HyDelta

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Executive summary

Since the Paris climate agreement, the attention for ways to decarbonize the existing energy system has grown immensely. Sustainable alternatives for fossil oil and gas which are still able to provide the same level of energy security, or better, are of particular interest. The implementation of these carriers will impact the existing energy system as a whole, mainly because of two reasons: new energy carriers need to fit within an existing energy system (e.g., H2, NH_3); and some existing carriers might increase significantly in capacity (electricity). New means of production, transport, storage and demand, i.e., value chains, will be required to realize these. In this report existing literature on the potential role of hydrogen in the future energy system is described. Following, the ways of modelling this future role in the energy system are distinguished, and how a modelling approach can influence the results. After the stage is set, the reasoning behind national decision making on hydrogen value chain development is described through their respective national hydrogen strategy. Finally, the design of hydrogen value chains within the environment of interest can be designed by identifying the chain elements, and the value chain models of interest. The condition of the existing energy system is an important fact to consider, to find the best way of decarbonizing it. The type of hydrogen economy, being it green or blue, import or export focused, primary gas demand or primary electrified demand, depends a lot on the strategy of the country. These national strategies are dependent on the costs of hydrogen production, growth of demand relative to production, and policy decision-making.

To find which potential value chains can be the most cost-effective within an energy system one can make use of value chain modelling. Two general types of modelling, optimization or calculation of value chains, return different perspectives on the results. Optimization returns one optimized solution within the given boundaries, and calculation gives a better opportunity to analyse scenarios and parameter sensitivities. In the (academic) literature, a lot of focus is on the planning (optimization) of HRS and costs for mobility sector. Typically, interdisciplinary consortia including governments, knowledge institutions and industrial stakeholders focus on the large-scale industrial end-use of hydrogen.

In the process of modelling value chains in general, the volumes and costs of hydrogen through the stages of the value chain are identified and provide insight in the economic and technical implications within a value chain. These insights can be of use for spatial planning, capacity planning and feasibility studies for the hydrogen value chain elements themselves.

Samenvatting

Sinds de totstandkoming van het mondiale Parijs Klimaatakkoord en het opvolgende Nederlandse Klimaatakkoord in 2017 is er sprake van de urgentie om het energiesysteem te verduurzamen. Het vervangen van fossiele energiedragers (olie en aardgas) door CO_2 lage energiedragers (groene stroom, groen gas, waterstof) is het doel van de komende decennia, terwijl de betrouwbaarheid van het huidige energiesysteem gewaarborgd dient te worden. Dit is een uitdaging doordat er enerzijds nieuwe energiedragers in een bestaand energiesysteem gepast moeten worden, en anderzijds omdat de verhoudingen van bestaande soorten energiedragers (elektrisch, warmte en moleculen) drastisch zullen veranderen. Diverse onderzoekers, bedrijven en publieke instanties onderzoeken hoe de omslag naar een klimaatneutraal energiesysteem zo goedkoop, spoedig en efficiënt mogelijk gemaakt kan worden. In dit onderzoek is een uiteenzetting gemaakt van relevante projecten en studies die een analyse doen van het energiesysteem, nationale waterstof strategieën, en waterstof waardeketens.

Het is de veronderstelling dat in dit nieuwe energiesysteem nog steeds een verhouding moleculen en elektronen aanwezig zal zijn om de transitie praktisch uitvoerbaar en betaalbaar te houden. Dit wordt ondersteund met systeem modellen, zoals het Energie Transitie Model (ETM). Een koppeling tussen het elektriciteitsnetwerk en het gasnet door middel van waterstof kan flexibiliteit opleveren wanneer er gebrek is aan zon en wind. Daarnaast kan waterstof gebruik maken van de bestaande aardgasleidingen en daarmee zijn er relatief weinig nieuwe investeringen in pijpleidingen nodig om transport mogelijk te maken.

Hoe groot de volumes, capaciteiten en investeringen zullen zijn om waterstof een effectieve energiedrager te laten zijn is mede afhankelijk van de volgende factoren: vraag naar waterstof, de hoeveelheid die Nederland zelf wil opwekken en de verhoudingen blauwe en groene waterstof. Deze factoren gaan zijn onlosmakelijk verbonden met het gevoerde nationale beleid. Nationale waterstof strategieën zijn de afgelopen jaren gepresenteerd van over de hele wereld, om een beleidsrichting te creëren voor de rol van waterstof in het nationale energiesysteem.

De ontwikkeling van potentiële markten zijn verantwoordelijk voor de hoeveelheid gevraagde waterstof, en ook voor de soorten waardeketens die zullen ontstaan om deze markten te beantwoorden. Productie, opslag en transport vormen zich naar de ontwikkeling van deze markten, en zullen op de meest kosteneffectieve manier moeten worden ingezet. Hoe kosten en volumes zich zullen verhouden in deze waardeketens kan worden benaderd met techno-economische waardeketenanalyses. Hierin wordt de kostprijs van de waterstof berekend aan de hand van alle ketenelementen die de waterstof doorloopt tot de eindgebruiker. Het vergelijken van deze ketens kan waardevolle inzichten bieden voor verdere besluitvorming in de energietransitie.

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Abbreviations and definitions

ATR	Autothermal Reforming
Bcm	Billion cubic meters
CAPEX	Capital Expenses
CCS	Carbon Capture and Storage
CCUS	Carbon Capture, Utilization and Storage
CEPCI	Chemical Engineering Plant Cost Index
CO_2	Carbon Dioxide
HRS	Hydrogen refuelling stations
LCOH	Levelized Costs of Hydrogen
LH2	Liquid Hydrogen
LOHC	Liquid Organic Hydrogen Carrier(s)
O&M	Operations and Maintenance
OPEX	Operational Expenses
PEM	Polymer Electrolyte Membrane
POX	Partial Oxidation
PSA	Pressure Swing Adsorption
RES	Renewable Energy Sources
SMR	Steam Methane Reforming
SOEC	Solid Oxide Electrolyzer Cell
STP	Standard Temperature and Pressure
TRL	Technology Readiness Level
TSO	Transmission System Operator
VC	Value Chain
WGS	Water Gas Shift

1. Introduction: The transition towards a sustainable energy system

In the Paris Climate Agreement, the urgency of keeping global average temperature increase below 1.5 C, or well below 2.0 C, has been acknowledged globally. This led to the release of national climate strategies everywhere, and therefore also in the Netherlands via its 2017 Climate Agreement ('het Klimaatakkoord') [1]. It is common knowledge that the climate issue represents one of the largest challenges of this century: large parts of the energy system need to be overhauled or extended while recognizing security of supply and affordability next to becoming green. A particular challenge resulting from the introduction of intermittent sources of renewable energy is to match supply and demand, a challenge that during the transition is becoming more tangible every year. Another challenge is to create green energy molecules that are needed because electrification of end-use energy demand is only applicable up to some level [2]. So far much of the policy incentives have been directed towards the production of green electrons; a major remaining challenge is to make sure that sufficient levels of green molecules for energy and feedstock purposes will be available via a solid value chain. There is a broad consensus that hydrogen will form a major component of that future value chain of green energy molecules; moreover, there is a comparable consensus that green molecules, and hydrogen in particular, may make a considerable contribution to dealing with the supply-demand mismatch of intermittent energy production.

In this report the focus will be on the hydrogen value chain. The main purpose of the paper is to provide a generic literature overview of this value chain, its components, how it is and can be modelled, and various national and international strategies towards the development of hydrogen value chain activity. In doing so, the focus on the hydrogen value chain in the Netherlands will be relatively strong, but will be put in the perspective of the broader hydrogen developments throughout Europe.

There are several reasons why a value chain analysis is indispensable for assessing the potential role of hydrogen in the future energy mix. First, just as any energy carrier, also for hydrogen it holds true that a serious hydrogen economic system can only come off the ground if all the value chain components are economically feasible and therefore the value chain as a whole. In actual practice the value chain main components – production, conversion, transport, storage, implementation in various end-uses (predominantly industry, mobility, build environment) – are covered by different stakeholders concentrating on just one or a few value chain aspects. Without a proper business case given any further incentives investment in a particular value chain component will not happen for those activities that are left to the private sector. The whole value chain can therefore only develop if all its components may involve investment on a solid economic basis. That is why a complete picture is important: the chain is as strong as its weakest link.

A second reason why value chain analysis is crucial in modelling the role of hydrogen in the energy system is related to the assessment of policies and measures to get the hydrogen economy off the ground. As was argued already, so far progress towards the massive introduction of green energy molecules has remained subdued: in the EU currently less than 10% of the energy molecules in end-use can be considered green; this will need to be close to 100% by 2050. So, the pressure to aggressively move towards speeding up and scaling up hydrogen production is growing as well as the recognition that the hydrogen value chain is currently still facing a 'valley-of-death'. Therefore, policies and measures will play a crucial role in launching a massive introduction of the hydrogen value chain. This also explains why a new wave of energy modelling activities is developing that may be helpful in guiding such policies and measures. In many of these models the value chain is an important concept because effective policies and measures require that the complete value chain of activities is explored in policy simulation. More specifically, in assessing the impact of policies and measures ultimately the overall social costs and benefits will be the main criterium determining which policy mix is optimal, not the costs and benefits of specific value chain components. Social costs and benefits relate to the complete value chain. For instance, in determining what the costs and climate mitigation impact of introducing hydrogen in mobility, or any other end-use, is, it is important not only to determine the direct costs and emissions' impact in mobility itself but also how the use of hydrogen affects costs and emissions related to production, transport and storage of the hydrogen used. In other words, for an appropriate assessment of the most effective energy policies and measures, the wider perspective on the overall value chain is indispensable.

The value chain of hydrogen is clearly not a mono-dimensional and static concept. For instance, the location of hydrogen production can vary from various offshore locations to all kinds of onshore locations. Also, the option to import hydrogen rather than to produce hydrogen in the own area will be subject to economic conditions and determined by security of supply considerations. Hydrogen can be produced either large scale by GW-scale electrolyzers, but also in much smaller units at the local level. The same applies for transport systems, where pipelines can be used, possibly existing ones, but also shipping or trucks to transport the hydrogen. Hydrogen can be 'packaged' in other chemical substances such as ammonia and methanol, which clearly affects which transport modes are the most economic. Also, for the storage for hydrogen various modalities do exist ranging from large-scale underground storages, to smaller but more flexible storages in tanks and tubes. So, what the optimal value chain is will typically depend on the specific spatial conditions, existing infrastructures that can be used, the overall market uptake, etc. Therefore, in the current literature overview also attention is given to the various modalities of the value chain components and their technical feasibility and costs.

In this literature overview existing techno-economic knowledge on hydrogen value chains and their components is collected and assessed. Various value chains are considered, with the identification of the most relevant ways of conversion, transport, storage and end-use. The most recent developments in these value chain elements are covered and can provide a starting point for further value chain research. Furthermore, various national strategies to develop a hydrogen economy are covered to identify hurdles and lessons learned from other countries. This, in combination with the Dutch hydrogen strategy as mentioned in the Klimaatakkoord [3] [4], will provide the setting of effective hydrogen value chain development in the Dutch context and the subsequent analyses in this HyDelta workpackage.

2. The role of hydrogen in the energy transition

2.1 Future energy system scenarios

The increasing interest in hydrogen as a key-enabler in the transition to an emission-free energy system is based on several advantages: it has energy-dense properties which compare to current molecular energy carriers; resources to produce green hydrogen[1] are abundant and the conversion of hydrogen to electricity or heat only emits water. On the other hand, the volumetric density of hydrogen is very low and the technology to convert electricity to hydrogen is capital intensive. The current energy system consists of two main energy carriers: electricity and molecules (gas, oil, biomass). Currently, these cover the energy demand in a ratio of respectively 20%/80% [1] for energy carrier demand for energetic end-use. As a direct result of projected efforts to replace fossil-based oil and gas demand by ("green") electricity demand (EV's, electric heating, etc.) a future ratio is expected to be more towards a more balanced distribution between electrons and molecules as energy carriers, as for example estimated in four national energy scenarios by Berenschot and Kalavasta (Figure 2) [1]. The molecular energy carriers in this projected future energy system consist of a significant share of carbon-neutral hydrogen and bio-based carriers, as these are the most promising.

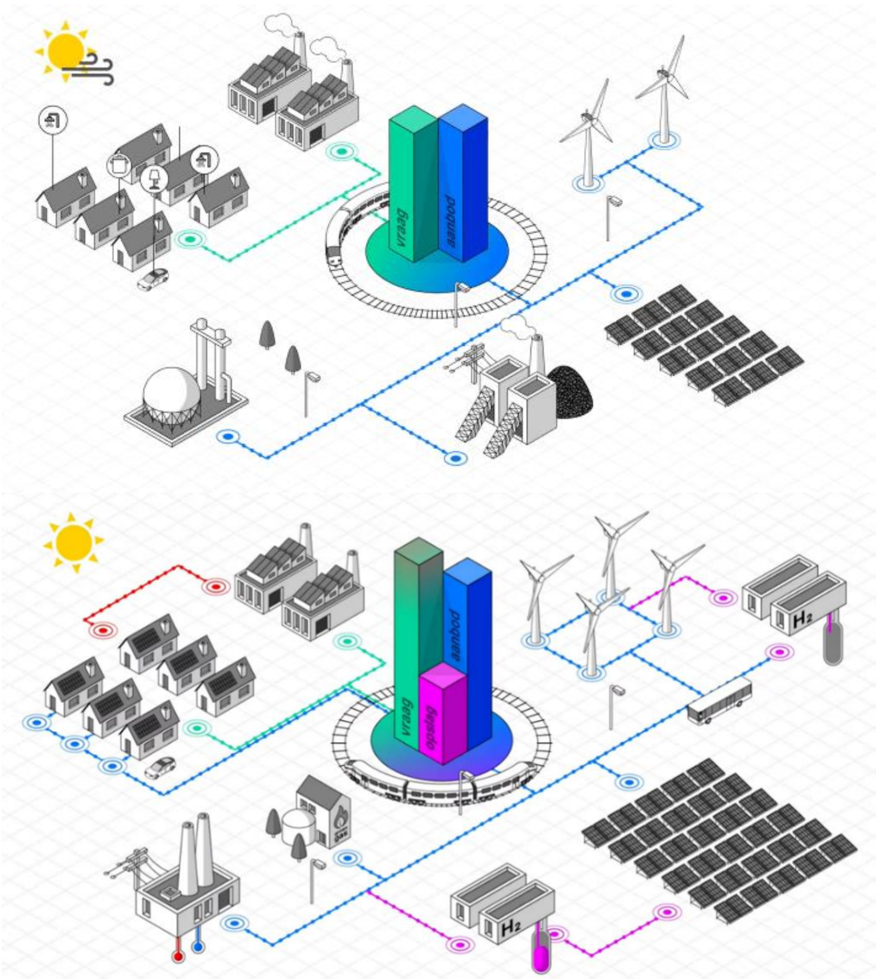


Figure 1 - Visualization of the current (top) and potential projected future energy system (bottom) by Gasunie [5].

As solar and wind energy are currently growing as a renewable energy source (RES) for electricity, due

[1] Considering conversion of electricity to hydrogen in the existing energy system, one could argue hydrogen also provides an opportunity of integrating the carbon-based natural gas grid to a carbon-free hydrogen network through "blue" hydrogen.

to their unlimited resource during operation and minimal marginal costs, the challenge of dealing with the intermittent characteristic is increasing proportionally. To tackle this problem, energy storage is required to provide flexibility in the electricity system (Figure 1) [6], while there are few large-scale storage opportunities for electricity storage aside from pumped-hydro storage (geographic limitations) or batteries (limited scaling potential). Therefore, energy conversion to carriers that are possible to store on a large scale has been researched extensively, among which hydrogen is considered to have a large potential due to its high energy density and abundant resources (renewable energy and water).

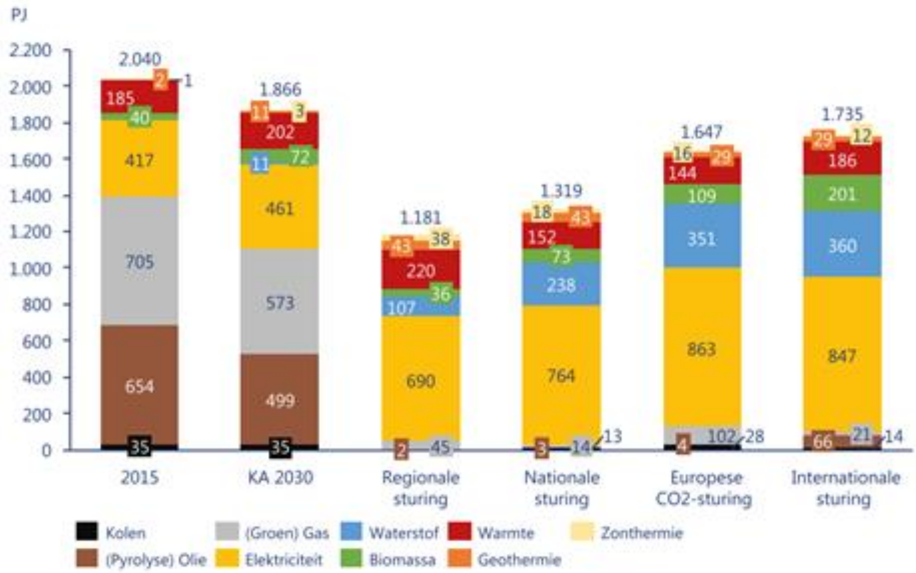


Figure 2 - The demand for energy carriers in 2015, prognosed in 2030 in the 'Klimaatakkoord', and in 4 potential future energy systems, as designed by Beerenschot and Kalavasta [7].

2.2 Scenario models

As the future energy system is subject to the decisions made in the present-day, and there are various paths which lead to a zero-emission energy system, there is still uncertainty about the future energy system. To aid in decision-making, scenario studies are developed to give insight in the potential direction of energy system development, the potential impact of policies, and the need for new infrastructure investments. However, they always remain a representation of reality. Various model typologies are applied in the hydrogen research field. The models chosen can be classified on the bases of their outcomes (type and objective of the outcome), or they can be classified based on the characteristics of the model (structure and mechanic).[2] An overview of the main characteristics of the models used by various scenario studies is given in the table below and a more detailed overview of studies using these models is given in the Appendix B – Modelling types.

[2] Classification of models is retrieved from http://www.energiemodelleren.nl/

Table 1: overview of various scenario models. Classification based on own interpretation.

Model	Source	Type of Result	Objective of Result	Structure of model	Modelling mechanism
ETM [8]	Quintel	System integration	Explorative models	Top down and bottom up	Exploration and calculation model
KEV [9]	PBL	Economic model	Policy support and explorative models	Bottom up	Calculation model
Opera [10]	TNO	System integration	Policy support	Bottom up	Optimization model
Competes [11]	TNO	Energy generation model	Policy support. Explorative models	Bottom up	Optimization model
Primes [12]	EU	Economic model	Policy support	Bottom up and top down	Simulation model
Times [13]	IEA	Energy generation (technologies)	Policy Support	Bottom up and top down	Calculation and exploration model
Cegoia [14]	CU Delft	Economic model	Policy support	Bottom up	Optimization and exploration model

Some commonalities coming back across the various models are:

2.2.1 Simulation model.

Distinct types of models were used to evaluate the scenarios. These models vary from spatial cost-optimization to naturally evolving hydrogen-based energy systems to setting limits on the different energy options to fulfil certain renewable or CO_2-abatement goals. By comparing these models, the effect of a coordinated approach can be assessed. The investigated studies often share databases and models, which can partly explain similarities in the results. By reusing databases and models scenario studies with a different approach can be performed quickly. The downside is that as these studies share databases and methods, uncertainty in the results can be underestimated.

2.2.2 Temporal resolution

Almost all models have either 2030 or 2050 as their time-horizon (some go on until 2070). The starting point is almost always the current situation at the time of the model (usually a year earlier). Some of the models also include current pledges in the model. The temporal resolution varies between daily to yearly. Including time as a variable can provide insight in the optimal timing of investments depending how costs evolve (decrease) over time due to learning effects (with all uncertainties considered).

2.2.3 Spatial resolution

Most studies focus either on a national, multi-national or European level. The advantage of national studies is that their level of detail is often high. However, they often miss interactions - both positive and negative - with how the energy systems of surrounding countries might develop. The advantage of European studies is that they can analyze a European transition encompassing a large variety of options and the integration of fundamentally different energy systems. However, their level of detail is often of lower granularity than national studies. Multi-national studies are in between the national and European studies regarding level of detail and geographic scope. Spatial resolutions vary between small grid points - 5 x 5 km -to entire countries represented as a single point.

2.2.4 Sector resolution and demand predictions

The extent to which the technologies and end-users are included in the different studies varies, as are the number of transport and storage options considered. Results show large variations and even contradictions in hydrogen demand volumes when they include more energy options and/or sectors. The various end-uses, whether it being as an energy carrier or a feedstock, have raised cross-sectoral attention for hydrogen in the last decade. Despite the current challenges of inserting a new commodity within a committed energy system, the urgency of achieving climate goals drives the developments towards a dedicated hydrogen economy in e.g., industry, mobility and build environment. This multifunctionality provides a wide range of projections on future hydrogen demand quantities (see also the figure below) [2]. The inclusion of hydrogen for synthetic fuels, for industrial feedstock and the developments in electrification can be considered as sensitive variables in projecting future hydrogen demand in a mature hydrogen economy.

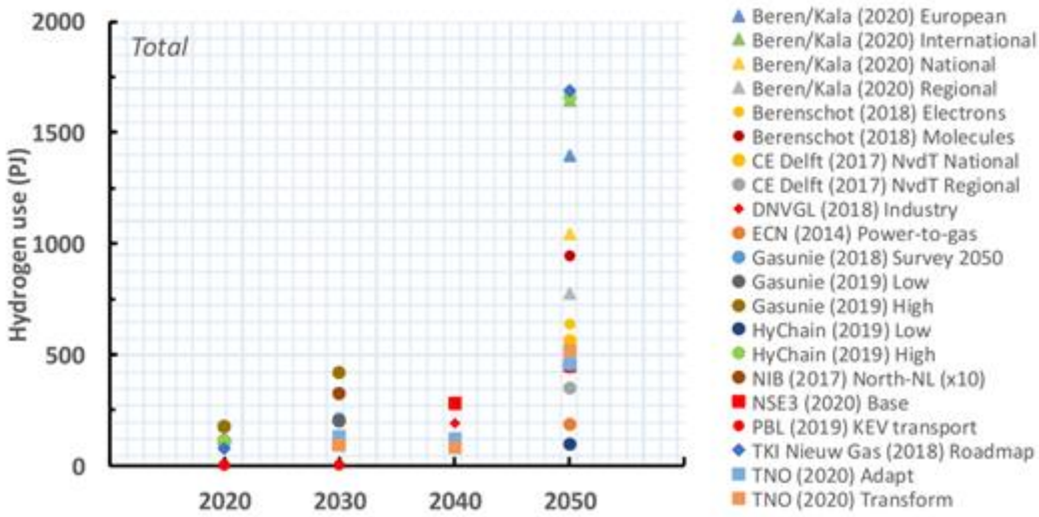


Figure 3 - Overview of various scenario studies that consider or project energy demand in the future. [2]

3. International studies and reports on the hydrogen value chain/economy

A large variety of studies have recently been published on specific technical and economic issues facing the introduction of hydrogen into the energy and feedstock systems. They cover topics such as: conversion efficiency, reuse of existing pipelines, storage facilities, electrolyzer and fuel cell technology innovation, hydrogen implementation issues, or factors determining hydrogen technologies' business cases. Also, at the hydrogen value chain or energy system integration level the number of studies and reports is growing rapidly, e.g., via country-specific case studies; studies on logistical optimization of hydrogen transport and storage given the broader energy supply and demand conditions; or via reports dealing with hydrogen value chain cost- or cost-benefit analysis in view of the wider energy and feedstock system. Finally, an increasing number of national and international roadmaps and visionary and/or strategic policy documents is emerging describing or suggesting action plans, financing mechanisms, investment incentives and legal action to provide the required momentum towards introducing hydrogen. In fact, the number of countries that have meanwhile published their national hydrogen strategy is rapidly increasing (see figure 4), illustrating the globally growing attention for hydrogen as key component of the energy transition strategies. Obviously, such strategies differ depending on the country-specific economic, geographical, or political conditions.

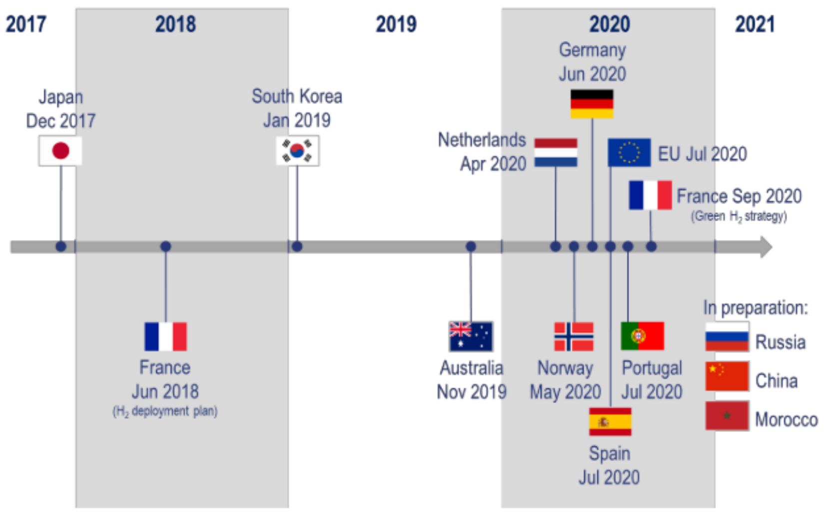


Figure 4 - Nations of the world with a published strategy on hydrogen. [15]

3.1 Strategies towards national 'tailor-made' hydrogen economies

As is typically reflected in the various national hydrogen strategies, countries clearly show different potentials to produce clean hydrogen. This depends on factors such as the availability of natural gas plus CCS capacity, the existing gas grid and storage capacity, or the available amount of renewable energy and water. For instance, a country such as Australia has a significant hydrogen supply potential based on its excess of renewable energy, which explains why it targets its national hydrogen strategy strongly towards exports, especially towards other Asian countries [16]. Also, European countries such as Spain and Portugal have strategies to develop hydrogen production from solar energy for export purposes, just as Morocco and Russia do. On the other hand, while high-tech developed countries such as Japan and South-Korea focus on hydrogen conversion innovation technologies, they do so while acknowledging their dependency on energy imports in a future hydrogen economy [17], including imports by way of methanol or ammonia or based on liquification [18] [19].

The availability of hydrogen transport capacities and related infrastructure is key for unlocking hydrogen value chains [15]. The development of long-distance trunklines between hubs often precedes gas market development by providing security of supply and substantial volumes for end-uses enabling economies-of-scale. Safety, reliability, and accessibility are key characteristics for any dedicated infrastructure linked to both large centralized and smaller decentralized hubs, and central coordination and public financing will typically be required for such infrastructure investment. For Europe, a first proposed hydrogen infrastructure scheme was published by European grid operators in 2020 [20], followed by an extended version in 2021: the so-called European Hydrogen Backbone [21]. This Backbone is expected to provide strong and reliable connections between supply and demand for European hydrogen value chains (see figure 6).

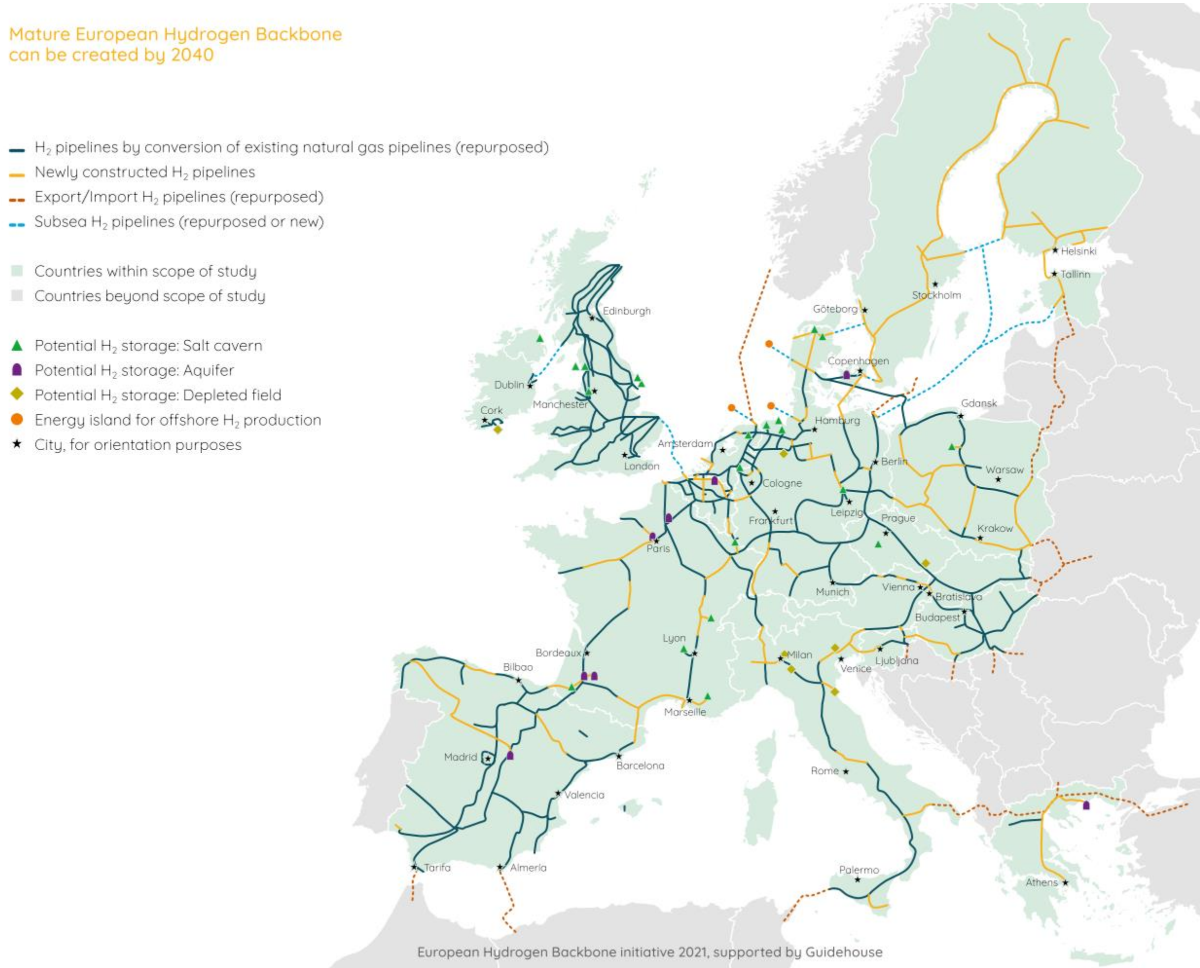


Figure 5 - Proposed European Hydrogen Backbone to provide a pan-European (21 countries) infrastructure for hydrogen in 2040 [21].

Also, the strategic national focus on hydrogen implementation differs from one country to the other. Countries with relatively large capacities of base industries (e.g., chemical, steel, refineries), such as France and the Netherlands, tend to emphasize the role of hydrogen in industrial feedstock applications. In other countries like Germany and especially Japan with their strong automobile sector and to some extent USA, progress is more focused on hydrogen for transport including the development of hydrogen refueling stations (HRS) [17]. It is noteworthy in this regard that FC passenger vehicles are projected to have a larger share in Asian than in European vehicles markets. So, all countries have slightly different emphases in their hydrogen implementation strategies (see figure 5), all contributing to the various learning curves, economies of scale and innovations.

Hydrogen use sectors	EU	DE	NL	FR	ES	IT	UK	NO	CH	UA	RU	JP	KR	CN	AU	CA	MO
Industry	✓	✓	✓	✓	✓	(✓)	✓	✓	✗	✗	✓	(✓)	✗	✗	✓	(✓)	✓
Power	(✓)	(✓)	(✓)	✓	(✓)	✗	✓	✗	✗	✓	✓	✓	✓	✓	✓	(✓)	(✓)
Transport	✓	✓	✓	✓	✓	(✓)	✓	✓	✓	✓	(✓)	✓	✓	✓	✓	✓	(✓)
Buildings	(✓)	(✓)	(✓)	(✓)	✗	✗	(✓)	✗	✗	(✓)	(✓)	✓	✓	✗	(✓)	(✓)	(✓)
Export	✗	✗	✗ 1)	✗	✓	✗	✗	✗ 2)	✗	✓	✓	✗	✗	✗	✓	✗	✓

✓ main sector (✓) less relevant ✗ not addressed

1) Hydrogen imports transit to other countries (e.g. Germany) considered.
2) For Norway, hydrogen is not targeted for direct export, but indirectly through the export of NG with local CCS.

Figure 6 – Targeted end-uses in national hydrogen strategies [15].

3.2 Netherlands' national hydrogen strategy

In the so-called national Climate Agreement of the Netherlands government of 2017 or 'Klimaatakkoord' [1], a national Hydrogen Program or '(Nationaal) Waterstof programma' was announced describing the role of hydrogen in the national energy transition strategy. The latter program is planned to be launched by the Ministry of Economic Affairs and Climate (EZK) in 2021 [3] [22] [1], and describes a pathway towards 2030 by means of a roll-out and upscaling of hydrogen value chains in the energy system based on: inducing clean hydrogen cost-price reductions by scaling up green hydrogen production and related transport capacities; the parallel development of investment in and infrastructural planning for green electricity supply; and the broader development of a potential international leading position in hydrogen development and implementation. The document argues that by 2030 green hydrogen production should be facilitated by 3-4 GW of national electrolyzer capacity, although the same document does not mention expected capacities with respect to blue or imported hydrogen. In a successive letter of EZK in 2020 imported and blue hydrogen gained more attention, so that it can be assumed that these issues will figure more prominently in the upcoming National Hydrogen program itself. In fact, some projects on rolling-out domestic blue hydrogen production initiated by consortia of industries and local governments, are currently in the phase of (pre-)feasibility studies (e.g., H2 Gateway [23] and H-Vision [24]). Moreover, the long and recently updated list of some 130 hydrogen-related projects [25] covering the complete hydrogen value chain currently under consideration throughout the country further illustrates the enormous potential the national industry and other stakeholders attach to the development of hydrogen.

As far as developing hydrogen infrastructure is concerned the Netherlands can be considered world-leading in preparing the repurposing of the existing gas-infrastructure for hydrogen transport. As the domestic supply (and demand) for natural gas and therefore its grid use continues to decline for several reasons, various initiatives have been taken to transform the natural gas grid (NG-grid) for the use of green gases including hydrogen. Especially the national transmission grid operator Gasunie, but also the distribution grid companies, do examine, or have examined how the existing transport facilities can be converted to transport green methane and hydrogen in a safe, efficient, and cost-effective way. Repurposing the NG-grid for hydrogen is, for instance, currently analyzed in the HyWay 27 project [26], initiated by the Ministry of EZK, Tennet, and Gasunie. This project is also a steppingstone towards a

European Hydrogen Backbone, the impact of which is potentially of truly global proportions. Furthermore, the electricity and gas transmission grid operators together, Tennet and Gasunie, recently (2021) published their joint report titled 'Integrale Infrastructuur 3050' [27] in which they list the necessary spatial and financial consequences of transforming the complete Dutch energy infrastructure. This 'coupling' of electricity and gas infrastructure adjustment and their interaction can be considered revolutionary in current energy infrastructural planning practices, and its purpose is: to enhance flexibility to balance the system, to create financial incentives to cope with the significant increases of some specific energy flows, and to find the most efficient solutions for network expansion and dealing with greening the energy system while respecting affordability and security of supply.

Overall, it seems logical that the Netherlands as a densely populated country with several energy-intensive industrial clusters and a strong and leading gas focus considers a focus on the hydrogen as a carbon neutral energy carrier to be a national top priority. But also, hydrogen as a feedstock is considered a huge opportunity to 'green' its massive chemical and steel clusters as well as refineries and other processing industries. An extensive list of hydrogen investments in the total value chain are therefore currently planned [28] [29]. In this sector, also the connection with nearby international industrial clusters in the ARRRA region is researched. For example, connecting Dutch and German hydrogen value chains for industry is treated in 'Hy3'[3], in which green hydrogen supply from import and North Sea wind energy is planned to be used in demand centres in Netherlands and Nordrhein Westfalen.

3.3 Take-aways hydrogen strategy

Most projected hydrogen strategies are based on and can be characterized by a few key assumptions:

Thrive to meet the 2050 climate goals.

All hydrogen strategies intend to truly achieve the set international climate goals as stated in the Paris Agreement, or as announced by the EU. The public and political motivation towards sticking to these targets, i.e., to be nearly carbon neutral by 2050, is fundamental for the projected development of the hydrogen economy. Less commitment to these targets immediately affects the hydrogen strategy especially towards 2030.

Electrification versus molecule transport. What strategies assume towards the electrification trend is another decisive factor. As priorly mentioned (2.1 Future energy system scenarios) current energy system is traditionally dominated by energy carriers by way of molecules (some 75-80%) leaving a relatively small role to electrons. All projections assume an increasing share of electricity in energy end-use, but views on this trend towards 2050 differ.

Such differences can have a pervasive impact on the role attached to hydrogen as future energy carrier. This in its turn has a strong impact on adjustments needed in the energy transport and storage infrastructure and energy implementation in industry, transport, and the built environment. How to determine optimal investment in energy infrastructure as long as it remains unclear what the role of energy electrons versus molecules will be? Or how to project future transport options if the role of hydrogen in transport versus electricity remains the object of speculation?

Supply (in)dependency. Being dependent on international energy sources is not new. Currently about two-third of the EU energy consumption is imported from outside the EU, and more than half of the

[3] https://hy3.eu/results/

Netherlands' energy uptake is based on imports (of which 63% is oil) [30]. With the decrease of the natural gas production in the Netherlands, the energy import share is projected to increases if only because of the rising natural gas imports (see also figure 7). But to what extent will import dependence considered to be an issue such that one may prefer domestically produced energy carriers even if that would cost more than importing such energy? The transition the energy system is currently facing may give rise to a re-assessment of the dependency on energy import, which in its turn may strongly affect projections towards the role of hydrogen in the energy system.

Current import flows of oil and gas are physically irreplaceable by domestic supply due to insufficient domestic geological energy reserves, reinforced by the upcoming shut-down of the Groningen gas field. However, when this energy carrier is replaced by a sustainable carrier, such as hydrogen, it can usually and to a certain extent be produced domestically. While such domestic green supply can provide energy-security and independence from political instability elsewhere, it can at the same time come at a higher cost-price and put more pressure on spatial planning and social acceptance (in particular in a densely populated country with no excess of renewable energy sources such as the Netherlands). So, national policies towards import dependance, globalization and international market developments are key factors determining the future share of domestic energy supply to our energy system, and therefore of the projected role of hydrogen.

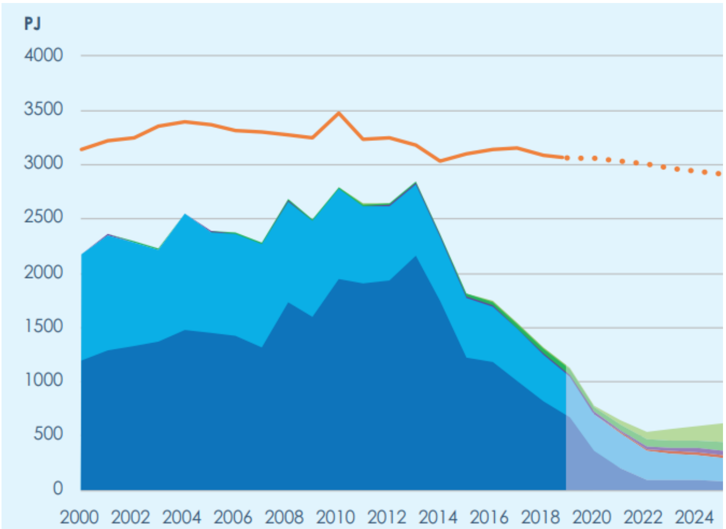


*Figure 7 - The amount of PJ of domestic energy production (area graph) in the Netherlands compared to the final demand of energy (line). **Dark blue**: Onshore Natural Gas, **Light Blue**: Offshore Natural Gas, **Green**: Renewables, **Orange line:** Final energy demand. [30]*

The colour profile of hydrogen. The carbon-neutral production of hydrogen in the Netherlands can grosso modo be subdivided into green and blue hydrogen technology, which both have their advantages and disadvantages to use as a hydrogen supply source. What share of domestically produced hydrogen will be blue or green depends on technical and economic factors but is primarily a political issue views on which may vary. Blue hydrogen is an option to accelerate the hydrogen economy as the large share of the technology (SMR/ATR) is already convenient, namely the CCS extension is new and challenging. The possibility to produce a constant large flow of hydrogen into the energy system is a clear advantage. The fact that: a fossil resource is generally required to produce blue hydrogen; the ATR/SMR+CCS process is still not 100% free of CO_2 emissions; and the fact that large-scale carbon storage is geographically restricted, can be considered disadvantages.

Green hydrogen copes with larger conversion losses and requires large-scale renewables, while: the sources are abundant, conversion can take place decentralized, and electrolyzer technology can produce hydrogen at an exceedingly high purity level. For all those reasons policy makers and investors can make quite different decisions in choosing between blue and green. This will obviously be another factor strongly affecting hydrogen projections, and therefore explain why projections tend to differ strongly.

4. Stages of the hydrogen value chain

4.1 Production

4.1.1 Hydrogen production pathways

There are several ways to produce hydrogen. The main technologies are typified by reforming, gasification, and electrolysis (see Figure 8). As of today, Steam Methane Reforming (SMR) is the main hydrogen production technology, using annually around 205 bcm of natural gas (6% of global natural gas use) to produce 70 million tonnes of hydrogen, which is three-quarters of the global hydrogen production [31]. Furthermore, coal gasification is the second technology, mainly located in China. Globally, 107 million tonnes of coal (2% of global coal use) are used yearly to produce 23% of the global hydrogen production [31]. Finally, oil and electricity are responsible for a small share of hydrogen production today. In the commonly used terms 'grey', 'blue' and 'green' hydrogen, grey includes production methods using resources and/or production technologies that include CO_2 emissions. For 'blue' hydrogen, the same resources and production methods are used as grey hydrogen, but (a large share of) the emissions are captured by carbon capture technologies. The CO_2 can be stored underground or re-used in other processes. The term 'green' (carbon-neutral) hydrogen is mostly used to refer to hydrogen that is produced via electrolysis of electricity generated by renewable resources. In this section, a brief introduction of the main hydrogen production technologies will be given, focusing on their levelized cost of hydrogen (LCOH[4]).

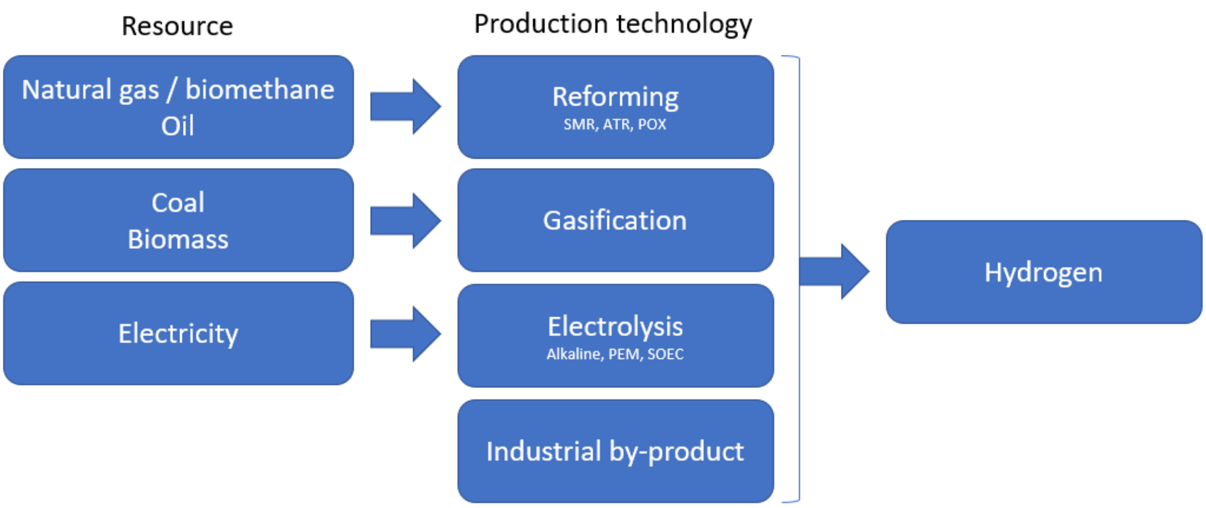


Figure 8 - Overview of hydrogen production technologies

4.1.2 Reforming (+CCS)

Reforming technologies use natural gas and water (and ATR also uses oxygen) to produce syngas mainly containing hydrogen (H_2), carbon monoxide (CO) and carbon dioxide (CO_2). Thereafter, water gas shift and purification processes are applied to receive pure hydrogen [32]. The costs of performing

[4] Levelized cost of hydrogen is the total costs per produced unit of hydrogen over the whole lifetime of a producing asset.

reforming to produce hydrogen are mainly based on the costs of natural gas, therefore availability of cheap natural gas has a substantial impact on the LCOH produced by SMR and ATR.

Currently, SMR has lower LCOH than ATR. However, if CCS is applied the cost competitiveness differs. For SMR, 60% of CO_2 emitted can be captured after the water gas shift process against relatively low costs (53 USD/tCO_2) [31]. But when also the CO_2 from the steam reforming step is captured, resulting in 90% CO_2 capture, these costs increase towards 80 USD/tCO_2 [33]. In the ATR process the CO_2 is produced inside the reactor which allows to capture more than 90% of the emissions and at relatively lower costs than SMR, along with faster response time of operation, resulting in the fact that new projects consider ATR as preferable technology for the future where higher CO_2 emission prices must be paid [34].

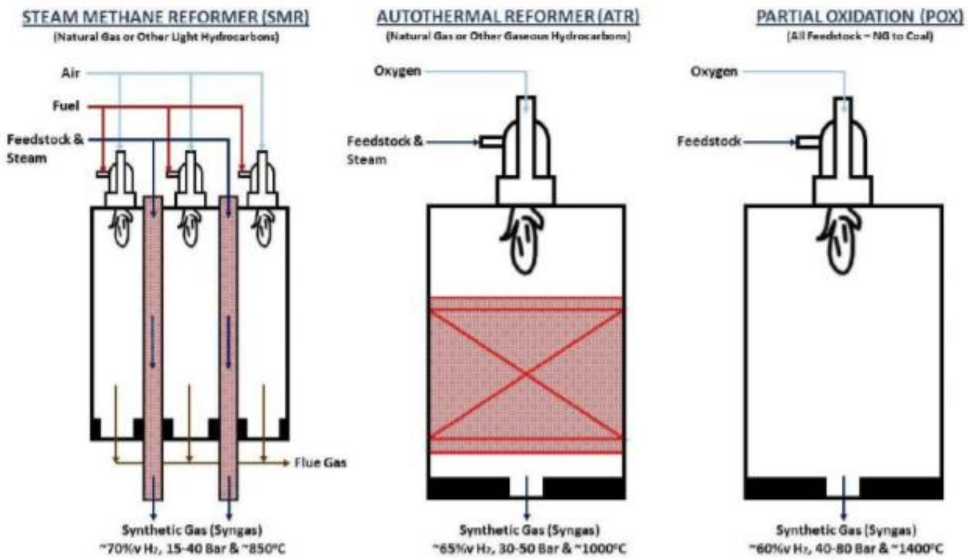


Figure 9 - Syngas reactors [35]

Since biomethane has the same characteristics as natural gas, theoretically also biomethane can be used as fuel to produce hydrogen via SMR and ATR that could be perceived as renewable. Even, when the CO_2 emissions are captured, this hydrogen production pathway could lead to negative emissions as the CO_2 is taken from the atmosphere by the biomass and stored underground by the CCS system. However, since the gas price can have significant impact on the LCOH this pathway currently would be an expensive way to produce hydrogen due to the inflated costs of biomethane compared to natural gas.

4.1.3 Gasification (+CCS)

Gasification, mostly Partial Oxidation is used to produce syngas from different kind of sources (mostly coal, but also rest products of refinery processes, petroleum, or dry biomass) [32]. In this process, less hydrogen and more CO and CO_2 are produced in the content of the syngas. Therefore, this technology emits a lot of CO_2 for each kg of hydrogen that is produced. Furthermore, the same water gas shift and purification processes are required as for the SMR and ATR technologies to obtain pure hydrogen. For coal gasification it is hard to capture CO_2 at existing plants since most gas separation technologies focus on either hydrogen removal or CO_2 removal in high purities [31].

Different other gasification technologies are being developed or in development to produce hydrogen from biomass, such as anaerobic digestion and fermentation. These technologies differ in their technology readiness level (TRL), but in general these pathways are considered more expensive than solar- or wind-based electrolysis pathways. Moreover, the availability of (cheap) biomass limits the potential of large-scale hydrogen production by this source, compared to the alternatives [36]. However, also this production pathway combined with CCS can lead to 'negative' emissions.

4.1.4 Electrolysis

Electrolysis is the process to split water molecules into hydrogen and oxygen, making use of electricity. The main electrolysis technologies are Alkaline and PEM. Both technologies produce hydrogen in relative high purities (>99.99$_{mol}$%). The main differences between the technologies are that Alkaline is more mature and therefore has relatively lower costs and higher efficiencies than PEM, but on the other hand more potential in cost reductions, efficiency improvements and economies of scale are foreseen for PEM in the future [31]. Moreover, advantages of PEM are that they can react faster on load differences, releasing the hydrogen at higher pressures and their installations have a smaller spatial footprint than Alkaline [31].

The LCOH produced by electrolysis are highly impacted by the electricity price. Thereby, also the efficiency, CAPEX, amount of load hours and scale play a considerable role in the LCOH. Figure 10 illustrates the role of electricity prices and the amount of load hours that the electrolyzer is operated on the hydrogen production costs. Higher utilization rates reduce the impact of the CAPEX on the hydrogen costs, but increase the impact of the relative costs paid for electricity [31]. In a future wher electricity prices are expected to become more volatile by the increased penetration of intermittent RES [37] and CAPEX of electrolyzers tend to decrease [38], the optimal amount of load hours for grid-connected electrolyzers tend to decrease. Furthermore, providing grid services, such as congestion management, can be used to increase the amount of load hours with relatively cheap electricity [39].

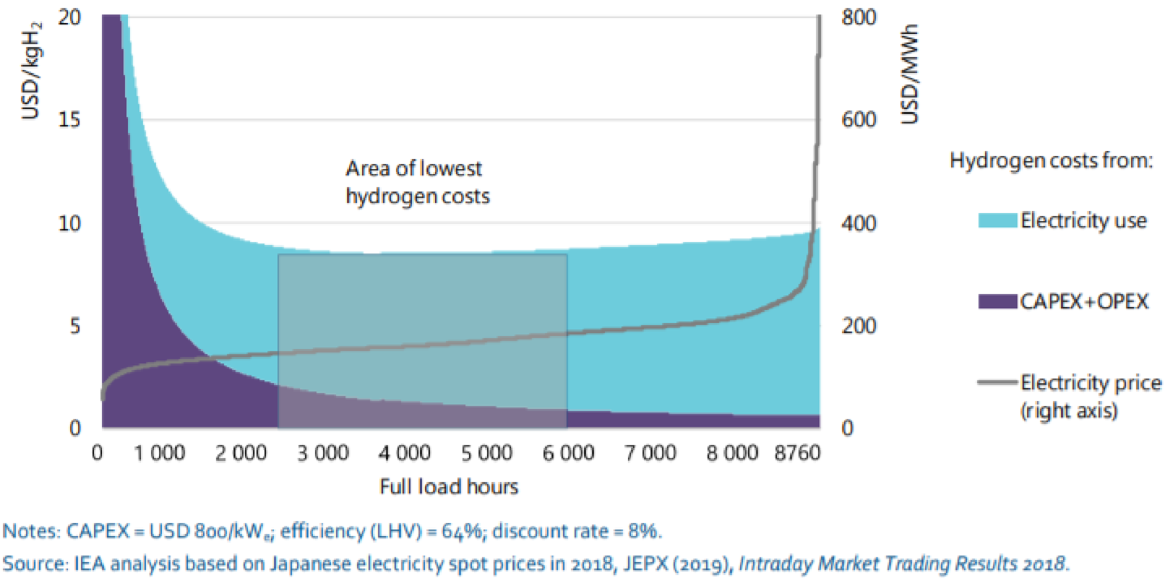


Figure 10 - Hydrogen costs by electrolysis with grid-connection [31], 1 USD/0.82EUR

For coupled RES-electrolyzer systems, which do not use grid electricity for hydrogen production, the LCOH are impacted by the scale of the electrolyzer compared to the RES capacity. The less RES capacity compared to electrolyzer capacity, the more the electrolyzer can be utilised and therefore the lower the LCOH, as illustrated in Figure 11. Moreover, strategies of combining solar and wind power as input for the electrolyzer are perceived to increase the utilization with 40-80% [40].

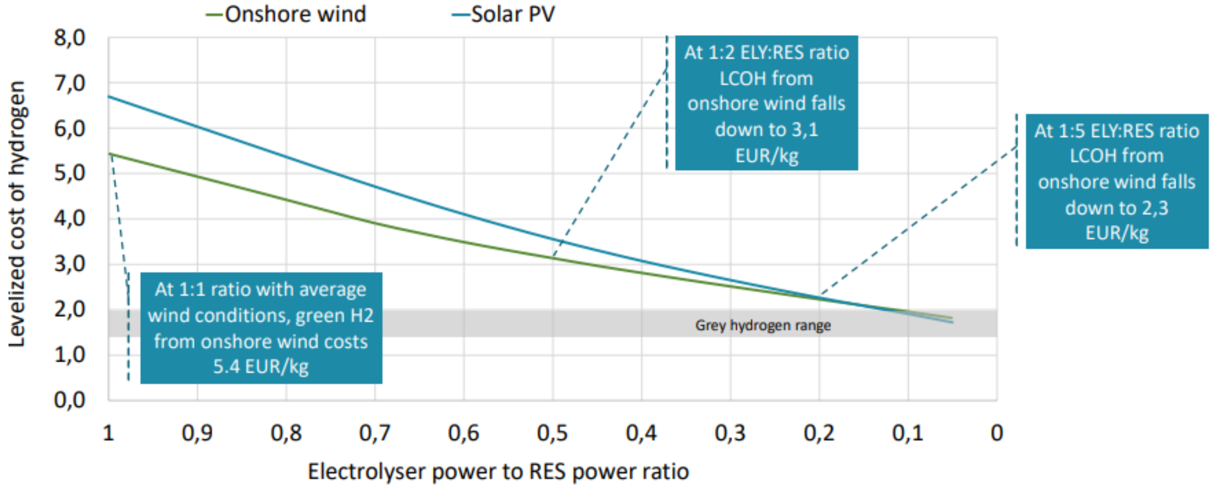
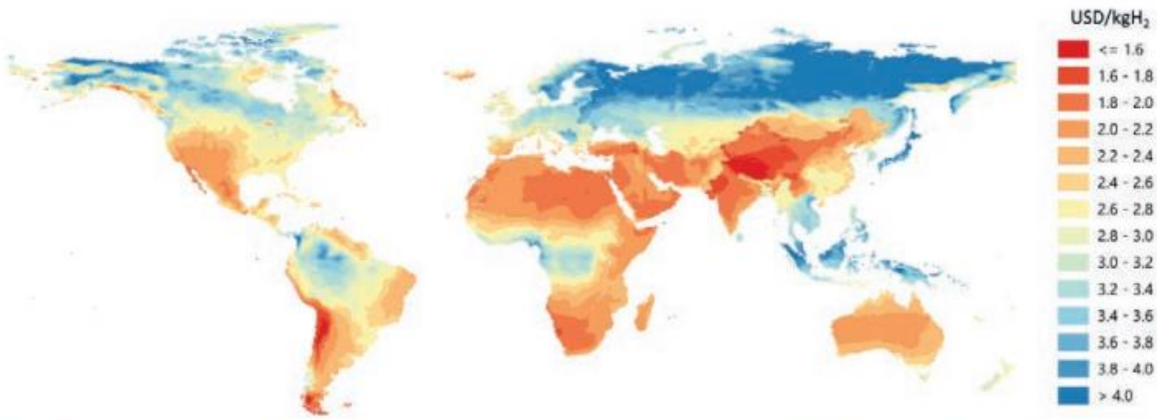


Figure 11 – The relation between RES capacity and the electrolyzer capacity is presented for onshore wind and solar energy, with the impact on the LCOH [41].

Lastly, the geographical aspect of hydrogen production by electrolysis is important to consider in respect to the LCOH. As the costs of renewables are highly determined by the availability of geographical aspects such as: high windspeeds, shallow waters, high solar radiation, and potential for hydroelectric plants. Figure 12 shows the potential for solar and onshore wind production in different regions, causing significant differences in hydrogen production costs [31]. These differences in production costs compared with the relative low transportation costs could be an incentive for international hydrogen chains in the future [42] [43].



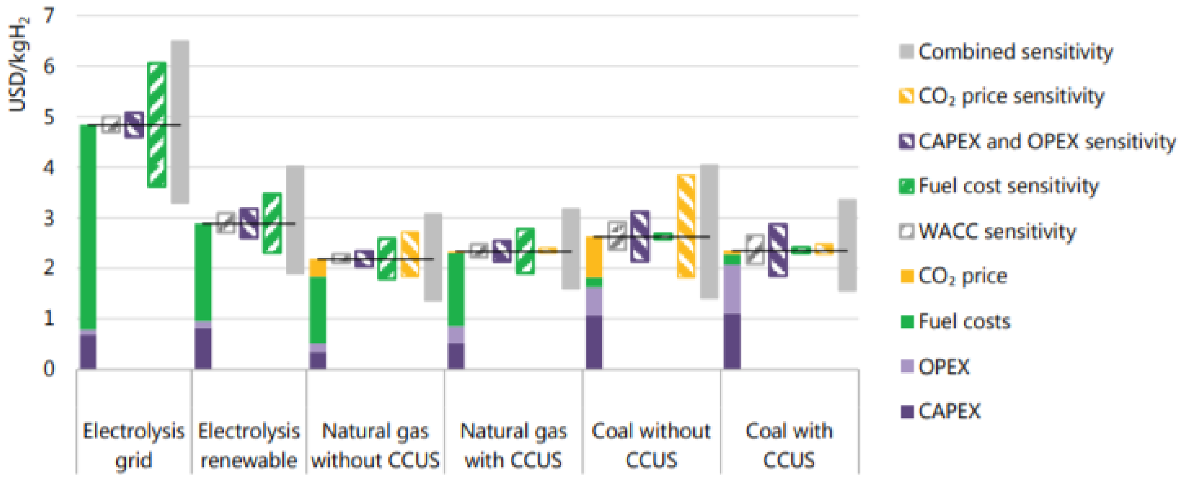
Notes: This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area. Electrolyser CAPEX = USD 450/kW$_e$, efficiency (LHV) = 74%; solar PV CAPEX and onshore wind CAPEX = between USD 400–1 000/kW and USD 900–2 500/kW depending on the region; discount rate = 8%.

Source: IEA analysis based on wind data from Rife et al. (2014), *NCAR Global Climate Four-Dimensional Data Assimilation (CFDDA) Hourly 40 km Reanalysis* and solar data from renewables.ninja (2019).

Figure 12 - Hydrogen production costs from hybrid solar and onshore wind systems in the long term [31], 1 USD/0.82EUR

4.1.5 Comparing the production technologies

The International Energy Agency made a comparison of the expected hydrogen production costs in 2030 via different pathways including their sensitivities (see Figure 13) [31]. It could be concluded that electrolysis and natural gas-based hydrogen production costs are mainly determined by its fuel costs. The main determinant in the competitiveness between these two pathways are the electricity compared to the natural gas prices that are paid by these production plants. Thereby, competitiveness of the natural gas pathway without CCUS compared to the other pathways also is mainly determined by CO_2 prices. On the contrary, the LOCH in the coal-based pathway is mainly CAPEX affected. The CO_2 price is more important here, as this pathway relatively has the most carbon emissions per produced kg of hydrogen. Without CCUS, natural gas-based hydrogen emits around 8.5 $kgCO_2/kgH_2$ while hard coal-based hydrogen emits around 20 $kgCO_2/kgH_2$. The emissions of electricity-based hydrogen mainly depend on how the electricity is produced: when renewable or nuclear generated electricity is used, the emissions are zero while gas fired generated electricity would cause 17.5 $kgCO_2/kgH_2$ and electricity mixes including coal-fired generated electricity even more.



Notes: WACC = weighted average cost of capital. Assumptions refer to Europe in 2030. Renewable electricity price = USD 40/MWh at 4 000 full load hours at best locations; sensitivity analysis based on +/-30% variation in CAPEX, OPEX and fuel costs; +/-3% change in default WACC of 8% and a variation in default CO_2 price of USD 40/tCO_2 to USD 0/tCO_2 and USD 100/tCO_2. More information on the underlying assumptions is available at www.iea.org/hydrogen2019.

Source: IEA 2019. All rights reserved.

Figure 13: Hydrogen production costs for different technology options, 2030 [31], 1 USD/0.82EUR

Besides the costs and emissions, production pathways differ in the purity of the hydrogen that is produced. SMR and ATR are technologies to produce syngas, including a mixture of multiple gaseous molecules (see Table 2). Generally, thereafter a Water Gas Shift (WGS) reaction is performed to converse more carbon monoxide into hydrogen and carbon dioxide [32], followed by a purification step done by Pressure Swing Adsorption (PSA, see 'Compression and purification of hydrogen'). The current PSAs are dimensioned based on the purity requirements of the other processes in the plants, which is generally >98_{mol}%. Electrolysis produces hydrogen with purities >99.99% after the hydrogen is dried by a Temperature Swing Adsorption (TSA) step [32].

Table 2: Overview of the difference in impurities of the hydrogen via different production technologies [32] [44]

Comp. (dry mol%)	SMR syngas	SMR after WGS	ATR syngas	ATR after WGS		Comp. (ppm)	PEM without TSA	Alkaline without TSA
H_2	63-66	70-80	63-66	72		H_2O	>100	>100[5]
CO	8-16	0.1-3	27-30	0.2-1.4		O_2	18-500	50
CO_2	7-14	15-25	5-6	27		CO_2	0.2-5.4	-
CH_4	3-8	3-6	0.3-1.4	0.2-2.4		Inert gases	Within the ISO 14867 standard	
N_2	0-3	0-0.2	0.7	0.7				

[5] Could contain K+ or Na+ ions

Ar	-	-	0.61	0.61			

4.2 Transportation

This section contains the main characteristics to consider when it comes to determination of hydrogen transport costs.

4.2.1 Trucks

Several studies have performed cost calculations for gaseous hydrogen transport by trucks. Table 3 provides an overview of the key aspects that were involved in those studies. All three studies in the table distinguish the costs for the truck itself and the trailer. Also, in Table 3, only tube trailers for gaseous hydrogen transport are included, but other trailers for liquid hydrogen or other hydrogen carriers can be used for transport of these molecules as well.

Table 3: Overview cost data for calculating the (gaseous) hydrogen transportation costs by trucks

	Main source	CAPEX[6]	Lifetime (years)	O&M[7]	Utilization	Driver wage	Average speed	Diesel demand[8]	Used sources
Truck	[45]	€151.000	4	*	75%	€23/h	55km/h	0.392	[46]
Truck	[47]	€148.000	5	6%	80%	€28.75/h	50km/h	0.392	[48] [49] [50]
Truck	[51]	€160.000	8	12%	22.8%	€35/h	50km/h	0.35	[52]
	Main source	CAPEX	Lifetime (years)	O&M	Utilization	Payload	Net capacity	Loading time	Used sources
Trailer	[45]	€100.000	6	*	75%	-	181 kg	2 hours	[46]
Trailer	[47]	€148.000	20	6%	80%	-	300 kg	1 hour	[48] [49] [50]
Trailer	[51]	€550.000	12	2%	22.8%	720 kg	670 kg	1.5 hour	[53] [54]

*0.0976 € km^{-1} maintenance expenses and 8.22 € d^{-1} general expenses for both truck and trailer.

The CAPEX of hydrogen transport by trucks contains the investment in trucks and tube trailers. The OPEX can be divided in fixed OPEX, such as maintenance, and the variable OPEX, including drivers' wages and fuel costs. The average driving speed and fuel consumption could differ from 35 km/h in urban streets to 70 km/h in rural areas, studies that do not assume a specific area generally use 50 km/h as an average driving speed [51]. Assumptions for CAPEX, lifetimes, utilization and capacities of trucks and trailers have significant impact on their costs and should be considered, given the differences seen in the studies. The capacities of the trailers highly depend on the pressure of the hydrogen that is transported. Yang & Ogden [47] assume pressures between 30 and 160 bars in their tube trailers, while Reuss [51] uses other tube trailers, which are more expensive but being able to carry more mass of hydrogen. Reddi et al. [55] states that also trailers are available being able to carry 1150 kg of gaseous hydrogen per trailer, but those trailers are very capital intensive (approx. 1 million USD). Besides the costs for trailers that can carry higher pressures and therefore more weight of hydrogen, the return pressure of tube trailers should be considered. When a tube trailer is dispensed at a delivery location, for example a hydrogen refueling station (HRS), the hydrogen will leave the trailer by the difference in pressure between the trailer and storage tank. When a 200-bar tube trailer fuels a HRS of around 50-80 bars, the trucks will drive back with around 90 bars return pressure, which is roughly half of the pressure required for hydrogen transport. The pressure of the transported hydrogen by the trailers, return pressure and compression capacity required at the point of delivery

[6] All costs are equalized to 2021 euros assuming a conversion factor of 0.82 US$/€ and historical CPI values
[7] O&M costs per year as percentage of the investment costs
[8] Litres of diesel per km

are essential in the optimization of the delivery operations [56], but those assumptions are not described in detail in the cost data shown in Table 3.

Transportation by trucks is characterized by relatively low minimal investment costs (i.e., the costs of one truck to transport tiny amounts of hydrogen), but the transport costs increase significantly when volumes and distances increase, since a lot more trucks, labor and fuel is needed to transport the hydrogen [52]. Secondly, trucks are flexible compared to pipelines, barges, or rail, in terms that one truck can be used at multiple locations, and those locations are barely restricted to availability of infrastructure due to the broad road network. Furthermore, trucks are fast compared to barge and rail transport.

4.2.2 Pipelines

Gaseous hydrogen transport by pipelines can be divided in three main categories: pure hydrogen transport in dedicated hydrogen pipelines, pure hydrogen transport in re-used (mostly natural gas) pipelines or hydrogen blended with natural gas in the natural gas grid. In this section will be focused on the first two options.

The investment costs of new pipelines are determined by its length, diameter and rights of way and they mainly include installation costs (e.g., engineering, civil work, project management, rights of way or location specific costs), material costs and miscellaneous costs (e.g., surveying, supervision, contingency, allowance, overhead and filling fee costs) [47] [57] [58] [59]. Moreover, compression costs should be considered for hydrogen transport by pipelines. An optimization should be made between the costs of sizing the pipeline diameter and the compression costs, since higher pressures of the gas increase the transport capacity of a similar diameter sized pipeline but include more costs for compression. The main aspects that should be considered are the throughput (i.e., flow rate) of hydrogen that can be transported by a pipeline with a specific diameter and the pressure drop of the hydrogen during transport. In Appendix A – Formula sheet, formulas for the pressure drop and compression requirements are given. Operational decisions about the maximum speed of the gas (velocity) through the pipelines and pressure regimes should be made, considering the technical limitations that the velocity should not exceed 15-20 m/s [60] [58] and the pressure limit of hydrogen within pipelines is expected to be 100 bars [58].

Several studies analysed databases with investment costs of new pipeline projects to derive general functions that could be used for cost estimations. Table 4 provides an overview of several cost functions and the main characteristics that should be considered.

Table 4: Overview studies that provide cost functions for hydrogen pipelines

Study		Cost equation	Variables	Notes
Parker [57]		$(674d^2 + 11754d + 234085)l + 405000$	$d = diameter\ (inches)$ $l = lenght\ (miles)$ $Costs\ in\ dollars$	Includes diverse types of pipelines (NG (Natural Gas), oil, petroleum) in the US
Yang & Ogden [47]		$1869d^2 + 300000$	$d = diameter\ (inches)$ $Costs\ in\ dollars/km$	Based on US studies
Krieg [58]	Min.	$0{,}0015d^2 + 0{,}72d + 213{,}9$	$d = diameter\ (mm)$ $Costs\ in\ euros/m$	Based on small pipelines (D=100-600mm) in Germany, including costs for compressors
	Avg	$0{,}0022d^2 + 0{,}86d + 247{,}5$		
	Max.	$0{,}004d^2 + 0{,}6d + 329$		
ACER [59] & ECN [61]		$1021{,}7d^2 - 20393d + 642720$	$d = diameter\ (inches)$ $Costs\ in\ euros/km$	Most pipelines analyzed were relatively large (16-57 inch), no distinction between NG and H2 pipelines

A lot of difference between the investment costs is seen when the cost functions are compared. Figure 14 shows the differences and includes two studies that provide cost estimations for new hydrogen pipelines with a given length and diameter [61] [62]. The difference in costs can partially be explained by differences in geography, size, and assumptions between the studies. But in general, studies mention that pipeline construction costs differ between projects due to project specific occurrences (e.g., delay) [57] and the specific location of the pipelines (e.g., rural, urban, nature, offshore etc.) [47] [62] [58]. In a study investigating hydrogen pipeline costs in Germany, the annual O&M costs were expected to be 4% of the CAPEX and new pipelines were assumed to have a lifetime of at least 40 years [58].

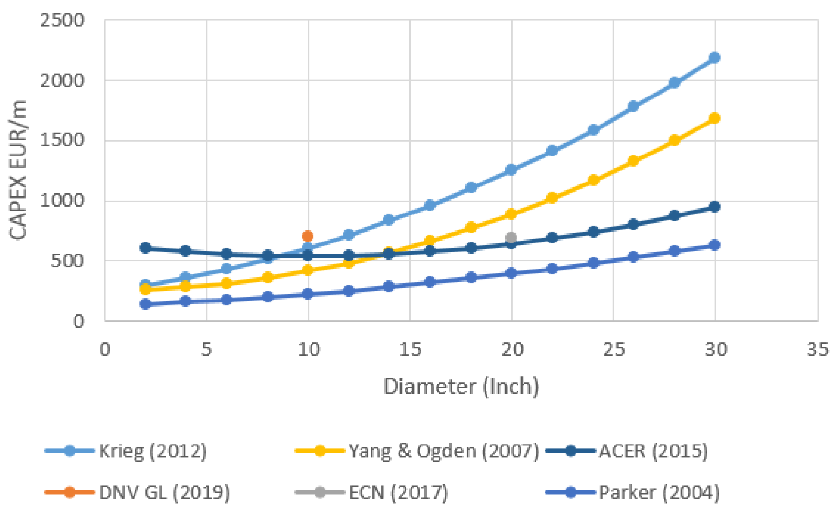


Figure 14 – Comparison of pipeline cost calculation functions in the literature

The second option is to reuse existing natural gas pipelines for dedicated hydrogen transport. Cerniauskas et al. [63] evaluated the costs of four re-use strategies: no modifications, use coating, use inhibitors (O_2, CO or SO_2) or pipe-in-pipe. Only using O_2 as inhibitor was cost-effective until a certain transport volume compared to new dedicated pipelines and the use without modifications could reduce 20% to 60% of the countrywide costs compared to new hydrogen pipelines [63]. Another strategy, that was evaluated as effective by the H21 project, was to identify the weak spots within the pipeline system and only replace those parts that were assessed to be 'weak' and involving more attention [64].

Cerniauskas et al. [63] provided three functions (see Table 5Table) to calculate the costs of reusing natural gas pipelines without modifications based on the diameter size and length of the pipeline, including installation of new compressors and gas pressure regulation stations and higher expected OPEX to deal degradation of materials.

Table 5: Cost functions of reusing natural gas pipelines for hydrogen transport without major modifications in Germany [63]

	Unit	Cost function (d in mm)
CAPEX	€/m/a	$(1{,}67 \times 10^{-4}) \cdot d^2 + (-2 \times 10^{-13}) \cdot d + (-7{,}8 \times 10^{-10})$
OPEX fixed	€/m/a	$(1{,}1 \times 10^{-4}) \cdot d^2 + (-1{,}6 \times 10^{-2}) \cdot d + 2$
OPEX variable	€/m/a	$(1 \times 10^{-4}) \cdot d^2 + (-1{,}5 \times 10^{-12}) \cdot d + (-2{,}9 \times 10^{-10})$

Studies of the European gas TSO's investigated the costs of the development of a 'European Hydrogen Backbone', including the reuse of existing natural gas infrastructure [65] [66]. Also, here they stated compressor and pipeline costs should be optimized, in the case of reuse sometimes relatively large pipelines are available for small volumes, which means that compression is barely required [65]. Another optimization that was mentioned is to use an inner coating in cases where relatively large capacities are required and small pipes are available, to be able to transport the hydrogen at higher pressures [65]. These studies expect that in the future a European Hydrogen Backbone would be able to transport hydrogen against the relatively low costs of 0.09-0.21 EU/kg/1000km [65] [66]. Some of the most relevant cost assumptions are shown in Figure 15.

Cost parameter				Unit	Low	Medium	High
Pipeline Capex, new	Small	< 700 mm	< 28 inch	M€/km	1.4	1.5	1.8
	Medium	700-950 mm	28-37 inch		2.0	2.2	2.7
	Large	> 950 mm	> 37 inch		2.5	2.8	3.4
Pipeline Capex, repurposed	Small	< 700 mm	< 28 inch		0.2	0.3	0.5
	Medium	700-950 mm	28-37 inch		0.2	0.4	0.5
	Large	> 950 mm	> 37 inch		0.3	0.5	0.6
Compressor station Capex				M€/MW$_e$	2.2	3.4	6.7
Electricity price				€/MWh	40	50	90
Depreciation period pipelines				Years		30-55	
Depreciation period compressors						15-33	
Weighted average cost of capital				%		5-7%	
Operating & maintenance costs (excluding electricity)				€/year as a % of Capex		0.8-1.7%	

Figure 15 – Cost input ranges used in the extended European Hydrogen Backbone study [66]

Also, for reuse of natural gas pipelines, costs depend a lot on location specific characteristics, such as the materials used in the pipelines (as they may constraint if the pipeline could be reused at all, or determine the costs for degradation of the materials) and the size of available infrastructure compared to the transport volumes [63] [65] [66].

Compared with other means of transport, pipelines' levelized transportation costs are characterized by relatively large share of capital costs which are less affected by increase of volume but large affected by the increase of distance [52]. As pipelines have a dedicated location and a long lifetime, their suitability increases when it is sure that a lot of volumes are expected to be transported for a longer timeframe. Lastly, it should be noted that pipelines have a storage function as well, when used for gas transport, commonly referred to as 'line packing'.

4.2.3 Ships, barges, and trains

International shipping, inland barges and trains can also be considered as means to transport hydrogen, although usually not gaseous hydrogen but liquid or other hydrogen carriers are assumed to make these means of transport suitable [52]. The advantage is that these means can transport larger volumes than trucks, and have a relatively minor increase of transport costs per increasing distance than pipelines [52]. These means of transport are geographically highly dependent on the availability of water, harbors, and rails, otherwise they must be combined with other means of transport (e.g., trucks) to connect supply and demand locations. However, in general a lot of industrial companies are already located near waters or rail connections due to their strategic supply value. Additionally, it should be considered that these transport modes have fixed transit times and containers are required to arrive a certain time before those transit times already (mostly 1 or 2 days), therefore a disadvantage of these means of transport are that they are slow in terms of the throughput time. Thereby, ships are characterized by a slow speed of 16 km/h [52].

4.2.4 Comparing means of transport

There are numerous studies comparing the transportation costs of hydrogen via different means of transport. Although different cost assumptions are used and therefore the results in actual costs might differ, comparable insights could be retrieved from the literature about when which means of transport would be most applicable. The most relevant variables of assessing the transport costs are the volumes or mass flow that must be transported and the distance [31] [47] [52] [67].

For short and medium distances (0-800km), the comparison between pipelines and trucks are usually made to transport hydrogen. DNV GL provided indications for multiple types of hydrogen transport: gaseous trailers, liquified trailers and pipelines (see Figure 16). However, those costs should be taken with great caution, as they are really an indication of transport costs for volumes and distances where those means of transport are typically used. The actual impact of those factors will be described more carefully below.

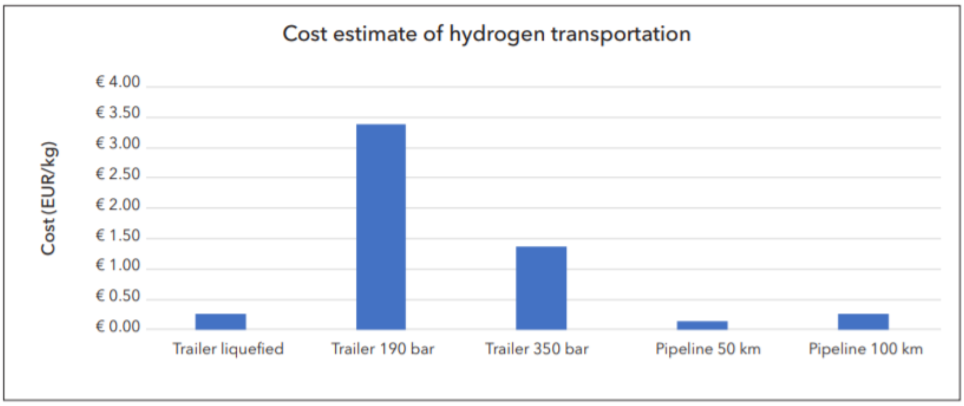


Figure 16 – Overview of indicative transport costs of hydrogen via various means of transport [62]

For the smallest distances and volumes, gaseous hydrogen transport by trucks seems to be most cost effective [47] [52], due to their relative low capital investment costs. The larger the transport volumes, the more suitable pipeline transport becomes due to its relatively low additional costs to increase the diameter compared to the extra costs for trucks, labor and fuel that is required for truck transport when the volumes increase [47] [52]. However, when the distance increases, pipelines do not have these advantage over trucks, due to the high capital costs of increasing the length of the pipeline [47] [52]. For increasing distance, it is especially beneficial that more hydrogen can be carried by the same truck, since then less trucks, labor and fuel are required to transport the same volume of hydrogen [47] [52]. Therefore, the use of carriers becomes more favorable, because at some point the benefits of decreasing transport costs are higher than the increased costs and losses for conversion [47] [52]. Usually, carriers in the form of liquid hydrogen (LH2), Liquid Organic Hydrogen carriers (LOHC), ammonia, methanol, metallic hydrides, or formic acid are suggested. Also, for increased distances it might be more beneficial to use barges and trains (mostly transporting the hydrogen via carriers) due to their lower transport costs per km compared to trucks [52], when there is less flexibility in transport routes required. For exceedingly long distances, pipelines are still the most cost-efficient means of transport, if the volumes are big enough [47] [52]. Figure 17 illustrates the influence of the distance and volumes on the costs per transported kg of hydrogen, including the most efficient means of transport.

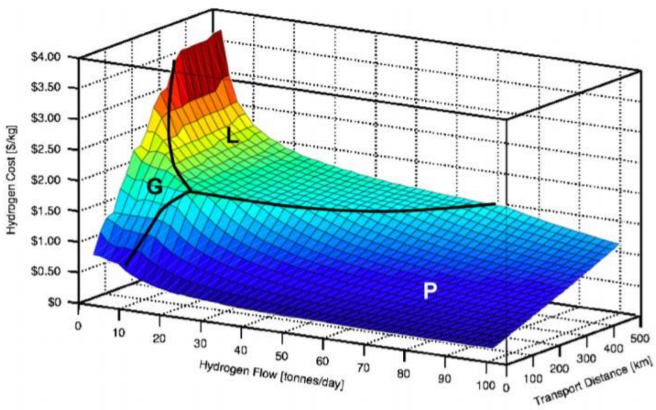


Figure 17 – Hydrogen transport cost per kg, based on volumes and distance [47] (G= gaseous H_2 by truck, L= liquid H_2 by truck, P= gaseous H_2 by pipeline), 1 USD/0.82EUR

For long distances (800-10,000km), mostly a similar comparison is made between shipping using carriers or use of pipelines. When the distance of transport increases, the advantage of using carriers increases, since the reduced transport costs weight out the conversion costs increasingly. Also, using ships instead of pipelines becomes more attractive when the distance increases, as the additional costs for ships (e.g., more fuel) are minor compared to pipelines (see Figure 18). The figure does not show the effect of volumes. Pipelines are more favorable in levelized hydrogen transport costs when the volumes increase, as the economies of scale are larger for pipes (material costs of increased diameter) than shipping (more ships, fuel, terminals, and conversion capacity required).

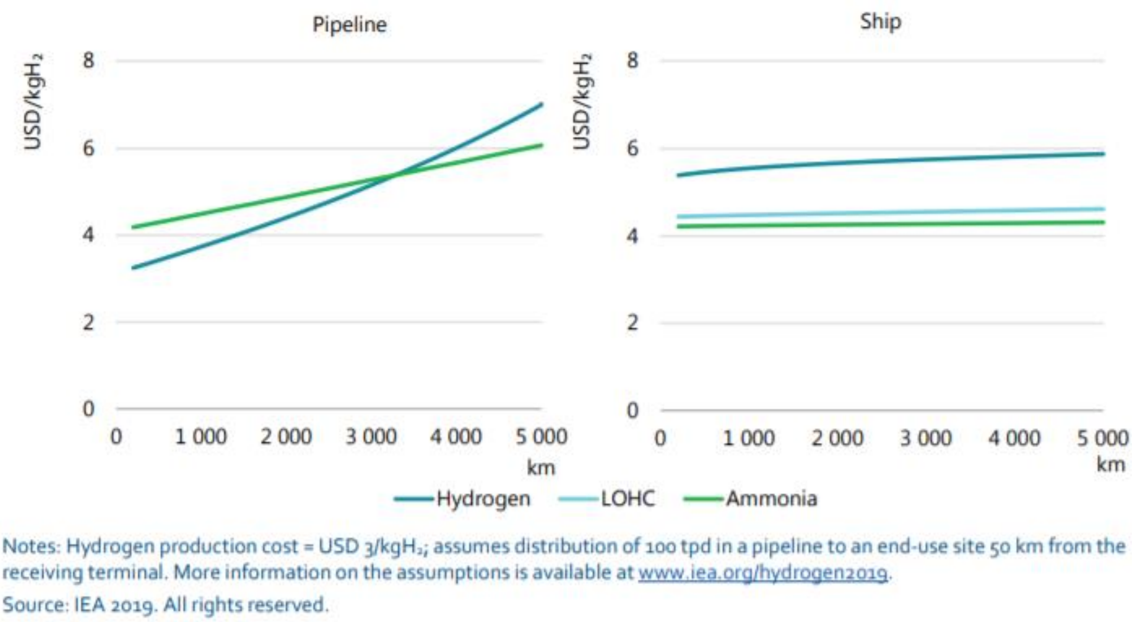


Figure 18: Full costs of hydrogen delivery (transport and conversion) at industrial scale and qualities for 2030 [31], 1 USD/0.82EUR

4.2.5 Compression and purification

Hydrogen compression

To transport or store the gaseous hydrogen more compactly, to deal with pressure drop in pipelines or to reach a pre-defined pressure for an end-application, hydrogen needs to be compressed. Mostly, reciprocating (i.e., piston) and centrifugal (i.e., turbo) compressors are used to compress gases. In general, it is perceived that centrifugal compressors are more suitable to handle larger volumes and reciprocating compressors for smaller volumes, due to their higher efficiency and flexibility in operation. In an assessment of the Dutch gas infrastructure, it was concluded that natural gas compressors mostly cannot be reused for hydrogen compression [60]. In Table 6Table , an overview of different hydrogen compression technologies is shown.

Table 6: Overview of hydrogen compression technologies [68]

	Scale/m^3h^{-1}	Maximum discharge pressure	Technology readiness (for H_2 application)	Vendors (exemplified)	Advantages
Turbo compressor	>1000 for large scale	< 5 Mpa	In development, references for selected applications such as H_2 compression for pipeline exist	Various but limited number for hydrogen compression	Good availability and lower maintenance, high volume flow
Ionic compressor	750 designed for HRS	100 Mpa	Commercial but limited number of installations so far	Linde	High efficiency, no contamination
Metal hydride	1-12 very small	25 Mpa	In development, references for selected applications	Hystorsys	Thermally powered, no contamination, no moving parts (good availability and maintenance)

Electrochemical	5-280 usually small	95 Mpa	In development, used on lab scale	Hyet Hydrogen Xergy, Skyre (recycler). In development: Bosch, Fraunhofer	No moving parts (good availability and maintenance) lower OPEX than mechanical comopressors
Screw	200-100000 medium – large	5.5 Mpa	Commercial, special applications but dry runner required for H_2 (uncommon)	MAN Turbomachinery, KobelCo, Adicomp	Good availability and lower maintenance, Δp independent of mole weight
Membrane	1-4000 small – medium	300 Mpa	Commercial, standard for H_2, small-scale	Howden, PDC Machines, Ventos, Neumann Esser, Sera ComPress	Good availability, Δp independent of mole weight, no contamination
Piston (dry)	10-115000 small – large	130 Mpa	Commercial, standard for H_2	Haskel, LMF, SLAD, Neumann Esser, Maximator, Resato, Sera ComPress, Sauer Compressors	Good availability, Δp independent of mole weight

Compression costs can be divided in CAPEX, fixed annual OPEX and electricity costs. The compression capacity depends on the flow rate and difference between inlet and outlet pressure and can be calculated by the formula provided by Castello et al. [69] and Andre et al. [70] that is shown in Appendix A – Formula sheet. Based on the required compression power, the CAPEX and fixed annual OPEX can be calculated. The electricity demand and costs of the compression could be based on the amount of full load hours, the compressor efficiency, and the electricity costs [43]. Parameters that are used to calculate these actual costs differ through the literature, in Table 7 the ranges that are used in the literature are shown.

Table 7: Overview difference in assumption in literature for hydrogen compression cost parameters

Compressor costs	Assumptions	Sources
CAPEX	1750 – 3900 EUR/kW	[70], [59], [54], [71], [72]
OPEX (annual)	3 – 8%	[73], [70], [74], [62], [54], [75]
Efficiency	80 – 91%	[70], [71], [72]
Lifetime (years)	15 – 25	[70], [74], [62], [54], [75]

Hydrogen purification

The hydrogen purity is the amount of hydrogen in $_{mol}\%$ that exists in the gas stream. In all stages of the value chain impurities could occur, due to all kind of infiltrations of other types of gases. But Polman et al. [32] state that there are two major places in the hydrogen value chain where purification could be applied most effectively:

1. Right after the production stage.
    - Same purification specifications can be applied downstream the chain.
    - Besides the higher purity, hydrogen will be supplied at higher pressure.
    - When hydrogen is produced at chemical sites, rest products can be re-purposed more easily.
2. At the location of end-use.
    - Especially for fuel cell high purities are required, which cannot be delivered by the grid at all, then purification at the end location cannot be overcome.
    - The level purification can be set on the purity requirements of the end-user, so therefore no redundant purification is done.
    - The pressure at local points in the grid can be low, which implies that at these points also extra compression capacity is required to be able to purify hydrogen.

Pressure Swing Adsorption (PSA) is currently the most widely applied technology to purify hydrogen, this step is also included in the existing hydrogen production plants using fossil resources (e.g., in combination with SMR, ATR, POX). Polman et al. [32] describes the major categories of hydrogen purification technologies and their technical characteristics are summarized in Table .

- Pressure Swing Adsorption: these systems make use of adsorbents and use the difference in adsorption characteristics of the gases to separate them.
- Temperature Swing Adsorption (TSA): makes uses of cooling and heating and a catalytic deoxidizer, which is mostly used in hydrogen produced by electrolysis, to separate the hydrogen from the oxygen and water.
- Membranes: those systems use the difference in permeability of the gases to separate them by a membrane. Polymer and palladium membranes are currently commercially available.
- Cryogenic: these technologies use the difference in boiling point to separate them.
- Electrochemical: an electrochemical cell, consisting of selective catalytic splitting and recombination of hydrogen molecules to separate the hydrogen.
- Methanation: CO and CO_2 could be extracted from hydrogen by methanation, producing methane, pure hydrogen, and water.

Table 8: Overview technical characteristics of purification technologies [32], [76], [77], [78], [79], [80].

Feature	PSA/TSA	Membrane	Cryogenic	Methanation	Electro-chemical[9]
H_2 purity	98 – 99.9999%	90 – 98%	95-99%	>99%	>99.9%
H_2 recovery	75 – 92%	85 – 95%	90 – 98%	>95%	>90-100%
Min. H_2 content	>40%	>25 – 50%	>10%	<25%	>8 – 100%
Typical capacity [H_2 Nm^3/hr.]	<400.000	<50.000	10.000 – 75.000		1 – 1.000
Operating pressure [bar]	10 – 40	20 – 200	20 – 50	<100	Very high pressure (up to 600 bar)
Operating temperature [°C]	Room temperature	0 – 100	-180	250 – 750	20 – 80
Pre-treatment	No	Minimal, H_2S removal	CO_2 and H_2O removal	Sulphur removal	Sulphur, CO, CO_2, NH_3 removal
Start-up time	Minutes	Minutes	Hours	Hours	Minutes/seconds
Availability	Traditional method	Traditional method	Traditional method	Traditional method	Early stage of commercialization
Investment costs	Medium	Low	Higher	Medium	High, but potential to reduce
Scale economics	Moderate	Modular	Good	Modular	Modular
Reliability	High	High	Average	High	High, no moving parts
Typical Impurities	CO_2, H_2O, CH_4 (HCs), CO	Hydrocarbons, CO	Hydrocarbons	CO_2, CO, CH_4	H_2O
Comments	The recovery is relatively low as hydrogen is lost in the purging step	He, CO_2 and H_2O may also permeate the membrane	Pre-purification step necessary to remove CO_2, H_2S and water	Sulphur-containing compounds poison the catalyst	Sulphur-containing compounds poison the electro-catalysts

[9] As part of the MEMPHYS project, it was found that electro-chemical systems could combine compression and purification of hydrogen [141]

The costs of purification are hard to estimate because for each technology they may depend on several situation specific characteristics and synergies [32]. PSA is no exception. Its costs depend largely on the gas flow mixtures present in the hydrogen containing inlet flow [81]. Moreover, in general the hydrogen recovery rate (the percentage of the total amount of hydrogen entering the process, that is recovered at the desired purity) decreases when the required purity increases [82]. In Appendix A – Formula sheet, formulas retrieved from Marcoberardino et al. [81] are given to calculate the relation between purity and recovery for a certain gas mixture for PSA.

Finally, for economic calculations formulas to estimate the CAPEX of PSA's retrieved from Marcoberardino et al. [81] and the NREL [80] are presented in Appendix A – Formula sheet. The electricity use of PSAs can be calculated by the formula defined by Wu et al. [83]. According to Cerniouskas et al. [63] 2.46 kWh/kg_{H2} would be a good estimation. Furthermore, fixed annual O&M costs can be estimated as 4% of the PSA investment costs [63] and PSA units have a lifetime of 15-20 years [63] [83].

4.3 Storage

4.3.1 Tanks

Gaseous hydrogen storage in tanks (e.g., pressure vessels) are used for multiple applications and therefore exist in sizes from small bottles until massive storage tanks. Often, pressure vessels are distinguished by four types, and since 2010 some companies speak about a type V pressure vessel [84] [85]:

- Type I: pressure vessels made of metals like carbon steel and low alloy steel.
- Type II: pressure vessels consisting of thick load-bearing metal liners.
- Type III: pressure vessels consisting of metal liners wrapped with a fiber resin composite.
- Type IV: pressure vessels with non-metal/polymer liners, or in some cases an ultra-thin metal liner that is fully wrapped with a fiber resin composite.
- Type V: linerless fully composite pressure vessels based on a fiber-reinforced shell.

Less metal is used in the walls of the tanks, whereby the weight of the vessels decreases. This is especially important for transport and applications in small and heavy weight vehicles. For example, type I storage vessels can handle pressures upon 500 bars, but this requires thick walls of carbon steel or low alloy steel [86]. Type IV pressure vessels can handle storage pressures up to 1000 bars and are the lighter [86], but the prices of these tanks are higher [87]. In this review the focus will be on stationary vessels that are used for low-cost hydrogen storage purposes, for example at fueling stations or industrial sites. Type I and II vessels are considered more economically viable for this purpose than the type III and IV vessels [88] [89] [90].

Overall, some optimizations can be made for stationary storage in hydrogen pressure vessels [84]:

- The higher the pressure the less space for storage required.
- The higher the pressure the smaller tank is required, but these thanks require thicker walls and other materials.
- The higher the pressure, the more compression costs should be considered.

It was estimated in 2013 that the investment costs of storage tanks for low (160 bar), medium (430 bar) and high (860 bar) pressured hydrogen are $600/kg, $1,100/kg, and $1,450/kg respectively [84]. Therefore, storage at lower pressures seems favorable. Of course, the desired storage pressure is also hugely depended on specific requirements of end-users.

To overcome disadvantages (e.g., embrittlement risks, leakage, difficult to monitor online) of seamless hydrogen storage vessels made from strength seamless tubes, multifunctional layered stationary hydrogen storage vessels were developed [91]. Another advantage is that these vessels can be operated on high pressure without restrictions on size. Indicative costs for storing hydrogen in these vessels at 160, 430 and 860 bar are $350/kg, $450/kg and $600/kg respectively [91].

Table 9 summarizes cost data and technical characteristics of gaseous hydrogen storage tanks from several studies. It should be noted that hydrogen storage in pressure vessels is only perceived applicable for small quantities. When larger quantities should be stored, liquid storage or alternative carriers become more relevant, or underground gaseous hydrogen storage could be an option.

Table 9: Overview of storage cost assumptions for hydrogen pressure vessels

Source(s)	Capacity	Pressure (bar)	CAPEX	OPEX	Lifetime	Hydrogen losses	Application
[84] [51]	Per 1 kg[10]	15-250	500 EUR/kg	2%	20 years	0%	HRS
[62]	10 GJ	700	7400 EUR/GJ	0%	-	0%	Stationary
[92]	89 – 616 kg	172	493 – 1134 EUR/kg	-	-	-	HRS
[93] [94]	290 kg	20-50	2500 EUR/GJ	-	20 years	-	Large scale
[91]	-	160	350 EUR/kg	-	-	-	Stationary
Invalid source specified.	100 - 1000 kg	875	756 EUR/kg	-	30 years	50 kg/year	Stationary

4.3.2 Underground storage

In some geological areas, large-scale underground storage of hydrogen is possible due to the availability of empty salt caverns, aquafers, and depleted gas fields. Figure 19 represents how hydrogen is stored underground geologically in salt caverns or depleted gas fields.

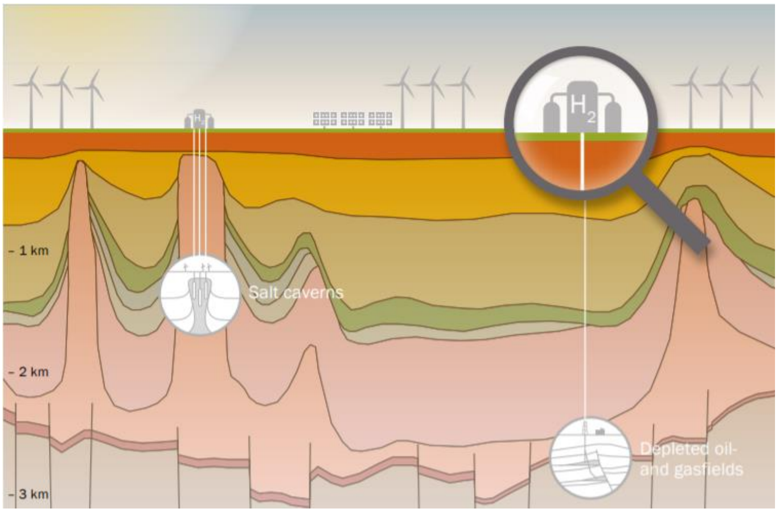


Figure 19: Geological representation of underground hydrogen storage in salt caverns and depleted gas fields

When gaseous hydrogen is stored into salt caverns, the hydrogen is compressed in a range between 60 – 250 bars [51] [62] [95] and temperatures of 15-40°C (Cooling could be required) [95]. When there are multiple caverns, compression capacity can be shared leading to economies of scale, however, the maximum injection rate also depends on the compression capacity. After compression, the hydrogen is injected more than 1000 meters underground in a salt cavern, which was created by pumping the

[10] CAPEX in costs per kg, with no economies of scale assumed (scale factor=1)

dissolved salt in water out of the bottom [96]. Salt caverns could differ in size of 100,000 m^3 until millions of m^3, but for energy storage they generally not exceed 1,000,000 m^3 [95]. At "Zuidwending" the salt caverns have sizes of around 600,000 m^3, including four empty caverns which could be used for hydrogen storage [95]. According to Gasunie they should be able to store more than 6,500 tonnes of hydrogen each with injection and production rates of around 10 tons per hour which could be increased to 40 tons per hour [97]. During extraction, drying of the hydrogen is required and potentially purification. It is expected that storage in salt caverns does barely impact the quality of the stored hydrogen, 99% purity levels can be preserved without significant cleaning [95]. For higher purity levels this is not specifically stated. Table 10 shows an overview of economic assumptions made in studies for calculation of storage costs of hydrogen in salt caverns.

Table 10: Overview of economic assumptions for underground hydrogen storage in salt caverns

Source(s)	Capacity	Pressure (bar)	CAPEX	OPEX	Lifetime	Hydrogen losses	Cycles per year
[51]	500,000 m^3	60 – 150	€81,000,000	2%	30 years	0%	-
[62]	5 PJ	250 bars	180 EUR/GJ	0,11 (€/GJ/yr.)	-	0.5%[11]	9 (6-12)
[93] [94]	500.000 m^3 / 0.5 PJ	60-180	€107,000,000	-	30 years	-	-

The main differences between underground storage in salt caverns and depleted gas fields or aquifers is that usually in depleted gas fields and aquifers larger volumes of gas can be stored, although this depends on the geological size of these cavities [62]. Moreover, storage in depleted gas fields and aquifers (TRL 3) have lower TRL than storage in salt caverns (TRL 7) and it is expected that more purity is of the hydrogen is lost in depleted gas fields, resulting in extra purification capacities [95].

4.3.3 Comparing storage options

Besides the options for gaseous hydrogen storage, unlike transportation, hydrogen could also be stored in liquid state or conversed to other hydrogen carriers (e.g., ammonia, LOHC or solids). Amos et al. [52] describe characteristics that could determine the best suitable hydrogen storage option for a specific situation: the application (is a certain carrier used as end-use or a typical pressure demanded?), the combination with the hydrogen delivery method, the quantity of hydrogen, the storage period, what forms of energy are available (e.g., electricity, waste heat etc.), geological characteristics for storage, future expansion needs, maintenance requirements and capital costs.

Comparing the different storage options, pressurized hydrogen storage in tanks is characterized by relatively large costs and low energy density. They are not suitable to store large volumes over longer times but have the advantage that they can be placed decentralized without geological considerations and could be customized on the required pressure and purity level of applications. Underground hydrogen storage has the advantages that large storage volumes can be stored for longer time frames, with minor increase of storage costs compared to other methods. Electricity is mainly used for compression of injected hydrogen, and therefore expected to match with the generation pattern of RES (as electrolyzer operation also is expected to depend on availability and costs of electricity). Therefore, underground storage has a large potential to deal with seasonality [51], disadvantages are that geological characteristics should be available and large volumes and investment costs are required. Liquid hydrogen does not need these volumes and geological requirements and has higher energy density than gaseous storage. Therefore, it is cheaper to store, but extra costs for liquification

[11] Percentage of hydrogen lost during every roundtrip/cycle

(and minimal costs for evaporation) should be considered. Moreover, hydrogen boils-off when stored in liquid form, therefore hydrogen losses increase when the average storage time increases, making this storage means less attractive than underground storage or LOHC storage to store hydrogen for longer periods [51]. Thereby, electricity is used continuously to cool the storage tank. LOHC are perceived as cost effective method to store small and medium volumes (i.e., not enough volume to invest in an underground cavern) of hydrogen over a longer time [51]. However, a disadvantage is that due to the heat required for dehydrogenation (separating the hydrogen from the carrier), the climate impact is higher when natural gas is used or that the costs increase significantly when the heat is provided by renewable hydrogen [98]. Other options, such as storing hydrogen in ammonia, metal hydrides of formic acid could be considered as well, expanding the spectrum of advantages and disadvantages. Finally, storage of hydrogen in pipelines could be provided when investments are made in larger pipeline diameters to avoid the need of additional storage [52]. Large natural gas pipelines could be re-used for the storage of small hydrogen volumes, having enough over-capacity to avoid additional storage or parts of the natural gas grids that are not used anymore for transport at all.

4.4 End-use

In this chapter, main end-use characteristics of hydrogen value chains are discussed, that typify hydrogen applications in several sectors. The main differences in hydrogen pressure, purity, demand profiles, demand (de-)centralization and the difference in willingness-to-pay of several sectors due to differences in (renewable and/or low carbon) alternatives. The considered sectors with existing consumption, or potential future consumption, of hydrogen are industry, mobility, built environment and electricity generation (storage).

4.4.1 Industrial use of hydrogen for heating or feedstock

Industry can be divided in two subcategories: hydrogen used as feedstock and hydrogen used for (low, medium, and high temperature) heating. Characteristics of (potential) industrial hydrogen use could be very process specific. Therefore, only general aspects are discussed.

4.4.1.1 Hydrogen as industrial feedstock

Demand for hydrogen as feedstock is mainly used for methanol (e.g., chemicals, fuels etc.), ammonia (e.g., fertilizers, plastics, pharmaceuticals etc.) and refineries (e.g., steel refinery). Demand for industrial feedstock in the Netherlands is characterized by large volumes and distributed over five large industrial clusters, located in Delfzijl, Ijmuiden, Rotterdam, Chemelot and Zeeland. Neighboring countries Germany and Belgium host chemical centers with potential hydrogen uptake as well, for which Dutch H_2 infrastructure could function as a corridor. The demand pattern is generally stable, to utilize the large installations and plants as much as possible. As the hydrogen is used as feedstock, specific purities are required per process (i.e., in general no blends with natural gas are possible). The purity grade for industrial processes is perceived to be from 90% to >99.95% [99]. For methanol synthesis, hydrogen should be compressed towards 50-150 bars, dependent on the reactor that is used [100]. In refineries, multiple processes could be used dependent on the input fuels used and the required output products. The most widely used cracking method using hydrogen is called hydrocracking, other examples processes in refineries that use hydrogen are hydrotreaters, isomerization plants, catalytic reformers and Fischer-Tropsch processes. The characteristics of the required hydrogen differ al lot for these processes. Mostly, waste streams involving hydrogen can be re-used in other processes within the refinery plant. For ammonia production with the Haber-Bosch process, hydrogen with a purity of 99.99% is required. Generally, the pure hydrogen will be mixed with the pure nitrogen and this mixture will be compressed towards 200 bars before the ammonia synthesis loop is started.

As these products require hydrogen by definition [101] there are technically no substitutes or alternatives for hydrogen use as a feedstock. Therefore, the only way to decarbonize these processes is to decarbonize the hydrogen production or avoid the need to apply the process at all using other type of end-products (e.g., no fertilizers or synthetic fuels).

4.4.1.2 Hydrogen as a source for medium or high heating in industrial processes

Secondly, a lot of industrial processes require medium or high temperature heating. The largest industries are in the industrial clusters, but a lot of heat is required by medium size industries located all over the country as well. Currently, there are 350 industrial delivery points of the Dutch gas transport grid to supply natural gas. Multiple sectors are using medium or high temperature heat, such as ceramic industries (1000°C-1200°C), food industries (<150°C), chemical industry (high temperatures involved), metal industry (until 1200°C), the paper industry (150°C) and the glass industry (1500°C and >2000°C). For these applications, multiple alternatives are potentially available besides hydrogen:

- Sometimes innovations in processes are possible to reduce the required heat or use a completely different process to obtain the desired purpose (e.g., Electric Arc reactors for steel production).
- For medium temperature heating (100°C-400°C) electrification could be an option, but it depends per application how cost efficient this is.
- For temperatures >500°C mostly only biogas, biomethane or natural gas with Carbon capture Storage are low carbon alternatives.

For these heat applications, the future willingness-to-pay for the hydrogen depends on the costs for the mentioned cost-effective alternative. As there are less alternatives for gas available when higher temperature is required, hydrogen has an increasing potential for the HT industrial market. In this market, the used source for heating must be able to meet quite large demand volumes per industrial site, and a rather stable demand profile. This demand-side load profile is currently rather stable to maintain the process temperature and to avoid reheating. Whether this will adapt in the future, through the developments in demand-side response to benefit from low energy costs, will also depend on the process and its ramp-up/ramp-down potential.

Technically, the required hydrogen gas pressures are comparable to gas grid pressures (40 bars) and the required purity is generally lower than for feedstock or fuel cell applications (95-99.9% [99] [102]). Pure hydrogen can also be blended with natural gas, to decarbonize the gas use partially. The current industrial thermo-processes can handle hydrogen blends up to 5% and with new or modified installations this can be increased towards more than 15% [103].

4.4.2 Hydrogen as a direct fuel in mobility

Renewable hydrogen can be used as a substitute for fossil fuels to produce synthetic fuels such as synthetic kerosine. As this fuel production happens at refineries, this section focuses on the use of pure hydrogen to power fuel cell electric vehicles (FCEV). Cars, trucks, busses, trains, ships and in the future possibly airplanes can be powered by hydrogen fuel cells. Currently, these types of vehicles are in an early stage of introduction, therefore demand volumes are small and expected to initially be developed together with refueling infrastructure at user-hubs (such as ports and train/bus stations). Depending on the developments of EV battery technology, the share of hydrogen and electric vehicles is uncertain. In the II3050 scenarios [27] vary from 0% to 40% of hydrogen use of the total mobility sector. The promising improvements in battery technology and the energy efficiency of EV's is the main reason it will represent a large share of future mobility. Advantages of FCEV are the higher energy density (compared large battery packs) which is necessary for long distances and heavy-duty transport, along with current rapid refueling rates compared to charging. Therefore, it cannot be neglected that

FCEV can provide a solution for certain transport demand segments. Finally, cost reductions and market competitiveness will contribute to the share of electric and hydrogen fueled vehicles on the mobility market.

Considering a share of mobility can consist of FCEV's, the demand pattern of this sector is expected to be quite stable, with higher levels on working days compared to the weekends, comparable to the current demand for fuels. Currently, both fuel cell vehicles for compressed hydrogen at 350 (mostly High-Duty vehicles (HDV) and 700 (mostly Low-Duty vehicles, but also increasingly HDV) bars exist, it is unclear if this will move more towards 700 bars in the future or a distinction between two levels of pressurized hydrogen will be distinguished in FCEV. Fuel cells require exceedingly high purities of hydrogen (>99.97%), otherwise the risk occurs that they will break down very rapidly. As these purities cannot be ensured by hydrogen transport through grids, it is expected that purification will always be required at points of the grid where hydrogen is demanded for fuel cell applications [32] (Regardless of if last mile logistics by trucks is required). Fuel cell powered vehicles are expected to be more competitive compared to electric alternatives for heavy weight vehicles, including heavy duty transport, especially on long distances. Heavy vehicles require more battery storage, which implies more weight, and longer recharging times. A cost competitiveness analysis of the Hydrogen Council represents the priority of some mobility end-uses over others. For example,[12] fuel cell powered forklifts can potentially be competitive against low carbon alternatives at hydrogen costs of 6-7 $/kg, trucks and busses at 4-5 $/kg, trains at 4.5$/kg and cars around 2 $/kg [101]. Synthetic kerosine can become competitive at 2.7$/kg to become competitive with biofuels [101].

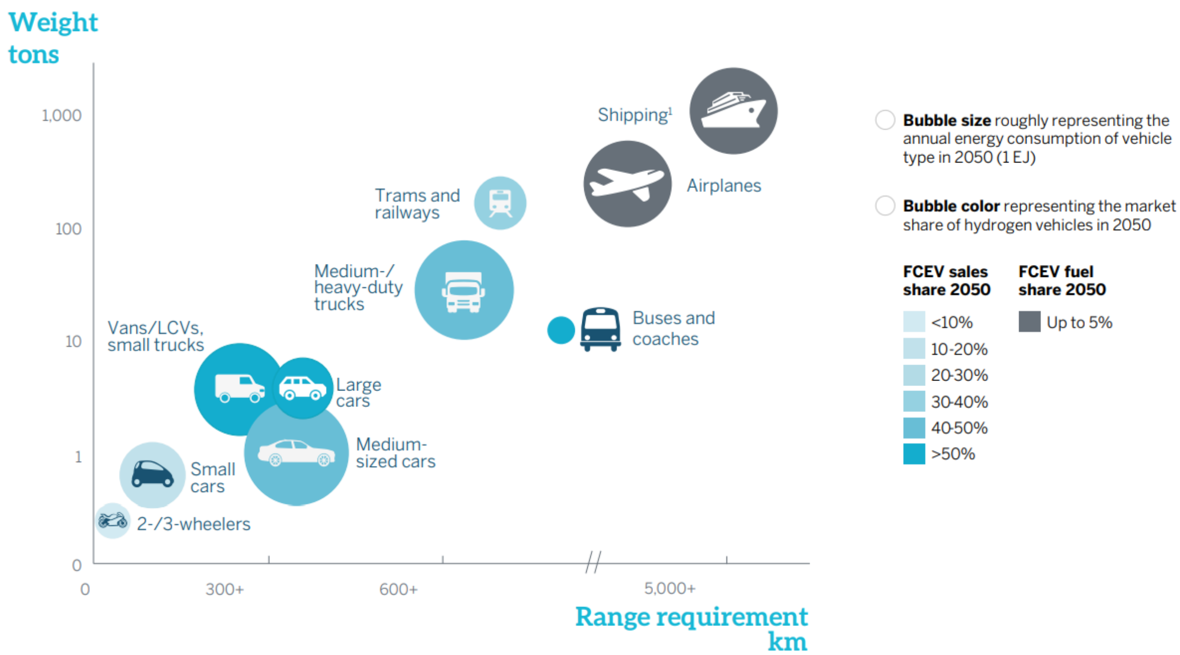


Figure 20 - Relation between vehicle size and range requirement of mobility end-use. Bubble size representing energy consumption in 2050, bubble colour representing estimated market share. [104]

Also specified gas engines for hydrogen are developed by some engine manufacturers, inspired by traditional gasoline powered engines. However, these so called 'hydrogen internal combustion engine vehicles' (HICEV) have lower efficiency potential than the fuel cell electric hydrogen vehicles. Most models were in development 10-20 years ago when the market did not seem to move towards

[12] Under the assumptions as mentioned in the report of Hydrogen Council.

hydrogen. It is unclear to what extend these types of vehicles are really passed by the FCEV's or that they will pop up again when the mobility market will make steps to move towards hydrogen.

4.4.3 Hydrogen as a use for heating in the built environment

Besides all-electric (heat pumps), heat grids and biomethane, renewable hydrogen is perceived as a practical option to decarbonize heating purposes in the build environment (BE) by hydrogen boilers or hybrid heat pumps, especially when existing infrastructure (gas-grid) can be reused. For modern, proper insulated buildings it will probably be the most cost-effective, and energy efficient, to use heat pumps for heating. In neighborhoods with old or monumental houses where heat pumps are not feasible due to low insulation quality using carbon-neutral gases is one of the few alternatives. Hydrogen council states that the combination of avoidance of removal costs by re-using the natural gas grid and higher utilization of the hydrogen gas grid by coupling BE, industry and HRS to the same grid can lead to significant cost reductions for hydrogen in the BE. According to this analysis, hydrogen is expected to be competitive when costs of hydrogen boilers fall, it will be more competitive than heat pumps for refurbished residences (taking costs of refurbishment into account) [101]. For newly built houses hydrogen costs need to drop below 3 $/kg to outcompete biomethane and heat pumps [101]. However, these costs have high uncertainties due to multiple factors as outdoor temperatures, combinations in refurbishments and it is unclear if potential cost reductions in biomethane and heat pump technologies are included.

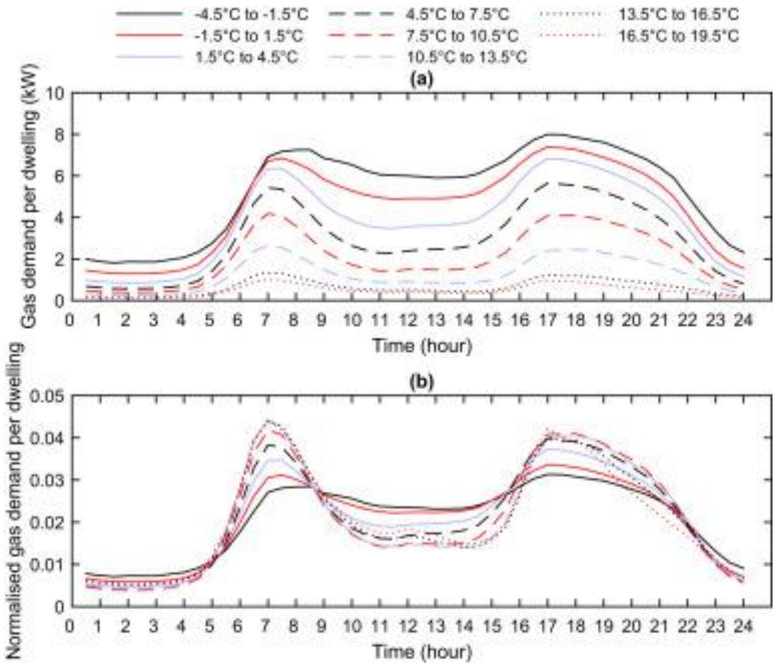


Figure 21 – Daily gas demand profile for built environment in GB, and its relation to outdoor air temperature [105]. Top: gas demand capacity pattern. Bottom: normalized pattern of gas demand.

The distribution of the hydrogen demand by the built environment depends on the political choices that will be made. In the Dutch strategy is determined that for each neighborhood will be decided how residential heat demand will be decarbonized, meaning that the demand will be decentralized per neighborhood and not per individual house. The demand profile is characterized by seasonal fluctuations due to the large demand for heat in the winter and low demand during the summer. Thereby, a daily profile is seen with peaks in the morning and evening. In distribution networks, hydrogen pilots in the built environment of Hoogeveen plan to distribute the hydrogen at pressures between 4 bar (inlet) and 100 millibar (outlet) [106]. The purity of hydrogen required for boilers and other residential applications is expected to be >98%, in accordance with the PAS4444 standards [99]

[32]. The built environment can also be partially decarbonized by blending hydrogen into the natural gas grid, blending up to 10% seems applicable without major modifications and could be increased towards 20% when installations in the grid and at end-users are modified or replaced [103].

4.4.4 Electricity

Hydrogen is also proposed as option to generate electricity in the long-term future, firstly in gas turbines and/or large fuel cells and secondly for back-up power and grid-balancing by smaller fuel cells. This utilization competes with future energy storage technologies on the large scale, to ensure the reliability of the energy system.

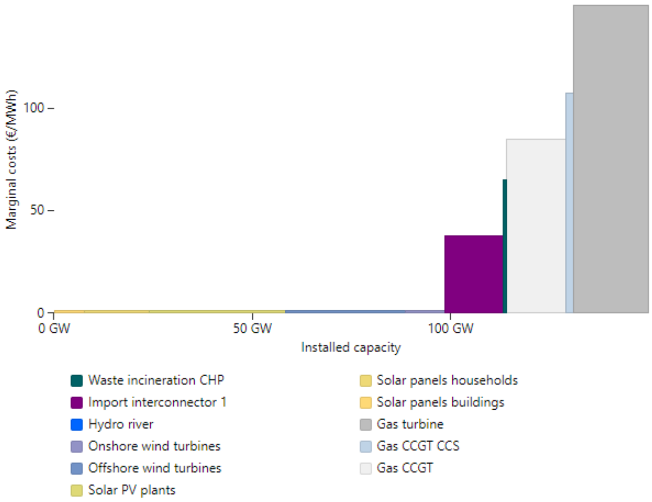


Figure 22 - Indicative representation of a future merit order in the energy system [8]. Only if demand exceeds a certain capacity (x-axis) the market will pay the marginal costs for electricity. Of course, when solar and wind are not available the higher marginal cost technologies shift to the left.

Large scale electricity production by gas turbines in the future will only be necessary at times when a high demand for electricity exceeds a low renewable energy supply. As this type of electricity generation has higher marginal costs (due to costs of hydrogen) than electricity generation by wind and solar, power generation by gas turbines shifts to the right of the merit order. Consequently, these technologies have a low-capacity factor, which affects the business case significantly. Currently, there are around 20 gas fired power plants (>50MW) spread through the Netherlands which could theoretically be used for future flexibility options. The largest share of capacities is located near large industrial clusters (e.g., Rotterdam and Eemshaven). It is mentioned that hydrogen should have purities of 99.9_{mol}% to be used for power generation with pure hydrogen [99]. On the other hand, hydrogen can be blended into natural gas streams, and it is perceived that until 1% this remains safe in gas turbines and 10% in gas engines [103]. In between, there are a lot of studies investigating electricity generation by syngas consisting of hydrogen up to 80_{vol}% [107]. Similarly, gas turbine manufacturer General Electric mentions that some of their turbines are fueled by hydrogen with concentrations ranging from 5_{vol}% to 95_{vol}% [108]. Hence, gas turbines differ in their suitability in handling hydrogen, potentially due to differences in research stages now.

When, however, the technology is ready to be able to have on-demand electricity production through hydrogen it still depends on the market if it will have a feasible business case, and if they are able to compete with other flexibility alternatives.

For large-scale fuel cell applications used for electricity generation purposes, similar demand patterns and locations could be considered as gas turbines. Moreover, fuel cells could be utilized for (local) smart grid network services (such as curtailment mitigation, congestion, and load balancing) or as backup power facility by end-users (e.g., datacenters and industry). Also, here, the fuel cells require very high qualities of the hydrogen (>99.97%) to avoid degradation of the installations [99]. For large scale electricity generation purposes, the technology will compete with the same technologies as the gas turbines. For back-up purposes, batteries could be considered as another low carbon alternative for diesel gensets [109]. These back-up functionalities are typically used for higher frequency flexibility purposes.

5. Value chain analysis

Value chain analyses can aid in answering the question how to effectively realize a hydrogen value chain. Providing a representation of reality by modelling value chains can give the opportunity to verify assumptions and check the impact of conditions before investing in the real world. The modelling of a value chain can be done to acquire insight in multiple goals: cost effectiveness, environmental impact, spatial requirements and volume/capacity requirements, or a combination of these. In recent years, the number of studies analyzing specific hydrogen value chains has grown significantly. An overview of the main characteristics of the models used by these studies is given in Appendix B – Modelling types. Some common elements of these studies are:

5.1 Common characteristics

5.1.1 Model mechanics.

The mechanics of a model are defined the calculations that are made, and what type of output is realized by the model. Optimization, calculation, exploration, or simulation mechanics can be present in one or multiple ways in a model. The approach of the study is related to the type of mechanic the modelling requires. In value chain analysis, for example, a clear distinction can be made between studies that really see the "chain" as a “sequence of activities” and those that analyse the "chain" as a network (Hydrogen supply chain network design, HSCND, studies [110]). The first category often uses calculation models to compare and evaluate various configurations of chain activities. The HyChain calculation model is a good example [21] which allows for the comparison of various energy carriers and import destinations. In contrast, network studies look at the most cost-efficient connections considering the (geographical) supply and demand locations and volumes. Network models – with or without spatial integration – mostly use optimisation models. Examples are the optimisation of hydrogen transport infrastructure [111], hydrogen fuel station network [112], or storage facilities [113].

5.1.2 Sector dimensions

The extent to which options for conversion, transport, storage, and end-users are included in the different studies varies, as do the number of transport and storage options considered. Most of the value chain analyses focus on hydrogen value chains to mobility end-use (Hydrogen fueling station-planning, HFSP [110]). Some studies take an integrated look at hydrogen for other end-use-applications [114] [115], or the integration of sectors [116]. The demand for hydrogen per sector – mostly mobility – is often taken as a given and constant parameter, except for stochastic variations in the demand volumes, or the development of demand over time. Quality specifications and pressure regimes are often not discussed nor clearly specified.

5.1.3 Temporal resolution

The temporal resolution of value chain varies between hourly to daily or yearly. The temporal resolution chosen can explain discrepancies between study outcomes. To illustrate, Guoming Yang et al. focused on the integration of off-grid wind siting combined with hydrogen conversion via electrolysis, while having a storage facility near the refueling stations to cope with the flexibility in demand [117]. In contrast, others showed that centralized storage is better than decentralized storage in terms of the levelized cost of hydrogen [113]. The economic benefits of a centralized storage model are mostly achieved by the economies of scale in storage facilities, by which dispersed storage areas are consolidated together.

5.1.4 Spatial resolution

Spatial integration is not a common element of value chain analysis. However, some optimization models have incorporated GIS-analysis with mostly a regional or national focus. The advantage of spatial integration is that the analysis is much more locational specific which can support policy makers in decision making. Most studies analyzing spatial characteristics of a hydrogen value chain incorporate optimization models, and give insight in the development of hydrogen fuel stations for a deterministic demand development (e.g., Figure 23 – A graphic representation of the optimization of lowest-cost hydrogen supply chains for Great Britain for a set of demand developments.Figure 23).

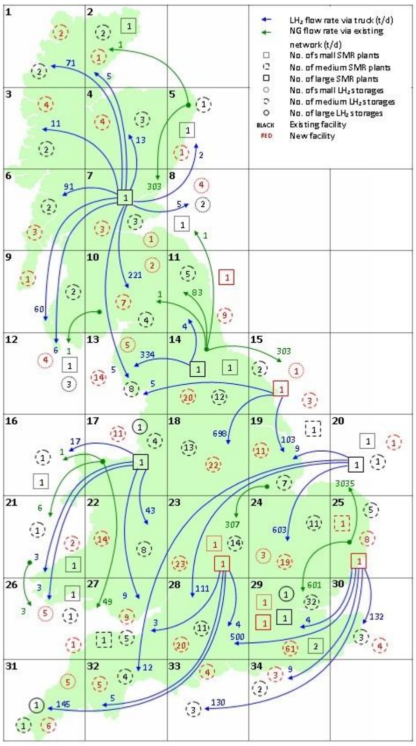


Figure 23 – A graphic representation of the optimization of lowest-cost hydrogen supply chains for Great Britain for a set of demand developments. [140]

5.2 Take-aways for value chain modelling research

5.2.1 Value chain design

Value chain optimizations models can be used to determine the optimal design of a hydrogen value chain by considering the individual position of hydrogen value chain activities, e.g., whether hydrogen production technologies would better fit into a centralized (urban) or decentralized (rural) location. Findings highlight the crucial importance of the effect of scale on plant costs and of the network losses in determining whether a supply chain is centralized or decentralized. More specifically, modular technologies (installation costs not affected by the size) are preferably installed at a small scale in a decentralized context, whereas technologies characterized by large, fixed costs (strong size dependence) are installed at a large scale mostly in a centralized location [118]. In addition, the structure of the resulting hydrogen supply chain strongly depends on the available technology portfolio and the resources/feedstock available per region. This trade-off between large scale production with cost benefits through scaling on the one hand, and the required transport costs to different demand hubs on the other runs like a thread through all spatial modelling research.

5.2.2 Standalone or grid coupled (operational mode).

The coupling of hydrogen production systems and renewable energy resources deserves some attention. The strategy taken affects the operational profile, and thus the profitability of electrolyzer systems. The number of operational hours of the electrolyzer system will be very low (below 1000) when using only surplus power, low (some 900-2000) when coupled to a dedicated solar system; medium (some 4000-5000) when coupled to dedicated wind generation [117]; high (5000-6000) when coupled to combined dedicated source of solar and wind [119], or can be very high (>8000) when coupled to the electricity grid. Apart of operational hours affecting the cost price of hydrogen, one must consider how the operational mode affects the local energy system (e.g., grid infrastructure).

5.2.3 Strong focus on techno-economic integration

Most studies only considered the pure techno-economic benefits and cost – summarized in LCOH or NPV parameter - incurred for the individual value chain activities or a combination of activities. So far, few studies give attention to the financial costs involved, such as loans and interest payments. Only some studies considered the cost of finance in the overall parameter, though, they do not consider that individual hydrogen chain activities may be operated by various parties which all have their own risk profile [120] [121]. In addition, external factors such as avoided greenhouse gasses, increased security of supply and a better-balanced energy system (e.g., flexibility provision) are less commonly studied. Several researchers have included emission factors, minimization of greenhouse emissions, usage of by-products in their analysis [118] [122], though limited studies comprise social benefits such as energy system security, planning efficiencies, and/or balancing revenues. Hydrogen production by electrolysis has several opportunities in serving flexibility to the energy system [123]. Firstly, flexible electrolyzer operation can be used to provide demand side management to the system, for example consuming more electricity when there is overproduction of VRE and less when there is shortage of electricity supply in the system [124] [125]. Secondly, it can also provide seasonal shifting and storage when hydrogen is produced during the supply peaks and stored until there is demand for hydrogen or shortage of electricity production at other moment [123]. The business value of these options is determined by the price incentives that different electricity markets provide. The social value of balanced markets is, however, much more difficult to capture. Lastly, the purity of hydrogen is not always considered of value, and there are only a few studies that take this into account from a techno-economic perspective [126] [127].

6. Main insights and research gaps

6.1 Energy scenarios and modelling

To assess and project the possible structures of sustainable future energy systems a vast amount of energy system modelling has been carried out especially during the past decade. In that modelling typically various energy sources of energy, various carriers of energy and various end-uses are linked in a reliable, sustainable, and resilient energy system. Obviously, all models have their own typology (see Appendix A for an overview). The model type will typically have an impact on the kind of results that are generated: optimization models will, for instance, usually optimize towards one solution whereas calculation models are used more to calculate multiple scenarios based on various assumptions. Irrespective of the modelling type, a common characteristic of modeling is that results are often strongly defined by the technical/cost parameter values used and by the assumptions made towards the ranges of sources and demand volumes. For example, with the help of one of the authoritative models of Dutch origin, the ETM, it can easily be demonstrated how changing parameter values immediately affect the resulting configuration of the energy system. The assumed values of several variables strongly affect the projected future energy mix. Typical examples of such variables are the role of energy electrons versus energy molecules and the electrification trend; the development and speed of introduction of various policy incentives including the acceptance of blue versus green hydrogen and of the role of imports; and the development of costs, learning effects, and the economies of scale.

6.2 Hydrogen strategies

Countries vary their hydrogen strategies by focusing on several aspects of the hydrogen value chain to meet their energy transition targets. Such differences are often inspired by the traditional national supply and demand profiles and industrial structures. For instance, countries with significant energy-intensive, carbon-based industrial hubs (Netherlands, chemical, steel, refinery etc.) tend to carbon-neutral hydrogen upscaling of production and large-scale transport to import, export and use the hydrogen as green feedstock and energy source. Countries with a relatively strong mobility and transport industry focus overall on introducing parts of the hydrogen value chain in mobility. This is sometimes done by typically supporting the related infrastructure, e.g., introducing many HRS (e.g., Germany); while sometimes the focus is on creating demand by deploying fleets of hydrogen vehicles in specific regions and expand the infrastructure accordingly (e.g., France).

As far as domestic hydrogen production is concerned, most countries tend to rely on their domestic RES and their potential of CO_2 sequestration. Low costs of RES (due to excess of sun or wind for example) combined with a relatively low domestic demand can typically lead to a hydrogen strategy to become an export hub (e.g., Australia), but if domestic RES is relatively small, strategies are often focused on technical innovation of hydrogen import technologies (e.g., Japan). For both cases, political drivers

The Dutch hydrogen strategy is somewhat mixed. There is serious potential for offshore wind energy, and it is much needed to cover the electricity demand and partially the hydrogen demand, but the volumes are insufficient for total domestic electricity and molecular (energy) demand, especially when feedstock for bunker fuels and chemicals (e.g., kerosine, fertilizers) is included. Imports will therefore probably be an important future source of carbon-neutral hydrogen. There are opportunities for domestic blue hydrogen production due to the large CCS potential and existing (gray) hydrogen production. So far, however, no explicit goals have been mentioned in the Dutch (or European for that matter) hydrogen strategy for blue hydrogen, as green hydrogen is generally considered the ultimate goal. It seems likely though, that blue hydrogen will play (at least) a transitional role towards a hydrogen economy. The 'Nationaal Waterstof Programma', which will be presented mid-2021, will elaborate on these characteristics and on cross-sectoral implementation of a future hydrogen system [22].

6.3 Stages of the hydrogen value chain

The multiple stages of hydrogen value chains, including their options and considerations, are described in this report. Thereby, there is focused on gaseous hydrogen value chains, while the advantage of using certain hydrogen carriers is not neglected.

Starting with the production of hydrogen, a lot of research is already performed evaluating the factors that impact the LCOH. There is a significant gap between the production costs of green and grey hydrogen. For hydrogen produced by electrolysis, the sourcing and operation strategy is essential, as the electricity costs dominate the business case of the electrolyzer. When comparing the cost of blue and grey hydrogen, the major component determining which is both if most cost effective are the costs accounted for carbon emissions.

With regards to transport and storage of hydrogen, also a lot of comparisons are made between the different options. Thereby, generic insights are created which means of transport and storage would be most suitable given the distances and volumes that should be processed. However, some aspects received less attention so far. One example is the purity of the hydrogen along the chain. Some types of transport and storage will not be able to keep hydrogen at very high purities, and therefore would require additional purification. Because of the significant role that is expected for fuel cells, a lot of research is currently performed in new and existing purification technologies. Moreover, the advantages of different carriers with regards to specific purity, pressure, storage, and flexibility demands is something that should get more attention in the decision-making at a specific value chain stage. The most common end-use categories and their unique characteristics were described, including their specific purity, pressure, and demand patterns.

6.4 Value chain modelling

Realizing a full-grown hydrogen economy requires fundamental investments in the existing energy system, and will impact the energy supply, transport, and demand activities sectors of various stakeholders. To create the most cost-effective and technologically promising hydrogen value chain, distinct designs are possible as previously mentioned. In the literature value chain models can be distinguished depending on their focus: models typically optimizing spatial planning profiles (decentralized or centralized supply/demand hubs, mostly regarding HRS infrastructure); models that typically assess least cost solutions such as calculation models for LCOH (levelized cost of hydrogen through various sources and modes of transport); and models that project future system characteristics based on varying assumptions.

Least cost calculation models typically provide insight in the costs of hydrogen as an energy carrier to be transported from A to B by using various sources and modes of transport. Parameters with significant impact are generally the cost-factors related to the production stage of hydrogen (P2G), incorporating the cost of electricity generation and the CAPEX of the electrolyzer[13]. Other important parameters are the scaling factor (some storage and production facilities thrive when installed in large capacities, like SMR, PSA and tank storage) and the costs of transport. Large-scale facilities, although economic in themselves, may at the same time raise transport costs if demand is decentralized, and

[13] The latter is also influenced by the operational mode of the electrolyzer, as an off-grid electrolyzer has a lower operational load-capacity which has a significant impact on the CAPEX per volume of hydrogen produced.

vice-versa, so that it may be a challenge to find the optimal spatial profiles of the supply-side and the market-side.

Spatial planning in the value chain modelling tradition is often focused on the mobility sector; there is less modelling on the planning of value chains for specific other end-uses or sector-coupling effects of end-use markets. Demand levels of hydrogen for mobility are generally based on population growth projections or existing fuel demand scenarios.

Despite the mobility sector being a high-value market, as mobility sector pays a significant price per MJ of energy, it could be interesting to reach much larger hydrogen uptake volumes if industrial heating and feedstock markets of hydrogen would also be included in modelling. This focus on mobility comes with a bottom-up perspective, in which small demand centers (HRS) are expected to develop over time to a larger market, requiring gradual, increase of upstream capacities (production, storage, transport). A top-down approach, instead, could consider the realization of a large-scale hydrogen value chain to decarbonize demand hubs of industry at once. By doing so, a steppingstone for cost reduction of hydrogen technology is realized over the whole value chain by scaling and learning effects. Even though the industrial sector might not directly be cost-competitive with the current carbon-alternative (low price per MJ of energy), these scaling and learning effects can echo down the further cost-effective development of a hydrogen economy to decarbonize other sectors.

The ideal hydrogen value chain model is yet to be developed. It could integrate various sources of supply, various transport and storage modes, and various end-use markets such as mobility, the various industry sectors and built environment. As the Netherlands have opportunities in multiple stages of hydrogen value chain development, a national hydrogen value chain model for the Netherlands could already be a major step forward. Consortia consisting of research institutions and industrial parties have been developing models and studies to analyze various parts of specific value chains.

Research in the impact of merging different markets, where in the future the mobility market can theoretically compete with built environment through green hydrogen as a commodity, and the hydrogen market and the fertilizer market suddenly compete through the demand for green ammonia, is something unaddressed in current literature. An example of exception could be the integration of electricity, gas and hydrogen markets as energy carriers, whose dynamics are addressed in the HyChain 4 study [115].

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Appendix A – Formula sheet

Energy delivery rate of pipelines

The energy delivery rate of a pipeline could be determined by the following equation provided by Quarton & Samsatli [128]. The energy delivery rate (H) is the capacity of energy that can be delivered by a pipeline in MW.

$$H = u_n Q_n$$

where:
u_n the gas energy density at Standart Temperature and Pressure (STP),
Q_n the volumetric flow rate at STP.

Volumetric flow rate of gas through pipelines

The volumetric flow rate at STP (Q_n) is the throughput of gas transported by pipelines. Assuming a horizontal pipe, can be calculated by the general flow equation for gas flows in steady state obtained from Abeysekera et al. [129].

$$Q_n = \sqrt{\frac{\pi^2 \rho_{air}}{64}} \frac{T_n}{p_n} \sqrt{\frac{(p_1^2 - p_2^2) D^5}{fSLTZ}}$$

where:
ρ_{air} the density of air at STP,
T_n the temperature of gas at STP,
p_n the pressure of gas at STP,
p_1, p_2 the inlet and outlet pressures,
D the pipeline diameter,
f the friction factor,
S the gas specific gravity,
L the gas temperature,
Z the gas compressibility factor (the volume of the real gas divided by the volume of a ideal gas at the same temperature and pressure).

Darcy-Weisbach Pressure Drop

Calculates the pressure drop of gas in pipelines.

$${P_{in}}^2 - {P_{out}}^2 = f \cdot \frac{16}{\pi^2} \cdot \rho \cdot P_0 \cdot \frac{T}{T_0} \cdot L \cdot Z \cdot q^2 \cdot \frac{1}{d^5}$$

where:
P_{in}, P_{out} Inlet and outlet pressure of pipeline (Pa),
f Pipe friction factor (Moody factor),
P Gas density under normal conditions (kg/m^3),
P_0 Normal pressure (101 300 Pa),
T Gas temperature (K),
T_0 Normal temperature (273.2 K),
L Pipeline length (m),
Z Compressibility factor of the gas,
q Volume flow under normal conditions (Nm^3/s),
d Pipeline diameter (m).

Compression power

Calculates the required compression power in kW based on the compression requirements and volumes [69] [70].

$$P = \frac{Q}{3600 \times 24 \times 33{,}33} \times \frac{Z \times T \times R}{M_{H_2} \times \eta_{comp}} \times \frac{N_\gamma}{\gamma - 1} \times \left[\left(\frac{P_{out}}{P_{in}} \right)^{\frac{\gamma - 1}{N_\gamma}} - 1 \right]$$

where:

Q	the flow rate (in kWh per day) by taking a low heating value (LHV) of 33.33 kWh/kg specific to hydrogen,
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,
T	the inlet temperature of the compressor (278 K),
γ	the diatomic constant (i.e. the adiabatic exponent) factor (1.4),
M_{H2}	the molecular mass/weight of hydrogen (2.0158 g/mol)[14],
η_{comp}	the compressor efficiency ratio (here taken as 75%), the universal constant of ideal gas R = 8.314 J K-1 mol-1.

Compression OPEX

Calculates the compression OPEX in euros per year, including fixed annual O&M costs and electricity costs [70].

$$OPEX_{compression}\left[\frac{€}{a}\right] = \left(A_0 \times H_{year} \times e/DTE\right) \times P + 0.04 \times CAPEX_{compression}$$

where:

A_0	Availability (85%),
H_{year}	Hours per year (8760h),
e	the electricity costs (0.06 €/kWh),
DTE	the Driver Thermal Efficiency (90%),
P	the compression power in kW.

PSA purity and recovery rate

Calculates the hydrogen purity and recovery rate, given the process and gas mixture characteristics [81].

$$Purity = \frac{\int_0^{t_{ads}} x_{H_2out} n_{H_2out} dt}{\sum_{i=0}^{n_{species}} \int_0^{t_{ads}} x_{i,out} n_{i,out} dt} \times 100$$

$$Recovery = \frac{\int_0^{t_{cycle}} x_{H_2out} n_{H_2out} dt}{\int_0^{t_{cycle}} x_{H_2in} n_{H_2in} dt} \times 100$$

Where:

t_{ads}	the adsorption time (seconds)
t_{cycle}	the cycle time (seconds
x_i	the molar friction
n_i	the molar flow (kmol/s)

PSA electricity use

Calculates the electricity use (E in kW) of the PSA unit [83].

$$E = (\frac{y}{y-1}) R_g T_{feed} \left[(\frac{P_{high}}{P_{low}})^{(\frac{y-1}{y})} - 1 \right] \frac{B}{1000\eta}$$

Where:

y	the heat capacity ratio of the feed gas (1.4 [63],1.5 [130]),
R_g	the universal gas constant,
T_{feed}	the feed stream temperature,
P_{high}	the discharge pressure (bars),
P_{low}	the blowdown pressure (1.1 bars [63]),
B	the molar flow rate that must be compressed for the adsorbent regeneration step (0.181 mol/s [63]),
η	the mechanical efficiency of the vacuum pump (0.8 [63], [130])

[14] Interview with Gasunie on 07/11/'17.

PSA capital costs

Two reference cases could be used to calculate an indication for the investment costs of a PSA unit. As mentioned in the purification chapter, costs for purification could differ a lot due to situation specific characteristics.

Marcoberardino et al. [81] provides the following equation to calculate the investment costs in euro's, based on a reference case with a capacity of 27.95 kmol/h. CEPCI are the Chemical Engineering Plant Cost Index, used as general index to adjust plant construction costs from a moment in the past to the present (A CEPCI from the current year can be used to adjust the formula to that year).

$$C_{PSA,2017} = (C_{PSA,0}\left(\frac{S_{PSA}}{S_{PSA,0}}\right)^{f})_{2007} \times \frac{CEPCI_{2017}}{CEPCI_{2007}}$$

Where:

$C_{PSA,2017}$	PSA CAPEX per kmol/h capacity installed in k€ for year 2017,
$C_{PSA,0}$	reference PSA CAPEX per kmol/h capacity installed in k€ in 2007 (27.95),
S_{PSA}	PSA size in kmol/h,
$S_{PSA,0}$	reference PSA size in kmol/h (17.069),
f	scale factor (0.6)[15],
$CEPCI_{2017}$	CEPCI in the year 2017 (562.1),
$CEPCI_{2007}$	CEPCI in the refrence year 2017 (525.4).

NREL [80] provides a similar type of equation to calculate the PSA investment costs in USD as function of the output of pure hydrogen (x in $kg_{H2}.day^{-1}$), assuming required purities >98% and using a base case of 115 $kg_{H2}.day^{-1}$.

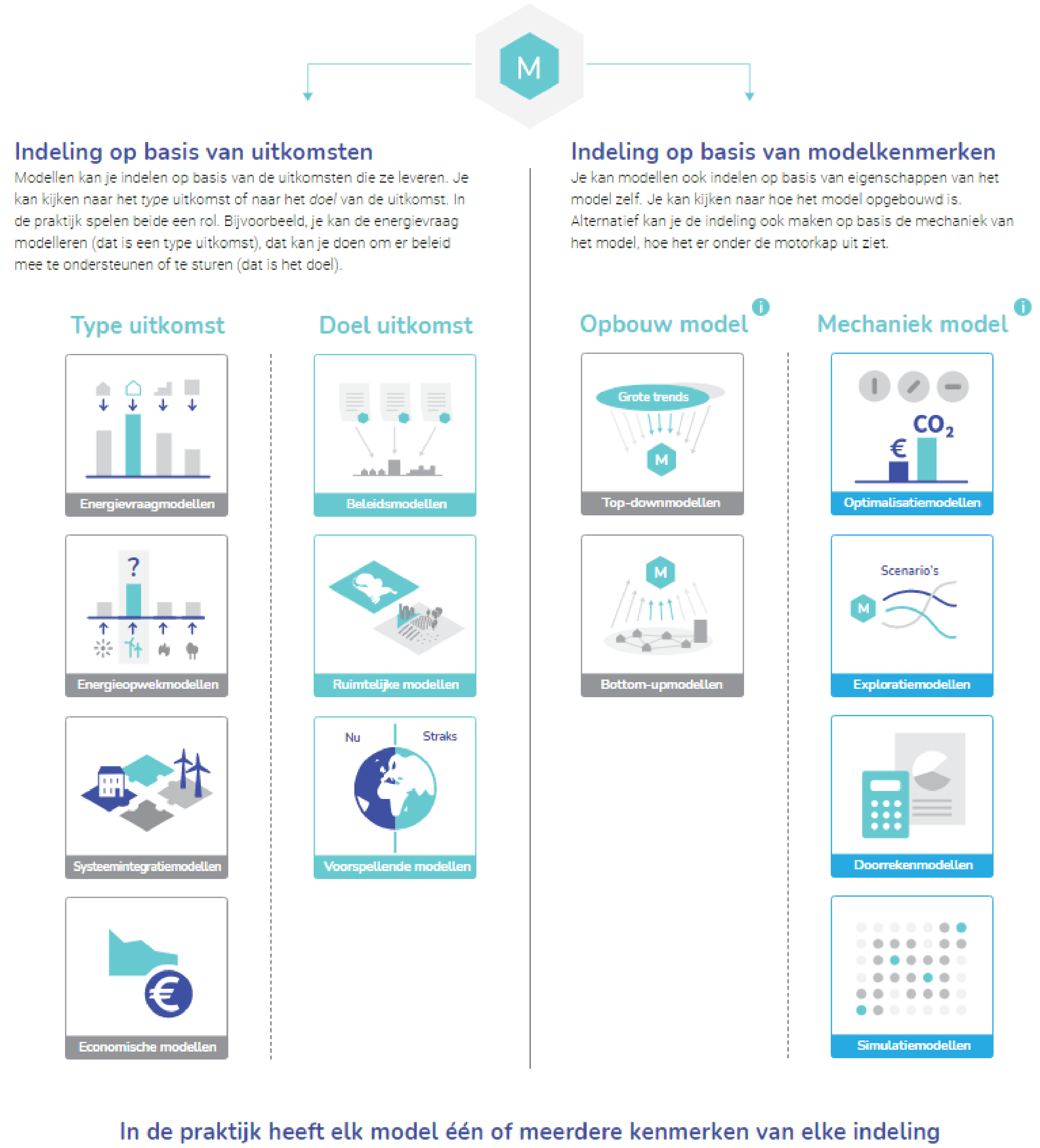
$$New\ PSA\ costs = BaseCost * (\frac{x}{BaseBedSize})^{Costfactor}$$

Where:

$BaseCost$	Reference PSA costs per kg-H_2.day^{-1} in USD (54750),
x	desired output capacity of pure hydrogen (>98%) in kg-H_2.day^{-1},
$BaseBedSize$	reference PSA bed size capacity of pure hydrogen (>98%) in kg-H_2.day^{-1} (115),
$Costfactor$	scale factor (0.4).

[15] Perry's Chemical Engineering Handbook assumes a scaling factor of 0.7.

Appendix B – Modelling types



[16]

[16] Bron: Types modellen - Energiemodelleren.nl , CE Delft, RVO, Topsector Energie, TU Delft