes. Again, in light that both modelling engines are not exact replicates, and the input parameters could not exactly be mimicked, the outcome still suggests that the HyDelta model is trustworthy. The costs allocated to ATR+CCS system displayed the largest discrepancy.

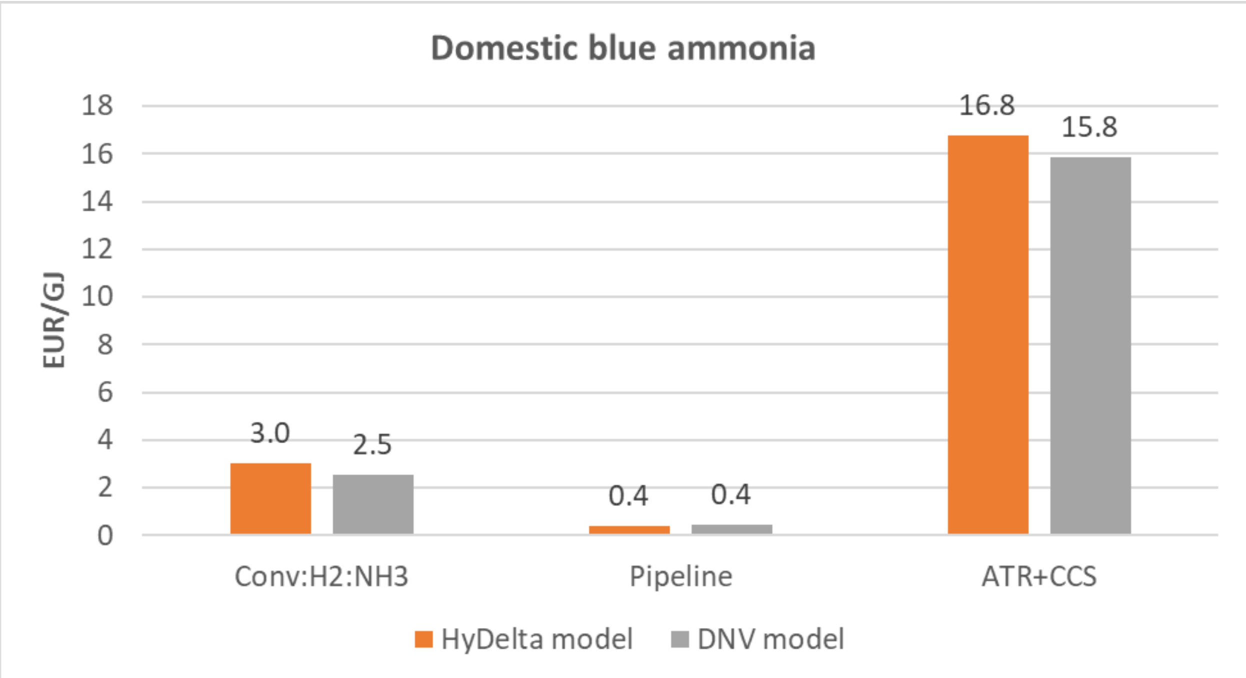


Figure 94 – Validation of the domestic blue ammonia value chain based on the DNV model.

1.1.2 Validation industrial heating value chain results

The industrial heat value chain was validated with the support of a DNV internal model[10] which has capability to assess several value chains based on various input parameters and with dedicated outputs (e.g., cost of energy).

For this specific case, the following two ammonia value chains were validated:

- Domestic industrial heat via green hydrogen transported via pipelines, *specific value chain name: IH.C {'Domestic', 'H2', 'Green', 'H2', 'Pipeline', 'IH', 'Pipeline'}*
- Domestic industrial heat via blue hydrogen transported via pipelines, *specific value chain name: IH.D {'Domestic', 'H2', 'Blue', 'H2', 'Pipeline', 'IH', 'Pipeline'}*

Domestic industrial heat via green hydrogen

See Figure 95 for a visualization of the validation outcome based on the domestic industrial heat (via green hydrogen) value chain. Overall, the discrepancy between the final cost value retrieved from the HyDelta model (30.3 EUR/GJ) and from the DNV model (29.7 EUR/GJ) resulted in 2% between the two model outcomes. Considering that both modelling engines are not exact replicates, and the input parameters could not exactly be mimicked, the outcome suggests that the HyDelta model is trustworthy. The costs allocated to the electrolyser and the windfarm displayed the largest discrepancy (although still minor).

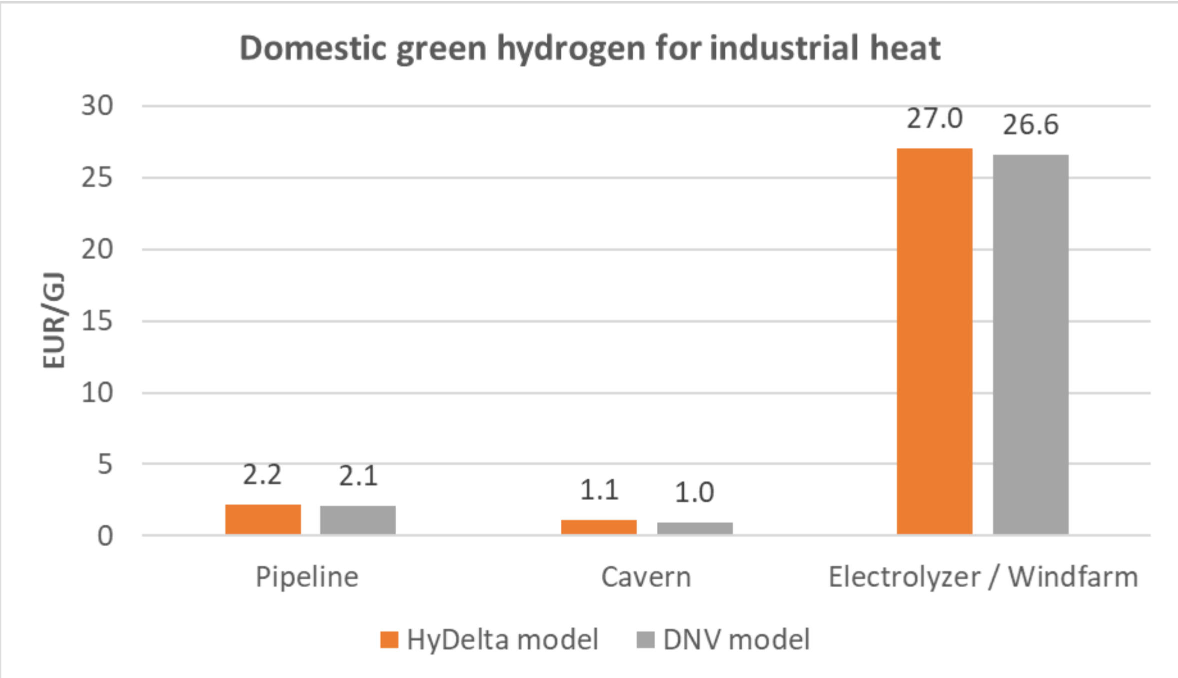


Figure 95 – Validation of the domestic industrial heat via green hydrogen value chain based on the DNV model.

Domestic industrial heat based on blue hydrogen

See Figure 96 for a visualization of the validation outcome based on the domestic industrial heat (via blue hydrogen) value chain. Overall, the discrepancy between the final cost value retrieved from the HyDelta model (16.6 EUR/GJ) and from the DNV model (17.1 EUR/GJ) resulted in 3% between the two model outcomes. Considering that both modelling engines are not exact replicates, and the input parameters could not exactly be mimicked, the outcome still suggests that the HyDelta model is

[10] ExplEnergy

trustworthy. The costs allocated to the electrolyser and the windfarm displayed the largest discrepancy.

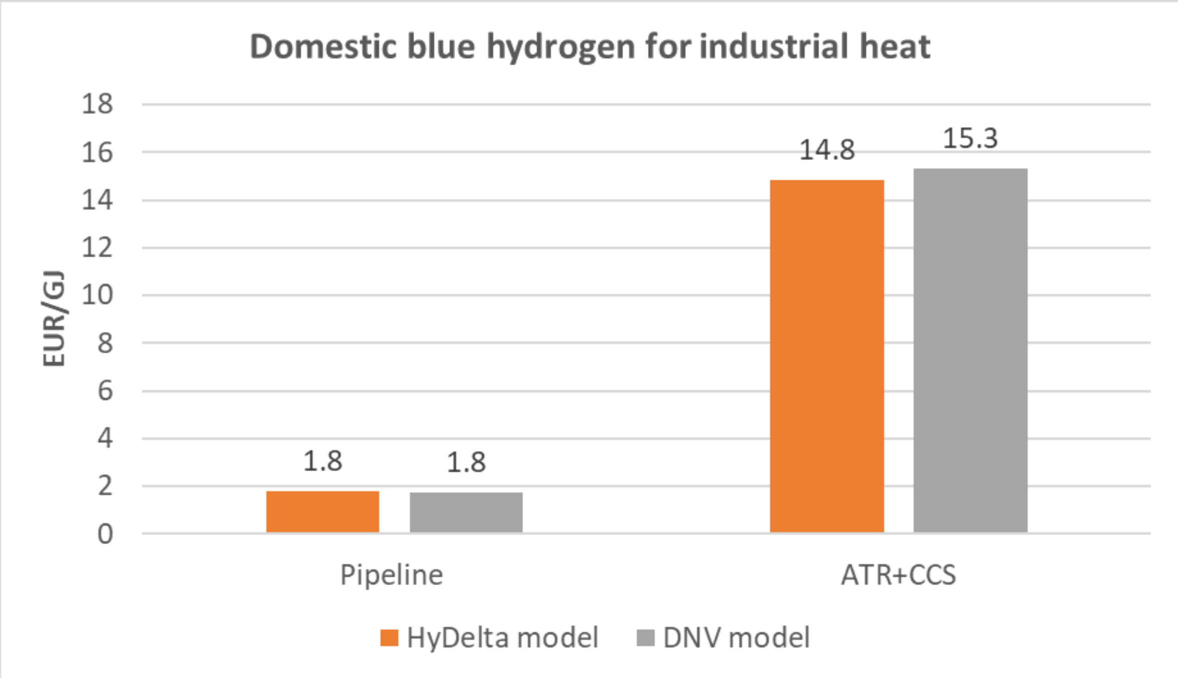


Figure 96 – Validation of the domestic industrial heat via blue hydrogen value chain based on the DNV model.

1.1.3 Main highlights of validation methodology

The validation process resulted in the following highlights:

- The difference in calculation methodologies resulted in a 3-10% discrepancy of the outcomes between the two models. Given the issue that not all input parameters could be mimicked for 100%, we think that the discrepancy of the analysed chains is minor;
- The main difference between the offshore wind and electrolysis costs between the models is that the electrolyser efficiency was calculated in a different way: the DNV model calculates the losses as a percentage of the energy content while the HyDelta model calculates it based on the physical streams, moreover, the division of sub-steps was done differently, making it hard to really use the same input data for the steps;
- The discrepancy in the ammonia conversion step can be explained in the way the electricity input for this process is calculated. In the DNV model it is assumed that electricity including its losses for transport is used from the offshore windfarm, while the HyDelta model assumes that green electricity is extracted from the grid, excluding specifying the exact origin of the electricity.

1.2 Validation based on extreme demand inputs

The methodology for validation was done by running the model for few selected supply chains over a range of capacities and assessing how the resulting techno-economic parameters scale with input capacities. The chains were analysed for 0.5, 1, 2 and 10 times its original demand value.

Scaling of the total costs of all value chains were evaluated and two (other than analysed in the previous validation method) chains were selected for a more detailed analysis. These are the Mob.H (Mobility chain: backbone + last mile LOHC trucks, without hubs) and BE.E (Built environment chain:

backbone + last mile gH2 trucks) chains. For these two chains scaling results of each chain element were evaluated based on the demand values.

1.2.1 Mobility chain: backbone + last mile LOHC trucks without hubs

The default demand for Mob.H chain was set in the model to 146 kT/y of H2. The demand was varied from 0.5 – 10 times the default demand, which resulted in respectively 73 kT/y, 146 kT/y, 292 kT/y and 1460 kT/y of annual demand.

The results of the analysis are shown in Figure 97. The chain elements scaled as could be expected, except the pipeline element: the discounted CAPEX, fixed OPEX and variable OPEX are higher when the demand is 0.5 times the default demand than when the demand is the default demand. This was caused by the decision methodology of choosing to repurpose the existing pipeline or construct a new pipeline. If both options are viable (i.e. the diameter of the existing pipeline is large enough to transport the demanded volumes) the decision is made based on the least cost option. Newly constructed pipelines could be a cheaper option in the extreme case when the diameter of the existing pipeline is way to large compared to the transport demand. In this extreme case repurposing very large pipelines would be more expensive than the construction of small new pipelines. The initial HyDelta model made this choice before discounting the CAPEX, OPEXfix and OPEXvar. Therefore, it was decided to chose for new pipelines when the mobility demand was 0.5 times the default, while after discounting the costs turned out to be still more expensive than reusing the existing pipelines (due to a perceived difference in rest value of repurposed vs new pipelines). The HyDelta model was adopted to make the choice between reused and new pipelines based on the discounted costs to overcome this issue.

1.2.2 Built environment chain: backbone + last mile gH2 trucks

The default demand for BE.E chain was set in the model to 359 kT/y of H2. The demand was varied from 0.5 – 10 times the default demand, which resulted in respectively 180 kT/y, 359 kT/y, 718 kT/y and 3590 kT/y of annual demand.

The results of the analysis are shown in Figure 98. The scaling of the elements for the chain BE.E followed the expectations and logical patterns. There were no errors to report.

1.2.3 Main highlights of validation methodology

The validation methodology resulted in the following highlights:

- The total costs (CAPEX + OPEXfix + OPEXvar) of all supply chains in NH3, IH and BE following scaling patterns that are logical/expected with end-use demand changes;
- The element ‘Pipeline’ in the Mob category of value chains showed unexpected cost results where a decrease in demand increased the total cost of the element. The cause of the error was discovered and fixed in the model;
- The MeOH chains could not be evaluated by the external modeller due to an error during printing the values in the Excel output sheet. The same methodology was used to evaluate the MeOH chain outcomes and those did not result in discrepancies.

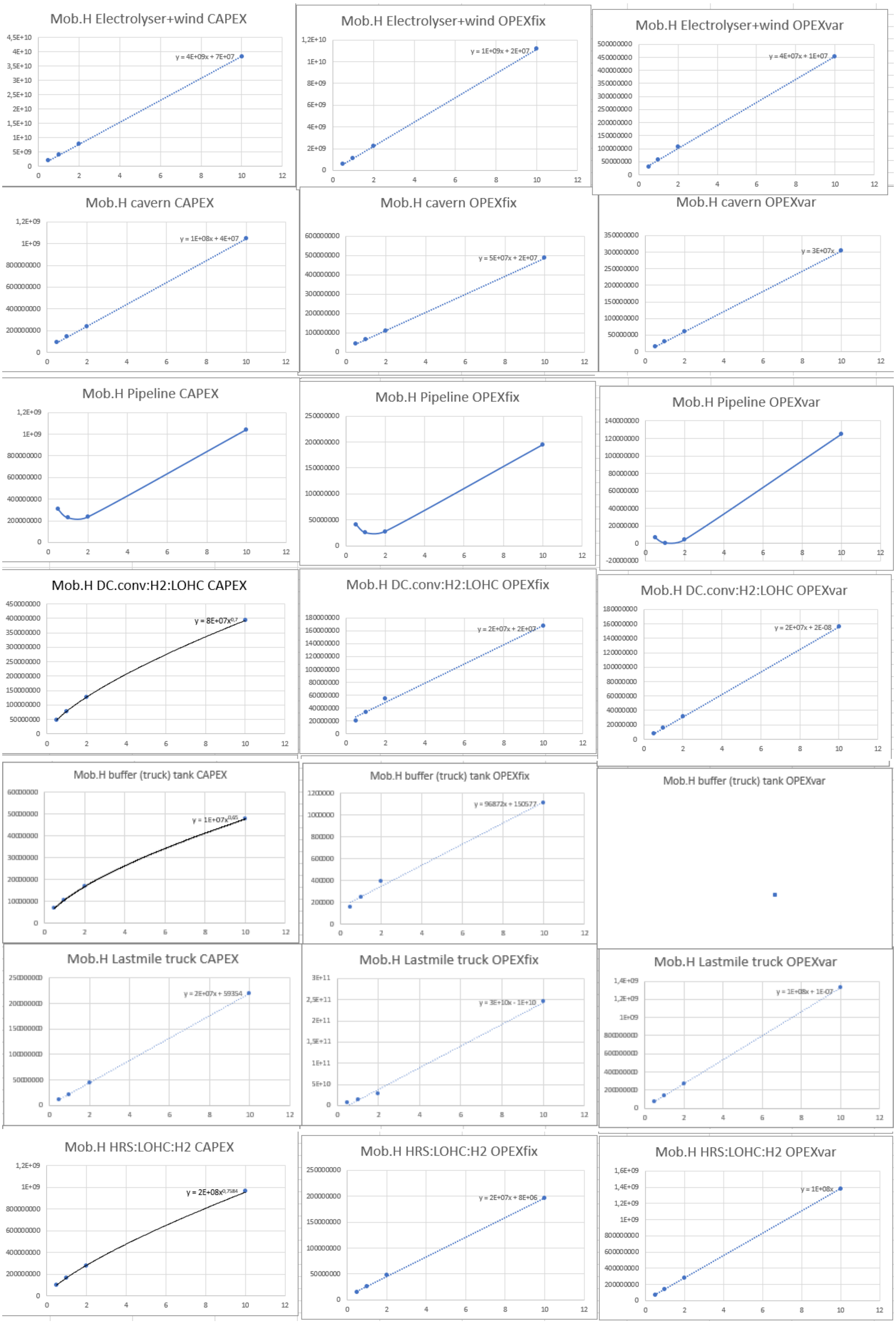


Figure 97 – Outcomes validation analysis of scaling on discounted costs per chain element: Mob.H chain

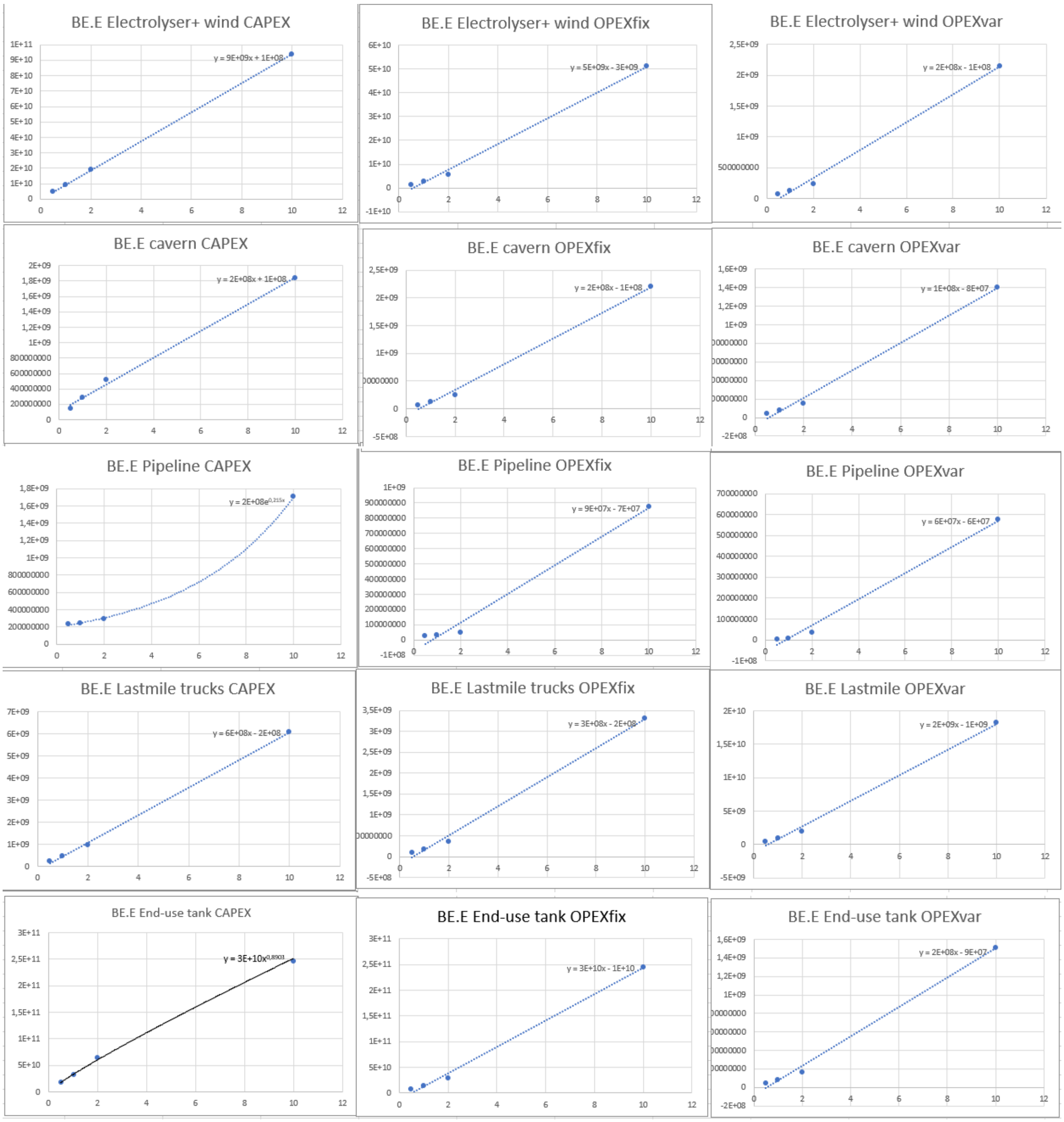


Figure 98 – Outcomes validation analysis of scaling on discounted costs per chain element: BE.E chain

Appendix C – Discussion of NPV results

The HyDelta value chain model can be used to calculate levelized costs and cash flows of specific chain elements, or total value chains. In the main report levelized costs are shown to indicate the required revenues or price of each chain element in order to earn back investments within 20 years and obtain the demanded margins of investors. In this appendix some insights and figures from the NPV analysis are shown and discussed. The main addition of these figures to the main content of the report are that insights can be retrieved in the difference between investment and operational costs required to develop the chains, from a helicopter perspective on the full chain (i.e. the Dutch national perspective). To remarks should be made for interpreting this appendix:

- In the report, sensitivities of several factors are explained: such as the natural gas price or the cost and efficiency development in green production technologies. The values taken in the NPV figures are just one value and could differ significantly before and during the lifetime of the investments. Therefore, the lines drawn in the figures should be seen as indicative and interpreted with the explained sensitivities and uncertainties in mind.
- Also for the revenues/prices/least cost alternative price a fixed value is taken, usually based on a possible, highly uncertain price of the perceived alternative. In reality, the revenues will be based on market prices and potential support, which are highly uncertain and unpredictable.

Hence, the lines should be interpreted as indicative and uncertain.

The main conclusions that could be drawn from the NPV figures:

- The green domestic chains analysed involve green hydrogen production via dedicated windfarm-electrolyser plants, large storage demand to balance the offshore wind pattern and relatively more domestic transport than the blue and import chains. Therefore, relatively large (Dutch) investment costs are involved to develop these chains compared to the blue and import chains. When the investment costs are made, relatively low operational costs are made during the years compared to the alternatives, as the main part of the total LCOP are involved in production, and the 0 marginal cost wind is used to produce the hydrogen. Hence, when the investment is made, green hydrogen is expected to have the lowest marginal costs in the market, but the risk of not earning back the huge investments is the highest.
- Blue hydrogen produced with new ATR+CCS plants have large investment costs, although significantly lower than the previous described green option. The operational costs are mainly determined by the natural gas prices, and higher than the green merit order. So theoretically in a worse-case scenario: if the natural gas price is high and the market price/least cost alternative (i.e. hydrogen, methanol or ammonia price) are low, situations could occur that the blue facilities will not produce, if marginal costs exceeds the market price. As seen in the report, the blue option becomes preferable compared to the alternatives if the natural gas price remains low, and the CO_2 allowance costs high.
- Since the import costs retrieved in this study are relatively high, and in the figures seen as marginal costs (a price for imported hydrogen is paid, only investments have to be made in domestic infrastructure to transport the hydrogen (carrier)), the NPV lines result in a negative line: the more is imported, the more costs are made that can not be sold profitable. However, if import costs go down, relatively the smallest investments risks have to be taken, from a national perspective. On the other hand, in reality import prices are not based on the production costs, but on uncertain developments in a world-wide hydrogen (carrier) market.

1.1 Industrial feedstock: Ammonia

In Figure 99 the NPVs for the four described ammonia chains are presented. In this figure, indicative market prices of 400 EUR/ton and 600 EUR/ton are used to show the impact on the NPV. The fossil reference price used in the main report was 250 EUR/ton, which could be increased to 400 EUR/ton by CO_2 allowance prices of 90 EUR/ton CO_2 or to around 600 EUR/ton if a natural gas price of 75 EUR/MWh is used. Obviously, if both a high CO_2 price and natural gas price would be the case, the potential ammonia market price will be even higher. In the end, the ammonia market price will be the result of a dynamic, global market with a lot of factors that could be of impact. In general, it is seen that grey will dominate at low CO_2 and natural gas prices, blue will dominate at high CO_2 and low natural gas prices, and the green (domestic and import) routes will dominate at high CO_2 and high natural gas prices, which can be strengthened further if innovations will lead to cost reductions in RES-based electricity and electrolyser technologies. In the case shown below, blue favours since a natural gas price of 25 €/MWh (relatively low) is taken and relatively high prices compared to the traditional seen ammonia price (400 and 600 EUR/ton, indicates a high CO_2 price if natural gas price is low).

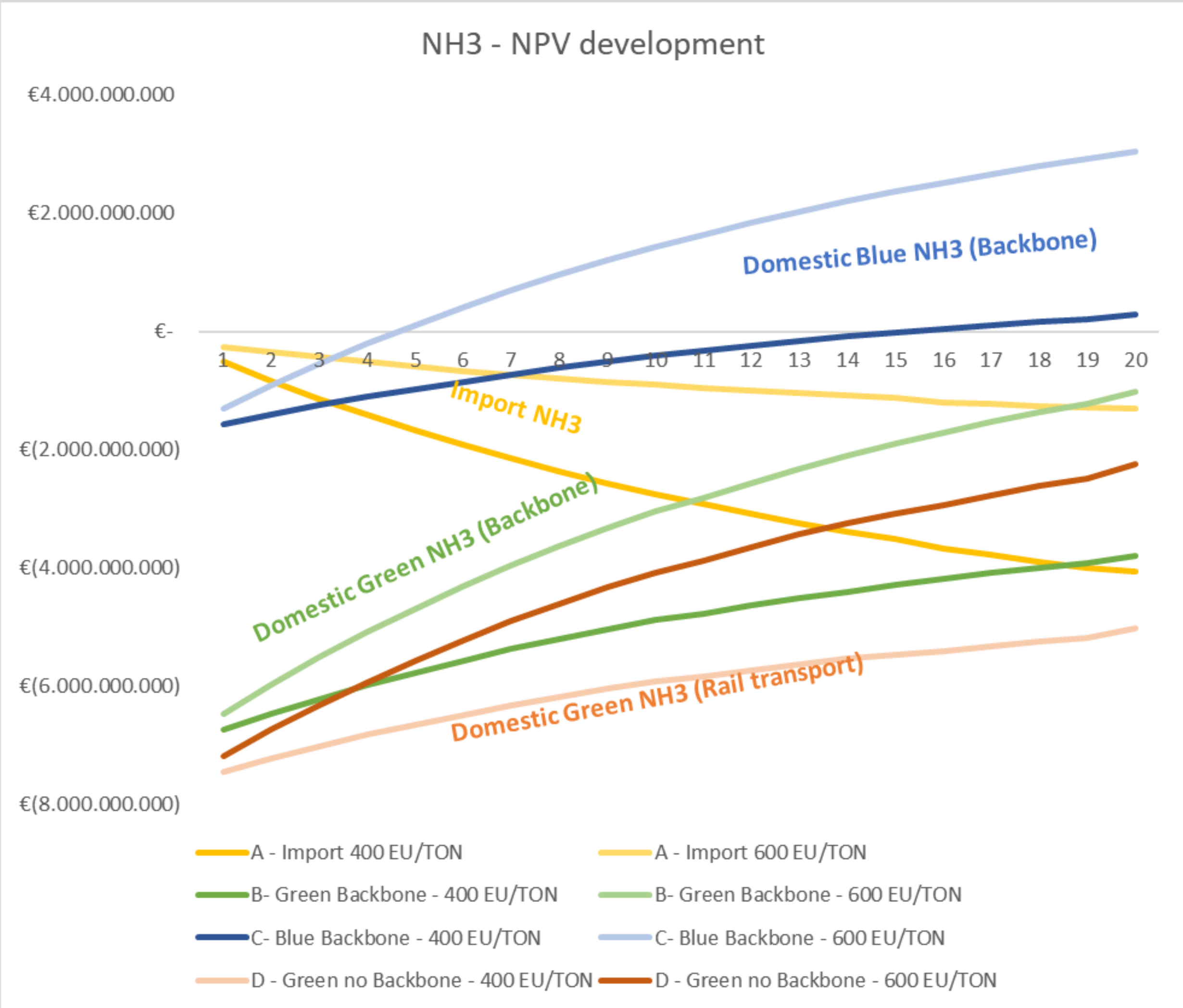


Figure 99 - NPV development of the complete value chain for NH3 prices of 400 and 600 eu/ton at the end-use location.

Main assumptions: Technical cost data of 2030 is used. Natural gas price 25 EUR/MWh, electricity grid price 60 EUR/MWh, LCOE of connected domestic offshore windfarm to electrolyser resulted in 60 EUR/MWh, green NH3 import costs include the average import costs by ship from Canada, Australia and Morocco, for the Green H2 Rail chain results of flexible conversion operation mode are presented. For all four chains, indicative ammonia prices of 400 EUR/ton and 600 EUR/ton are shown.

1.2 Industrial feedstock: Methanol

In Figure 101 the NPVs for the three described methanol chains are presented. The results can be interpreted similar to the ammonia chains. Figure 100 shows the historical European and Asian methanol market prices. The figure shows that the prices on both markets are related to each other, which shows the international connectiveness of those markets.

Also here, the blue case is the only profitable one when a natural gas price of 25 EUR/MWh is assumed and a relatively high methanol price. If a higher natual gas price would have been assumed, the blue lines would become flat, or even decreasing, instead of rising. Figure 39 in the main report shows the dynamics of what the actual CO_2 and natural gas price will mean for the levelised costs of the different 'colors' (i.e. green, blue and grey).

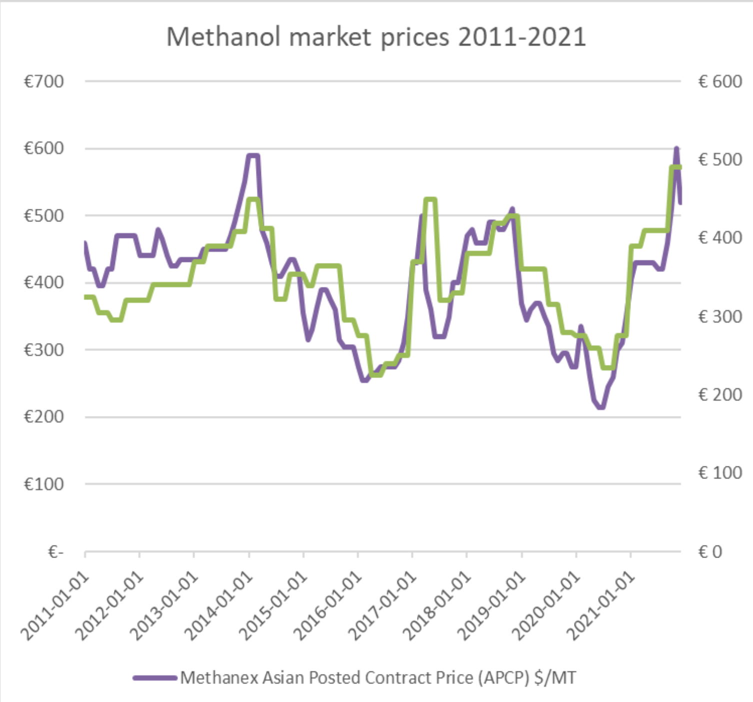
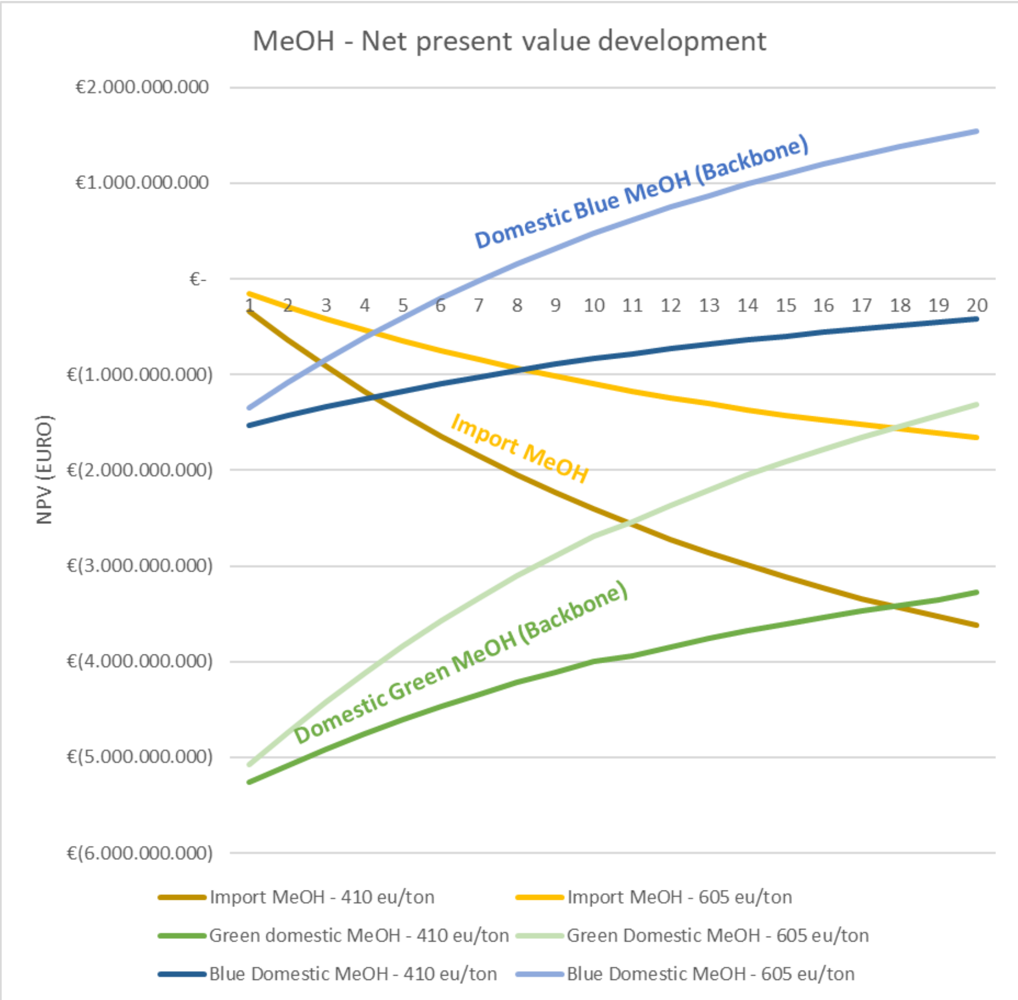


Figure 100 - Methanol market prices of the last decade from 'Methanex Monthly Average Regional Posted Contract Price History.' [67]

Figure 101 - NPV development for complete value chains for Methanol at market price of 410 eu/ton and 620 eu/ton.

Main assumptions: Technical cost data of 2030 is used. Natural gas price 25 EUR/MWh, electricity grid price 60 EUR/MWh, LCOE of connected domestic offshore windfarm to electrolyser resulted in 60 EUR/MWh, green MeOH import costs include the average import costs by ship from Canada, Australia and Morocco.



1.3 Industrial high temperature heating

In Figure 102 the NPVs for the three described methanol chains are presented. The revenues included are 1.2 €/kg and 2.4 €/kg, or in terms of energy respectively 40 €/MWh and 80 €/MWh. To give an indication: these prices match with natural gas prices of respectively 40 €/MWh and 80 €/MWh, or respectively a natural gas price of 24 €/MWh and CO_2 penalty of 80 €/ton CO_2, and a natural gas price of 64 €/MWh and CO_2 penalty of 80 €/ton CO_2 (See Figure 48 in the main text for a more detailed overview of impact of the prices). Actually, quite high CO_2 prices are required to make the NPV of the blue case positive compared to natural gas, if a similar natural gas price is assumed for both blue production and direct natural gas use: Figure 102 shows that if for both a natural gas price of 25 €/MWh and CO_2 is assumed (which seems logic), none of the investments will be earned back after 20 years (See line: 'Domestic Blue – Backbone 1.2 EU/kg'. If still a natural gas price is assumed of 25 €/MWh for both blue hydrogen production and direct use of natural gas, the CO_2 price has to achieve 270 €/ton CO_2 to achieve the NPV shown by the 'Domestic Blue – Backbone 1.2 EU/kg'. Hence, the impact of the natural gas price on the competitiveness is larger than the CO_2 price, and the green routes can benefit or harmed by both while the competitiveness of blue is only impacted by CO_2 penalty. These aspects should be taken to account by policy makers as well. For example: increasing taxation on natural gas does increase the competitiveness of green hydrogen compared to natural gas, but does not impact the competitiveness of blue hydrogen to natural gas.

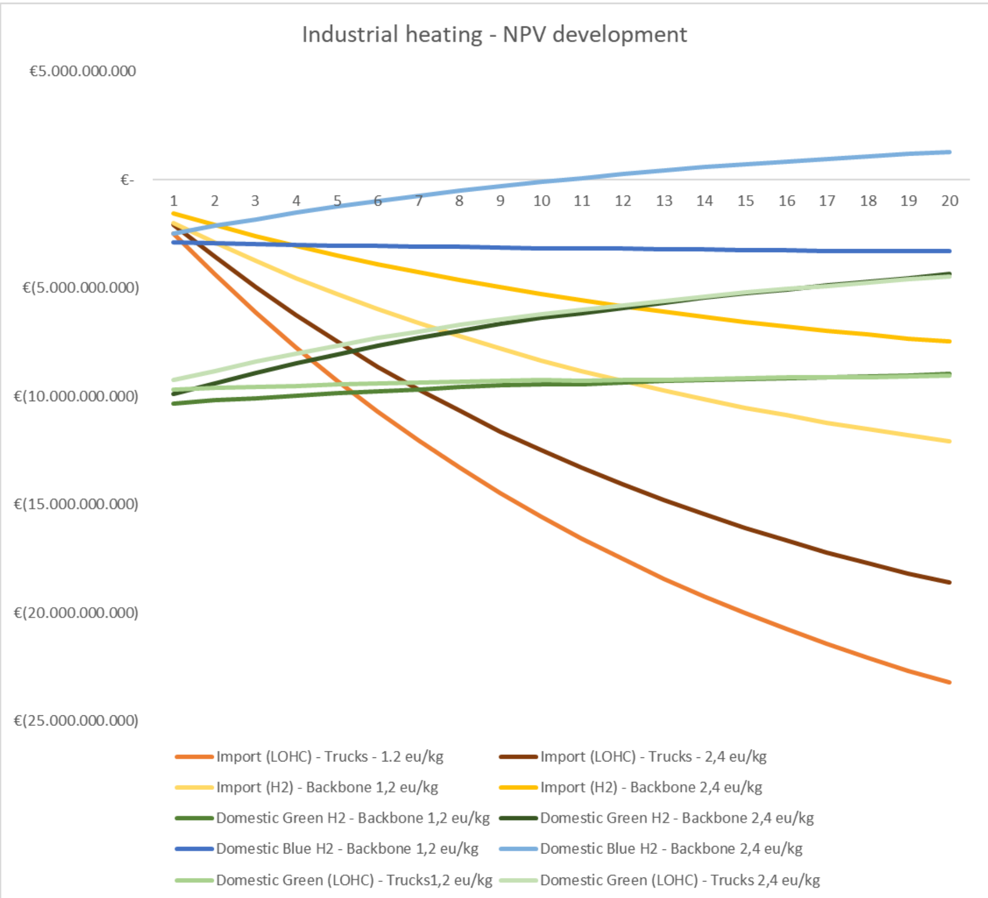


Figure 102 - NPV development of Industrial heating value chains for 1.2 eu/kg H2 and 2.4 eu/kg.

Main assumptions: Technical cost data of 2030 is used. Natural gas price 25 EUR/MWh, electricity grid price 60 EUR/MWh, LCOE of connected domestic offshore windfarm to electrolyser resulted in 60 EUR/MWh, green hydrogen import costs via LOHC include the average import costs by ship from Canada, Australia and Morocco, the green gaseous hydrogen import costs assumes the import costs from Morocco by pipeline, if an European Hydrogen Backbone would be available. Heat for LOHC reconversion is considered to be waste heat of 0 EUR/MWh.

Appendix D – Additional figures describing end user scenario's

1.1 Industrial feedstock: Ammonia value chains

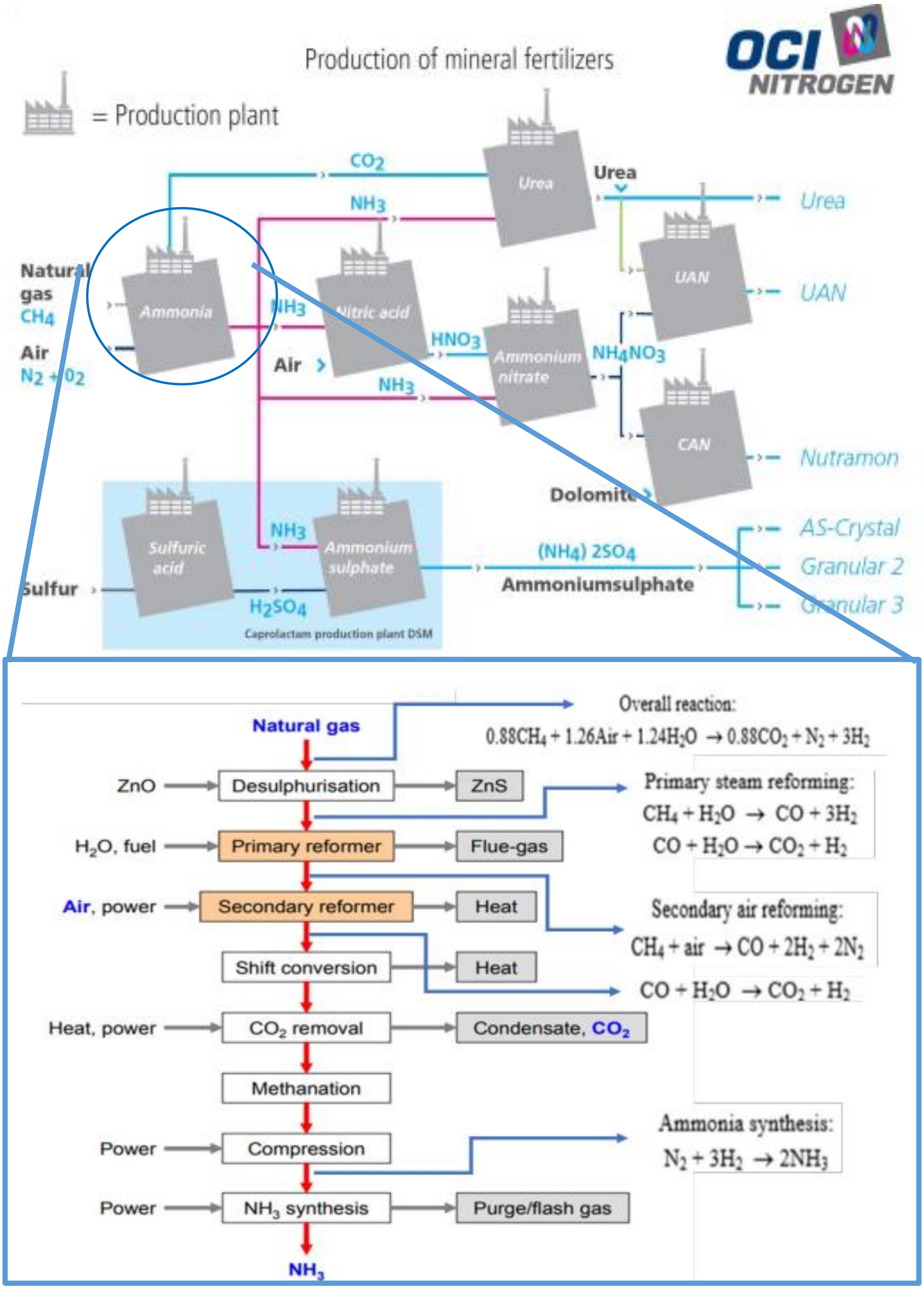


Figure 103 - Production process fertilizer, including the follow-up production steps after the ammonia production [1]. Note: the methanation process is used to remove last small amounts of CO and CO_2 from the synthesis gas stream to prevent poisoning of the catalyst in the ammonia synthesis step. So this does not mean that the hydrogen is converted back to CH_4.

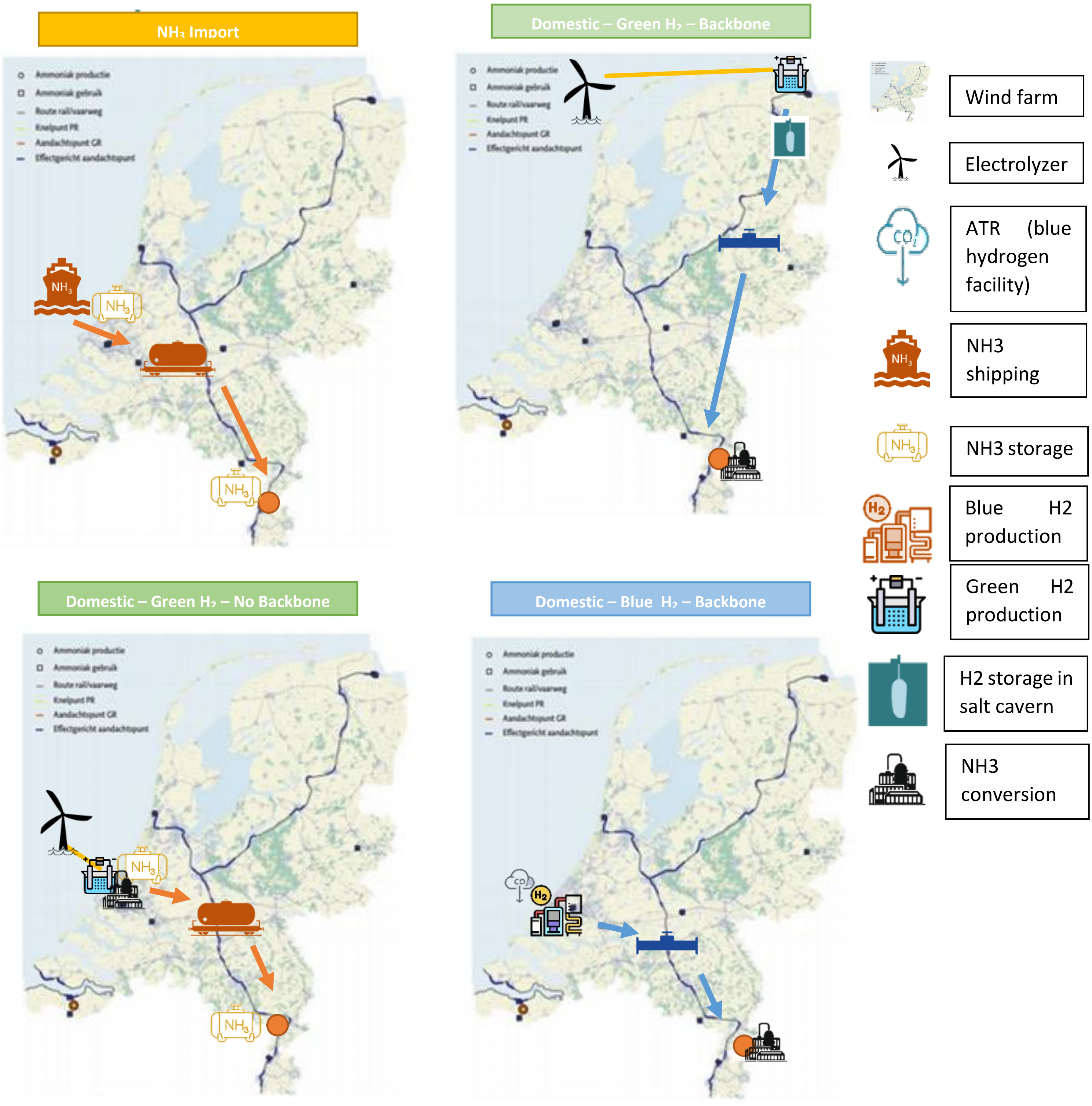


Figure 104 – Geographical representation of ammonia value chain designs on the Dutch national level for a typical location

*Table 10 - Description of value chain characteristics of a fertilizer plant demanding 1300 kT of ammonia per year. Renewable energy capacity is based on the required capacity to meet yearly demand levels (Appendix A - Cost functions) and distances are indicative. *For the transport of green hydrogen extra distance is estimated because of the storage required in salt caverns for fluctuating hydrogen production. **in case of flexible NH3 conversion accompanied by 4603 H2 storage tanks of 500kg, without flexible NH3 conversion incredible amount of gH2 storage tanks would have been required.*

	Domestic – Blue H2 – BB	**Domestic – Green H2 - BB**	**Domestic – Green H2 – No BB**	**NH3 Import**
Energy source – location (H2 production)	Natural Gas (ATR)	Offshore Wind (electrolysis)	Offshore Wind (electrolysis)	Internationally (electrolysis)
	0.95 GW	2.2 GW	2.2 GW	~3 GW
Transport to mainland Netherlands (carrier)	Pipeline/LNG (CH4)	Cabling (e-)	Cabling (e-)	Ship (NH3)
	Misc.	100 km	100 km	Misc.
Main storage	-	4 salt caverns 8 kT	3 NH3 tanks of 54 kT**	1 NH3 tank of 51 kT
Inland transport means (carrier)	Backbone (H2)	Backbone (H2)	Train (NH3)	Train (NH3)
	250 km	500* km	250 km	250 km
Input in end-use process	H2	H2	NH3	NH3

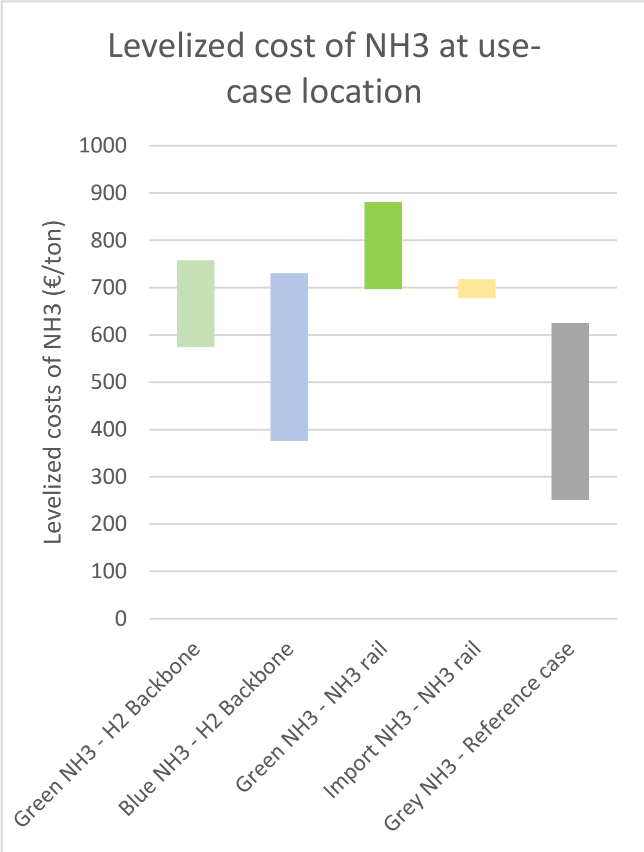


Figure 105 - Levelized cost ranges of NH_3 at the end-use location for the different value chains considered, and the grey NH_3 reference case. Parameters varied are: Windfarm costs, Electrolyzer costs (green),, Natural gas price (blue, grey), import countries (import)

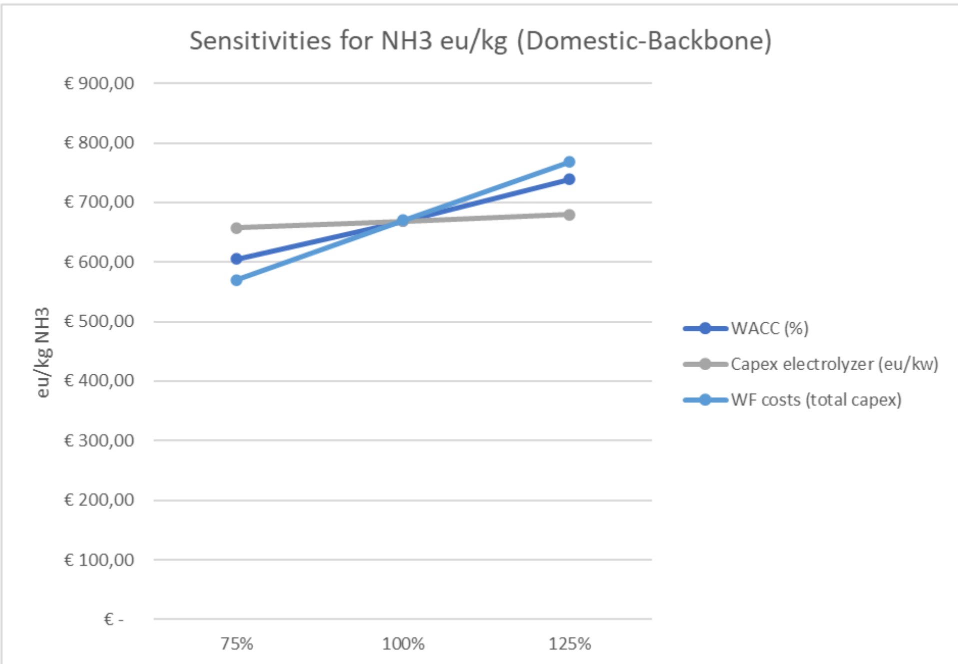


Figure 106 - Impact of parameter changes on levelized costs of green NH3 production (domestic green production with backbone). The sensitivities shown here are also used in the cost ranges of Figure 105.

1.2 Industrial feedstock: Methanol value chains

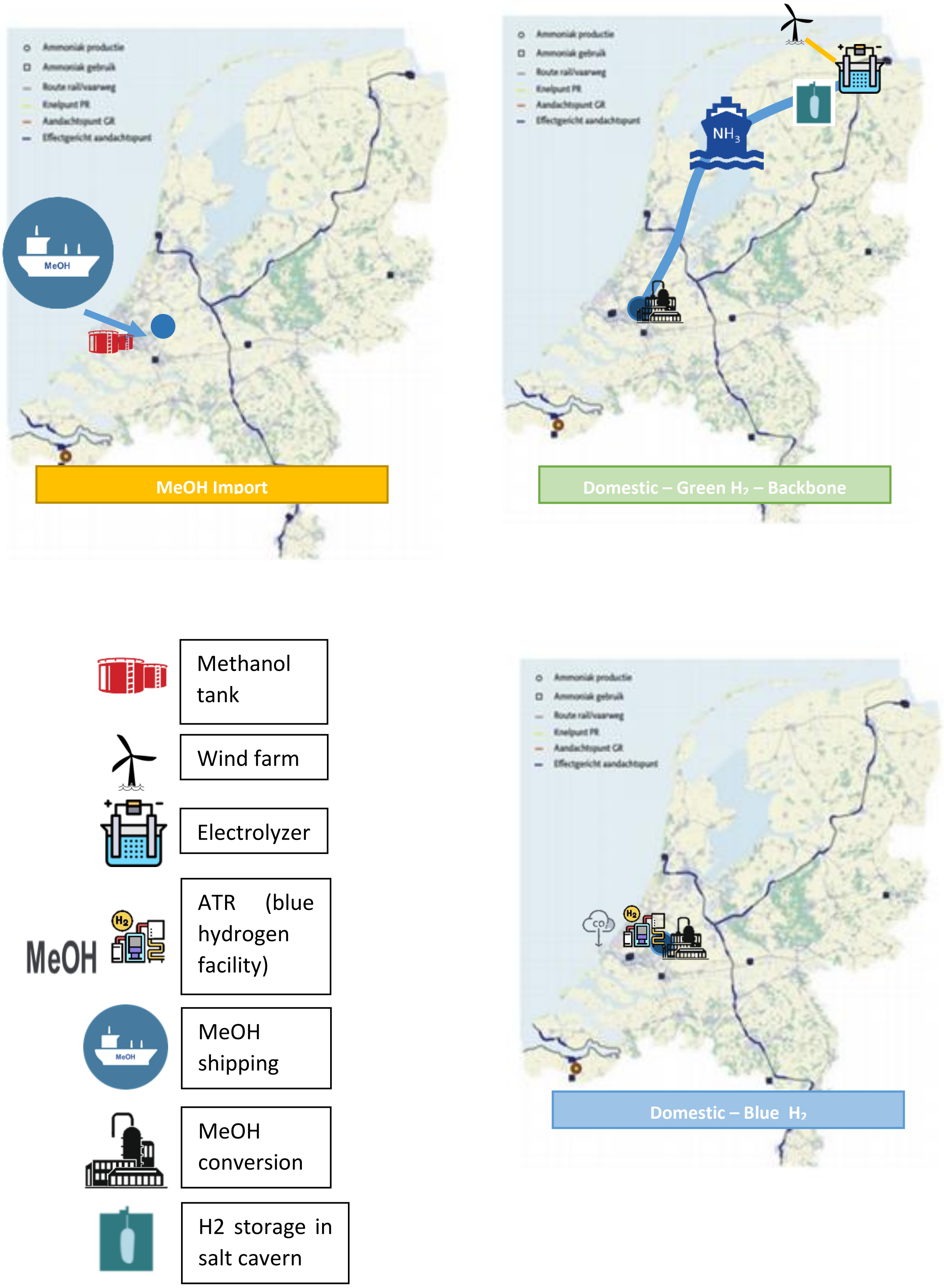


Figure 107 – Geographical representation of methanol value chain designs on the Dutch national level for a typical location.

*Table 11 - Value chains to meet a E-fuel plant demanding 900 kton methanol per year. *For the transport of green hydrogen extra distance is estimated because of the storage required* in salt caverns *for fluctuating hydrogen production.*

	1 - Domestic – Blue H2 - BB	**2-Domestic – Green H2 – BB**	**3 - MeOH Import**
Energy source – location (H2 production)	Natural Gas (ATR)	Offshore Wind (electrolysis)	Internationally (electrolysis)
	0.95 GW	1.7 GW	~3 GW
Transport to mainland Netherlands (carrier)	Pipeline/LNG (CH4)	Cabling (e-)	Ship (NH3)
	Misc.	100 km	Misc.
Main storage	-	3 salt caverns of 8 kT	2 MeOH tanks of 18 kT
Inland transport means (carrier)	N/A	Backbone (H2)	-
	-	500* km	-
Input for end-use process	H2	H2	MeOH

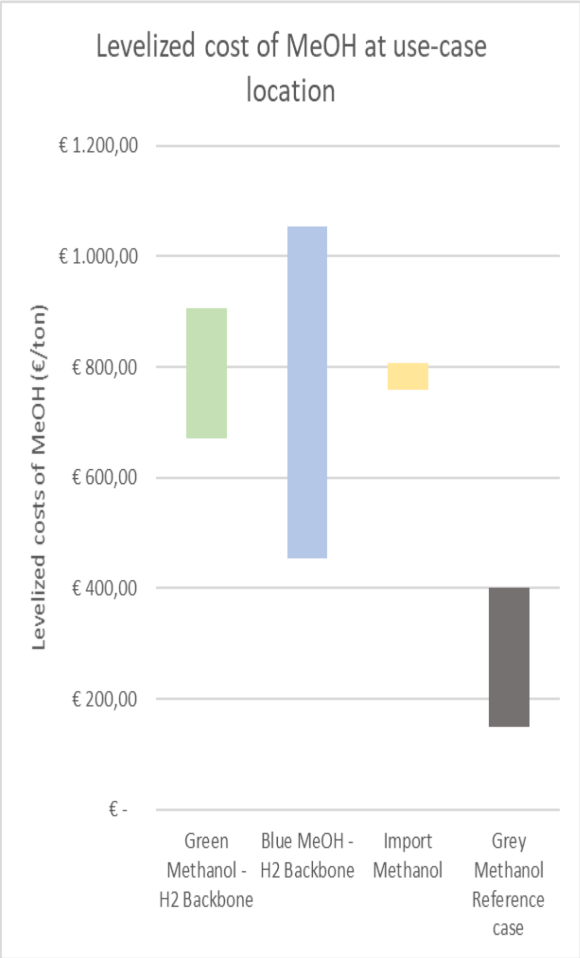


Figure 108 - NG price varies between 25-100 eu/MWh. Windfarm costs -50%/+50

1.3 Industrial high temperature heating

Figure 109 – Geographical representation of distributed HTH value chain designs on the Dutch national level for a typical location

*Table 12 - Value chain descriptions Industrial heating. *For national transport a shared hydrogen backbone is assumed, which covers a larger distance.*

		Domestic – No BB - Green	**Domestic – BB – Blue**	**Domestic – BB - Green**	**Import (LOHC) + Trucks (LOHC)**	**Import (H_2) + Backbone**
Energy source – location (H_2 production)		Offshore Wind (electrolysis)	Natural Gas (ATR)	Offshore Wind (electrolysis)	Internationally (electrolysis)	Internationally (electrolysis)
		3.49 GW (2.97 GW)	0,95 GW	3.49 GW (2.97 GW)	3.49 GW (2.97 GW)	3.49 GW (2.97 GW)
Transport to mainland Netherlands (carrier)		Cabling (e-)	Pipeline/LNG (CH_4)	Cabling (e-)	Ship (LOHC)	Pipeline/ship (H_2)
		100 km	Misc.	100 km	Misc.	Misc.
Main storage		6 salt caverns of 8 kT	-	6 salt caverns of 8 kT	5 LOHC tanks of 2.4 kT	-
Inland transport means (carrier)	**Main distance**	Trucks (LOHC) (2-3 trucks pd)	Backbone (H_2)	Backbone (H_2)	Trucks (LOHC) (2-3 trucks pd)	Backbone (H_2)
		150 km	1200* km	1200* km	150 km	1200* km
	Last-mile	-	Pipeline (regional)	Pipeline (regional)	-	Pipeline (regional)
			50 km	50 km		50 km
Input in end-use process		H_2	H_2	H_2	H_2	H_2

Figure 110 - Cost ranges of hydrogen at end-use location

1.4 Mobility

Figure 111 – Geographical overview of analysed chain designs for mobility end-use

*Table 13 – Value chain descriptions main Mobility chains. *For national transport a shared hydrogen backbone is assumed, which covers a larger distance. **Amount of storage tanks can be reduced if connected to the E-grid and seasonal fluctuations of wind production are not stored at the HRS. If 3.65 days of storage would be required, one gH2 storage tank would be sufficient.*

		Domestic BB last mile pipeline	**Domestic BB last mile LOHC trucks**	**Domestic carrier LOHC trucks**	**Local chain**
Energy source – location (H_2 production)		Offshore Wind (electrolysis)	Offshore Wind (electrolysis)	Offshore Wind (electrolysis)	Onshore wind (electrolysis)
		1.42 GW (1.21 GW)	1.42 GW (1.21 GW)	1.42 GW (1.21 GW)	2.3 MW (2.3 MW) per HRS
Transport to mainland Netherlands (carrier)		Cabling (e-)	Cabling (e-)	Cabling (e-)	-
		100 km	100 km	100 km	-
Centralized conversion		-	-	211 kT/y LOHC capacity	-
Main storage		3 salt caverns of 8 kT	3 salt caverns of 8 kT	8 LOHC tanks of 2.4 kT	33 gH2 storage tanks of 500 kg** per HRS
Inland transport means (carrier)	**National transport**	Backbone (H_2)	Backbone (H_2)	LOHC trucks (~0.2 deliveries p/d, 0.9 trucks per HRS)	-
		1200* km	1200* km	150 km	-
	Hub	no	Hub LOHC conversion 7.3 kT/y for 50 HRS, 1 LOHC tank of 0.07 kT	-	-
	Last-mile	Pipeline (regional)	LOHC trucks (~0.2 deliveries p/d, 0.02 trucks per HRS)	-	-
		25 km	25.4 km	-	-
HRS	**Input carrier**	H_2	LOHC	LOHC	H_2
	Processes	gH2 storage, purification, compression	LOHC storage, reconversion, purification, compression	LOHC storage, reconversion, purification, compression	gH2 storage, compression
	Delivered H2	400 kg/day	400 kg/day	400 kg/day	400 /day

1.5 Built environment

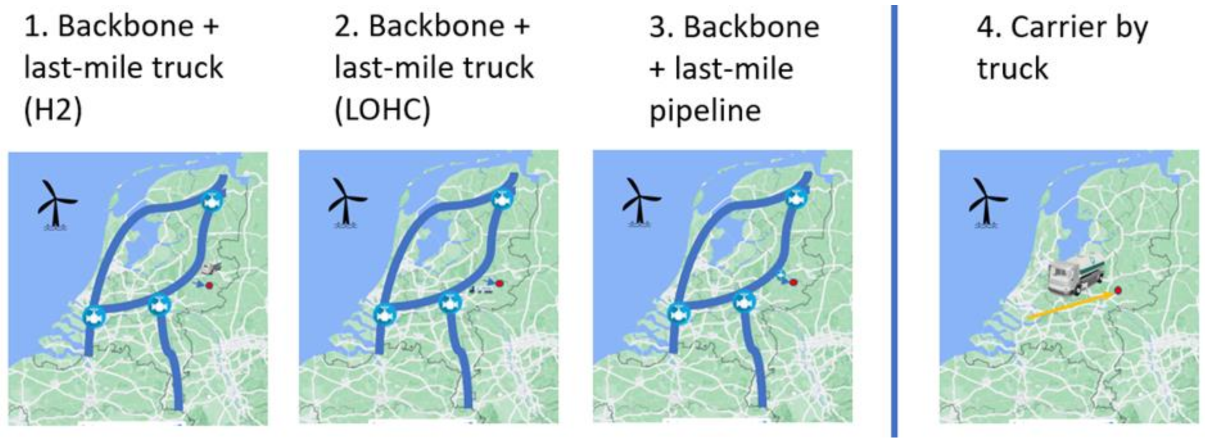


Figure 112 – Overview of the main types of value chains towards the built environment end-use

*Table 14 – Value chain descriptions main Mobility chains. *For national transport a shared hydrogen backbone is assumed, which covers a larger distance.*

		Domestic BB last mile pipeline	**Domestic BB last mile gH2 trucks**	**Domestic BB last mile LOHC trucks**	**Domestic carrier LOHC trucks**
Energy source – location (H_2 production)		Offshore Wind (electrolysis)	Offshore Wind (electrolysis)	Offshore Wind (electrolysis)	Offshore Wind (electrolysis)
		3.5 GW (3 GW)	3.5 GW (3 GW)	3.5 GW (3 GW)	3.5 GW (3 GW)
Transport to mainland Netherlands (carrier)		Cabling (e-)	Cabling (e-)	Cabling (e-)	Cabling (e-)
		100 km	100 km	100 km	100 km
Centralized conversion		-	-	-	519 kT/y LOHC capacity
Main storage		3 salt caverns of 8 kT	6 salt caverns of 8 kT	6 salt caverns of 8 kT	18 LOHC tanks of 2.4 kT
Inland transport means (carrier)	**National transport**	Backbone (H_2)	Backbone (H_2)	Backbone (H_2)	LOHC trucks (~0.16 deliveries p/d, 0.1 trucks per neighbourhood)
		1200* km	1200* km	1200* km	150 km
	Dec. conversion	-	-	LOHC conversion 0.16 kT/y, 1 LOHC tank of 0.024 kT	-
	Last-mile	Pipeline (regional)	gH2 trucks (~0.7 deliveries p/d, 0.13 trucks per neighbourhood)	LOHC trucks (~0.25 deliveries p/d, 0.05 trucks per neighbourhood)	-
		25 km	25 km	25 km	-
End users	**Delivered carrier**	H_2	H_2	LOHC	LOHC
	Local storage & conversion	-	110 gH2 tanks of 500 kg per neighbourhood	1 LOHC tank of 0.06 kT and LOHC reconversion 0.64 kT/y	1 LOHC tank of 0.06 kT and LOHC reconversion 0.64 kT/y
	Distribution grid	H2 distribution grid	H2 distribution grid	H2 distribution grid	H2 distribution grid
	Consumers	2244 neighbourhoods of 165 houses	2244 neighbourhoods of 165 houses	2244 neighbourhoods of 165 houses	2244 neighbourhoods of 165 houses

Appendix E – Hydrogen value chain market dynamics

The market dynamics appendix is an independent readable document that belongs to the D7A.2 work.

Document summary

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Document history

Version	Date	Author	Affiliation	Summary of main changes
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NEC	Joris Kee
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Table of Contents

Terminology

Energy source = Form of <u>primal</u> energy that can be extracted from nature (e.g. wind/solar/biomass/geothermal/NG/oil)

Energy carrier = Form of <u>extracted</u> energy that can be transported (and stored) from production to consumption (conversion/end-use) location.

Sustainable molecule = any type of molecule that has a of synthetic or biogenous instead of fossil origin.

Feedstock = Ingredient to production process. Resource in industry to develop higher value **products**. Building block/part of an end product. (e.g. hydrogen, nitrogen, CO, CO_2)

Application of an energy carrier = usable form of an energy carrier, either in an intermediate or end-use process

Energy market = Container of formal/regulatory and informal processes, price-setting mechanisms and physical exchange infrastructure that facilitate the trade of energy carriers.

1. The energy and material transition changes our value chains

According to the latest IPCC report, our climate is changing in an unprecedented way and the role of human influence on this is undisputed. On the other hand, human actions still could have the potential to determine the future course of climate. The Paris Agreement acts as a cornerstone and urges us to act. The evidence is clear that increasing levels of greenhouse gases (GHG) in the atmosphere are the main driver of climate change, with carbon dioxide as the main contributor. Limiting the emissions is therefore one of the key challenges in our energy transition.

1.1 Energy throughput dominates the Dutch energy balance

In Europe, the trilateral region of North Rhine-Westphalia (Germany), Flanders (Belgium) and parts of the Netherlands, the so called ARRRA cluster, is home to one of the most powerful clusters of the chemical industry in the world. The cluster holds 40% of the petrochemical industry of the European Union. The Dutch petrochemical and chemical industry is a global player in the production of bulk chemicals (Figure 113) and has a large share (17%) in total Dutch exports. Different well-established value chains are served via integrated infrastructures and ecosystems of suppliers and consumers. The ARRRA cluster claims an annual turnover of 180 billion euros and provides jobs for over 350.000 persons[11]. However, the chemical and oil industry is also a large contributor of GHG emissions.

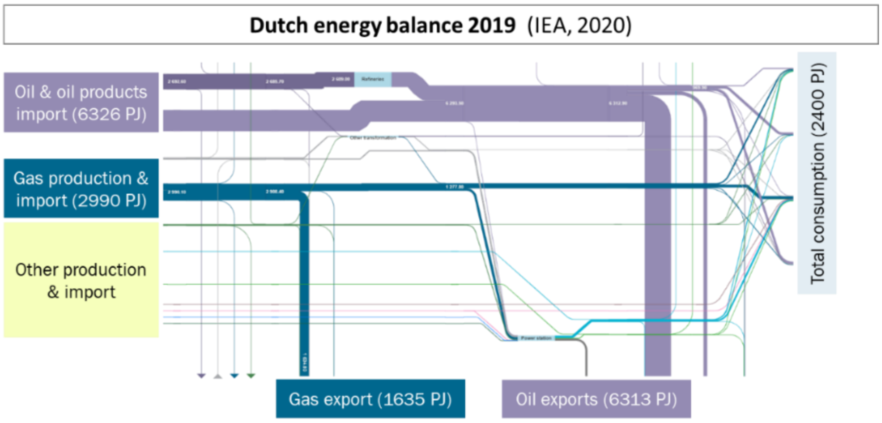


Figure 113 High level energy balance 2019

Primary energy and raw material sources are imported and partially sourced from regional resources in the form of coal, oil and natural gas. These fossil molecules act as building blocks, naturally combining H_2, C, N_2 And O_2 molecules, from which many societal needs are met. In fully sustainable future energy and material value chains we may trade these molecules separately to build our own more complex molecules, such as ethylene (C_2H_4) or jet fuel (e.g. C_9 to C_{16}) from the ground up.

In this paper we focus on hydrogen (H_2), touch upon hydrogen carriers (ammonia, NH_3 and methanol, MeOH/CH_3OH) and refer to sustainable molecules when addressing synthetic or biogenic molecules of any kind, from hydrogen and methanol to other fuels and feedstock.

1.2 Needs for new products results in new value chains

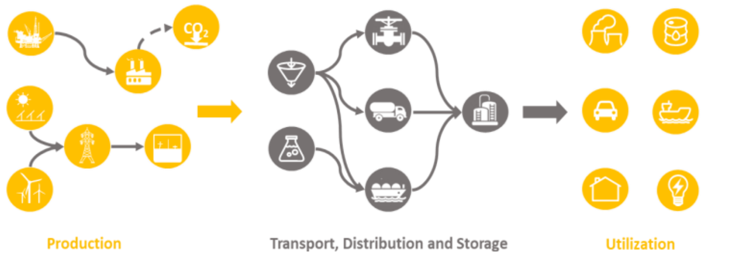
Transforming the well-integrated ARRRA industry cluster into a circular and decarbonized system, via a smooth adjustment of the (accompanying) economy, is a major challenge. To decarbonize, renewable energy needs to replace fossil energy. As with the fossil-based energy, the renewable energy can be obtained from local natural sources by harvesting mainly wind and solar energy. Alternatively, it could be imported from other regions that have cheaper renewables, in which case an energy carrier could facilitate transport over long distances. Not only the supply side would need for fossil fuels for road transport will diminish due to electrification of the vehicle fleet, fuels for shipping

[11] www.trilateral-chemical-region.eu

and airplanes require new chemical processes and the re-use of carbon from (plastic) waste would change the demand to change.

The demand for primary energy and products should also change. For example, the need for primary (fossil) energy in the value chains of the petrochemical and oil industry.

Energy commodity value chains create value by linking the sources of energy to energy needs in different end-user markets. Production and utilization of energy carriers in the value chain are connected via transportation, distribution and storage infrastructure.



The decarbonization challenge will therefore change value chains and create new markets. It will generate new dynamics in existing markets for energy carriers. It is, however, not only the environmental goals that influence the development of value chains. The companies that act as a supplier, service provider or client in the value chain represent a large share of economic activity in the Dutch economy. Changing the value chain could have an impact on the jobs and the competitive edge of a region. A dependence on imported energy carriers from other countries compared to the current exporting countries will result in new geopolitical relations and could change the country's independence. Policies have to balance between economic positions or security of supply and decarbonization goals.

1.3 Market dynamics between fossil and sustainable molecules is inevitable

On the economic side, value chains are often interconnected and mutually dependent. When searching for an overall positive business model, the total chain efficiency requires an optimization over the chains by system integration. Such an integrated approach could conflict with short-term profit opportunities for a single stakeholder, or result in an impossible business case for a single key stakeholder. Restructuring of the value chain would benefit from a coordinated approach as different stakeholders in the chain are affected. All these complications make the energy transition complex and uncertain, but could also open new opportunities. Restructuring of the value chain may build on existing skills and knowledge (e.g. oil & gas offshore experience for the construction of offshore wind and hydrogen production). New export markets or technologies will develop and lead to continuously evolving energy market activities.

1.4 Introducing the focus and the structure of this paper

In this paper we explore the complicating factors that determine future hydrogen carrier market dynamics, we untangle these factors to identify bottlenecks in the development of liquid and scalable hydrogen carrier market, and present recommendations to overcome those bottlenecks.

The paper consists of four chapters: we explore the complicating factors that determine the future market dynamics of sustainable hydrogen carriers in *Chapter 2*. In *Chapter 3* we untangle the complexities faced in the development of a liquid hydrogen market by identifying three key issues. And we discuss solutions to address those issues in *Chapter 4.*

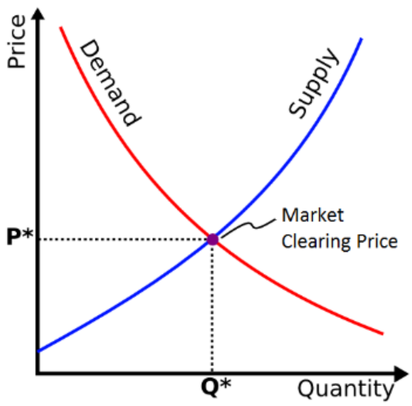
Energy markets are a tough subject. Given the large influence of market participants on the behaviour an continuous development of the energy system it is useful for energy market and infrastructure strategists and policy makers to continuously develop their understanding of these ever-evolving markets. This paper aims to equip experts with the knowledge required to anticipate on developments in a timely manner. For this purpose, we look at energy market developments in an abstract and simplified way and complement theory with practical examples taken from the current and future energy system.

2. Energy markets: matching supply and demand

A market economy is an economic system in which economic decisions and the pricing of goods and services are guided by the interactions of a country's individual citizens and businesses (=market forces) via free will. In a market economy, most economic decision making is done through voluntary transactions according to mechanisms of supply and demand. A market economy gives entrepreneurs the freedom to pursue profit by creating outputs that are more valuable than the inputs used, and free to fail and go out of business if they do not. As such market players look for opportunities in the market to create value and build for example a value chain around the demand and supply for hydrogen. Yet, market failures can occur, for example resulting in market inefficiencies such as oligopolistic or monopolistic markets[12]. Or externalities where societies have additional goals besides efficiency which are often not accounted for in the free market, such as safety, education, opportunity, health and climate change mitigation. In these cases government interventions can be implemented in the market design, assuring that private incentives are aligned with societal goals.

Economists broadly agree that market-oriented economies produce better economic outcomes, but differ on the precise balance between markets and central planning that is best for a nation's long-term wellbeing. In theory, a free-market economy uses resources and labour most efficiently, in order to order to reach the optimal short term added value in economic terms. In practice, governments make policies, restrictions, rules and regulations, to guide market forces.

Central to market economies are the market places where demand and supply are matched. Matching of supply and demand primarily occurs via bilateral long-term contracts, complemented by markets with shorter time horizons such as auction-based day-ahead (or spot) markets. The basics are similar for these different market places: At a moment in time, a product quantity (Q*) is exchanged against a market clearing price (P*). For both long-term continuous exchanges and short-term single exchanges, both the off-takers and suppliers match their *demand* and *supply*, forming a demand and supply curve as depicted in the figure below. For each energy carrier, these curves may look quite different. When looking at the market place for hydrogen (carriers) we thus need to investigate the shape of current and plausible future demand (2.2) and supply curves (2.1).



2.1 The range of hydrogen supply costs

Analogous to electricity generators, the available large scale hydrogen production units may form a stepwise shape of the supply curve (a merit order), visualized in Figure 114, once they are adequately connected with infrastructure to the demand side market. The price levels reflect the order of their short-run marginal costs. Production technologies with low marginal costs are typically the first ones starting production to meet demand. In a centralized management the production technologies costs of production with the highest marginal costs are the last to be brought online.

[12] Recent discussions regarding the public-private collaboration in the Dutch NorthH2 project are an example of such market developments: www.nos.nl/nieuwsuur/artikel/2402564-sprong-in-het-duister-met-waterstofmiljarden

Dispatching hydrogen production in this way, known as *economic dispatch*, minimizes the cost of production of hydrogen. The time-scale and transparency of market paces varies, from long-term bilateral contracts without public available information to hourly-based open spot-markets.

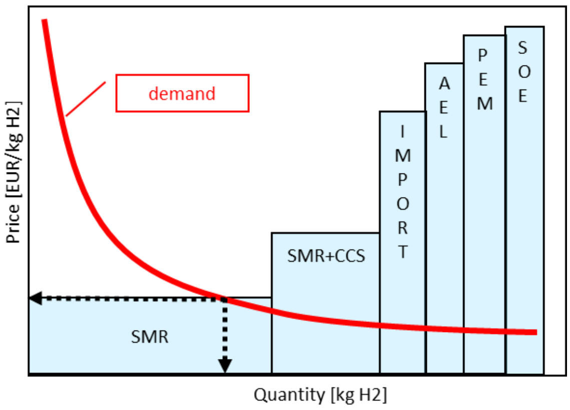


Figure 114 Schematic merit order hydrogen supply

On the supply side different technologies to produce hydrogen lead to different costs per quantity of hydrogen. Renewable electricity based hydrogen production via electrolysis is more expensive compared to grey hydrogen production from natural gas using SMR. Incentives for decarbonization such as carbon taxes or subsidies, and ongoing capacity growth and R&D investment for electrolysers or other hydrogen technologies can eventually change the order of the technologies and cost levels in the supply merit order. The figure shows an indicative merit order for hydrogen production.

2.2 Hydrogen demand for decarbonisation will be determined by possibilities of lowest-cost decarbonization alternatives within a similar time horizon

Currently hydrogen is primarily used as feedstock in the chemical and oil industry, e.g. in fertilizer and refinery products. Hydrogen may be an attractive decarbonization option for many use cases that currently use fossil sources. In addition to hydrogen there are, however, other decarbonization options to consider that can be more preferable. Figure 115 presents a high level overview of power-to-X technologies in different use cases and thereby sketches the uncertainty regarding the hydrogen applications of the future.

		Direct electrification options					PtX-Technologies			Other renewable energy options	
Field of application	Previous (fossil-based) technology	Electrode boiler	Resistance heating	Induction heating	Plasma process	No technologies foreseeable	Hydrogen feedstock	Synthetic fuels	Synthetic raw materials	Biomass	Biogas
Industry											
Industrial process heat	gas burners, steam	x	x	x	x			x		x	x
Steel (primary route)	Coke					x	x			x	x
Refinery	By-product hydrogen, fossil hydrogen					x	x			x	x
Chemicals	Petroleum- and natural gas-based basic chemicals					x			x	x	x

Figure 115 Decarbonization options industry[13]

Currently, hydrogen supply and demand are largely balanced locally in real time. Possibilities for storage and international trade are limited. Substantial new demand would simultaneously require new supply capacity as well as transport and storage. Hydrogen costs will depend on the specific quality and infrastructure requirements for the applications and the most suitable supply option to

[13] Fraunhofer (2019) Study on the opportunities of "Power-to-X" in Morocco

meet these requirements. In the near future, the market will not be flexible, lacking multiple interchangeable supply and demand options. In the longer term this may develop gradually.

Depending on the alternative options and urge to decarbonize, the demand curve for hydrogen can change. Figure 116 shows an indicative demand curve for hydrogen. The price levels indicate prices that different demand sectors are willing or able to pay. High prices (but low volumes) could be accepted by buyers in specialty chemicals where the energy cost share is minor or products closer to the end user where the sustainable origin can be valued, either by regulation or consumer willingness to pay. Thus, mobility applications are expected to be a higher price segment. At the lower side of the demand curve we find heating processes for basic commodities, where the fuel cost share is higher and global competition with fossil fuel use is expected.

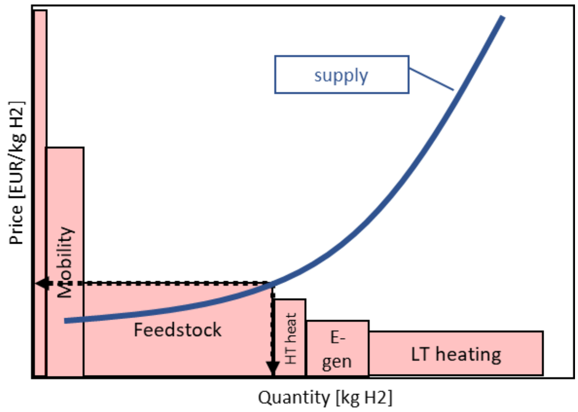


Figure 116 Schematic merit order hydrogen demand

For all applications of hydrogen an acceptable price for the sustainable hydrogen is thus determined by the lowest-cost alternative (e.g. other colours and purity levels of hydrogen, other technology options) that can be made available *within a similar time horizon*.

2.3 Competing demand for sustainable molecules introduces new market places

In the long term, multiple sectors could be consuming the same type of sustainable molecules. This leads to a different shapes of market places for hydrogen, ammonia, methanol and electricity and other possible commodities such as syngas. Each energy carrier has a (non-exclusive) role to play in the future.

Ammonia and methanol already have the role of a platform molecule with their multiple use cases and substantial globally traded volumes. Electricity also serves multiple applications already. To what extend these hydrogen carriers and electrons will act complementary or conflicting is yet to be seen. Hydrogen could fulfil role as a platform molecule as it may find a broad range of applications: it may be used (1) as a fuel or feedstock, (2) as a building block to be converted into more complex molecules, or (3) to be stored for (strategic) security of supply purposes.

The decarbonization options per sector (Figure 115) will determine the required energy carrier(s) per sector, and thus the energy carrier(s) through which that sector is coupled to others. The more sectors are coupled, the more actors are entering the market place of that energy carrier. Figure 117 illustrates the current (full line) and possible future (dashed line) applications of electricity, hydrogen, ammonia and methanol, and the subsequent interplay between market places.

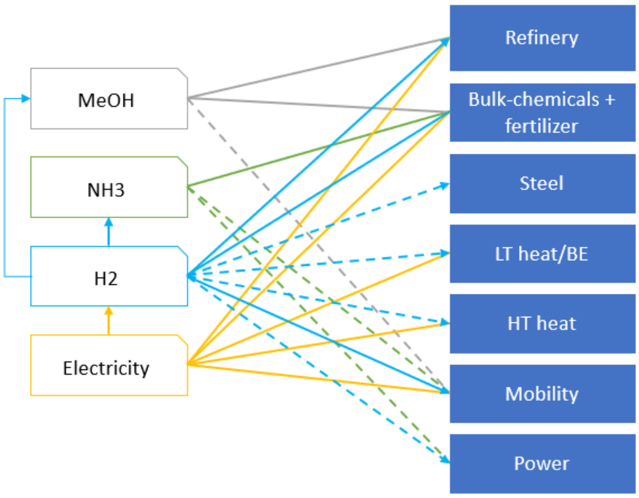


Figure 117 Indication of current (full line) and future (dashed line) sector coupling. Fossil oil and gas are left out.

2.4 Dynamic clearing of supply and demand on hydrogen markets

The marketplaces of the different energy carriers are coupled and highly interactive which complicates predicting future market behaviour. On the marketplace the crossover-point between demand and supply curves determines the market price and quantity of a commodity that is traded on that market. If demand increases at a fixed supply curve, the price and quantity will increase, as depicted in Figure 118. When *both* supply and demand increase, the quantity will increase whereas the change in price will depend on the marginal cost of the production technologies.

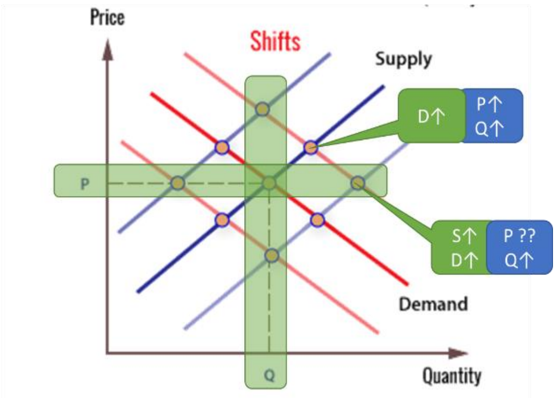


Figure 118 Theoretical visualisation of dynamic market effects on price and quantity

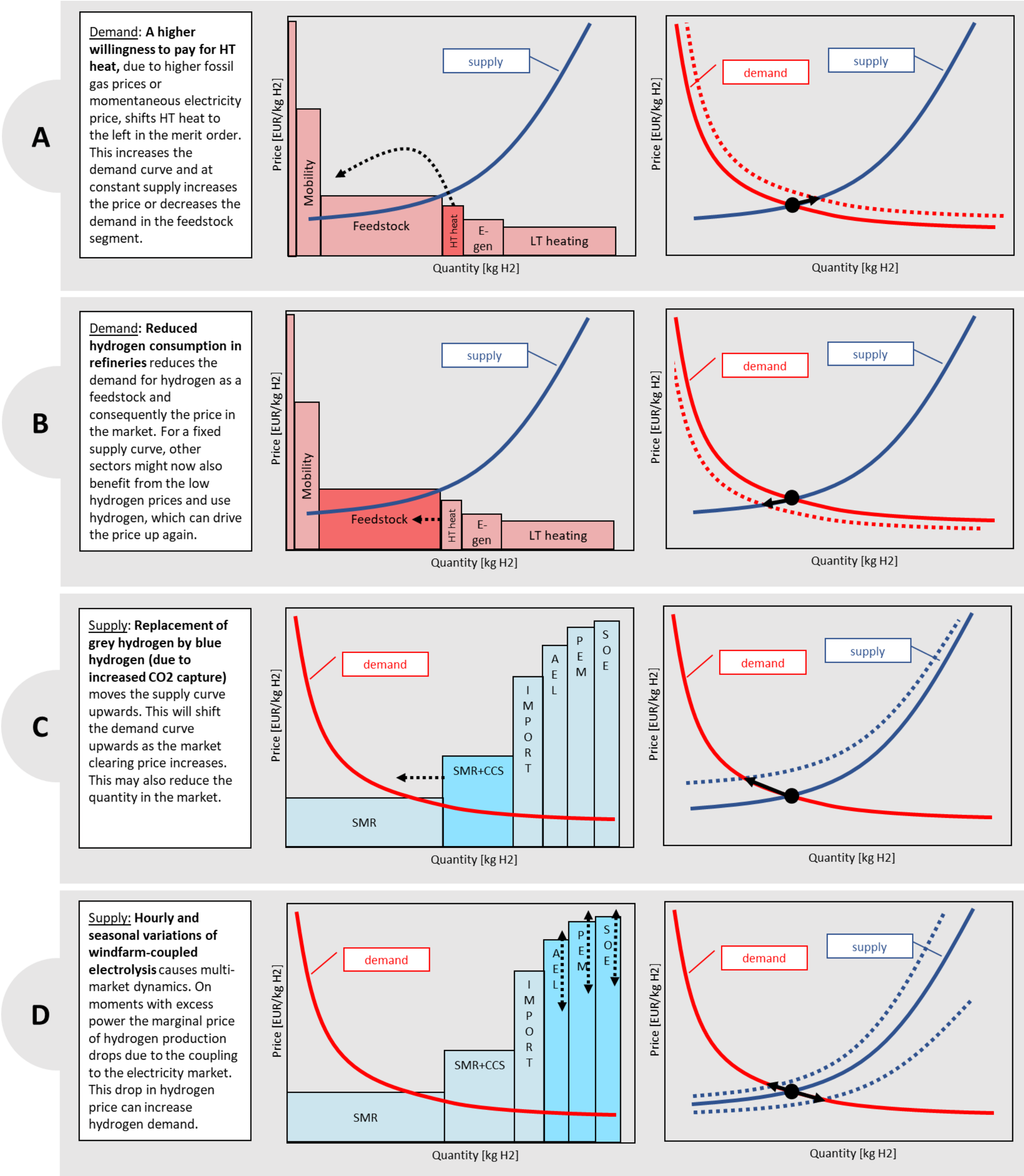
Supply and demand assets can only be operated when they are commissioned. When analysing energy market behaviour, a distinction needs to be made between *economic dispatch logic* (i.e. when to operate existing installations) and *investment decisions* (i.e. when to build new installations). We thus observe two different time scales: the multi-year investment decisions that shape the installed supply and demand capacity, and the actual market participation of those assets on an operational (minutes, hours) time scale. To deepen our understanding of both the economic dispatch logic and investment decisions we discuss four examples that illustrate briefly the strong interaction between different energy markets, the consequences of market volatility and the introduction of new producers and consumers within these markets. From these examples it can be concluded that clear prognoses on installed production and consumption capacity (Q*) as well as acceptable supply and demand prices (P*) in the future are difficult to establish and yet they are essential to move towards new market places that can serve our sustainable society of the future.

Industrial high temperature heat: An example of electricity, natural gas, carbon and hydrogen market interactions

Large amounts of energy are required to generate high temperature (HT) heat (100+C). Many industrial heat users generate HT heat locally. The majority of this heat is currently generated by natural gas combustion. With rising carbon prices, volatile natural gas prices and declining electricity prices it may become attractive to switch to electricity as an energy source. But consequently large-scale baseload electricity demands will increase the average electricity price. For renewable hydrogen to be an attractive source for HT heat, it needs to be a cheaper fuel than the current natural gas + carbon price, and cheaper than electricity. And, as expected, a major increase in hydrogen demand on a functioning market will drive its price up, leading again to possible re-evaluations of the chosen fuel type.

For a market to be effective, the physical flow of products such as hydrogen (carriers) from a supply location to a demand location needs to be facilitated. Transport and storage infrastructure needs to be in place in time. The major uncertainties related to hydrogen (carrier) supply and demand volumes over time consequentially leads to challenges in the development of appropriate infrastructure. The following chapters discusses the issues (Chapter 3) and possible solutions to these issues (Chapter 4) and thereby facilitate the emergence of new hydrogen-related marketplaces.

Examples A and B illustrate the aforementioned *economic dispatch logic* on the market and examples C and D showcase the impact of *investment decisions* on installed capacity of assets.



3. Three issues obstruct the emergence of a hydrogen market

The extent to which market dynamics can be predicted and influenced goes beyond theoretical macro-economic market logic as discussed in the previous chapters. Many real-world 'drivers of complexity' will need to be considered when we want to predict the future of a hydrogen market. One can think of different stages of development of demand and supply for hydrogen both in technology as in economic feasibility, competition between different energy carriers over different sectors and the development of connecting infrastructures between demand and supply. All of these drivers have their own dynamics and influence each other. In this chapter we focus on three issues that needs to be thoroughly understood and dealt with during the establishment of open hydrogen carrier markets:

I. **Bringing together suppliers and consumers at an immature market place is a challenging task.**
II. **A just distribution of sustainable molecules amongst sectors is not trivial.**
III. **Uncertainties cloud the development of market-facilitating infrastructure.**

Dealing with these issues can reduce the complexity of establishing an open and scalable market of sustainable molecules. One could consider the described issues *design criteria* for a liquid and healthy market place that aids society in achieving our climate change mitigation goals. After addressing the nature of the three issues in the subsequent paragraphs, ways forward to deal with the issues are suggested in Chapter 4.

Issue I: Bringing together suppliers and consumers at an immature market place is a challenging task

Market places do rarely emerge without guidance and once they exist, their structure and rules are continuously evolving. A well-functioning energy market design has three fundamental principles[14]:

1) One single commodity should be traded at a market place (e.g. MWh_e or a crude oil barrel)
2) A multiplicity of actors should voluntarily participate in the market and provide information on their perceived value the traded commodity at specific moments in time. The latter is crucial to achieve market equilibrium between supply and demand.
3) The market place needs to be freely accessible, non-discriminatory, transparent and liquid to be able to create a so-called *wisdom of the crowd* regarding the value of the commodity.

In line with these principles a market requires multiple types of actors (i.e. suppliers, consumers and infrastructure operators) that actively share information on the quantity and price of the commodity that they are willing to trade. This information corresponds with the depicted *blocks* in the supply and demand curves of Chapter 2 at a specific moment in time. In our case of the emerging sustainable molecule markets it is difficult for the supplying and consuming actors, as well as the infrastructure operators, to provide early assurance on the quantities, timing and pricing of the commodity. There can be many reasons[15] for this difficulty:

Factors that complicate decision-making of energy consumers and suppliers

- ✓ Development projects are capital-intensive, do not always have a conclusive business case and technology TRL can be (too) low.
- ✓ Sustainability projects are often assessed in a global playing field and decisions may be made in boardrooms abroad.
- ✓ There can be multiple options to decarbonize energy-intensive processes and these options may rely on different energy carriers.
- ✓ Drastic changes in the production process are often only possible if the entire production process is shut down. In practice, this only happens once every 10-20 years and is preceded by years of planning and organization.
- ✓ There are mutual dependencies between *actors* within the energy systems (supply, demand, transport, storage) and between the energy systems themselves (e.g. blue hydrogen requires a natural gas, hydrogen and CO_2 infrastructure).
- ✓ Physical space and environmental space, above and below ground, is limited which makes long-term planning and coordination between infrastructure operators, landowners and a variety of other land uses essential to realize infrastructure on time. No regret decisions in infrastructure developments therefore become highly preferable.

[14] Gimon, E (2021) Market Design for the Energy Transition, interview at The Energy Transition Show episode 157, October 13 2021
[15] TNO (2020) Energie-infrastructuren 2030; DNV (2020) TIKI Meerjarenprogramma Infrastructuur Energie en Klimaat 0.1

The consequences could be that we are assuming supply and demand contributions (blocks) in the supply and demand curves, but that their presence in the future is, in reality, highly uncertain. Supply or demand **quantities** could be much smaller/larger than anticipated on, marginal production **prices** may be higher/lower, or market entree may happen at a different moment in **time**.

Sustainable hydrogen production technologies are currently mature enough to start upscaling their production and installation globally. One could argue that, once there is sufficient demand and a high (enough) willingness-to-pay for sustainable molecules, hydrogen production will develop. This turns our attention to the demand-side of the hydrogen marketplace.

The investment cycles through which the changes in demand and supply can be initiated vary a lot as these investment decisions happen at an individual actor level. Some decisions can be made on the short term, others might require a longer implementation period due to permitting, industrial turn-around cycles or implementations of governmental incentives on (inter)national levels. A dominant factor in the decisions to develop hydrogen (carrier) demand is the maturing of novel technologies. The hydrogen adoption readiness overview per sector, as depicted in Figure 119, provides insights in the possible gradually expanding hydrogen marketplace based on the timing, demand volume and acceptable price per sector.

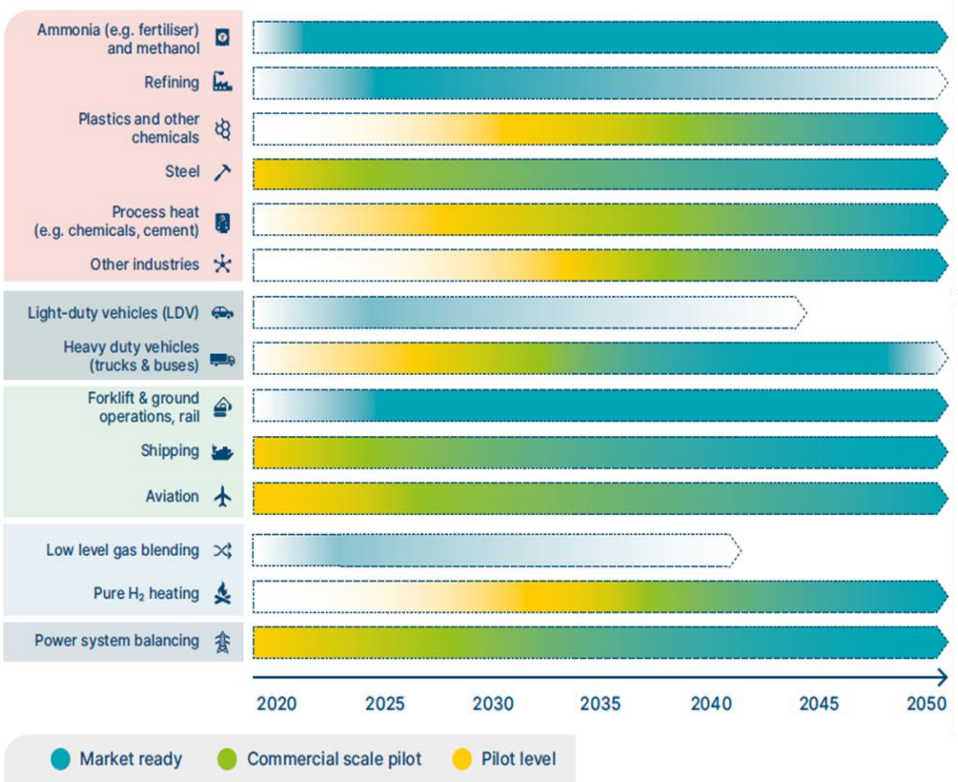


Figure 119 Hydrogen adoption readiness projections of sectors[16]

Actors on the demand and supply side of the market have different time scales on which they can act and their decisions influence each other directly. We conclude that uncertainties in hydrogen demand and supply (and in transport and storage capacity, which will be discussed as Issue III) are complicating

[16] Energy Transition Commission (2021) Making the hydrogen economy possible: Accelerating clean hydrogen in an electrified economy

the development of both simultaneously. This is often referred to as the chicken and egg problem. ***Solution I*** discusses a way forward to address this first issue.

Issue II: A just distribution of sustainable molecules amongst sectors is not trivial

Hydrogen carriers may be utilized in a variety of applications. Each application has its own maturity (readiness) level and level of confidence in large-scale adoption. Figure 120[17] illustrates this relationship. In addition, each application has its own decarbonization effectiveness (emission reduction per kilogram of hydrogen: ton CO_2eq/kg H_2). Figure 120 also shows that the application of green hydrogen in the fertilizer industry is mature and there is consensus on this application for sustainable hydrogen, while applying hydrogen as a (co-firing) fuel for power generation is currently a less convincing application, even though the maturity level is growing. One could add all plausible hydrogen carrier applications in this overview to gain a complete overview.

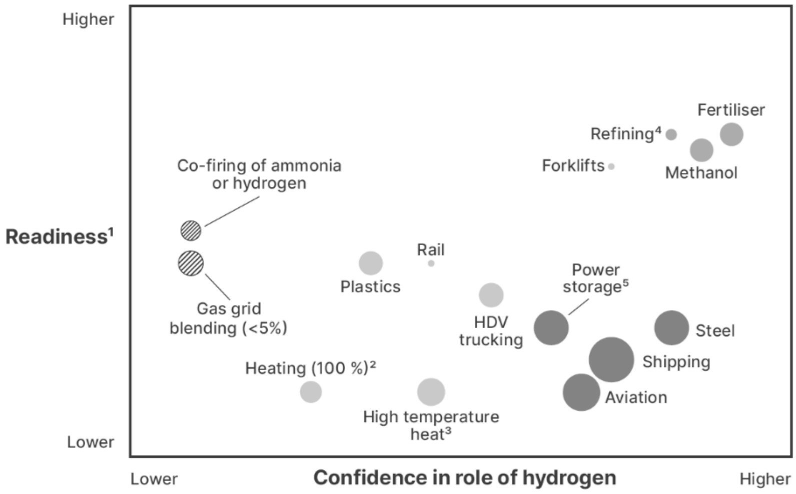


Figure 120 Hydrogen application readiness vs. confidence

The figure also indicates the potential hydrogen demands per application (the sizes of the circles). It is clearly visible that the possible hydrogen offtake differs substantially amongst sectors. Large demands may however not equal a large emission reduction potential. And this introduces our second complex issue: A just distribution of sustainable molecules amongst sectors is not trivial.

Sectors can be divided into *harder-to-abate* and *eager-to-abate*. When limited supplies of renewable hydrogen (derivatives) are available, trading at an open market cannot be assumed to lead to the most effective use of hydrogen from an emission reduction point of view. Sectors that are (already) eager-to-abate may be willing to pay a high price for green hydrogen. However, this may not necessarily lead to effective emission reductions from a systems perspective as harder-to-abate sectors, for whom such a high price is unfeasible within their business model, may be able to realize more emission reduction per kilogram of hydrogen. Thus, if it is up to an open market to decarbonize via hydrogen, it is to be questioned whether hydrogen is used most effectively.

Harder-to-abate: Heavy industry (steel, cement, chemicals) and heavy-duty transport (shipping, trucking, aviation) are currently responsible for 30% of global emissions[7a]. These economic sectors are referred to as 'harder-to-abate', *not because we lack the technological solutions but because these solutions carry a higher abatement cost* than the current higher-carbon technologies used.

Eager-to-abate: For specific sectors or use cases, the replacement of the current technologies/processes with low-carbon options may be a business-as-usual cost optimization as the business case of a new technology is positive (which may be due to subsidies/CO_2 taxes etc.). Decarbonization may be incidental or a welcome side-effect for this type of sectors.

[17] Energy Transitions Commission (2021) Making the Hydrogen Economy Possible: accelerating Clean Hydrogen in an Electrified Economy
[7a] Energy Transition Commission (2018) Mission Possible: Reaching net-zero carbon emissions from harder-to-abate sectors

Prioritizing of sustainable hydrogen applications, and thus interfering with free economy principles, may be needed to accomplish a decarbonized society in time. Five typical situations may opt for a preferential treatment:

- ✓ A sector or use case can have **limited decarbonization options besides hydrogen**.
- ✓ The lead time for adoption and/or scaling up hydrogen applications differs per sector. Sectors may need minimal volumes of hydrogen to **experience its added value** in their operation. For example: a minimal amount of hydrogen refuelling stations is required for long-haul trucking.
- ✓ There may be **critical paths** that require minimal volumes of hydrogen at specific moments in time to successfully transform a site, region or sector. Large step-wise hydrogen consumption technology investments (e.g. centralized steel manufacturing) has different demand profiles than incremental changes (e.g. an expanding fuel-cell truck fleet).
- ✓ **Socio-economic added value** of specific actors may also play a role. Harder-to-abate sectors may relocate outside the ARRRA cluster if decarbonisation measures are unfeasible.

Maximizing the emission reduction potential of each unit of energy should never be limited to hydrogen only. **A holistic view on decarbonization options is critical.** Direct electrification or hybrid energy consumption may be more efficient (direct electrification) or more reliable (hybrid, by using for example electricity, natural gas and/or hydrogen). Figure 116[18] illustrates how a merit order of effective electrification can guide the prioritization of scarce sustainable energy carriers. A similar approach may aid the optimal allocation of sustainable molecules. ***Solution II*** discusses the topic of just distribution of scarce sustainable molecules in more detail.

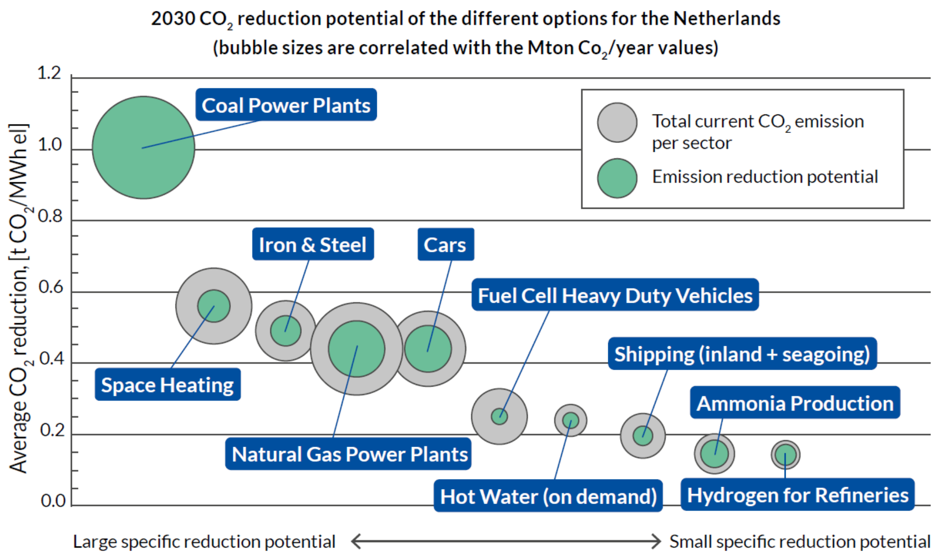


Figure 121 Decarbonisation effectiveness of sectors (CO2eq. reduction potential per consumption of 1 MWh renewable power)

It is evident that predicting the whereabouts of small and large-scale hydrogen-based decarbonization solutions throughout the ARRRA cluster is subjected to many uncertainties. Both from a practical stakeholder decision perspective (bottom up) as from an optimal systems perspective (top down). The uncertainties regarding the emerging hydrogen supply and demand centres complicate the development of hydrogen transportation and storage infrastructure. While the need for this infrastructure is widely acknowledged, many infrastructure-related questions remain unanswered. The next issue dives into more detail on the challenges regarding market-facilitating infrastructure.

[18] VoltaChem (2022) Key insight #1: Merit order of electricity

Issue III: Uncertainties cloud the development of market-facilitating infrastructure

Transport and storage infrastructure is required for the sustainable molecule market to function at large scale. On the system level we identify four factors that are related to infrastructure development that are currently uncertain: *molecules of choice, transport modalities, storage and the self-sufficiency of actors.* Understanding the complications that these four factors cause with respect to the development of infrastructure is a precondition to informed decision-making of infrastructure development. ***Solution III*** offers perspectives to address the uncertainties from a market perspective.

Molecules of choice: A wide variety of sustainable molecules can plausibly contribute to a climate neutral society. And there will not be a silver bullet: we probably need many different molecules. As hydrogen-derivates such as ammonia, methanol and syngas can serve both a carrier function and a traded commodity function. It is crucial to keep a keen eye on the end-user molecule needs when discussing hydrogen supply and demand. A hydrogen demand for commodity production (e.g. ammonia for urea) could decrease drastically if that ammonia commodity is traded directly.

Transport modalities: Transport infrastructure has the purpose of **moving a product between locations**. The cost-optimal transport modality depends on the volumes to be transported and distances to be covered. Initial volumes could be small, resulting in most efficient transport via road, rail or barges. When volumes grow large and their routings are clear, pipelines become more efficient. Three tipping points between cost-optimal modalities is shown in Figure 122. Many other factors can influence the decision for a specific type of modality. Repurposing existing natural gas infrastructure for hydrogen could, for example, build a large transport capacity before this capacity is required by the market. Deciding which modality is best suited, when and where to start its development, and how the infrastructure should evolve over time is a challenging task with many interests and actors involved.

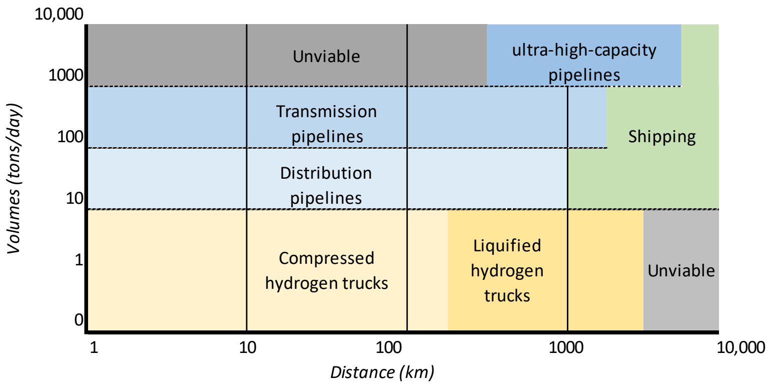


Figure 122 Hydrogen transport modality matrix (volumes vs. distance). Adapted from Energy Transitions Commission (2021)

Storage: Storage infrastructure has the purpose of **moving a product in time**. Flexibility on a system level is required to match supply and demand over time as intermittent and base-load supply or consumption will inevitably cause moments of scarcity and abundance in the market. Large quantities of hydrogen storage in Dutch or German salt caverns as well as line packaging and demand-side management can offer (part of this) storage capacity that secures the supply to end-users. The timing and volumes of security of supply needs and the willingness-to-pay of consumers is currently unclear, which complicates the development of storage infrastructure. In addition, the transitional period of hybrid operation (e.g. high temperature provided by natural gas/hydrogen hybrid, hydrogen blends, grey-green-blue hydrogen feedstock mixes) can introduce alternative and competing security of supply solutions.

Self-sufficiency: In the current system, demand and supply for hydrogen is decentralized: grey hydrogen is mainly produced at the demand location and the required volumes are produced on-demand. Self-sufficient clusters are currently in place and collaborations with neighbouring companies or usage of private companies in industrial clusters or hubs provides the security of supply needed. In a future system it is broadly envisioned that (inter)national infrastructure will connect supply and demand centres to solve temporal and special misalignments of supply and demand. However, self-sufficiency on an actor or hub level through actor collaboration or vertical market integration may have an impact on the need for large-scale (public) infrastructure. For example, one actor can operate offshore windfarms to produce hydrogen for the actors own synthetic kerosine production purposes, which eliminates both a hydrogen provider (large-scale green hydrogen supply) and consumer (large-scale industrial demand) from the public market place).

4. How to establish a dynamic hydrogen (carrier) market place

In this paper we discussed how the urge to decarbonize our energy system results in changing ecosystems and value chains, and thereby developing the current energy carrier markets. Sustainable hydrogen-based molecules could play an important role as platform molecules in those markets, connecting demand and supply in a zero-emission future.

However, the demand and supply of hydrogen in the future remains uncertain. New renewable hydrogen production methods will change the existing hydrogen supply curves. And at the demand-side, current fossil hydrogen consumers may switch to other energy carriers and/or substitute grey with green hydrogen. In addition to current consumers, sectors that currently use natural gas or oil as a fuel or feedstock might switch to hydrogen or hydrogen-based molecules such as ammonia, methanol or Fischer-Tropsch products.

In market theories, a healthy market is characterized by balancing the demand and supply of products via rational behaviour of market participants. In reality, the decisions of those actors are not the only causes of marketplace dynamics. Renewable molecule marketplaces will not be isolated markets; they will have interactions with other energy carrier marketplaces, such as the electricity and natural gas markets.

While the underlying dynamic mechanisms of a hydrogen market have been discussed in this paper, the actual performance of such a market is subjected to many unknown or uncertain factors. Three of these uncertain factors have been discussed in the previous chapter. In the subsequent paragraphs we describe a way forward for each of those three issues with the aim to contribute to the emergence of a functioning market place for sustainable molecules.

Solution I: Facilitate mutual commitment of supply chain actors through governance

The first issue brought forward in Chapter 3 is the **challenging task of bringing together suppliers and consumers at an immature market place**. Matching hydrogen supply and demand quantities and at acceptable prices comes down to decision-making problems for multiple actors and on multiple time scales. And each actor has its own incentives and interests at stake while making their own decisions. Three major issues[19] need to be dealt with:

- The system perspective is often absent in decision-making: an optimal decision from a system perspective could interfere with the best economic decision for a single stakeholder in the chain and vice versa.
- Essential information for the decision-making is insufficiently available to actors.
- It is unclear which actor is to take which risks and who needs to invests first.

[19] TNO (2020) Energie-infrastructuren 2030

Suppliers and consumers cannot or do not want to share information, or they do not know which type of information they are required to share and with whom. To break free of this situation, **a clear governance structure is required that facilitates mutual commitment between producers, consumers, transport and storage service providers** to stimulate the timely availability of the required information per actor and thereby take the first steps towards the implementation of a fully functioning market.

When this governance framework creates an acceptable level of insight regarding the quantities, locations, timing and pricing of supply, demand, transport and storage, this chicken-egg-hen-rooster-problem can be solved.

Steel sector: Hypothetical example of changing energy carrier choices and supply chain actor interdependencies

A car manufacturer may want to use 'sustainably processed' steel to brand her product and has multiple purchase options. Currently, steel produced in NL (80% gray electricity and fossil feedstock) can be considered more sustainable than import from China (production more carbon intensive and adding of transport emissions). A possible more sustainable alternative now could be steel produced with an Electric Arc Furnace process. This steel is *now* available and yields the greenest image. But the car manufacturer may be willing to make large purchases of H_2-based steel in the future. If the price of H_2-based steel can be low enough, the car manufacturer is a potentially large consumer of green hydrogen embedded in the steel and can be willing to pay a high price per kilogram of steel (and thus green hydrogen). This willingness to pay may exceed the current steel price as the green steel image yields intangible added values too. However, before the car manufacturer can commit to a long-term contract with the steel producer, that steel producer needs to transform his equipment to H_2-based DRI, for which the steel producer requires a secured supply of sustainably produced hydrogen for an acceptable price from a hydrogen producers.

Solution II: Use the available hydrogen to minimize the emission of our society

The second issue brought forward in Chapter 3 is the expected inefficiency of the market to decarbonize our society through hydrogen use: **A just distribution of sustainable molecules amongst sectors is not trivial.**

Many potential use cases of renewable hydrogen have emerged in parallel with the growing political attention of hydrogen as a swiss army knife for various decarbonization challenges in our society. The objective of any of those hydrogen use-cases should be kept in mind at all times: we need to systematically and permanently decarbonize our society. The important question to answer then becomes: which application of 1 kilogram of hydrogen realizes the largest environmental impact reduction on the short and/or long term?

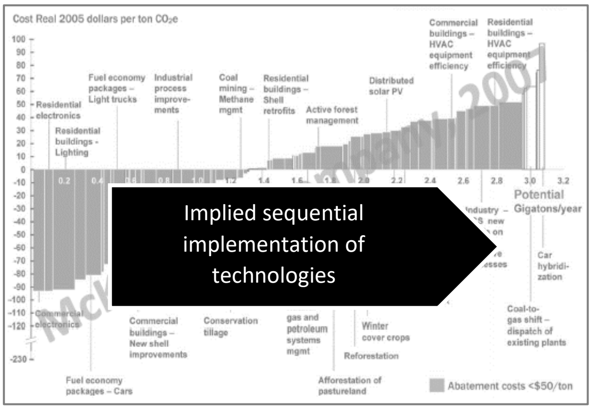
An effective use of renewable molecules is not trivial (see issue II) when left to the free market. Governmental interference in this emerging market place is thus inevitable to **realize the largest emission reduction possible of our society** on the short and the long term. Two essential topics need to be incorporated in a *prioritization policy of renewable hydrogen application*:

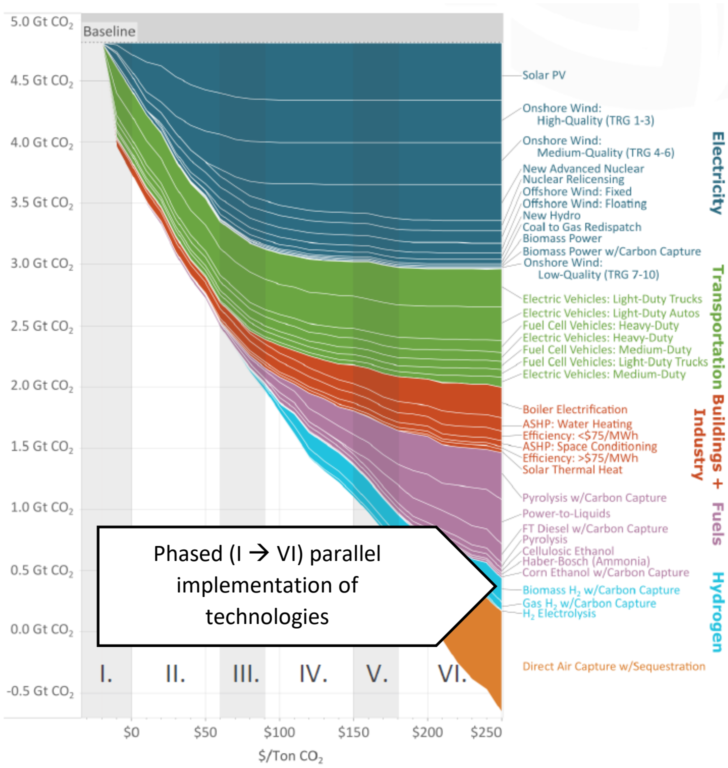
1) Renewable hydrogen is often one of many possible decarbonization alternatives (see section 2.2) and should therefore be treated as such: more effective decarbonization options should be considered before hydrogen is selected as the option of choice.
2) The *marginal abatement cost (MAC) curve* perspective needs to be treated with great care. Unconscious users of this curve may falsely interpret this frequently used curve as a preferred suppliers curve. The MAC methodology is ill-suited for this task as many other factors are of importance when deciding the sequence of hydrogen deployment (the text box on page 16 provides a more in-depth discussion on the advantages of the new generation of MAC curves).

The need for next-generation Marginal abatement cost (MAC) curve usage

A revised use of MAC curves is required to capture the interaction (and underlying dependencies) between decarbonization measures and move from isolated measures to the system effects of a combination of measures. Upscaling electric vehicles is, for example, only an effective decarbonizing measure when the electricity mix comprises of a renewable electricity mix simultaneously. We thus need to think and act on parallel implementation of measures instead of simplistic sequential upscaling.

Evolved Energy Research (2021)[20] on the limits of the traditional MAC curve (left illustration): **“**While traditional MAC curves directly present potential abatement and associated cost, they do not necessarily show the reader what order measures should be adopted. The curve’s apparent simplicity can leave some readers to infer, incorrectly, that the figure is a supply curve. Interpreting a MAC curve as a supply curve suggests that it shows the preferred order of adoption and that measures should be deployed sequentially by abatement cost, moving from the left side of the curve to the right. Many factors beyond marginal cost influence the order of measure deployment that will lead to decarbonization at the least cost, including interactive effects between measures and the time needed to develop mature markets to deliver technologies at scale.”





Solution III: Create infrastructure to facilitate local open market places

In line with the first complex issue, which describes the difficulty in matching supply and demand, the third issue explicitly on the development of infrastructure is defined in Chapter 3. This issue entails the **many uncertainties that cloud the development of market-facilitating infrastructure**. These uncertainties apply not only to future hydrogen infrastructure but also to electricity, natural gas, heat and CO_2 infrastructure on the transmission, distribution and interconnection scale.

The uncertainties regarding the **molecules of choice, transport modalities, storage** and the **self-sufficiency of actors** may reduce over time as the five sectors (electricity, industry, agriculture, built environment and mobility) make their decarbonization decisions. However, these sectors are of lasting great importance for the earning capacity of the Netherlands, direct employment and the position of the Netherlands in many (global) value chains. Access to renewable energy is an important precondition for many of the stakeholders within these sectors, which underlines the importance of timely available infrastructure.

Establishing a hydrogen system operator and making pre-investments in infrastructure, aid or influence the decisions of actors within the different sectors and thus prevent undesired consequences

[20] Farbes, J. Haley, B. Jones, R. (2021) *Marginal Abatement Cost Curves for U.S. Net-Zero Energy Systems – A Systems Approach.* Evolved Energy Research. p.10

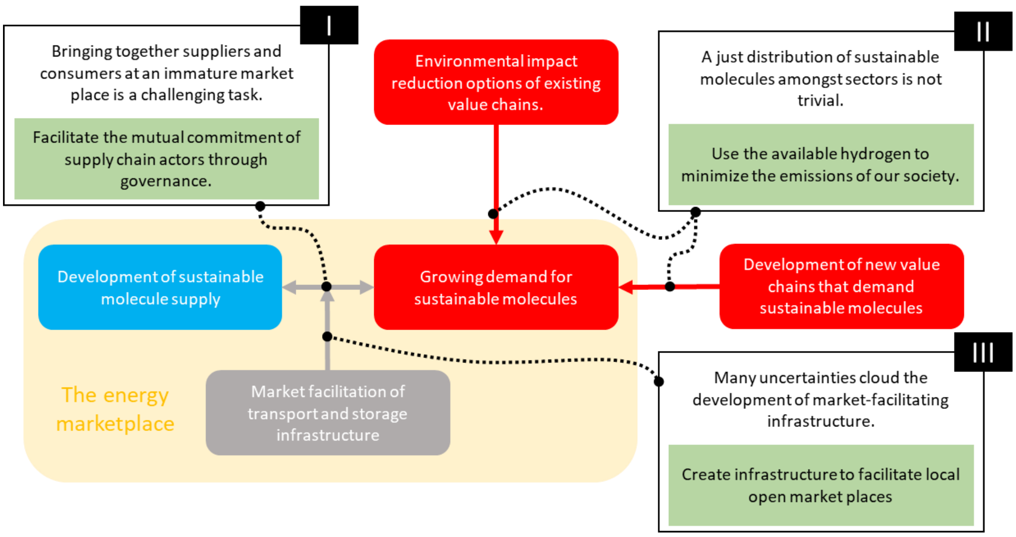
for the Dutch society. The underutilization risk of such pre-investments, the loading risk, is a major concern for individual actors to bear and has a direct impact on the business case of the project. But given that infrastructure development decisions are urgent given the long lead times (3 to as much as 10 years) between decision and realization of infrastructure, delaying decisions on the construction of energy infrastructures could lead to climate targets not being met. Starting with the development of hydrogen transport and storage infrastructure that has low loading risk can be considered the natural way forward.

Connecting regional and international clusters via public infrastructure aids the establishment of a mature and liquid market that reaches beyond the (current) self-sufficient point-to-point contracts all the way to a hydrogen market of international scale. In addition, we suggest to **accelerate the emergence of local liquid hydrogen markets through infrastructure developments** at the locations that are most promising in this respect.

5. Summary and closing statement

In this paper we set out to explore the complicating factors that determine future hydrogen carrier market dynamics. We untangled those factors to identify bottlenecks that hamper the development of a liquid and scalable hydrogen carrier market. And we presented recommendations to overcome those bottlenecks. A schematic summary of this papers findings is given below.

We described the theoretical functioning of energy market places and used these rules to gain an understanding of a future hydrogen market (yellow shade below). The three challenging issues that where identified, and the ways forward to deal with those issues, all point towards a vital element of the market: (I) addresses the presence of both suppliers and consumers, (II) challenges the effectiveness of the market to decarbonize, and (III) focusses on the challenges regarding fit-for-purpose infrastructure development.



<u>Closing statement</u>: The large variety of energy vectors and energy market commodities are not to be ignored when conducting an analysis on a system level. We have focused mainly on the role of hydrogen and hydrogen related molecules as energy carriers. While this simplification may not acknowledge the actual complexity of the energy sector, we believe that an increased understanding from the perspective of hydrogen (carriers) contributes to the understanding of the system as a whole.