Summary

Consortium

TKI NIEUW GAS
Topsector Energie

gasunie

Netbeheer Nederland

New Energy Coalition

TNO innovation for life

kiwa

DNV

Main results of the HyDelta 1 project

Acknowledgements

This report has been drafted between April and June 2022 and summarizes all the results of the HyDelta 1 project. In the process of drafting this report, we greatly benefitted from the invaluable comments and suggestions from a large number of consortium participants, and especially from Frank van Alphen, Sytze Buruma, Tom Eijsackers, Tessa Hillen, Raymond van Hooijdonk, Elbert Huijzer, Udo Huisman, Johan Jonkman, Stefanie van Kleef, Johan Knijp, Pascal te Morsche, and Bart Vogelzang.

Groningen, the Netherlands, July 2022
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Foreword

This document summarizes the main findings of the HyDelta (phase 1) project, a research program on the introduction of clean hydrogen as energy carrier and feedstock in the Netherlands and the role of infrastructure in particular. The HyDelta 1 project was the first part of a planned series of projects within the so-called HyDelta programme. The project was carried out during the period between December 2020 and April 2022 and has a particular focus on hydrogen transport and distribution through the gas grid, the costs of the value chain and some other factors that urgently need clarification in order to set the conditions for a wider implementation of hydrogen. The program also tries to connect the research findings with policies and measures.

Most of the research questions have been formulated in close collaboration between the consortium partners carrying out the research, New Energy Coalition (coordinator), DNV, TNO and Kiwa, and the consortium sponsoring partners Gasunie and Netbeheer Nederland (NBNL) who are responsible for much of the Netherlands' current and future national and regional transport and storage activities of natural gas. Funding from the national innovation subsidy body, TKI Nieuw Gas, significantly contributed to enabling the HyDelta 1 project.

In HyDelta 1 a total number of 37 deliverables has been produced (Annex 1), all of which are publicly available as of June 2022 on the hydelta.nl/research-programme website. This summary is meant to provide a snapshot overview with a fairly strong focus on the societal impact of the complete research findings. Readers interested in a deeper understanding of the research, methodology and detailed findings are invited to visit the site mentioned.

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List of abbreviations

ATEX	Atmosphères Explosibles (Explosive atmospheres)
ATR	Autothermal reforming
CAPEX	Capital expenditures
CCS	Carbon capture and storage
CEN	European Committee for Standardization
DOI	Digital Object Identifier
DS	District (gas) station
DSO	Distribution system operator
EU	European Union
FCEV	Fuel cell electric vehicle
FMEA	Failure mode and effects analysis
FTE	Full-time equivalent
GOS	Gasontvangststation (Gas reception station)
HBO	Hoger beroepsonderwijs (Higher professional education)
HRS	Hydrogen refuelling station
HTL	High-pressure transmission line
ISO	International Organization for Standardization
LEL	Lower explosion limit
LOHC	Liquid organic hydrogen carrier
MBO	Middelbaar beroepsonderwijs (Secondary vocational education)
NEN	Nederlands Normalisatie Instituut (Dutch Standardization Institute)
OPEX	Operational expenditures
PE	Polyethylene
PVC	Polyvinyl chloride
QRA	Quantitative risk assessment
RED	Renewable Energy Directive
RES	Renewable energy resources
RFNBO	Renewable fuel of non-biological origin
RNB	See DSO
RPS	Renewable portfolio standards
RTL	Regional transmission line
SAF	Sustainable aviation fuel
SMR	Steam methane reforming
TGC	Tradable green certificate scheme
THT	Tetrahydrothiophene
VWI	Veiligheidswerkinstructie (Safety work instruction)
WACC	Weighted average cost of capital
WF	Wind farm

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Introduction

Background of the HyDelta 1 programme

Why the introduction of hydrogen is needed

During the first decades of the currently ongoing energy transition much of the focus in the EU has been on the introduction of renewable energy sources (RES) such as wind and solar. As a result, some 40% of the electricity produced in the EU is green, i.e. RES-based. By contrast, something similar has yet to take place with respect to the energy molecules, representing some three quarters of overall energy uptake. Some policy initiatives have been taken to introduce bio-based gasses in the natural gas system, but at least in the Netherlands this is done on a voluntary basis only. Also, some mandatory fuel blending has been introduced for mobility, but still in relatively limited percentages. Despite such policy initiatives the percentage of the energy molecules that can be labelled 'green' so far remains limited to probably less than 5%. Also, energy carriers used as feedstock in, for instance, the chemical industry, such as hydrogen and the derived products, so far have not yet been subject to any (mandatory) greening. As a result, virtually all feedstock carriers are still 'grey', i.e. produced with a (considerable) fossil footprint.

This difference in decarbonising in the EU energy/feedstock system between electrons and molecules has contributed to the notion that greening the energy and feedstock molecules is a major challenge and should be given serious attention. Without that it seems impossible to get to a decarbonized economy by 2050, also because it is likely that the share of energy molecules in the energy and feedstock system uptake, although coming down, may, depending on the scenario eventually settle – even in a completely green energy system – to anywhere around half of all uptake.

During the last 20 years a vivid discussion has taken place on the potential role of biomass as a source of green energy molecules. The mandatory blending scheme for fuels (introduced by 2009 across the EU as a start to green mobility) was, for instance, based on the expectation that sufficient biomass would be available to stepwise decarbonise fossil fuels for mobility. During the last decade, however, discussions emerged on the risks of large-scale introduction of biomass to replace fossil fuels. This caused the earlier expectations on the role of biomass to be lowered down, and more importantly reinforced the notion that alternative options would need to be explored to replace fossil molecules by others. This contributed strongly to a shift in public attention towards hydrogen as an alternative source of green molecules assuming hydrogen can eventually be produced without a carbon footprint. In fact, introducing clean hydrogen at a massive scale is probably decisive to get to the required volumes of clean molecules to accelerate the decarbonization of the energy system.

A timely introduction of clean hydrogen

It is extremely important both for investors and policymakers to get a better understanding of what it takes to get the clean hydrogen value chains of the future quickly and successfully off the ground. Unless mandatory quota-based or command-and-control policies and measures are introduced to enforce the introduction of clean molecules, replacing 'grey' by clean hydrogen and hydrogen carriers will be based on market conditions and therefore prices and costs. Most of the literature suggests that the prices of natural gas and CO_2 penalties are the most vital factors determining the competitiveness of the production of clean versus 'grey' hydrogen (carriers). The HyDelta 1 project findings do suggest that:

- If offshore wind and electrolyser CAPEX costs come down towards 2030 as generally is expected based on the learning curves, and if the 2021-22 natural gas prices and CO_2 penalties will remain at such levels towards the end of the decade (respectively around € 100/MWh and € 100/ton), then green hydrogen is very likely to outcompete the 'grey' (and possibly 'blue') hydrogen already by about 2030. For green ammonia and methanol this result will emerge already earlier than 2030. It is therefore conceivable – given the usual lead times for setting up new and significant value chains and the tendency to lower energy import dependence – that large – scale introduction of clean hydrogen is no longer something of the distant future

This puts pressure on speeding up and scaling up the production of clean hydrogen as well as on paving the way for clean hydrogen transport, storage, distribution and its various implementation options. For all this, standards, rules, and regulations have to be put in place, but this again does require research revealing what is safe, sound, and acceptable. This explains the strong pressure on the related research agenda of the entire value chain.

The HyDelta 1 project

HyDelta 1 served the purposes mentioned above by researching a number of the most pressing topics where research is indispensable to pave the way for next steps. This report summarizes its main findings and is structured along the following lines.

First the main results on the complete clean hydrogen value chain cost structure will be presented (section 1), clarifying how costs of value chain components relate as well as why the future will show various hydrogen-based value chains next to each other, often with international linkages and mutual connections. It will also show that the transport component, although generally relatively modest in overall value chain costs, can typically benefit from multi-use and regional concentration of hydrogen activity and vice versa.

Then in section 2 the heart of HyDelta 1 will be discussed, namely what needs to be done, from a safety perspective, to make the transport of hydrogen using the existing natural gas infrastructure and uptake in the built environment, as safe as the current natural gas transport and uptake under the same conditions. What adjustments are needed in the various components of the distribution grid and some specific parts of the high-pressure grid if hydrogen enters the existing transport system for natural gas?

In section 3 the attention will shift towards what policies and measures can be introduced to enhance the implementation of hydrogen by introducing it into the transport system. One option currently discussed is to introduce – next to pure hydrogen – also blending options in order to allow for a stepwise introduction, but it is important to assess what issues need to be addressed in order to do so in a careful manner, and what gas quality and other standards will need to be in place and therefore researched to be able to make such steps.

Finally, section 4 will forward some suggestions on further research that is needed for enhancing a further introduction of hydrogen into the gas infrastructure.

Section 1

The hydrogen value chain

1 The hydrogen value chain

Sources for this section

DELIVERABLE:

D7A.1 – Hydrogen value chain literature review

Link to deliverable

DELIVERABLE:

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

Link to deliverable

Development of the hydrogen value chain

For an effective large-scale introduction of clean hydrogen, all value chain components must be put in place almost simultaneously and given the incentives, be operated cost-effectively to enable an economically sound hydrogen application in its various end uses. Without that hydrogen will have problems coming off the ground.

In practice, however, such simultaneous introduction is complex in the absence of a clear coordination mechanism, so that value chain development may get paralysed because actors wait for each other, leading to the well-known 'chicken-and-egg' problem. A further complexity is that hydrogen can be introduced in various different hydrogen value chains, based on different production, transport and storage modes, different end use applications and even different types of hydrogen carriers, ranging from pure or blended hydrogen to hydrogen derivatives such as ammonia, Liquid Organic Hydrogen Carriers (LOHC) or methanol. What value chain will be the winner under what circumstances?

Another complexity of getting clean hydrogen value chains off the ground relates to their cost effectiveness, also due to its early stage of market penetration, and is referred to as the 'valley of death': investors invest in assets of which capital expenditures are still relatively high due to the: infancy of the technology, low scale of manufacturing, and limited experience with implementation. Market perspectives therefore are often uncertain and weak, while learning benefits may easily leak away. As long as the 'valley of death' applies, without policy intervention the early-stage commercial prospects for clean hydrogen are often poor, while demand is still unstable. Moreover, (prospective) early supportive policies and measures are generally hard to predict, creating yet another challenge for potential investors in hydrogen value chain components.

In almost all hydrogen value chains analysed in the HyDelta 1 project (see *Figure 1* for an example hereof), the hydrogen production step involved the largest share of total value chain costs, and therefore contributed significantly to the chains' overall competitiveness. Compared to that cost component, the contribution of transport costs both internationally and nationally to the overall value chain costs on the whole was found to be modest, unless dedicated transport modalities are installed for specific destinations only.

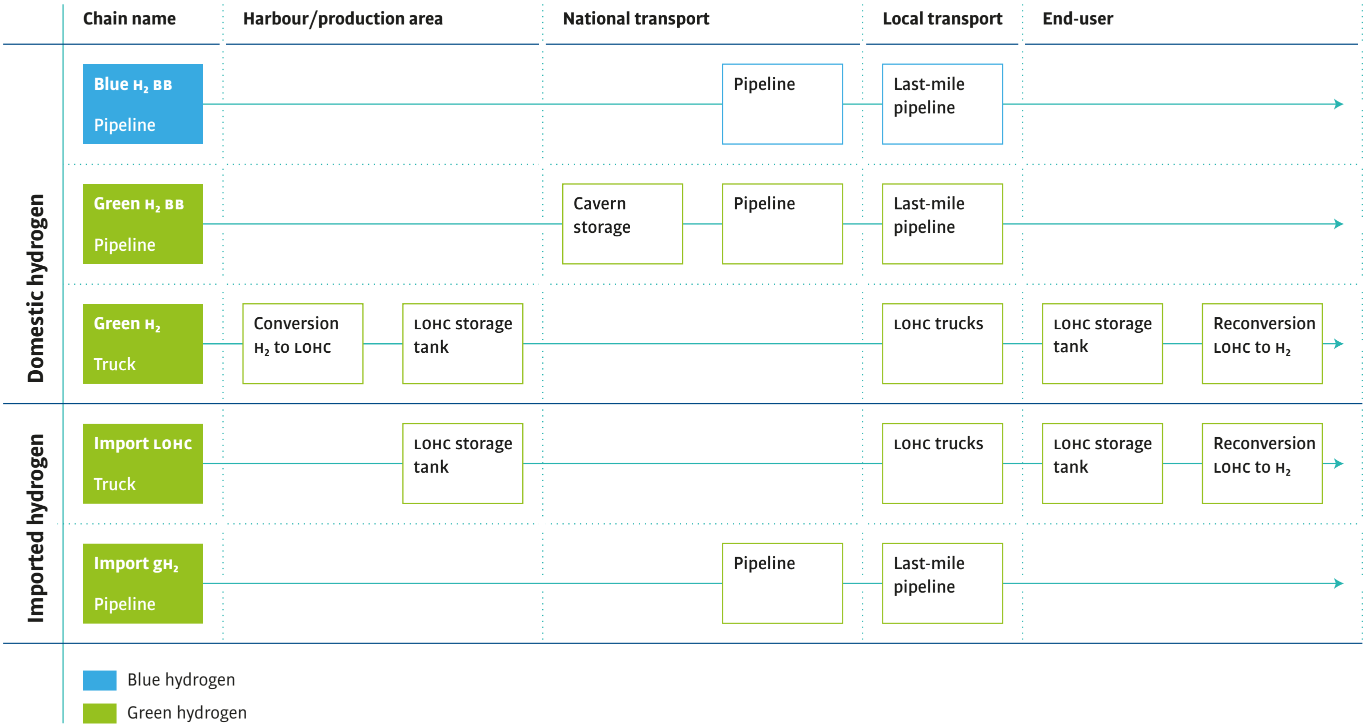
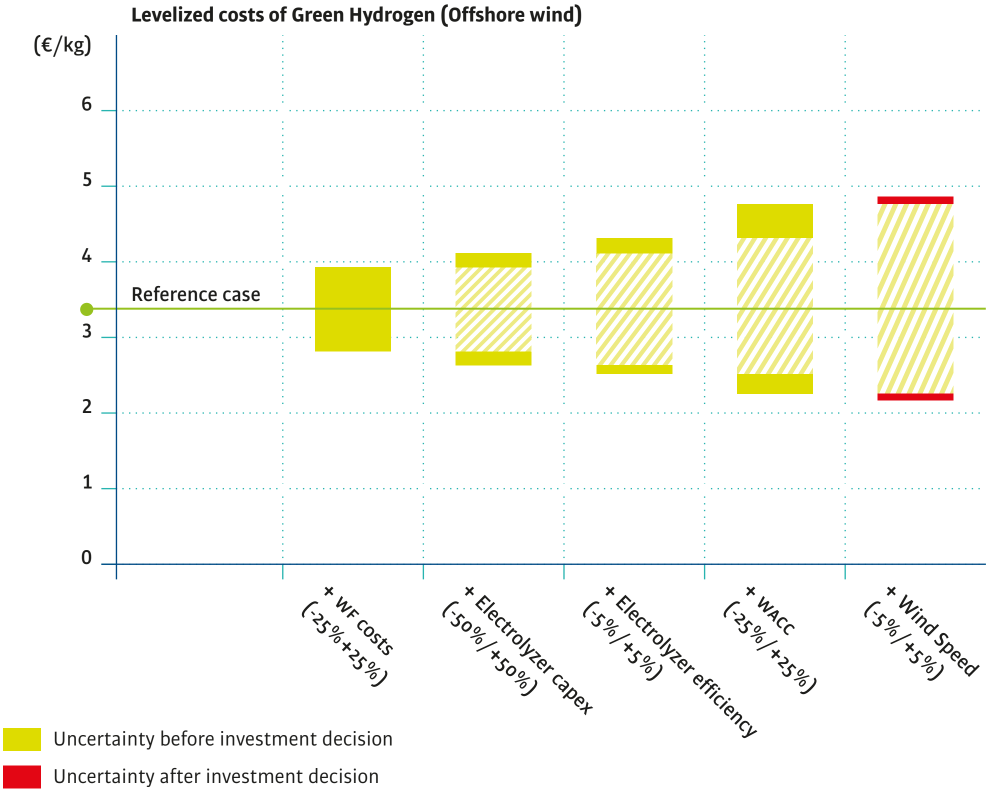


Figure 1. Example of a family of hydrogen value chains analysed in the HyDelta project.
Source: D7A.2.

For green hydrogen produced from North Sea wind power, the value chain costs on which the analysis was focussed, the so-called levelized costs of hydrogen (LCOH), i.e. the average discounted costs to generate the electricity, plus the costs to transport the electricity to shore, and of converting the electricity into green hydrogen via electrolysis, were found to be € 3.40/kg by 2030 with a range of € 2.20 - € 4.80/kg. Its main costs and cost uncertainties turned out to relate to capital investment in wind farms and electrolyser plants. A dominant uncertainty in this production cost is acceptability criteria regarding the cost of capital and the subsequent impact on the LCOH, as is, among others, reflected in the Weighted Average Cost of Capital (WACC) of 7% and the large uncertainty bars when varying the WACC by 25% i.e. between 5% and 9%. This also explains why the dominant part of the overall green hydrogen LCOH uncertainty range relates to the early investment stage.

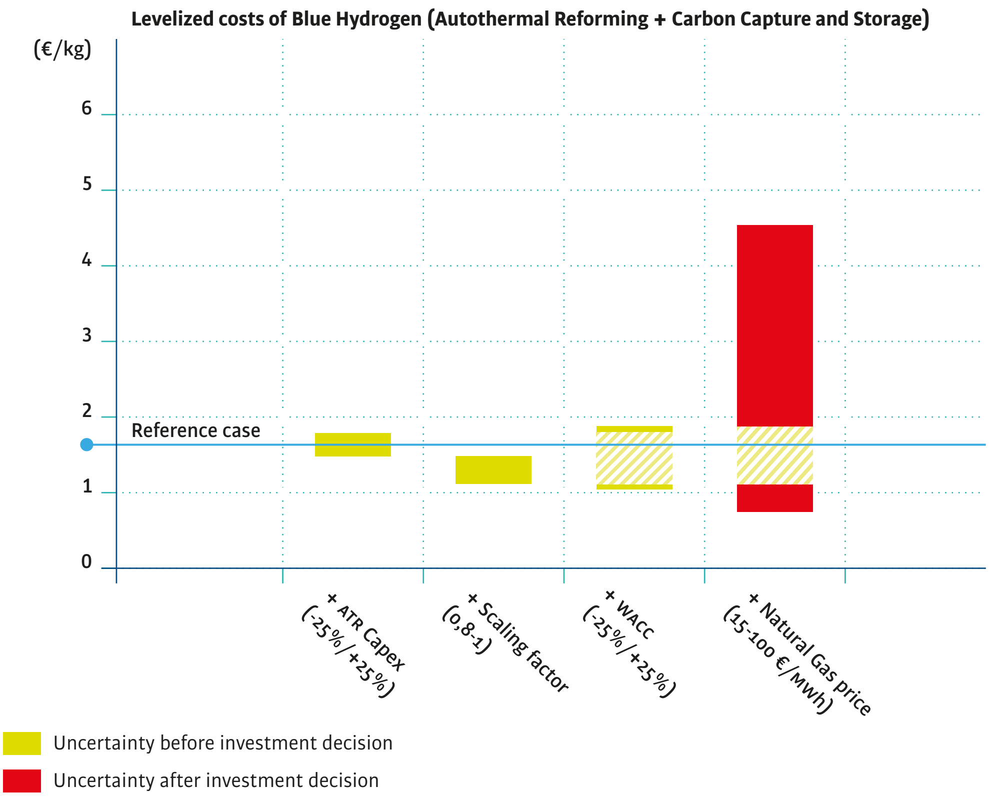
Figure 2. Levelized Cost of Hydrogen (LCOH) of green hydrogen using production via offshore wind in the North Sea. WF = wind farm. WACC = weighted average cost of capital. Source: D7A.2.W



This is quite different for the production of blue hydrogen from natural gas via Autothermal Reforming (ATR) + Carbon Capture and Disposal (CCS) in the Netherlands. Here our analysis indicated projected 2030 LCOH of € 1.95/kg (based on a € 0.80 - € 5.10/kg range), while now production cost uncertainties typically relate to post-investment stage OPEX cost components, and the future natural gas prices in particular. Investors in this technology typically face uncertainties once the final investment decision has been made and the system is up and running: OPEX uncertainty covers some three quarters of total LCOH uncertainty range. That such margins are realistic was illustrated recently when natural gas prices rose sharply after the outbreak of the Ukraine crisis.

It is important to point out that, while the projected 2030 average blue hydrogen LCOH is considerably lower than that of green hydrogen, this is not necessarily decisive for investment decisions, because the latter will also depend on the time profile of commercial feasibility. If, for instance and as our simulations suggested, after 2030 green hydrogen would relatively rapidly start to outcompete blue hydrogen, the investment horizon of the latter may be too short to generate a sound enough business case.

Figure 3. Levelized Cost of Hydrogen (LCOH) of blue hydrogen using production via autothermal reforming (ATR) and carbon capture and storage (CCS).
Source: D7A.2.



Another important and striking conclusion from our LCOH-based value chain cost analysis was that the typical 2030 LCOH of green hydrogen imported from the seven researched non-EU source countries (for more details, see also the next section on 'International value chains), ranging between € 4.2 - € 11.7/kg, turned out to be (considerably) higher than the corresponding € 2.2 - € 4.8/kg cost range of green hydrogen produced from North Sea wind power. The relatively low hydrogen transport costs in the North sea area compared to those of transport from elsewhere turned out to be decisive in making the competitiveness of North Sea-based green hydrogen relatively strong. Only the import case from Morocco assuming low pipeline transport costs via a pipeline connected with the European hydrogen backbone resulted in a somewhat lower 2030 LCOH than the corresponding figure of EU North Sea wind-based options. So, from a LCOH perspective importing green hydrogen from non-EU sources is second-best.

If hydrogen is imported as a hydrogen carrier such as ammonia or methanol, the above conclusion changes. Then the LCOH were on the whole found to be very similar between the non-EU import and domestic route, although even then the LCOH of the domestic route were quite consistently at the low end of those of the import route.

In determining the total value chain costs, expenditures to deal with intermittency of power supply and thus of related green hydrogen production, clearly can represent a crucial cost factor as well. From the various cost assessments of providing such flexibility, notably via storage options, it turned out that the costs of the various options to provide flexibility are typically time-, location-, site-, and value-chain-specific, so that it is very difficult to draw general conclusions about their optimal implementation and costs. Our findings corroborated that for seasonal storage gaseous hydrogen storage in tanks is most likely too expensive to become a suitable large-scale flexibility option, and that therefore national hydrogen transport combined with large-scale storage e.g. in salt caverns is crucial.

Other options analysed were: local conversion into hydrogen carriers, and their transport and storage; combining domestically produced green hydrogen with blue hydrogen production and/or imports; and matching the seasonal supply profile with demand flexibility by, for example, the seasonal off-take profile of hydrogen in the built environment sector or a more flexible seasonal off-take by industrial users. Because these options can coexist with one another, a mix of them can lead to an overall value chain cost optimum.

As was already argued, a factor with a serious impact on the overall hydrogen value chain costs is whether or not the hydrogen is used in its gaseous or liquid form or packaged via a carrier such as ammonia or methanol. Therefore, if the carriers are needed for specific industries, transporting the carriers directly from the import points to the end-users may be a cost-effective option.

A second important point is that to the extent that carriers rather than gaseous hydrogen is imported, this affects their own national transport and storage chain modalities and thus levelized value chain costs – e.g. ammonia transport by rail, barges, or even dedicated ammonia pipelines –, as well as the economies of scale, and therefore costs, of the gaseous transport and storage facilities. In other words, a combination of gaseous and carrier-based hydrogen sources will not only involve separate costs of each of their own transport and storage requirements but will also indirectly affect the costs of other value chains.
How, when and where hydrogen is offered on the market will somehow and at some stage affect the development of their transport and storage modalities and end uses, but the reverse is equally true: once the transport and storage infrastructure has been installed this will to a large extent determine what types of hydrogen sources and end-users will be attracted to the existing value chain ecosystem.

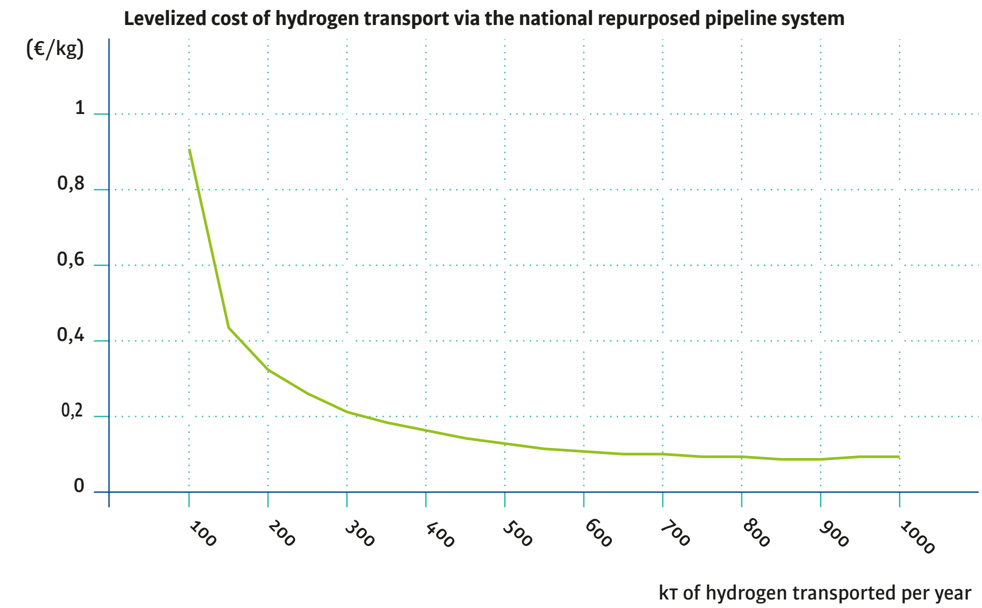


Figure 4. Indicative impact of the transported hydrogen quantities on the levelized cost of hydrogen transport via the national repurposed pipeline system. Source: D7A.2.

In the Netherlands the existing gas transport capacities are such that the costs of national hydrogen transport based on the use of repurposed existing natural gas pipelines will be almost completely independent from volumes subsequently transported through it. So, the more end-users and end-use sectors will utilize such a system once it is ready for use, the greater the cost benefits for all of them (for an illustration of how transport costs depend on the volumes transported, see *Figure 4*). To capture such benefits, large industrial demand clusters can act as launching customers to make the transport system cost effective enough for being initiated, so that after that stage other (smaller) end user categories may strongly benefit as well.

Another important HyDelta insight relates to the interrelationship between storage and transport of hydrogen. If in the Netherlands considerable seasonal storage in salt caverns is crucial to deal with the need for flexibility on the hydrogen market, this will have considerable consequences for the transport infrastructure needed. Because in the case of the Netherlands such storage is only foreseen to be available in the northern Netherlands (and possibly offshore), depending on where the hydrogen is fed into the pipeline system a national transport system will be required enabling it to channel hydrogen flows back and forth to and from these storages. Our analysis therefore showed that if the demand for seasonal storage increases, so will the need for transport. At the same time, it has to be mentioned that the average costs of domestic large-scale pipeline transport and seasonal storage are relatively modest (€ 0.20 - € 0.30/kg) compared to the 2030 LCOH for green hydrogen of € 3.40.

In the HyDelta 1 project's research on value chains, three types of potential hydrogen distributed end- users have been distinguished in analysing how demand patterns may affect transport and storage costs, namely: industries requiring High Temperature Heat (HTH); Hydrogen Refuelling Stations (HRSs) for mobility; and units of the built environment demanding hydrogen for heating. The spatial profile of demand of all types will obviously differ, but the challenge is to try to develop smart transport (and storage) combinations of different units of hydrogen end-users. The HyDelta analysis has shown that via such smart end-user combinations, the transport cost savings over the 'last-mile' by collectively connecting end-users can have a significant impact on total value chain costs.

Fundamentally two modes for national hydrogen transport can be distinguished: by tube trailers and by pipeline. Both modes have their pros and cons. Tube trailers have the advantage that relatively small hydrogen volumes can flexibly and easily be transported against acceptable costs. Regional and local hydrogen transport by pipelines, instead, typically has much larger CAPEX levels and will therefore only be an economic option if transported volumes are large enough. So, the denser hydrogen demand is in a specific region, the more cost-effective hydrogen pipeline transport becomes. The generally relatively large regional demand volumes of distributed plants requiring HTH can sometimes – by opening attractive pipeline transport options – act as an accelerator of other hydrogen demand in the same region. Our empirical results for the situation in the Netherlands clearly showed that the LCOH for the built environment and mobility may well come down some 40% if their end-users can be connected to an already existing pipeline for transport (see *Figure* 5).

It is altogether clear that local and regional delivery costs of hydrogen strongly depend on regional characteristics such as: options to create the end-user smart combinations for transport mentioned, the overall regional demand volume of hydrogen, the distance of potential end-users in the region from a potential hydrogen backbone, the availability of waste heat for cases in which LOHC reconversion is needed, or the potential for local hydrogen production. That is why in assessing local transport (and storage) costs of introducing hydrogen a regional approach is imperative. For instance, without such a regional approach the benefits of joint, multi-sector use of (repurposed) pipeline transport or storage options would be unduly disregarded, etc. Therefore, for a proper analysis of the development of value chains one should take the perspective of both the individual sectors and the geographical clusters as well: it may in itself be too costly to connect a particular industrial area with the backbone, but if combined with other end users it may perfectly make sense to do so from a cost perspective.

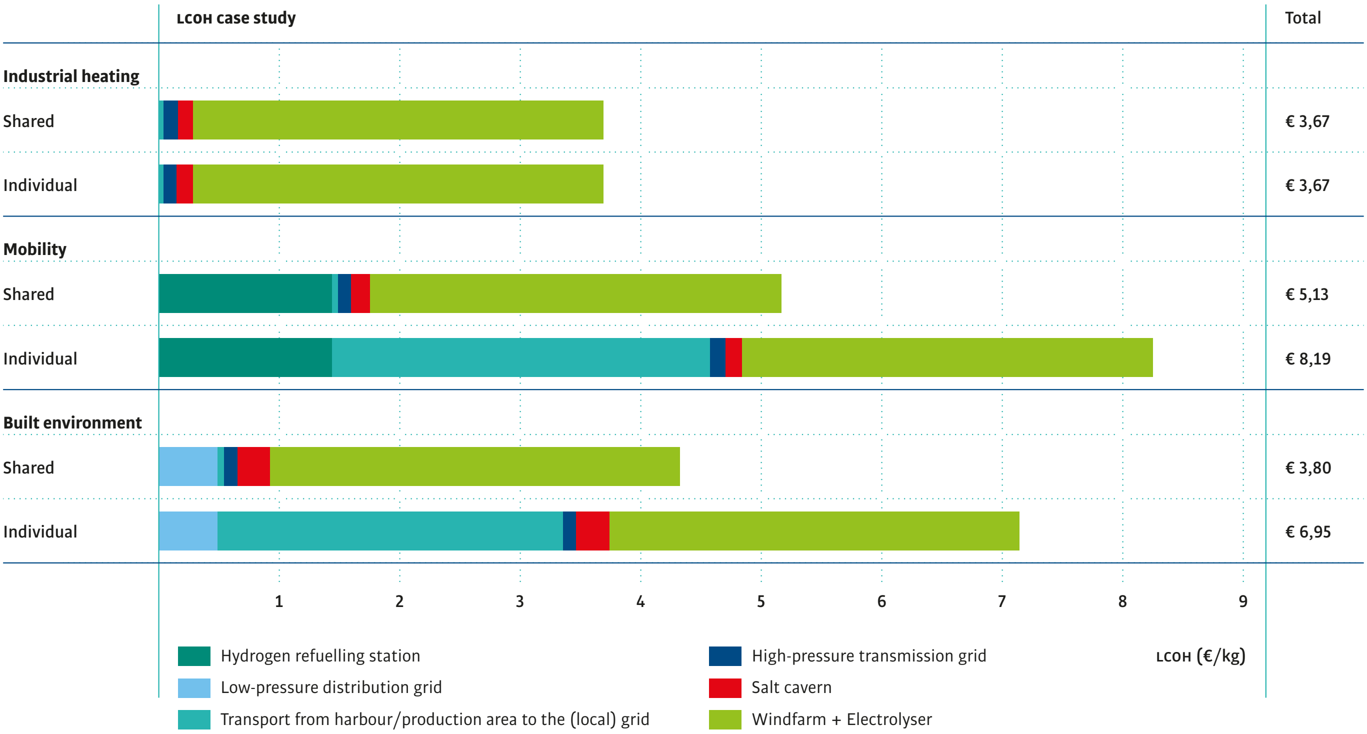


Figure 5. LCOH for the three cases studied (industry, mobility, and the built environment) where the bottom bars represent the LCOH of hydrogen if the transport infrastructure only services one particular consumer, and the top bars represent the LCOH of hydrogen if the transport infrastructure can be shared. Source: D7A.2.

Any hydrogen value chain can only develop if there is sufficient demand against prices that can compete with the alternative, initially fossil and eventually carbon neutral, options. In the HyDelta 1 value chain modelling work five types of end-users have been distinguished each with its own most logical carrier: ammonia as resource for the fertilizer industry; methanol as resource for fuel production; high temperature heat with the help of hydrogen for decentral industries; and gaseous hydrogen for refuelling stations for mobility and for the built environment, respectively. For all applications studied the simulations suggested that the value chain costs with clean hydrogen are higher than the fossil alternative society has been used to during the last decades. In several cases, such as greening of the production of ammonia or methanol or heating houses that are very hard to insulate, except from using carbon neutral hydrogen, virtually no alternatives have sufficiently high technological readiness levels to be implemented at short notice on a considerable scale. So, higher energy/feedstock cost levels than in the fossil past will need to be accepted as fact of life if the accepted mitigation targets are to be achieved.

Sources for this section

DELIVERABLE:

D7B.1 – Database with the filled-out factsheets about different components of the H_2 value chain elements to be modelled

Link to deliverable

DELIVERABLE:

D7B.2 – Accompanying report to D7B.1 where the factsheets are explained in more detail

Link to deliverable

DELIVERABLE:

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

Link to deliverable

DELIVERABLE:

D7B.4 – A roadmap on transport and storage of hydrogen and hydrogen carriers for five sectors in the Dutch economy

Link to deliverable

Finally, from a LCOH perspective, mobility and the built environment were found to often have serious economic potential as end users of green hydrogen, but whether there is a solid business case always strongly depends on location-specific conditions. To illustrate, battery-electric vehicles can often be fuelled relatively cheaply at home, but if driving ranges are > 400km and external electric fuelling can only be done at a relatively high fast-charging rate of some € 0.55/KWh, then fuelling FCEVs instead with green hydrogen becomes the more cost-effective alternative if the price of hydrogen can be less than € 6.20/kg (taking the assumed purchasing and use costs differentials of vehicles into account). For heavy-duty mobility the corresponding break-even hydrogen price was found to be € 6.40/kg.

It was also found that if the natural gas price (without energy tax) remains at levels above € 70/MWh, renewable hydrogen is likely to compete with natural gas as a fuel for the built environment by 2030, at least if the current energy tax on natural gas remains and renewable hydrogen would benefit from an energy tax exemption. If, in addition, the energy tax on natural gas would rise towards 2030 by 75% from its current level, as projected in the Netherlands' Climate Agreement, only a natural gas price > € 50/MWh is needed to make clean hydrogen competitive against natural gas.

International value chains

International hydrogen value chains based on imports from non-EU regions are generally expected to be part of our future with clean energy and feedstock possibly sometimes for reasons of costs, but in any case, because of simply insufficient domestic production capacities of clean hydrogen. It is therefore important to try to assess expected value chain costs of possible future imports by the Netherlands of hydrogen and hydrogen carriers from what currently seem to be promising locations such as non-EU countries with abundant renewable energy potential. Doing so is complex because most of the involved value chain processes are yet to be developed. The process and technology mixes involved, the demanded hydrogen volumes-over-time, and the dependencies between the hydrogen carrier import supply chain elements in an efficient global supply chain, all are still uncertain.

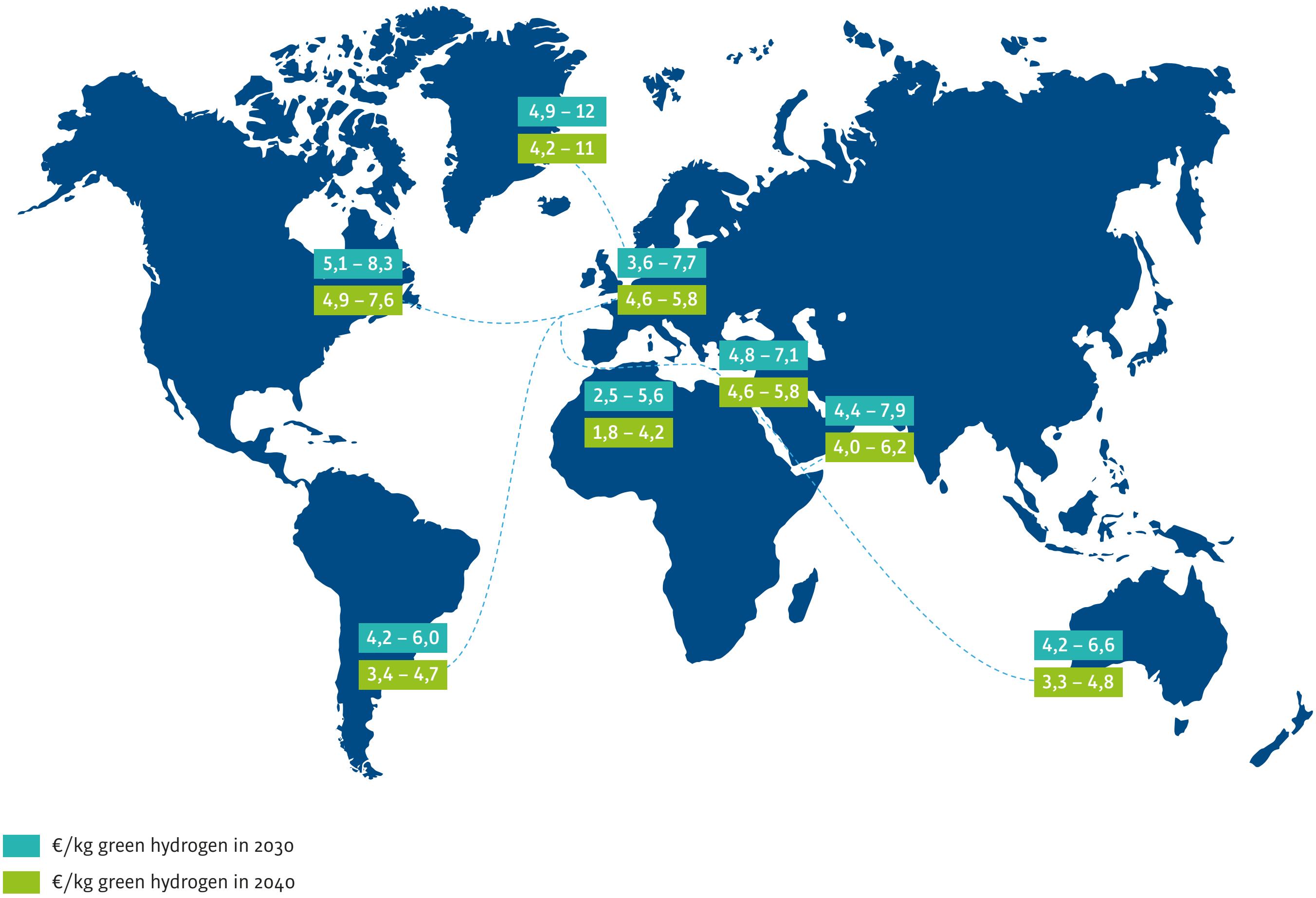


Figure 6. Expected LCOH ranges of green hydrogen production in different parts of the world in 2030 and 2040 . Source: D7B.3.

1) As a general note it should be added that the projected cost data used in the HyDelta 1 project – when compared with the comparable results of a representative set of benchmark studies – are at the high end or somewhat above that benchmark range. This may relate to issues such as hydrogen purity levels, utilization rates of equipment or other assumptions; however, this does not impact the main conclusions mentioned.

To get insight in the expected cost development in 2030 and 2040 of imported hydrogen and related carriers, five hydrogen carrier options have been distinguished: synthetic ammonia, synthetic methanol, liquid hydrogen, compressed hydrogen, and the liquid organic hydrogen carrier methylcyclohexane, and – apart from the domestic North Sea source – seven source countries: Australia, Argentina, Morocco, Iceland, Saudi Arabia, Oman, and the United Kingdom. The reference LCOH estimates, and their likely ranges are presented in *Figure* 6. It shows first of all what was already mentioned before, namely that, except for the imports from Morocco, the LCOH (without further conversion) from the North Sea are lower than of all other sources, irrespective if international transport is with ships or via pipelines. Second, it shows that the cost ranges of the non-EU sources are still too large to clearly distinguish the most cost-effective import routes to the Netherlands[1].

A further analysis of what determined the LCOH for the various source countries of imports suggested that, again, hydrogen production costs were the main cost component (compressed hydrogen 90%), even in the chains dominated by: liquid hydrogen (50%), liquid organic hydrogen (50%), and ammonia and methanol (70%). This once again showed that the role of (international) transport costs in the value chain costs is (much) more modest than that of the commodity itself. Hydrogen production costs in turn were found to be extremely sensitive to local costs of renewable energy and the number of full load hours of use of the production and conversion assets.

Section 2

Safe transportation

2 Safe transportation

What needs to be done to make hydrogen transport and distribution as safe as natural gas transport, using the existing natural gas infrastructure?

Transporting hydrogen 100% without risk is not possible: there will always be risks associated with the transport of a flammable gas. This also means that the transport of natural gas (or other forms of energy, for that matter) is not 100% without risk either. When the safety of a natural gas installation (or any physical or chemical process, and even consumer products) is assessed, a risk analysis is typically carried out. The names of the risk analyses vary per sector and even per country, with a few examples being the QRA (quantitative risk assessment) and the FMEA (failure mode and effects analysis).

Regardless of the name, all risk analyses are set to identify the same three main variables:
1. The cause of a safety incident
2. The probability of the safety incident to occur
3. The effect of the safety incident

The risk analysis then identifies the safety incidents that lead to the largest amount of risk and propose mitigation strategies to diminish those risks to a threshold, which typically comes from an agreement between relevant stakeholders. In the case of the natural gas network, these stakeholders include gas network operators, research institutions, authorities, etc., and they determine what kind of risk is acceptable as well as the acceptability criteria of an existing risk e.g. that a particular situation is not likely to lead to a catastrophic consequence (such as loss of life).

All in all, risk assessment methodologies are not designed to give a binary answer to the question 'is this process safe or not?', but rather address the issue 'what needs to be done to make the process at least as safe as required by the existing standards and regulations?'. A main driver of the HyDelta 1 project was to help the gas transport industry (the network operators in particular) in assessing safety levels of transporting and distributing hydrogen in the existing natural gas infrastructure. This implies that there is an inherent risk in transporting natural gas, and this risk has been agreed upon by the relevant authorities given that the existing risk will (with very high probability) not lead to disastrous consequences. As a consequence, there is an existing risk in transporting natural gas and there will be a risk in transporting hydrogen. The goal of assessing the risk of hydrogen transport will be to identify a set of rules and mitigating strategies that lower the risk of transporting hydrogen to at least the level of accepted risk of transporting natural gas.

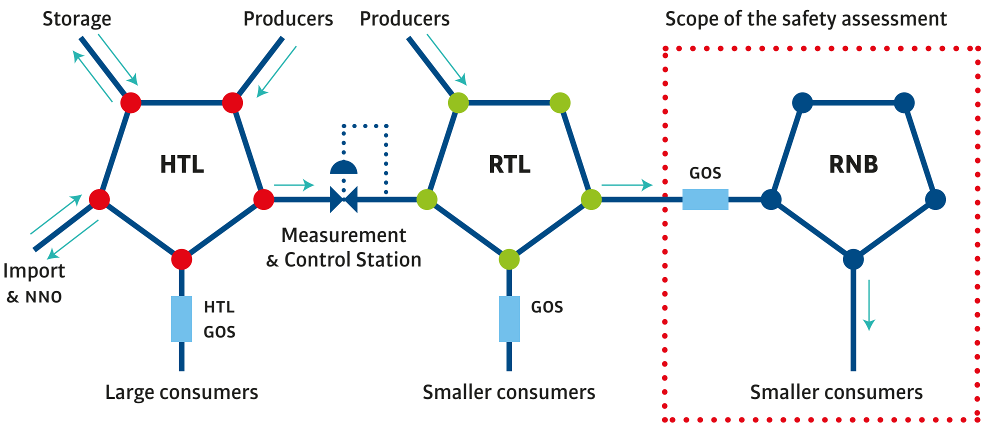


Figure 7. Overview of the Dutch natural gas transport and distribution network; in red the scope of HyDelta 1's safety assessment including experiments. HTL: high pressure (67 bar) transport network. RTL: regional (40 bar) transport network. RNB: regional (distribution, 8 bar) gas network. GOS: gas reception station, where the pressure of the gas is decreased. NNO: Neighbouring Network Operator, the operator of a network that shares an interconnection with the Dutch natural gas network operators. Source: modified from D1E.1.

One of the possible applications of hydrogen is to substitute natural gas consumption in the built environment i.e. households and (commercial) buildings, to decarbonize heat at homes. To learn and demonstrate, the Dutch Distribution System Operators (DSOs) are developing so-called 'hydrogen pilots'. These hydrogen pilots are projects spread out in different municipalities in the Netherlands where several groups of houses that typically consume natural gas for heating, will be supplied with hydrogen instead. The objective of such pilot projects is to show that it is possible to substitute natural gas for hydrogen in the built environment using the existing infrastructure; the Dutch DSOs aim to understand its most critical aspects, focusing on the safety as well as on the hydrogen-compatibility of the assets in the natural gas distribution network.

The activities on the technical part of the HyDelta 1 project were designed to answer one critical question: what needs to be done to make hydrogen distribution as safe as natural gas transport, using the existing natural gas infrastructure?

There were four main activities carried out within this part of the HyDelta 1 project:

1. The design of a Quantitative Risk Assessment (QRA) method and the execution of a series of experiments to provide initial input in understanding the potential risks associated with hydrogen leaks in the distribution system and inside a house or building, and how ventilation can be optimized to mitigate such risks
    - Recent literature from the UK-based projects H21 and Hy4Heat was studied, and a comparison was made between the British and Dutch natural gas distribution networks and household installations to translate the results from the aforementioned projects to the Dutch situation
    - A series of recommendations were issued to the hydrogen pilots to consider when the first hydrogen in the built environment projects are planned and executed

2 The study of safety-related natural gas system topics to be able to estimate the risks associated with the transport of hydrogen in the distribution and transport network in comparison with the use of natural gas
   - Odorization of hydrogen was studied; odorization is a critical safety measure because it adds a distinctly noticeable odour that helps identify leaks
   - Simulations were done to try and uncover additional situations associated with hydrogen that have yet to be documented in the literature so far i.e. high flow speed-related effects of hydrogen in the natural gas transport network

3 The analysis of the suitability of the current hardware (i.e. the existing natural gas infrastructure) to transport pure (> 98% purity) hydrogen to end consumers. The studied assets were
   - Piping and pipeline components
   - Pressure reduction stations
   - End-consumer connections and appliances in households

4 A study on the future demand and training requirements for technical personnel in the future hydrogen transport and distribution industry

Hydrogen-related risks in the distribution network and built environment

As the safety level of natural gas is taken as reference, it is important to know the differences in probability and consequences of safety-related events with natural gas and with hydrogen. The probability relates in particular to the possibility of a dangerous situation occurring; the consequences can be expressed in damage caused by a fire or explosion. Mitigating measures are then aimed at reducing the chance of a dangerous situation developing. With the aid of (existing) risk models, opportunities and consequences can be quantitatively modelled for both natural gas and hydrogen. In order to answer the objectives established at the start of the project, the first steps were taken towards the development of a QRA model suitable for predicting risks in the transport of hydrogen using the existing Dutch natural gas transport infrastructure, with emphasis on the distribution (<8 bar) network as well as the use in the built environment.

Sources for this section

DELIVERABLE:

D1A.1 – Report with results from Hy4Heat, H21, Hyhouse, and interviews, translated to the Dutch situation

Link to deliverable

Comparative analysis of the results from the H21 and Hy4Heat projects to the Netherlands

Started in 2014 and 2018 (respectively), H21 and Hy4Heat are two of the most relevant hydrogen-related research projects in the UK, with total budgets of £25 million per project and different project phases. The primary objective of these projects is to study the feasibility of transporting hydrogen using the existing British natural gas distribution network (H21) and replacing natural gas for hydrogen in the British built environment (Hy4Heat). As such, both projects bear close resemblance to the HyDelta 1 project, where both goals are combined under one programme.

Between late 2020 and mid-2021, the H21 and Hy4Heat projects released documents regarding their respective quantitative safety assessments, where they showed the most important safety aspects to consider when switching from natural gas to hydrogen in the distribution grid and the built environment, and they gave a set of risk-mitigating measures. One of the key activities in the HyDelta 1 project was to study those safety assessments and recommendations and to translate the results to the Dutch situation. The goals were 1) to make a comparative analysis of the Dutch and British situations using the H21 and Hy4Heat results as a starting point, and 2) to identify and fill the gaps in the existing knowledge towards developing a safety assessment and design a list of recommendations for the gas distribution network and the built environment in the Netherlands.

It was found that the low-pressure distribution network in the UK is constructed from mostly the same materials as in the Netherlands, but in different proportions in terms of lengths, diameters, and pressures. In particular, a large proportion of the pipe materials used in the UK is made of cast iron, a material that also represents a risk even for transporting natural gas. In this regard, the Netherlands holds an advantage with respect to the same situation, given that in the Netherlands cast iron pipelines are currently being replaced and that, by the time hydrogen is introduced in the existing infrastructure, the remaining cast-iron pipes will have been replaced. Furthermore, a large extent of the Dutch distribution grid is already composed of polymer materials, which have been found to safely handle hydrogen as well as natural gas.

Moreover, the typical layout of Dutch houses differs from that of the UK; in the UK, the gas meters (i.e. where the connection to the natural gas network is) can be found both inside of the house as well as outside whereas in the Netherlands most measuring cabinets are indoors. The location of the gas meters in houses plays a major role in determining the risk associated with hydrogen leaks in houses. Furthermore, in the UK there are proportionally more outdated houses compared to the Netherlands: poorer insulation, less mechanical ventilation and ventilation that does not comply with existing regulations regarding building codes and standards.

Among the rest of the insights gained from the comparative analysis of the H21 and Hy4Heat projects with the Dutch situation, there were two key insights that show that hydrogen could be inherently safer than natural gas in the following aspects:

1. Hydrogen concentrations below 10% in air (~2 times the lower explosion limit, LEL) are less likely to ignite than natural gas and, even if they do ignite, they seem to cause less damage than natural gas-related explosions at the same concentration (10% in air). This is of particular importance, because this means that there is a lower risk of hydrogen-related effects than of natural gas-related effects e.g. when small leaks occur
2. The innate advantage of hydrogen with respect to natural gas is that hydrogen combustion does not lead to the release of carbon monoxide (CO). CO poisoning is the most common type of incident involving natural gas according to the incident registration in both the UK and the Netherlands

The aforementioned insights show that, when the risk of hydrogen transport and use in the built environment is eventually brought to the accepted levels of risk of the transport and use of natural gas, it could be that the overall risk of hydrogen will end up being lower than natural gas due to the innate properties of hydrogen when it comes to avoidance of CO poisoning and the lower probability of ignition as a consequence of leaks. The risk for situations with a concentration of more than 10% of hydrogen in the air is higher than with a similar concentration of natural gas in the air; therefore, it needs to be investigated if additional measures will be needed to deal with this.

Sources for this section

DELIVERABLE:

D1A.2 – Report with additional questions for the Dutch situation and test program

Link to deliverable

Understanding the role of ventilation on the safety of indoors hydrogen installations

The most critical safety component where the Dutch DSOs wanted additional recommendations is in the area of ventilation i.e. how to properly ventilate a house to minimize the risk of hydrogen mixtures reaching or exceeding the LEL i.e. the lowest concentration at which an ignition (fire) can occur. The LEL of natural gas is 5% (50,000 ppm) in air, whereas for hydrogen it is slightly lower (4% or 40,000 ppm of hydrogen in air). Hydrogen concentrations in air of 10% or more can lead to explosive atmospheres.

The testing program of the HyDelta 1 project regarding leak testing was focused on small hydrogen leaks only (such as could occur in a household environment).[2] The results of the testing showed that even in closed spaces the concentration of hydrogen never reached anywhere close to the LEL, giving early indications that even moderate ventilation in closed spaces (such as can be found in older houses and buildings) might be sufficient to prevent explosive hydrogen-air mixtures from forming. Furthermore, initial insights showed that the ventilation of hydrogen follows a similar pattern as that of natural gas; experiments were carried out with both gases in a closed space, and both gases showed the same response to different levels of ventilation inside a closed space). For larger leaks (such as can be caused by e.g. a pipeline fracture), additional testing is required.

The literature suggests that the standard consumer-grade CO (carbon monoxide) detectors are cross-sensitive for hydrogen, meaning that it is (in principle) possible to take advantage of the existing safety infrastructure in houses to detect hydrogen leaks at an early stage. Odorising the hydrogen (discussed in detail in the next section) can lead to the detection of hydrogen concentrations that are beyond the detection range of the CO sensors and still lower than the LEL. Adding consumer-grade CO sensors in households can be an additional safety measure used as a redundancy to further increase the level of safety of hydrogen in the built environment. All this opens up the possibility for hydrogen to replace natural gas as fuel in existing as well as new houses, where the level of safety of hydrogen consumption can reach the current safety level of natural gas consumption while taking advantage of the existing safety infrastructure in households.

2) In household installations, the leaks that can be expected are of smaller magnitude than what could be expected in the distribution grid e.g. during a pipeline fracture.

Regarding the safety measures needed to introduce hydrogen in the built environment, the HyDelta 1 project proposed a list of mitigating measures for the hydrogen pilots in the built environment so that these pilot projects can be safely carried out in the coming years. The list of measures covered all the phases of a project (preparation, design, implementation, and operation); such measures were conservative because the idea behind these hydrogen pilots is to build up confidence in hydrogen transport and consumption in households and buildings. Since the natural gas distribution infrastructure has been operating for decades, it may be that some of the natural gas installations no longer conform to the state-of-the-art safety requirements; therefore, attention needs to be paid to the first hydrogen pilots to elucidate which parts of the distribution grid need to be reassessed as per the current safety standards. It is expected that, with the accumulation of experience from these hydrogen pilots, some of the recommendations might be rolled back or deemed unnecessary.

Sources for this section

DELIVERABLE:

D2.1 – Choice for a sulphur free odorant

Link to deliverable

DELIVERABLE:

D2.2 – Influence of sulphur containing odorant on end-use appliances

Link to deliverable

DELIVERABLE:

D2.3 – Stability of odorants in hydrogen

Link to deliverable

DELIVERABLE:

D2.4 – Report on the risks of not odorizing hydrogen.

Link to deliverable

DELIVERABLE:

D2.5 – Report with advice over odorizing hydrogen including a possible choice for a defined type of odorant and its dosing

Link to deliverable

Further hydrogen-related risk mitigation

Odorization of hydrogen

Of the suggested risk-mitigating actions, there is one that has the highest level of impact towards risk mitigation: odorization of hydrogen. Most natural gas distribution networks worldwide contain an odorant i.e. a chemical substance added in small quantities (in the order of ppm) to the gas network. Odorants make use of the acute sense of smell of humans to detect gas leaks without the need for dedicated hardware that would be expensive to purchase and install in every household.

Following the standard ISO 13734, the odorant of choice selected for the Dutch natural gas distribution network is tetrahydrothiophene (THT). Before the HyDelta 1 project began, the main question was: does THT work with hydrogen in a similar fashion as with natural gas? Thus, the goal of this work was to prove that the (aforementioned) list of properties of THT in natural gas were also applicable to THT in hydrogen. Another goal of this research was to propose an alternative odorant for hydrogen next to the evaluation of THT, and to assess which end-user equipment is incompatible with sulphur-containing odorants (e.g. fuel cells).

The research has shown that no insurmountable problems are to be expected for hydrogen combustion equipment, such as central heating and hot water boilers, kitchen appliances, ornamental fireplaces, outdoor stoves and patio heaters, and gas engines when using hydrogen that has been odorized with a sulphur-containing odorant, such as THT. The presence of sulphur in hydrogen leads to irreversible damage to fuel cell systems, so the odorant should be removed before use. Furthermore, all tested odorants i.e. THT as well as sulphur-free products such as Gasodor® S-Free and 2-hexyne, were found to exhibit stable behaviour in a hydrogen atmosphere over a three-month test period. In the case of a gas leak from a mixture of an odorant in hydrogen, no separation of the odorant and hydrogen was found to take place. With regard to the distribution of gas in a room and the smell of a gas leak, odorization of hydrogen is just as effective as odorization of natural gas.

Sources for this section

DELIVERABLE:

D1E.1 – Impact of high-speed hydrogen flow on system integrity and noise

Link to deliverable

Potential effects of high-speed hydrogen in the transport system

The volumetric energy density of natural gas is ~3 times higher than for hydrogen i.e. at the same operating pressure, hydrogen needs to flow at 3 times the speed of natural gas to provide the same amount of energy to a consumer. This increased flow rate can be a limitation when optimising the gas transport installations for hydrogen. For natural gas, a speed limit is usually set at 20 m/s, but for hydrogen this limit needs to be set at 60 m/s to maintain the existing gas transport capacity in terms of energy. The increased velocity of hydrogen with respect to natural gas could in theory cause potential problems that are known not to occur in the existing natural gas network, such as flow-induced risk pulsations, vibrations, problems in equipment such as thermowells and other intrusive equipment, and erosion, to name a few. These problems would need to be investigated if found to occur under hydrogen.

As far as the impact of transporting hydrogen on noise is concerned, the study revealed that hydrogen flowing at higher speeds can cause lower sound levels, but that the frequency of this sound will be about 3 times higher than for natural gas. Moreover, the higher frequency of the sound may cause noise problems under particular circumstances. All this means that measures may be needed to restrict vibrations to acceptable levels or to introduce sound reduction for the hydrogen transport infrastructure.

Erosion appears to be the most uncertain mechanism that may cause problems when transporting hydrogen in the existing natural gas transport infrastructure. In general, transporting the same amount of energy as hydrogen instead of as natural gas will result in hydrogen flowing at high speeds (~60 m/s), which in turn could translate into an erosion potential of one order of magnitude larger compared to flowing natural gas (which flows at 20 m/s to deliver the same amount of energy). An important parameter is the level of solid particle contamination in the gas stream, which is uncertain. Filters are in place to prevent this contamination. Assuming currently acceptable limits (i.e. for natural gas) would already render unacceptable levels of erosion (i.e. for hydrogen). Further research is hereby recommended on flow-induced effects to completely disregard erosion as a potential risk, or to design a corresponding risk-mitigating strategy. It is recommended that further investigations regarding erosion are done as follows:

1. Exploring the performance of filters in the different parts of the natural gas transport network systems (high pressure, regional transport, and distribution networks) with high-speed hydrogen flow. This should enable a more educated choice for the solid loading in the gas stream
2. Perform dedicated flow simulations to characterise worst-case erosion rates in the RNB systems, in combination with suitable material constants (e.g. for PVC pipes and materials such as steel and PE), for which tests may be required

It is important to mention that in the current distribution system of natural gas, no significant levels of erosion have been detected.

Suitability of the current hardware for hydrogen transport

The Dutch RNB network has more than 125,000 km of pipelines as well as around 8 million connections to houses and buildings. Any changes in the existing components can have consequences regarding costs, disruptions to the gas delivery, and potential capacity constraints due to availability of technical personnel. This is why it is paramount to study whether there exist components in the current natural gas distribution network that are also suitable for hydrogen. The components in the low-pressure gas networks in the Netherlands that were studied in the HyDelta 1 project, can be catalogued in the following groups:

1. **Piping and pipe components:** including the pipes themselves but also fittings, welds, gaskets, safety equipment, etc.
2. **Gas pressure reduction stations:** these are points where the gas pressure is reduced (e.g. from the RTL, see *Figure 7*) and distributed to a group of houses connected to it
3. **End-consumer connections and appliances:** mainly comprising pressure reducers, gas flow metres, and appliances (boilers, stoves, etc.)

Piping and pipe components

It has been established in previous research done in the Netherlands and abroad, that the materials used for low-pressure distribution pipes (mainly polymers i.e. PVC and PE) are suitable to transport hydrogen as well, meaning that within the HyDelta 1 project, the suitability of pipe materials to transport hydrogen did not need to be researched. The main focus of the research on pipe components in the HyDelta 1 project related to determine the following:

1. Whether leak-tightness requirements as applied to natural gas distribution pipelines can also be applied to hydrogen
2. To what extent the existing natural gas network influences the quality of hydrogen through desorption of THT and through permeation of oxygen, nitrogen, and water
3. The risks associated with household installations after conversion from natural gas to hydrogen
4. Whether emergency shut-off valves in the high-pressure natural gas transport network are suitable for reuse in a hydrogen network

About the leak-tightness requirements, four types of connections were assessed: primary connections (i.e. connections between the network and a house), new household connections (e.g. to the boiler in a newly built house), existing household connections, and the connections of a gas flow metre. Based on the results achieved, a proposal was made to alter the Dutch standard NEN 7244-7 for assessing the leak-tightness requirement for existing connection pipes when transporting hydrogen, to ensure that all four types of connections remain within acceptable leak rates when hydrogen is being consumed e.g. in a house.

Sources for this section

DELIVERABLE:

D1C.1 – Purging of natural gas pipelines with H_2

Link to deliverable

DELIVERABLE:

D1C.1a – Entry of air into a hydrogen pipeline in case of a pipe rupture

Link to deliverable

DELIVERABLE:

D1C.2 – Leak-tightness of distribution pipes

Link to deliverable

DELIVERABLE:

D1C.3 – The influence of the existing natural gas distribution networks on the purity of hydrogen

Link to deliverable

DELIVERABLE:

D1C.4 – Domestic pressure regulators

Link to deliverable

DELIVERABLE:

D1C.5 – Insights in the risks to convert the current gas installations to 100% H_2 and determining mitigating measures for these risks

Link to deliverable

DELIVERABLE:

D1C.6 – Development of 100%-hydrogen compatible domestic components

Link to deliverable

DELIVERABLE:

D1F.1 – Hydrogen compatibility of ball valves from the natural gas transmission grid

Link to deliverable

Furthermore, it was found that the hydrogen purity will be influenced by desorption of THT and by permeation of oxygen, nitrogen, and water through the (polymer) pipe wall. The research has determined key parameters that can be used to calculate up to what extent these components will end up in the hydrogen and how much the purity of hydrogen will decrease as a result thereof.

Regarding the risks associated with an indoor installation (in the Dutch context) when switching from natural gas to hydrogen, while the chance of carbon monoxide poisoning drops to zero and the risk of injury from small gas leaks (< 1 l/h) remains extremely small, the risk of injury in the event of larger gas leaks (> 10 l/h) increases when consuming hydrogen instead of natural gas. To reduce this probability, mitigating measures are described in the corresponding report (See also the Section Understanding the role of ventilation on the safety of indoors hydrogen installations)

Furthermore, in the HyDelta 1 project a significant number of shut-off (i.e. ball) valves were tested; the selection of the valves to be tested was done in coordination with Gasunie (the operator of the high-pressure and the regional transport networks). The largest share of the valves was tested with both natural gas and hydrogen, and no external leaks were found. In addition, no other points were found that make the possible reuse of valves in a hydrogen network impossible.

In summary, the existing piping and pipe components for transporting natural gas can be expected to operate with hydrogen without problems. The caveat will remain that it is a good practice to replace old or damaged components before switching over to hydrogen; recurring replacements are common practice in the existing natural gas infrastructure, meaning that there is no deviation proposed from the standard operating practices of the Dutch natural gas network operators in this regard.

Sources for this section

DELIVERABLE:

D1B.1 –Operation of gas stations with spring loaded regulators with hydrogen

Link to deliverable

DELIVERABLE:

D1B.2 – Safety during maintenance works for hydrogen gas stations

Link to deliverable

DELIVERABLE:

D1B.3A – Ventilation in gas stations

Link to deliverable

DELIVERABLE:

D1B.3B – Preliminary work plan for explosion testing in gas stations

Link to deliverable

DELIVERABLE:

D1B.4 – Dust transport properties of hydrogen and natural gas in filters of gas stations

Link to deliverable

Gas pressure reducing stations in the low pressure (distribution) gas network

One of the key components in the natural gas transport infrastructure are the gas reducing stations, since they are the main connecting points between different parts of the gas grid (as can be seen in *Figure 7*). The primary function of a gas reducing station is to decrease the pressure of the incoming gas to the operating pressure of the downstream pipes. To maintain the security of supply to consumers, it is important to ascertain that the current gas pressure reduction stations are compatible with hydrogen. The main focus of the research pertaining to gas pressure reduction stations was to assess the hydrogen compatibility of these assets, and in particular:

1. The correct functioning of district stations (i.e. that decrease the pressure from 8 bar to 100 mbar) under a hydrogen atmosphere and with an increased (i.e. 3 times) flow
2. The safety operating procedures when performing (routine) maintenance and switching over from natural gas to hydrogen
3. Since the volume flow (i.e. Nm^3/h) of hydrogen needs to increase threefold with respect to natural gas to provide the same energy (i.e. MWh/h), the work package assessed the risk of a potential increase in dust transport that may clog the dust filter in gas stations
4. If there is adequate ventilation of the housing of a gas station in case of a hydrogen leak and how it compares to the operation with natural gas

Regarding the correct functioning of (district) gas stations, it was found that the tested district gas stations (that represent the most common type of gas stations in the Dutch gas network) can be used for hydrogen without modification.

About the safety operating procedures, it was recommended to continue applying the existing procedures for natural gas as described in the safety work instructions described by the NEN 7244-7 standard; additionally, a recommendation was issued to add a few safety steps for working with hydrogen, such as the use of flame arresters and double-checking and removing obstacles (as would be done for natural gas in any case).

The results from the experiments about the transport of dust show that more dust transport can be expected when the distribution networks are switched from natural gas to hydrogen, but this depends on the type of dust already existing in the pipelines. Moreover, it was recommended that more research should be done to study the transport of dust at higher pressures to be able to confidently rule out the potential risks associated with the transport of dust that occurs when transporting hydrogen (at a higher flow speed than natural gas).

Lastly, about ventilation, it was found that, with the chosen leak rates, hydrogen leaks are more likely to form an explosive atmosphere than natural gas leaks within the casing of a gas station. That being said, and after discussions with both experts from the distribution system operators and from the industry, it appears that the chosen leak rates are significantly larger than what can be reasonably expected in practice. Therefore, a recommendation was issued that more experiments be carried out while choosing leak rates that are more representative of past experiences with natural gas as well as with the current method for doing safety analysis when developing and installing gas stations.

Sources for this section

DELIVERABLE:

D1D.1 – Hydrogen flow metering for the built environment

Link to deliverable

Inhouse connections and components

In terms of number of connections, households are the most numerous consumers of natural gas in the Netherlands with 7 million connections (1 million connections are located in commercial buildings). A typical household gas connection consists, among others, of two main components: a pressure reducer (to reduce pressure from 100 mbar to 30 mbar) and a gas flow metre (to measure consumption). Both components were developed to function with natural gas so in the HyDelta 1 project the compatibility of these components for hydrogen was researched.

Moreover, there are three main uses of natural gas in households: cooking, space heating and warm water. Those last two uses are accomplished with a single device namely, a (high efficiency) boiler. Despite the HyDelta 1 project having no direct activities around developing household gas appliances, it is important to understand the state of development of such devices i.e. to carry out an early identification of potential hazards and compatibility issues with the distribution network.

In the HyDelta 1 project, research was carried out regarding end-consumer connections and appliances to determine:

1. What the developments are in the field of hydrogen components and hydrogen appliances for consumers
2. The risks in the situation that a house pressure regulator is not replaced when converting natural gas to hydrogen
3. The suitability of natural gas flow metres for hydrogen

It was found that existing pressure regulators intended for natural gas appear to also work under hydrogen atmospheres. After discussions with the Dutch gas network operators, a series of guidelines were designed that network operators can use to decide whether to replace a domestic pressure regulator.

Moreover, it is expected that components and gas appliances intended for domestic applications and suitable for use on 100% hydrogen will be available as prototypes in 2022. Central heating combi boilers that are being developed for hydrogen are currently not suitable for short-term operation on natural gas, but central heating combi units are being developed that can operate on natural gas and are easy to convert to allow the operation with hydrogen. About the gas flow meters, the suitability of measurement principles for small consumption (i.e. household) meters capable of measuring hydrogen was investigated based on gas characteristics, the measurement technology and availability. Hydrogen has a density 9 times lower than natural gas, so the current technology (based on the movement of a diaphragm) is unsuitable for hydrogen. It was found that the current technology for natural gas flow metering is incompatible with hydrogen due to the lower density of hydrogen compared to natural gas.

The availability of alternative gas flow meters for hydrogen was investigated through interviews with meter suppliers; ultrasonic meters and thermal mass flow meters seem to be the preferred options for household hydrogen flow meters in the short-term future. That being said, the purity of distribution-quality hydrogen (> 98% pure) may contain up to 2% gaseous impurities (the main expected impurities are nitrogen, carbon dioxide, methane, and oxygen) and, since both the thermal conductivity and the speed of sound properties of these impurities differ significantly from that of hydrogen, the presence of such impurities might impact the accuracy of such gas flow meters beyond what is currently accepted by the existing standards regarding gas flow meters. When hydrogen meters are evaluated by gas network operators, it is useful to examine the aspects mentioned above in more detail.

Sources for this section

DELIVERABLE:

D4.1 – The requirements for technical personnel and advice for reinforcing education on the subject of hydrogen

Link to deliverable

Future demand and educational requirements for technical personnel in the future hydrogen transport and distribution industry

To be prepared for the future hydrogen economy, we need to be ready to educate future technical personnel that will be tasked with converting the existing transport and distribution grids from natural gas to hydrogen. As such, this part of the HyDelta 1 project mapped the potential demand for MBO-trained technical executive personnel for the conversion, maintenance and operation of the hydrogen transport and distribution network. In addition, an inventory was done regarding the current training offered at MBO (secondary vocational education) level in different parts of the Netherlands.

Most of the currently available e-learning and physical courses, workshops and masterclasses deal with the basics of hydrogen and hydrogen applications and are mainly intended for MBO+ and HBO (higher professional education/ university of applied sciences) levels. In addition, the available training focuses mainly on mobility. The limited supply of hydrogen training courses and the absence of adequate training for MBO-trained technical personnel in the infrastructure and distribution sector is a cause for concern.

It was estimated that the future demand for technical personnel in the Netherlands will be between 3500 and 7000 FTEs (full-time equivalents) by 2050. Relevant studies in this level of detail could only be found to a limited extent, meaning that there is a large uncertainty in the aforementioned values.

Moreover, the following points emerge from this research as necessary actions in the area of education and training of technical personnel:

1. Develop adequate MBO education in the field of hydrogen in the infrastructure and technology sector, including the relevant curricula and learning goals. A first proposal was made in this research
2. Attract sufficient MBO staff and teachers to train them. Currently there is a high level of scarcity on the labour market and an urgent need for professionals (both technicians and executives) who are trained in relevant hydrogen topics

Section 3

Safety standards

3 Safety standards

Safety standards, blending, policy, norms, etc.

In this section a number of HyDelta 1 research issues will be addressed that all are dealing with preconditions that need to be clarified and fulfilled if hydrogen is to be introduced into the existing infrastructure. It subsequently covers the HyDelta main findings on: which standards urgently have to be in place, particularly regarding safety conditions; which public support levels are required to enable sufficient progress in introducing hydrogen; and how mandatory blending quota schemes start creating new market uptake perspectives.

Sources for this section

DELIVERABLE:

D3.1 – Development of standards for hydrogen with a focus on hydrogen transport

Link to deliverable

Status of standards regarding hydrogen (safety)

A lot of research is currently being done on how to introduce hydrogen and natural gas/hydrogen blends more widely into the energy system. Much of the results of that research will eventually be incorporated into new or existing gas standards. In fact, considerable work is already underway on such standardization both in the Netherlands and the EU. In order to gain insight into what gas standardization gaps still need to be (urgently) filled to include hydrogen, HyDelta 1, with the help of various expert stakeholders, created an overview of standardization projects currently underway and their status to see what is still missing.

Based on this a gap analysis was carried out on around seventy topics related to gas grid administration. For each topic, knowledge gaps have been assessed to determine which standards or standard adjustments require attention most urgently; the list requires regular future updates. The following seven topics were shown to have the highest priorities of being researched with an eye on inclusion in (new) gas standards for hydrogen transport via the existing natural gas distribution network:

1. Pressure tests for pipelines
2. Gas volume measurements
3. Rapid measurement of gas composition
4. Safety
5. ATEX classification
6. Requirements concerning leak-tightness and leak testing
7. Requirements for permissible gas leaks

The extension of standards to include hydrogen typically proceeds at the NEN-, CEN- and ISO-levels. For all these processes it is important that the best national experts are delegated to the (inter)national standards committees, and that the topics with the identified highest and average priority are dealt with accordingly.

Table 1. Support intensities required to make hydrogen value chains competitive against the fossil alternative, for ammonia and methanol (top) as hydrogen carriers, and Industrial heating and the Built Environment as end-users (bottom). The values in the table have been derived assuming: a natural gas price of € 50/MWh, a CO_2 allowance price of € 60/ton, and the LCOHs of the base scenarios of the study in HyDelta 1's WP7A & 7B. Source: D7A.3.

	Ammonia			**Methanol**		
Support intensity	Blue	Green	Import green	Blue	Green	Import green
€/ton of product	52	142	153	94	207	250
€/kg H_2	0.29	0.80	0.86	0.47	1.04	1.25
€/ton CO_2 reduced	31	81	87	49	106	128

	Industrial heating			**Built environment**	
Support intensity	Blue	Green	Import green	Green (without tax differentiation)	Green (with tax differentiation)
€/MWh	42	64	83	70	23
€/kg H_2	1.25	1.90	2.49	2.11	0.69
€/ton CO_2 reduced	64	96	126	107	35

General policies for introducing hydrogen

HyDelta analysed for a large number of hydrogen value chains (or end-use and hydrogen source combinations) what public monetary support would be needed to make clean hydrogen competitive against fossil alternatives (see *Table 1*). The results show first of all that in all general cases the imported hydrogen needs more support to compete with fossil alternatives than all corresponding domestically produced hydrogen (carriers). In other words, besides some exceptions, imports of green hydrogen (carriers) are economically attractive only to the extent that domestic production levels – for whatever reason and even if the business case is sound – remain insufficiently large to meet national demand.

The table also illustrates that clean hydrogen for ammonia production requires the lowest financial support intensity of the four options considered. For instance, per ton of CO_2 reduced an overall support level of € 142/ton is needed to make domestically produced green ammonia competitive against fossil ammonia. This result is especially so, because the natural gas and CO_2 allowance price impact on fossil ammonia costs are largest compared to the other hydrogen applications (it explains why the impact of CO_2 allowance prices is less for the 'grey' methanol value chain, as part of the carbons are used to produce the methanol). Finally, clean hydrogen used for heating (both industrial and in the built environment) requires more support to get its chain competitive than if used as feedstock.

Sources for this section

DELIVERABLE:

D7A.3 – Summary for policymakers: hydrogen value chains in the Netherlands

Link to deliverable

DELIVERABLE:

D8.1 – Admixing literature review

Link to deliverable

DELIVERABLE:

D8.2 – Assessment of admixing schemes

Link to deliverable

DELIVERABLE:

D8.3 – Pilots for introducing hydrogen blending quota

Link to deliverable

DELIVERABLE:

D8.4 – Economic analysis of potential market development of hydrogen certificate markets

Link to deliverable

DELIVERABLE:

D8.5 – Mandatory blending of hydrogen: summary for policymakers

Link to deliverable

The role of blending in launching clean hydrogen

To introduce hydrogen, subsidies are necessary e.g. to get hydrogen technologies through the 'valley of death' and initiate scaling up and speeding up of clean hydrogen production. This, however, will probably be insufficient to get to mature hydrogen value chains: launching demand is equally important. For this, introducing mandatory blending quota (either physical or virtual blending, or both [3])of hydrogen in the gas system comes into the picture, also because it gets clean hydrogen demand off the ground immediately.

Mandatory physical blending prescribes that a certain percentage of a portfolio of fossil gasses or fuels is replaced by carbon neutral hydrogen (carriers); if mandatory virtual blending applies, certificates are accepted as a way to comply with the blending obligation. Such mandatory blending is challenging, because if implemented in an unsuitable manner, it may even slow down the hydrogen introduction. In HyDelta 1 the following five key challenges of introducing this policy instrument have been identified and will be discussed shortly in the sections below.

Virtual vs physical blending

A basic conceptual issue with respect to blending is the distinction between physical and virtual blending. Physical blending means that clean hydrogen is actually mixed into the existing flows of fossil gasses or liquids; virtual blending means that a blending obligation is fulfilled with the help of certificates proving that the hydrogen was physically introduced into the energy system anywhere else. A party under a quota obligation can only comply with certificates if other parties in the scheme exceed their obligation; otherwise, there would be double counting or 'greenwashing'. Compliance via certificates can only work if trading of certificates functions properly and guarantees exist that the certificates are backed up by true non-mandatory decarbonization activity. This requires rules and regulations such that schemes are perceived as reliable, watertight, and secure. If it works, it generates advantages compared to a scheme accepting physical blending only, because it contributes to the cost-effectiveness of compliance insofar as due to the trading option blending will be concentrated where it can be done most cost effectively.

3) Other terminologies are mandatory quota, quota obligations, binding quota targets, admixing schemes, renewable portfolio standards (RPS), or tradable green certificate schemes (TGCS).

A virtual blending scheme therefore is by definition the mirror image of a physical blending scheme, but physical blending, instead, is possible without virtual blending. In pure physical blending the scheme is simpler. The backdrop, however, is that physical blending should be measured and accounted for, and that the scheme is (much) less cost effective. That is why in actual practice most mandatory blending schemes involve a combination of physical and virtual blending. An extreme case of a combined scheme is when the flows in one part of the fossil energy system are completely physically replaced by a clean alternative, whereas the surplus of certificates from that switch is used to virtually decarbonize another part of the energy system. For instance, the 'grey' hydrogen transported towards chemical plants is replaced by (almost 100%) pure clean hydrogen, while the (surplus) certificates are all sold to owners of tank stations to comply with their obligation to green their fuels.

An interesting issue of physical blending of multiple gasses and/or fluctuating/increasing concentrations in the public grid is what technical adjustments and costs are needed to guarantee the safety of the grid and the connected appliances. If, for instance, safety-related costs of grid adjustment and/or adjustments of connected appliances rise steeply once the blended hydrogen levels surpass some limits, one may for techno-economic reasons decide to maximize the accepted physical blending percentage to a predetermined limit, but to accept higher blending levels by way of virtual blending only. If one would want to raise blending rates even higher, the outcome could then even be to jump from there directly to pure hydrogen systems.

Another point related to physical blending is the measurement and billing of gas. Currently measurement of gas flows is done by volume of gas. Because hydrogen and natural gas differ in energy density per volume, volume measurement may need to be adjusted, especially if blended volumes fluctuate over time.

Quota differentiation

A specific design issue of mandatory blending is whether specific production technologies of hydrogen are distinguished. This relates to the fact that clean hydrogen can be produced with different technologies. One option is to produce ‘green’ hydrogen with electrolyzers turning RES-based power into hydrogen; another is ‘blue’ hydrogen where mostly steam methane reforming (SMR) is used to split natural gas into hydrogen and carbon and oxygen components, and the carbon is stored usually underground. Other ways of producing clean hydrogen are via pyrolysis possibly combined with CCS or using nuclear power as an input. Policy makers can prefer technology neutrality by leaving it to the market to produce the clean hydrogen most cost-effectively.

An alternative policy perspective is that one wants to steer the technology such that some technologies have a good chance to develop (thus preventing locking in of the technology). This asks for a differentiated quota, e.g. prescribing that x % be fulfilled with technology A, y % with technology B, etc. Proponents of technology neutrality generally argue that the market knows best how to mitigate most cost effectively. Opponents argue that without further specification promising green technologies will be unduly locked out because time- and scale-dependency of technologies favour the early cost-effective ones at the cost of ‘later’ ones.

Certificate market design

Certificate trading may meet public suspicion of being easily abused by fraud, lack of control, or greenwashing: who guarantees that the certificate genuinely represents mitigation, and that trade is not manipulated? Governments therefore have to see to it that certificates and their trading scheme are reliable, transparent, and carefully controlled. This requires institutions to do the checks and balances and rules and regulations guaranteeing the quality of the system. Carefully testing this requires time and money and may slow down actual blending to quickly mature. Also, buyers and sellers of certificates generally are reluctant to comply with too much paperwork and its costs; traders typically want to generate acceptable trading margins while being free of all kinds of restrictions to promote market transparency and liquidity. The challenge is to speed up certificate market maturity fast enough for blending to become successful, while preventing the frustration of private stakeholders to ensure their continued participation in the market. Pilots are helpful tools in trying to find the right balance (see also Section Introducing hydrogen blending via pilots in the Netherlands on this).

Volatility of certificate prices

A major challenge of mandatory blending from an economic incentive perspective is the right incentives for clean hydrogen investors to actually raise their volumes. A characteristic of blending quota is that the certificate price is left to the market so that upfront it is unclear how prices will behave. Modelling future certificate prices has learned that it is very hard to make reliable predictions, which adds to certificate prices' uncertainty acting as a disincentive to invest. For policy makers the challenge therefore is to somehow provide (some) certainty on the likely price trend of certificates as well as volatility ranges. This is, however, problematic because then policy makers somehow have to intervene in the market introducing risks of speculation and perceptions of regulatory uncertainty. Experiences from other quota schemes suggest that a balanced system of minimum and maximum prices for certificates, some quota allocation flexibility, the introduction of some market stability reserve facility, and possibly some kind of buffer fund, could work to stabilize the certificate market.

Import of hydrogen

Rough estimates of the future need for green power across the EU seem to suggest that for the time being the EU will not be able to generate enough to also cover all green power for green hydrogen (carriers') demand. So, part of the energy molecules needed may need to be imported. This makes imports a likely part of blending schemes of clean hydrogen. The issue then is how to include such imported flows into EU blending schemes. So far little attention has been given in the literature to this issue, e.g. how this may affect incentives to invest in domestic production, etc.

Introducing hydrogen blending via pilots in the Netherlands

Introducing hydrogen with the help of mandatory blending quota either as feedstock or as energy carrier can have a far-reaching business impact for all stakeholders involved. That is why as a first step pilots are indispensable to assess how such schemes work out in practice. A lot can be learned from comparable mandatory blending schemes that have been introduced in other sectors, but nothing can replace real-life testing of considered policy measures for specific market conditions. So, mandatory blending pilots are crucial in dealing with all kinds of obstacles, hick-ups and behavioural complexities that may show up in actual practice.

In designing pilots, one therefore has to carefully select quota schemes such that pilots have best chances of being realistic, effective, and ultimately successful. Also, pilots need to be well prepared, because it takes time for the various stakeholders involved to prepare themselves for the new opportunities of replacing fossils by carbon neutral alternatives. Suggested early pilots in the spirit of recent policy proposals are the following.

A first pilot: Introducing a quota in industrial applications of hydrogen. Our analysis suggests that mandatory blending quota pilots can relatively easily be initiated for those cases in which the number of stakeholders is relatively small, and where a tradition of directly using hydrogen does exist, i.e. in the chemical industry. So, one could as a start and in close communication with the main industrial and other stakeholders investigate how an increasing percentage of hydrogen, currently still 'grey', can stepwise be replaced by clean hydrogen, while assuring that such volumes can indeed be delivered and that the transport system to do so is in place. Such a pilot could end up being complex – and may in fact be preceded by a pilot 'on paper' – because the complete value chain of hydrogen needs to be sufficiently developed and in the same timeframe. However, if it works for a number of showcases, it will show the rest of the industry that it is possible and doable. The mandatory quota pilot will need to be made sufficiently attractive for the first firms to join and will also need to be closely monitored. Thereby, the effect of the pilot on the public opinion should not be underestimated, both a successful and failing result can frame the public perception of the instrument's effectiveness.

A second pilot: Fuels. Another pilot option is to extend an existing mandatory blending scheme to include hydrogen. The only mandatory scheme currently functioning in the EU is based on RED II and prescribes the following: fuels for mobility are somehow decarbonised up to a certain percentage. Introducing clean hydrogen or derived products into the fuel mix, next to biobased fuels, on a mandatory basis can extend the greening of fuels without fundamentally altering the existing scheme. That is why it is proposed to introduce blending pilots in mobility by extending the fuel mix by including hydrogen – both delivered purely or via the so-called 'refinery route' – under the 'advanced' sub quota.

A third pilot: generic gas mix. A final pilot option relates to locally switching parts of the distribution grid to 100% hydrogen, and gradually adding small percentages of hydrogen to the natural gas mix where this can be an in-between step towards full conversion. Such pilots are more complex than the ones mentioned before, because the number of end users and their appliances is much larger, and the volumes of hydrogen that need to be fed into the grid possibly too. The advantage of such a pilot, however, is that it shows that greening gas for public use is possible.

The above three pilot options match with some recent proposals by the European Commission and some national governments to introduce mandatory blending schemes. Considering this, it seems advisable for the Netherlands' authorities to set-up the suggested pilots at short notice, and to prepare for a timely hydrogen blending regime.

Table 2. Proposed amendments of different articles and further policies in the Netherlands and the EU that match the designed pilot proposal for the rollout of mandatory hydrogen consumption quotas proposed in the HyDelta 1 project.

Proposed amendment of	Description of the amendment
RED II (2021/0218), article 22a	"Member States shall ensure that the contribution of renewable fuels of non-biological origin used for energy and non-energy purposes shall be 50% of the hydrogen used for final energy and non-energy purposes in industry by 2030." (excluding "hydrogen used as intermediate products for the production of conventional transport fuels.")
RED II (2021/0218), article 25b	A sub-target for RFNBOs used for transport is introduced: "…, and the share of renewable fuels of non-biological origin is at least 2.6% in 2030."
ReFuelEU (2021/0205), article 4 and annex I	"Aviation fuel suppliers shall ensure that all aviation fuel made available to aircraft operators at each Union airport contains a minimum share of sustainable aviation fuel (SAF), including a minimum share of synthetic aviation fuel in accordance with the values and dates of application set out in Annex I." ("From 1 January 2030, a minimum share of 5% of SAF, of which a minimum share of 0.7% of synthetic aviation fuels.")
Gas Markets and Hydrogen Regulation (2021/0424), article 20.1	"Transmission system operators shall accept gas flows with a hydrogen content of up to 5% by the volume at interconnection points between Union Member States in the natural gas system from 1 October 2025, subject to the procedure described in Article 19 of this Regulation."
Dutch national blending obligation of transport fuels based on RED II (2018/2001) (revised as of January 2022, after publication of the respective HyDelta 1 deliverable)	Including Renewable Fuels of Non-Biological Origin (RFNBO) under the 'advanced renewable fuel entity' category. So legally introducing the proposed fuel pilot is already possible

Section 4

Research

4 Research

The need for more research on hydrogen transport, storage, and distribution

As was pointed out before, further research is needed to fill the still remaining knowledge gaps with respect to hydrogen introduction into the (existing) transport, storage, and distribution infrastructure. A number of the issues that deserve further studies will be picked up in the HyDelta 2 project that started in May 2022 and is scheduled to be finalized by the summer of 2023:

1. Modelling of hydrogen market dynamics in an integrated energy system
2. Risks, uncertainty, and collaboration in the hydrogen-based value chain
3. Hydrogen blending and congestion management
4. Safe operations of the transmission (high-pressure) grid
5. Safety of hydrogen in the distribution grid and built environment
6. Compatibility of assets and working methods in the distribution grid and built environment
7. Analysis of the conversion of a natural gas distribution network to hydrogen
8. Analysing digitalization in network management
9. Implications of hydrogen in combustion use: NO_X effects
10. Social acceptance for hydrogen transport and storage
11. Labour market and training implications for hydrogen

In addition to this, further insight seems to be urgently needed on issues such as:

Infrastructure

1. Determine necessary technical adjustments of the different parts of the existing gas grid (transport and distribution), optimal management and maintenance strategies, as well as optimal operating conditions (e.g. pressure levels) and gas quality requirements for different end-users of hydrogen
2. Expand the current knowledge base on the optimal geographical in-feed potential and determine an integrated optimised hydrogen transport strategy linking pipeline infrastructure with finer distribution and local production

Safety

Complement the existing natural gas standards to cover hydrogen safety requirements (e.g. in collaboration with WVIP H_2-platform)

Upscaling

1. Analyse how to optimize the successful development and interlinkages of regional hydrogen (carrier) production hubs in the North Sea region, determining synergy factors and promising co-siting options in and between regional hydrogen consumption hubs
2. Study the potential impact of hydrogen carriers on accelerating the introduction of hydrogen and on the need for dedicated transport and storage infrastructure for such carriers

Offshore hydrogen production, storage, and transport to mainland

1. Analyse further concepts as locations for offshore energy conversion and other economic activities (e.g. platforms, energy islands and other floating constructions), and determine the optimal international energy transport configurations given existing grid systems for the transport of offshore energy to shore
2. Study offshore or nearshore optimal storage modalities for hydrogen and hydrogen carriers, both from the national and international perspective, and the role of harbour areas for industrial clustering

Storage

1. Define the optimal technical and economic conditions to enable the development of underground or aboveground storage of hydrogen, with a focus on salt caverns or depleted gas fields for large-scale storage of hydrogen
2. Analyse the role of hydrogen storage in balancing the electricity and gas markets, as a tool for grid flexibility services, and as a means to alleviate electricity grid congestion issues

Social acceptance

Study public acceptance and regulatory issues related to all components of the hydrogen value chain, in particular to transport, storage, and distribution

The research agenda under the national hydrogen programme Groenvermogen (https://www.groenvermogennl.org/), and in particular its work package 2 that covers transport, storage, and distribution of hydrogen, has been designed to analyse the aforementioned issues and is expected to be carried out starting 2023, potentially until the end of the decade.

Annex I

List of publications

Annex I

List of publications of the HyDelta 1 project

The HyDelta 1 project led to a total of 42 publications, divided as follows:

1. 37 deliverables, where all the research results have been published
2. 4 plenary presentations, where the researchers involved in the HyDelta 1 project discussed the progress of the different work packages
3. 1 summary report, which refers to this document

All publications from the HyDelta 1 project are publicly available and can be found in the hydelta.nl/research-programme website. To increase the traceability and findability of all publications e.g. to be cited or included in further research down within and without the HyDelta programme of projects, each publication was given a Digital Object Identifier (DOI) i.e. a persistent identifier that uniquely points at each publication. Below is a list of all publications and their respective DOIs, whence the insights that were included in this summary report were taken.

DOI	Publication
https://doi.org/10.5281/zenodo.6598258	D0.3 – Summary of the references used in the HyDelta 1 project
https://doi.org/10.5281/zenodo.6598279	D1A.1 – Report with results from Hy4Heat, H21, Hyhouse, and interviews, translated to the Dutch situation
https://doi.org/10.5281/zenodo.6598307	D1A.2 – Report with additional questions for the Dutch situation and test program
https://doi.org/10.5281/zenodo.6469611	D1B.1 – Operation of gas stations with spring loaded regulators with hydrogen
https://doi.org/10.5281/zenodo.6469666	D1B.2 Safety during maintenance works for hydrogen gas stations
https://doi.org/10.5281/zenodo.6566429	D1B.3A – Ventilation in gas stations
https://doi.org/10.5281/zenodo.6541887	D1B.3B – Preliminary work plan for explosion testing in gas stations
https://doi.org/10.5281/zenodo.6483247	D1B.4 – Dust transport properties of hydrogen and natural gas in filters of gas stations
https://doi.org/10.5281/zenodo.5142228	D1C.1 – Purging of natural gas pipelines with H_2
https://doi.org/10.5281/zenodo.5707275	D1C.1a – Entry of air into a hydrogen pipeline in case of a pipe rupture
https://doi.org/10.5281/zenodo.5901917	D1C.2 – Leak-tightness of distribution pipes
https://doi.org/10.5281/zenodo.6513377	D1C.3 – The influence of the existing natural gas distribution networks on the purity of hydrogen
https://doi.org/10.5281/zenodo.5902014	D1C.4 – Domestic pressure regulators
https://doi.org/10.5281/zenodo.6566493	D1C.5 – Insights in the risks to convert the current gas installations to 100% H_2 and determining mitigating measures for these risks
https://doi.org/10.5281/zenodo.5902088	D1C.6 – Development of 100%-hydrogen compatible domestic components
https://doi.org/10.5281/zenodo.6424111	D1D.1 – Hydrogen flow metering for the built environment
https://doi.org/10.5281/zenodo.5901833	D1E.1 – Impact of high-speed hydrogen flow on system integrity and noise
https://doi.org/10.5281/zenodo.6504400	D1F.1 – Hydrogen compatibility of ball valves from the natural gas transmission grid
https://doi.org/10.5281/zenodo.5707271	D2.1 – Choice for a sulphur free odorant
https://doi.org/10.5281/zenodo.5902157	D2.2 – Influence of sulfur containing odorant on end-use appliances
https://doi.org/10.5281/zenodo.6504435	D2.3 – Stability of odorants in hydrogen
https://doi.org/10.5281/zenodo.6566517	D2.4 – Report on the risks of not odorizing hydrogen
https://doi.org/10.5281/zenodo.6598333	D2.5 – Report with advice over odorizing hydrogen including a possible choice for a defined type of odorant and its dosing
https://doi.org/10.5281/zenodo.6382535	D3.1 – Development of standards for hydrogen with a focus on hydrogen transport

https://doi.org/10.5281/zenodo.6372782	D4.1 – The requirements for technical personnel and advice for reinforcing education on the subject of hydrogen
https://doi.org/10.5281/zenodo.5591962	D7A.1 – Hydrogen value chain literature review
https://doi.org/10.5281/zenodo.6477440	D7A.2 – Techno-economic analysis of hydrogen value chains in the Netherlands: value chain design and results
https://doi.org/10.5281/zenodo.6523339	D7A.3 – Summary for policymakers: hydrogen value chains in the Netherlands
https://doi.org/10.5281/zenodo.6469569	D7B.1 – Database with the filled-out factsheets about different components of the H_2 value chain elements to be modelled
https://doi.org/10.5281/zenodo.6469593	D7B.2 – Accompanying report to D7B.1 where the factsheets are explained in more detail
https://doi.org/10.5281/zenodo.6514173	D7B.3 – Cost analysis and comparison of different hydrogen carrier import chains and expected cost development
https://doi.org/10.5281/zenodo.6598363	D7B.4 – A roadmap on transport and storage of hydrogen and hydrogen carriers for five sectors in the Dutch economy
https://doi.org/10.5281/zenodo.5142247	D8.1 – Admixing literature review
https://doi.org/10.5281/zenodo.5566782	D8.2 – Assessment of admixing schemes
https://doi.org/10.5281/zenodo.6044859	D8.3 – Pilots for introducing hydrogen blending quota
https://doi.org/10.5281/zenodo.6420995	D8.4 – Economic analysis of potential market development of hydrogen certificate markets
https://doi.org/10.5281/zenodo.6425267	D8.5 – Mandatory blending of hydrogen: summary for policymakers
https://doi.org/10.5281/zenodo.5079095	HyDelta 1.0 First plenary progress meeting – 30-06-2021
https://doi.org/10.5281/zenodo.5079070	HyDelta 1.0 Kick-off meeting – 19-01-2021
https://doi.org/10.5281/zenodo.5779888	HyDelta 1.0 Second plenary progress meeting – 07-12-2021
https://doi.org/10.5281/zenodo.6598382	HyDelta 1.0 Third plenary progress meeting – 17-06-2022
https://doi.org/10.5281/zenodo.6598395	Summary report HyDelta 1