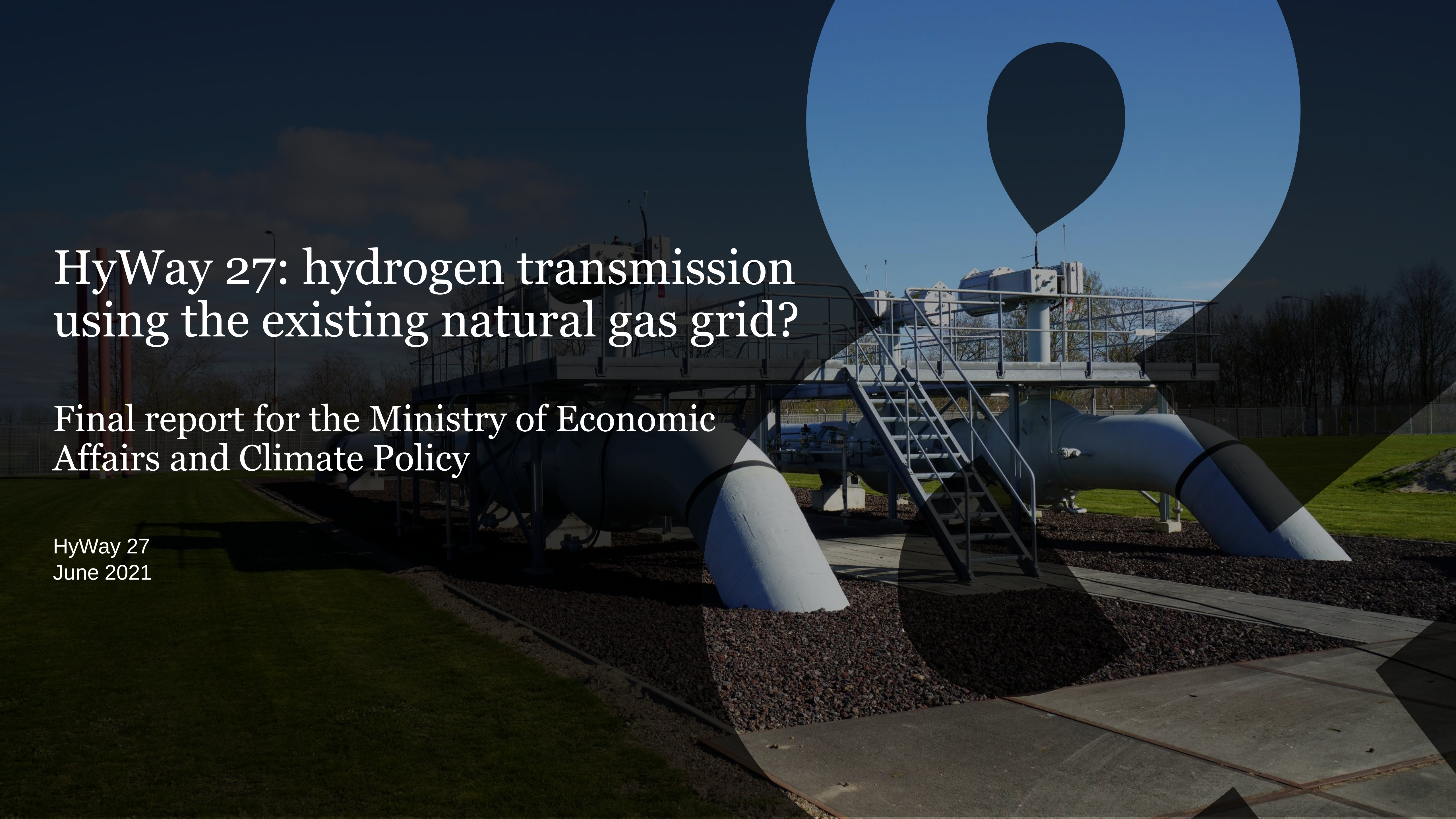

HyWay 27: hydrogen transmission using the existing natural gas grid?

Final report for the Ministry of Economic Affairs and Climate Policy

HyWay 27
June 2021

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To: Ms Yeşilgöz-Zegerius
Secretary of State for Economic Affairs and Climate Policy
Subject: final HyWay 27 study report

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Dear Secretary of State

It is with great pleasure that I present to you the report that we have compiled in the context of the HyWay 27 process. Working in close collaboration with the other HyWay 27 stakeholders, PwC/Strategy& has studied over the past few months whether, and if so under what conditions, the existing natural gas network can be used for hydrogen transmission. This report presents the conclusions and recommendations from this study.

For background to the commissioning of this study, please refer to the agreed award decision and the official brief entitled 'Samenstellen rapport Studie Backbone HyWay 27 202006047' (Compilation of a report on the HyWay 27 Backbone study 202009047) dated 24 July 2020. We do not accept liability, including for negligence, towards any party other than you or for any use of this report other than its intended use. Please refer to the applicable disclaimers at the end of this document.

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Yours faithfully,

Prof. Gülbahar Tezel

Strategy& Partner

PricewaterhouseCoopers Advisory N.V.

Scope

The role of PwC/Strategy& and the involvement of stakeholders

This report presents the results of the HyWay 27 study. PwC/Strategy& was commissioned by the Dutch Ministry of Economic Affairs and Climate Policy to write the report for this study. PwC/Strategy& helped the parties involved structure and analyse the information. Our focus was purely on the economical side, we did not issue any technical advice on things such as the safety of hydrogen transmission, and neither did we perform any work of an accounting or auditing nature.

This report was approved in a steering group of representatives from the Dutch Ministry of Finance, Gasunie, and TenneT that was chaired by the Dutch Ministry of Economic Affairs and Climate Policy. The Port of Rotterdam Authority, Netbeheer Nederland, the Ministry of Ministry of Infrastructure and Water Management and the Netherlands Authority for Consumers & Markets (ACM) were involved in the process through various working groups. Furthermore, there was a focus group that allowed a large number of organisations to weigh in on the approach for the study and review a draft version of the report summary.

Scope of the analyses

Limited Extensive

PwC/Strategy& has been involved in the HyWay 27 project since August 2020. The HyWay 27 study was split up into three work streams: i) hydrogen demand, supply, and storage, ii) legal and financial aspects to the creation of nationwide hydrogen infrastructure, iii) the technology needed and safety requirements. Over the subsequent period from January 2021 through to the end of March 2021, the study went into greater depth to consolidate the various analyses and formulate the recommendations.

The utility of repurposing the natural gas grid hinges greatly on how demand for zero-carbon hydrogen develops. The starting points for the HyWay 27 study were the following: a) realising the ambitions set in the Dutch Climate Agreement (including having 3-4GW of installed electrolysis capacity by 2030) and b) the scenarios from the 2030-2050 Comprehensive Infrastructure Survey (II3050). PwC/Strategy& did not assess the merits of these ambitions and scenarios or the likelihood that they will materialise.

Information availability and quality

Limited Extensive

Two types of information were used for the analyses presented in this report. Firstly, information was obtained from publicly accessible (academic) literature, market research, and policy documents, which contain ample information about hydrogen's potential role in a climate-neutral economy. There is much less information available in public sources about the costs involved in converting natural gas networks into hydrogen transmission networks. Secondly, the analyses drew on non-public information provided by Gasunie, which largely concerned information about network specifics and cost estimates. We did not analyse the factual accuracy of the information obtained, and neither did we conduct any other analyses of a due diligence nature. We analysed this information and, where possible, cross-checked it against other, public sources of information.

Detailed summary

HyWay 27

The HyWay 27 project explored whether, and if so under which conditions, parts of the existing Dutch natural gas network can be repurposed for the transmission of hydrogen

The Netherlands has an ambitious hydrogen agenda with a view to achieving the climate goals

- The Dutch government has presented various policy documents formulating ambitions to kick-start the hydrogen supply chain. In the Government Strategy on Hydrogen, which was presented in 2020, the government announces that it wants the Netherlands 'to be at the forefront' in hydrogen in Europe. The Dutch Climate Agreement of 2019 sets the ambition of kick-starting the zero-carbon hydrogen supply chain by realising 3-4GW of installed electrolysis capacity by 2030. These ambitions were formulated before the European carbon reduction targets were tightened from 40% to 55% reduction by 2030.
- There are several reasons behind the Netherlands' hydrogen ambitions. Green hydrogen will be essential in the long term if we want to hit the climate targets. In the short term, blue hydrogen is a cost-effective way to achieve the 2030 targets. On top of that, the Dutch government wants to empower basic industry in the Netherlands to decarbonise their operations, which is where green and blue hydrogen play a key role. Finally, the Dutch government sees opportunities for the Netherlands to become a hub for climate-neutral energy and resources, given the country's strategic location and good infrastructure. The governments of various other EU member states have also revealed ambitious hydrogen plans.

This report presents the results of the announced HyWay 27 study

- Against this backdrop, the Government Strategy on Hydrogen announced a review of whether the existing natural gas network could play a role in hydrogen transmission. In specific terms, the Dutch government announced a study in partnership with national transmission system operators, the Port of Rotterdam Authority, and network operators Gasunie and TenneT to look into *whether, and if so under what conditions, part of the current gas grid can be used for the transmission and distribution of hydrogen*. This study also seeks to identify potential supply, demand, and the required storage capacity, while factoring in the development of the north-western European hydrogen market.
- This report presents the results of the HyWay 27 study. PwC/Strategy& was commissioned by the Dutch Ministry of Economic Affairs and Climate Policy to write the report. This report has been compiled based on three key study topics, as specified in the figure on the right.

Reading instructions

Study questions	Chapter
1 Do we need a transmission network for hydrogen, and if so, when?	2) The role of hydrogen in a climate-neutral economy 3) The utility of a transmission network for hydrogen
2 Can the existing natural gas network be used for hydrogen transmission, and if so, would that be desirable?	4) Conversion of existing natural gas networks
3 What government intervention will be required to create a transmission network for hydrogen?	5) Policy challenges 6) Conclusions and recommendations

In a climate-neutral economy, a pipeline-based hydrogen transmission network is needed to efficiently connect consumers to suppliers of zero-carbon hydrogen and hydrogen storage facilities

Hydrogen is an essential building block of a climate-neutral economy

- In the future, our energy and resources system will have to be entirely climate neutral, albeit that the specifics of such a system are as yet uncertain. Scenario studies into the structure of a climate-neutral energy and resources system, such as the 2030-2050 Comprehensive Infrastructure Survey (II3050), show that zero-carbon hydrogen's role in that system is set to grow.
- The reason behind this increase is that we need a zero-carbon system molecule. Our energy and resources system consists of electrons (currently roughly 20%) and molecules (roughly 80%). While the share of electrons in a climate-neutral economy is expected to grow, molecules will continue to be needed (roughly 30%-60%). The molecules in the system are currently mainly of the fossil variety, i.e. natural gas, oil, and coal. In a climate-neutral system, these will have to be zero-carbon or low-carbon molecules.
- There are not many candidates to fulfil this role of zero-carbon molecule in our future energy system. Hydrogen can be produced synthetically on a large scale from renewable power (green hydrogen), which involves no carbon emissions at all, or from fossil sources in a process where the carbon produced is captured and stored (blue hydrogen). Besides zero-carbon hydrogen, organic alternatives such as biomass and biogas will also be needed.

Increasing demand for zero-carbon hydrogen calls for new transport supply chains

- The various explorations presented in the II3050 document outline four possible future scenarios for a climate-neutral economy. The scenarios project that hydrogen consumption will vary between 200PJ and 900PJ by 2050. As a comparison, this is 10%-35% of the Netherlands' current total final energy consumption. To create access to such volumes of hydrogen, new transport supply chains are needed, for two reasons.
- Firstly, sources of renewable power, such as offshore wind farms off the Dutch coast or wind and solar farms elsewhere in the world, need to be made readily accessible and connected to hydrogen consumers. The transport supply chain can be based on molecules (whereby electrolysis takes place close to the source of renewable power and hydrogen is transported) or based on electrons (whereby renewable power is transported and electrolysis is done locally).
- Secondly, ways are needed to get hydrogen to and from natural storage locations. Domestic production of green hydrogen is weather-dependent and differs over the seasons. Storage capacity will be needed to bridge these fluctuations. At this point, salt caverns (in the northern Netherlands) in particular seem very suited for this purpose. In the future, storage in offshore salt caverns and empty gas fields may also be an option.

Pipelines are the most efficient option for transport

- Hydrogen can, in theory, be transported in various ways. In compressed or liquid form, hydrogen can be transported by road (efficient for short distances and small volumes), by ship (efficient for large volumes over long distances) and through pipelines (for large volumes and medium distances). For comparison purposes: transporting 0.5PJ of hydrogen per year would require around 10 tank lorries every day; once the volume approaches that level, transmission by pipeline becomes the cheaper option.
- A hydrogen transmission network made up of pipelines would make it easier to choose efficient electrolysis locations. In many cases, producing hydrogen close to the source of the renewable power that is needed in the hydrogen production process and then transporting the hydrogen to consumers through pipelines is cheaper than transporting electrons of renewable power and carrying out the electrolysis on-site at the consumer's location.
- A pipeline-based hydrogen transmission network can also boost the development of the hydrogen market. The more producers and consumers are interconnected by the network, the greater the potential market for producers and the greater the freedom of choice for consumers. These dynamics will contribute to the development of a liquid (commodity) market for hydrogen.

To achieve the ambitions for 2030, in the coming years transmission capacity aimed at facilitating the first large hydrogen projects will be needed. Transmission demand will also arise as a result of the need for storage

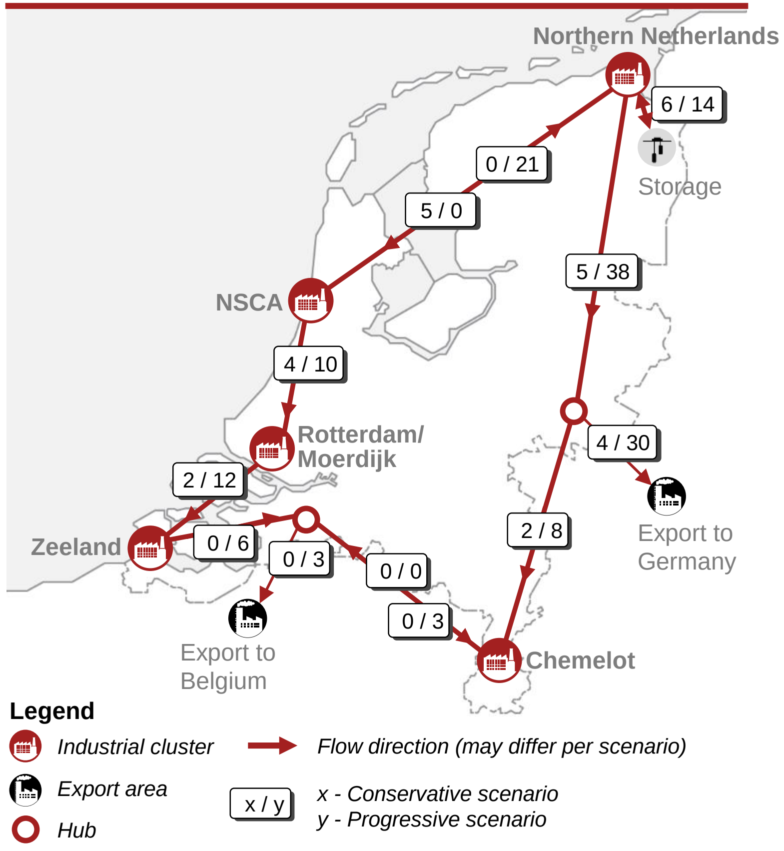
In order to hit the 2030 targets, we need connections between hydrogen suppliers and hydrogen consumers

- The main hydrogen ambitions for 2030 are to have 3-4GW of installed electrolysis capacity and to decarbonise industry by switching to blue hydrogen. transmission capacity is key to realising both these ambitions.
- Initially, transmission capacity will be needed *within* industrial clusters, i.e. the hydrogen produced will have to be transported to consumers nearby. Most industrial clusters currently lack a fit-for-purpose hydrogen network that can connect potential consumers to suppliers.
- It may also be necessary or beneficial to create transmission capacity *between* clusters. The expectation is that large-scale green hydrogen production plants will be based along the coast. Potential hydrogen demand from industrial clusters located further inland, such as Chemelot, but also potential export destinations such as North Rhine-Westphalia in Germany, will depend on a transmission network that transports hydrogen between clusters.
- On top of that, the increasing need for storage and flexibility as electrolysis capacity is ramped up will further push up demand for transport *between* clusters. The salt caverns in the northern part of the Netherlands are likely to be a cost-effective way to meet this need for flexibility. For access to these salt caverns, the northern Netherlands will have to be connected to electrolysis hubs and/or to areas with high-volume demand for hydrogen.

Where transport capacity will be needed and when depends on the specifics of large-scale projects

- The illustrative analysis on the right provides insight into inter-cluster transmission capacity usage based on the 2030 hydrogen ambitions. The figure outlines two scenarios: a conservative scenario where the clusters are largely self-sufficient (1.5GW of a total of 3.5GW of green hydrogen is transmitted on the grid) and a progressive scenario based on the 2030 Climate Agreement scenario from the II3050 document (6.5GW of green and blue hydrogen on the grid). In, the spread of demand over the various locations is based on projected hydrogen consumption levels in the industrial clusters in 2030.
- The analysis shows that achieving the 2030 targets will generate demand for hydrogen transmission between clusters. The average transmitted volume per route is 4PJ in the conservative scenario and 15PJ in the progressive scenario, which equals between 70 and 290 tank lorries of hydrogen per day. Transmission flows are driven by a regional imbalance between supply and demand (approx. 60% to 75%) on the one hand and by a need for storage capacity (approx. 25% to 40%) on the other.
- The analysis does not automatically mean that all connections outlined will actually be needed or societally beneficial in the coming years. What is key to realising the ambitions is to help major hydrogen projects, the details of which are as yet unknown, get off the ground over the coming years.

Illustrative analysis of transport flows in 2030 based on the Dutch government's hydrogen ambitions *(Cumulative annual volume in PJ [on an hourly basis]). Source: Strategy&*



The existing natural gas network can be used to accommodate the interregional transmission flows that are expected in the long term: key pipelines can be freed up entirely and repurposed for hydrogen transmission.

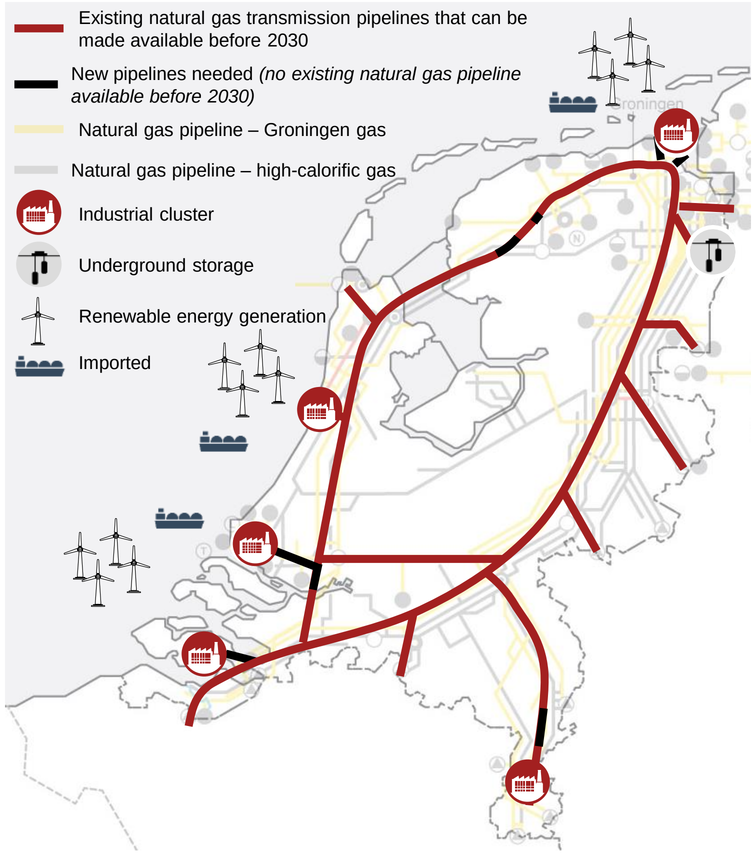
Parts of the existing natural gas transmission network can be repurposed for hydrogen transmission

- Natural gas transmission volumes in the Netherlands will have dropped by around 40% in 2030 compared to today's levels, partly due to falling gas exports as gas extraction from the Groningen gas field is phased out. As a result of declining demand for gas transmission and the fact that the Dutch natural gas backbone transmission network is largely made up of multiple parallel pipelines, Gasunie can reorganise existing natural gas transmission flows in a way that frees up certain transmission pipelines for alternative uses.
- Previous studies showed that pipelines that are currently used for natural gas transmission can, in principle, be reused for hydrogen transmission. It will, however, require a few changes to the pipelines and how they are operated and maintained, most notably the following:
  - replacement of the valves;
  - thorough pipeline cleaning (depending on the required level of purity);
  - replacement or configuration of metering equipment;
  - new pipeline operation methods, including pressure fluctuation control;
  - new management and maintenance methods.

A large number of consumers will be easy to hook up to the network and it offers great potential capacity

- The figure to the right shows what a hydrogen transmission network based on existing natural gas pipelines could look like. This example projects a national transmission ring that connects Dutch and foreign industrial clusters to hydrogen producers and storage providers. Such a transmission network could, in principle, be created as early as in 2030. However, new pipelines will have to be laid in various locations to connect consumers to the transmission network (shown in black on the map).
- The gas pipelines that can be freed up and repurposed have a diameter of 36 inches or larger. 36-inch pipelines offer a theoretical capacity of 10 to 15GW, depending on the pressure level. In most of the scenarios, this capacity will be enough to meet capacity demand through to 2040. On top of that, parallel natural gas pipelines and other existing natural gas pipelines can be freed up after 2030. Given the great capacity, the transmission network can also be used as a basis for connection of *regional* natural gas transmission and distribution networks that will be repurposed for hydrogen transmission. This means that hydrogen will also be available to other companies, such as those in the 'sixth cluster', and sectors such as transport & mobility and the built environment.

The contours of a possible hydrogen transmission network in 2030 *Source: Gasunie, Strategy&*



Reusing existing natural gas grids is more cost-effective than laying new pipelines for hydrogen transmission. A transmission network connecting all industrial clusters to producers and storage locations requires an investment of around €1.5 billion.

Reusing existing natural gas pipelines is four times more cost-effective than laying new hydrogen pipelines

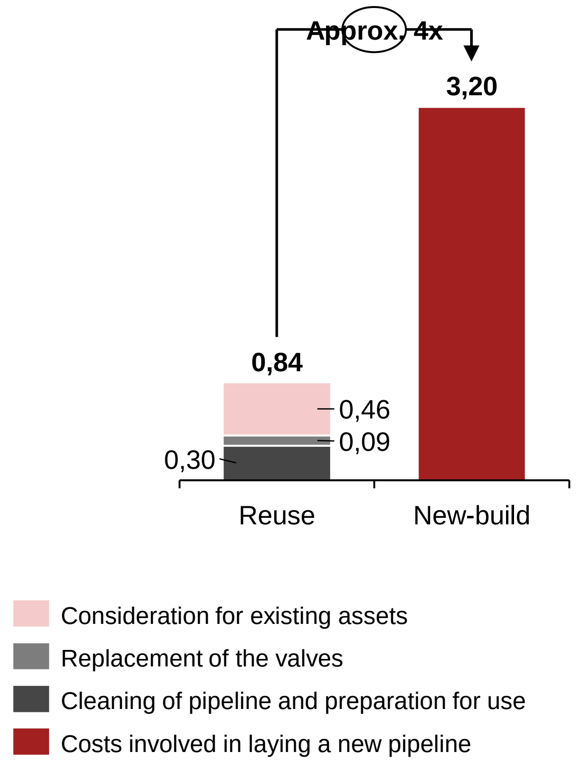
- The figure to the right offsets the investments needed to convert and reuse existing natural gas networks against laying new pipelines with the same length (approx. 1200km) and diameter (36 inches). It shows that the investment required for reuse is 4 times lower than the investment that would be needed for new pipelines. This figure corresponds to the international benchmarks that assume that reuse costs between 10% and 35% of the value of a new pipeline.
- Around 45% of the total investment for reuse consists of actual conversion costs. Most of the costs are related to cleaning and preparing the pipelines, which Gasunie estimates at roughly 10% of what a new pipeline would cost. This percentage depends partly on the required level of hydrogen purity. Replacing the valves is the other major cost item.
- Around 55% of the investment for reuse is made up of the consideration payable for acquisition of existing assets. Most of the natural gas networks that would be reused for hydrogen transmission are owned by network operator GTS. The consideration payable for these assets is based on the average regulated asset value per km (approx. 0.46 million per km) of the entire natural gas grid, as set by the Dutch regulatory authority, ACM.

A national hydrogen transmission network requires investments totalling approximately €1.5 billion

- The previous page outlined the contours of a national hydrogen transmission network that is based largely on existing natural gas pipelines. Gasunie estimates that an investment of around €1.5 billion will be needed to make a national transmission network a reality. This investment breaks down into €850 million for the acquisition and repurposing of existing natural gas pipelines and €650 million for the construction of new pipelines. Given that laying new pipelines is more expensive, the laying of new pipelines represents around 40% of the costs but only around 15% of the total length of the transmission network.
- Gasunie estimates annual operating expenses at 1% of the investment value, which is in line with the operating expenses that ACM has estimated for GTS. According to Gasunie, there are no or only limited differences in operating expenses between a hydrogen transmission network based on repurposed natural gas pipelines and a hydrogen transmission network made up entirely of new pipelines.
- A pipeline takes around three years to develop, counted from the date of the final investment decision (FID) to commissioning. Given the possible freeing up of existing pipelines, Gasunie estimates that a national hydrogen transmission network can be up and running by 2030, provided that the decision-making process is not delayed.

Comparison of per-km investment required for reuse and new-build

(millions of € per km).
Source: Strategy& based on figures provided by Gasunie



The refurbishment of transmission networks requires a government intervention because investments involve a high risk of slow capital recovery due to slow uptake, while also being strongly linked to the development of the hydrogen supply chain as a whole

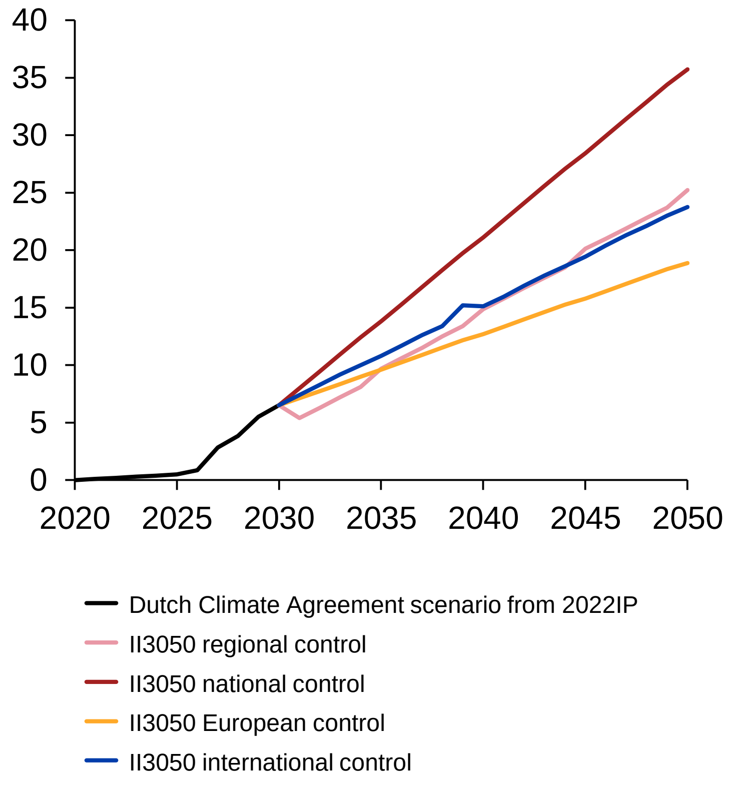
Creating a transmission network must be seen in correlation with an intervention focused on the supply chain

- Without government intervention, there will be no, or insufficient investment in (the gradual conversion of) transmission networks. This is firstly down to the fact that there is currently simply no demand for hydrogen transmission, because there are, as yet, no profits to be made from the supply chain for green and blue hydrogen. Green hydrogen is currently between three and as much as ten times more expensive than grey hydrogen.
- One of the ambitions set in the Dutch Climate Agreement is for the Netherlands to lead the way in hydrogen through programmes such as the roll out 3-4GW of electrolysis capacity. Having this kind of capacity available will create demand for transmission. What is clear is that, depending partly on market factors and government support, billions will be needed in financial support to be able to realise the ambition (at least €5 to €10 billion in total spread out over twenty years).
- Transmission is a special link in the supply chain. On the one hand, transmission capacity is *necessary* to connect producers and consumers. On the other hand, transmission capacity alone is *not enough* to get the supply chain going. Transmission networks will, therefore, have to be created ahead of the curve, albeit in step with the developing supply chain to prevent capacity going unused.

Assuming some of the risk of slow capital recovery to incentivise investments in pipeline reuse

- Even with financial support for production and/or consumption, there are few incentives for early investment in transport networks. Investors in transmission face a long, and uncertain, wait to recoup their investment as it takes time for the network to be used to full capacity. This is due to the fact that transmission and the use of the transmission network do not develop at the same pace. To enable reuse of the natural gas transmission network, we advise the government to assume part of the risk or to compensate investors.
- The figure to the right shows estimates for the development of zero-carbon hydrogen volumes based on the II3050 scenarios . Transport demand will develop over a period spanning several years/decades, as it takes time for zero-carbon hydrogen applications to become profitable. However, the best way to go about dimensioning the transmission network is to do it based on long-term transmission demand. One large-capacity pipeline is significantly cheaper than multiple pipelines with smaller capacity. In the case of repurposing the natural gas network, the dimensioning is predetermined by the diameter of the existing pipelines. The problem of the initial mismatch between available capacity and demand is further confirmed when you consider that an existing natural gas pipeline with an average diameter will in most scenarios suffice to meet transmission demand through to at least 2040.

Zero-carbon and low-carbon hydrogen capacity development forecasts for the Netherlands (GW per year).
Source: II3050



Our advice is to decide in principle to use part of the existing natural gas networks for the transmission of hydrogen. To achieve the ambitions for 2030, it is necessary to initiate decision-making now

	Recommen-dation	Explanation
1	**Make a decision of principle**	• Zero-carbon hydrogen is an essential building block of a climate-neutral economy. Zero-carbon hydrogen requires new transmission supply chains, In this report, we argue that reusing the existing natural gas transmission networks would provide a cost-effective basis to accommodate the hydrogen flows that will materialise in the long term. • One key driver behind this report is the desire to realise the ambitions for 2030 from the Dutch Climate Agreement and the Government Strategy on Hydrogen. Given that these ambitions mean that transport demand will start to develop as early as over the coming years, several decisions will have to be made in the short term. Our advice is to decide in principle to use part of the existing natural gas networks for the transmission of hydrogen and to steer the further decision-making process towards working out the specifics (where, when) and implementation (who, how).
2	**Decide where and when to roll out the network ('what')**	• The next question is where and when to create the transmission network, for which we advise drawing up a roll-out plan. This rollout plan will have to be backed up as much as possible by a societal cost-benefit analysis and be based on objective principles that help prevent market disruption. • Based on the 2030 ambitions, a rollout plan will primarily have to describe the targeted contours of the transport network in 2030, as well as the actions that will be needed for that over the next couple of years. It must also strike a balance between creating clarity for potential consumers and the gradual development of the network so that ongoing market developments can be taken into account.

	Recommen-dation	Notes
3	**Define the required market regulation for transmission ('who')**	• As the hydrogen market grows, the transmission network is likely to develop into an infrastructure that requires access and tariff regulation. In order to be able to decide in the short term who is to be responsible for repurposing the natural gas networks and ultimately for the management of the newly created hydrogen transmission network, we need clarity on how to regulate the hydrogen market. This includes clarity on possible access and/or tariff regulations and whether the transmission network will be publicly or privately owned.
4	**Make a plan to kick-start the integrated supply chain ('how' and 'how much')**	• The ambition to have 3-4GW of electrolysis capacity installed by 2030 can only be realised with a government intervention In addition to supporting policy on pricing and standards, the core of this should be financial support for green hydrogen projects. At this point in time, however, no funds have been earmarked for that. This also affects the transmission network, as investments in a transmission network will not produce financial and societal yields when there is little supply and demand for hydrogen. • We advise the government to create clarity on the funds that are available to kick-start the supply chain. What is also needed is a plan specifying which financial instruments can best be used to distribute those funds. Our advice is to, from an integrated perspective on the supply chain, decide what part of the supply chain to subsidise (hydrogen production, consumption, transport or combinations thereof) and what type of instrument would be the most effective in eliciting prompt investments and making sure public funds are spent efficiently.

Contents

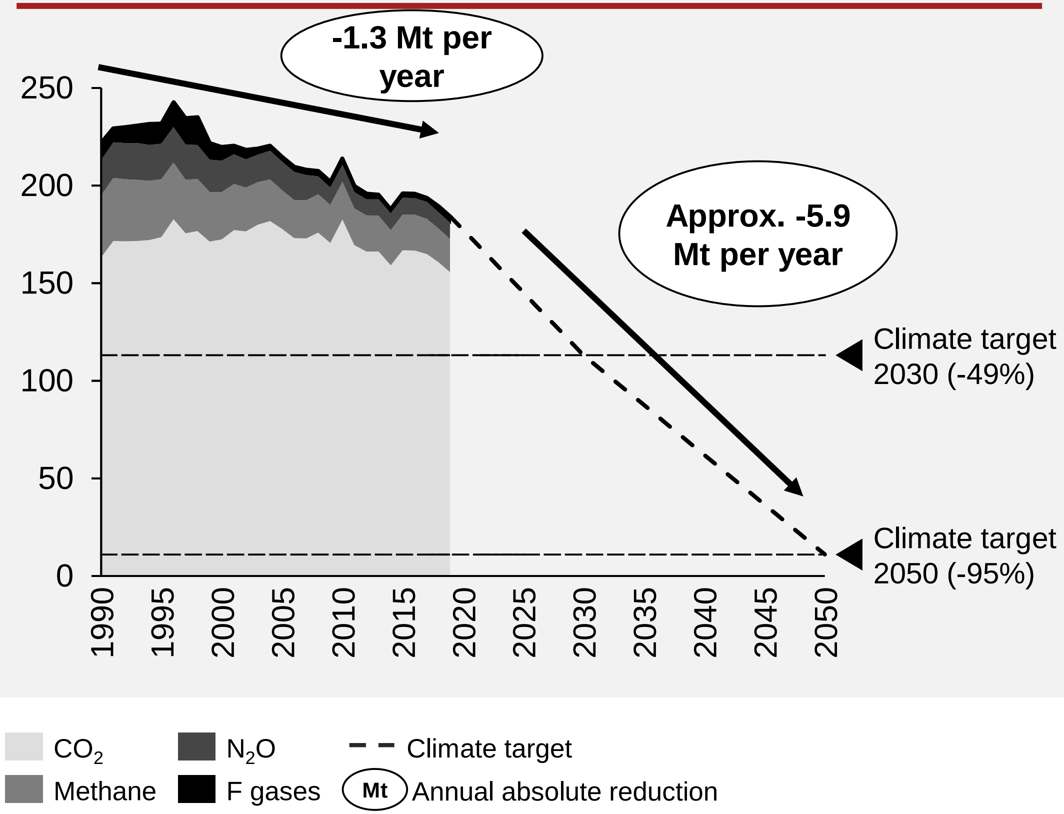
1 Explanation of the study topic and approach

HyWay 27

Climate-neutral hydrogen is expected to play an important role in achieving carbon reduction goals

For the economy to be climate-neutral by 2050, we need a rapid and radical change

Greenhouse gas emissions in the Netherlands[1]
(Mt of CO_2 equivalent), source:
Source: CLO11/12/'20



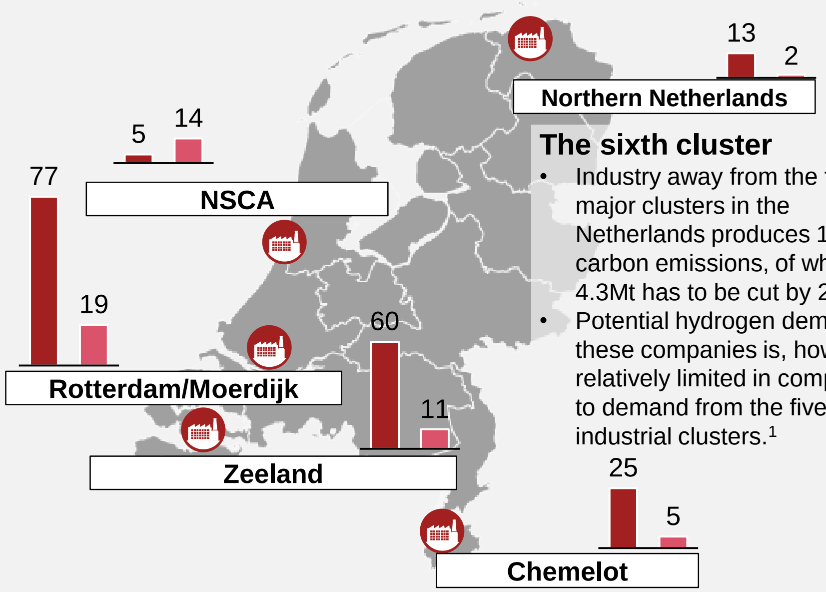
- The EU and the Netherlands have committed to a climate-neutral economy by 2050. Climate-neutral means zero net carbon emissions. This does not mean, however, that carbon emissions are eliminated entirely, but rather that any remaining emissions have to be offset by, for example, removing CO_2 from the atmosphere through natural means or using carbon capture technology.
- The EU and Dutch targets follow the targets agreed in the Paris Climate Agreement. Climate neutrality by the halfway point of the 21st century is a necessity to keep global warming within the agreed boundaries. To achieve climate neutrality by 2050, we must make the first step in 2030. The European Commission had initially set 40% carbon reduction as the target for 2030[2]. A subsequent review of the energy and climate plans by the EC[3] showed, however, that a balanced, realistic, and cautious path to climate neutrality by 2050 requires an emission reduction target of at least 55% for 2030. This prompted the EC to tighten its target. While it is as yet unclear how this reduction will be split between the EU member states, what is clear is that the Netherlands will have to step up its reduction efforts.
- Carbon emission reduction requires a switch from fossil to renewable energy sources, and with that a fundamental change to the energy and resources system. This has major implications for the structure of our economy. Climate-neutral hydrogen plays a key role in achieving a climate-neutral economy, because zero-carbon system molecules are needed in the energy and resources system (Dutch Ministry of Economic Affairs and Climate Policy, 30 March 2020; CIEP, 2019; Berenschot, 2018). Hydrogen is a scalable zero-carbon molecule. A hydrogen system is expected to fulfil a number of essential purposes within a zero-carbon energy and resources system (RLI, 2021; Dutch Climate Agreement, 2019).

1. Historically up to 2019. After that, forecast based on targets set in the 2019 Dutch Climate Act. The tighter targets set in the subsequent Green Deal have not been included. 2. This resulted in a reduction target of 49% for the Netherlands, which is the figure that was enshrined in law by the Dutch Climate Act. 3. See European Commission (2020b). 4. Dutch Ministry of Economic Affairs and Climate Policy (30 March 2020). Government Strategy on Hydrogen; Clingendael International Energy Programme (2019); Berenschot (2018).

The Dutch government wants to empower basic industry in the Netherlands to decarbonise their operations

Zero-carbon or low-carbon hydrogen is expected to be needed to decarbonise industry

Current hydrogen demand in the Netherlands and carbon emissions per location *(PJ per year)*. *Source: TNO (2020d), VNCI (2020)*



The sixth cluster

- Industry away from the five major clusters in the Netherlands produces 16.5Mt of carbon emissions, of which 4.3Mt has to be cut by 2030.
- Potential hydrogen demand from these companies is, however, relatively limited in comparison to demand from the five major industrial clusters.[1]

Hydrogen demand in PJ

Carbon emissions[1] in megatonnes

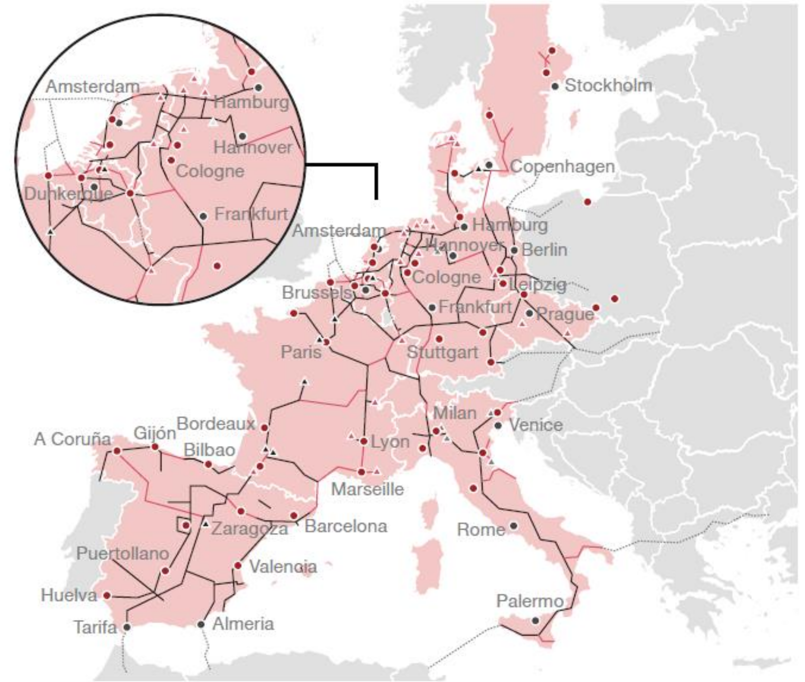
- The Dutch government wants to play an active role in decarbonising industry, seeing industry as a key pillar of the Dutch economy. Basic industry contributes €17 billion to the Netherlands' GDP and employs 120,000 people. The Netherlands has set itself the ambition to become *the* (European) hub for sustainable industry (Ministry of Economic Affairs and Climate Policy, 15 May 2020).
- In order to hit the climate targets, Dutch industry has to decarbonise. The parties to the Dutch Climate Agreement have agreed on a 14.3Mt carbon emission reduction target for basic industry by 2030, compared to 2015. The aim is for basic industry, like the economy as a whole, to be climate-neutral by 2050.
- There are various technological options for the decarbonisation of industry. Apart from simply cutting back on energy consumption, options include sustainable electrification, blue and green hydrogen, and fundamentally different production processes such as bioplastics (Dutch Ministry of Economic Affairs and Climate Policy, 15 May 2020).
- The Dutch government has made the development of blue and green hydrogen a top priority in decarbonising industry (Dutch Ministry of Economic Affairs and Climate Policy, 30 March 2020; Dutch Ministry of Economic Affairs and Climate Policy, 16 October 2020). At present, as much as 180PJ of hydrogen is already consumed across Dutch industry. This figure breaks down into 100PJ of freshly produced grey hydrogen and 80PJ of hydrogen that is produced as a by-product of other processes. Production of 100PJ of grey hydrogen generates around 7.5Mt of carbon emissions. Decarbonising all the 'grey' SMR systems in the Netherlands could, in theory, cover around 7.5Mt of the required 21Mt of carbon reduction by 2030[2]. Aside from that, the use of hydrogen in industry is expected to increase as hydrogen starts to play a role in new sustainable chemical processes and as a zero-carbon energy carrier in the process industry (Dutch Climate Agreement, 2019).

1. Provided by VNCI (Royal Association of Dutch Chemical Industry) (2020). *2.* Based on an emission factor of 9kg CO2/kg H_2.100PJ is LHV and the corresponding energy content of hydrogen is 120MJ/kg. This means 75g/MJ or 75kt/PJ. At 100PJ, this is 7.5Mt.

The Dutch government sees opportunities for the Netherlands to become a European hub for climate-neutral energy and resources

The development of a hydrogen supply chain is an opportunity for the Dutch economy

Illustration of the possible European hydrogen backbone in 2040
Source: Guidehouse (2020)



- ▲ Potential H_2 storage: existing/new salt cavern
- ▲ Potential H_2 storage: aquifer
- ▲ Potential H_2 storage: empty gas field
- ● Industrial cluster
- ● City, for orientation (if not already specified for industrial cluster)

- The Dutch government sees opportunities for the Netherlands to become a European hub for zero-carbon energy and resources, given the country's strategic location and other factors (Dutch Ministry of Economic Affairs and Climate Policy, 30 March 2020; Dutch Ministry of Economic Affairs and Climate Policy, 15 May 2020; Dutch Climate Agreement, 2019), specifically:
  - **Ports:** having various large ports makes the Netherlands a good location for hydrogen trade and transport;
  - **Green power from the North Sea:** possibilities for large-scale production of green power from wind at sea;
  - **Storage capacity:** the Netherlands has salt caverns and empty gas fields available for hydrogen (and CO_2) storage.
  - **Gas grid:** an existing extensive network of pipelines with good connections to other countries that can be converted into a hydrogen transmission network.
- The Netherlands would benefit from being a hub in the future hydrogen supply chain, as hydrogen has the potential to become a globally traded commodity with major demand across north-western Europe. Being a hub will improve the business climate for energy-intensive companies, because affordable, reliable, and sustainable energy supply is a key factor in energy-intensive companies' decision to establish operations somewhere. In the report by TIKI (Industry Climate Agreement Infrastructure Task Force [Taskforce Infrastructuur Klimaatakkoord Industrie]), the industrial parties interviewed stress the importance of a hydrogen backbone for the ability to develop and scale up green hydrogen production (DNV GL, 15 April 2020).

Against this backdrop, the Dutch Climate Agreement and Government Strategy on Hydrogen formulate various hydrogen ambitions

Hydrogen programme announced for 3-4GW electrolysis capacity by 2030

Main points from the Dutch Climate Agreement and Government Strategy on Hydrogen

Source: Dutch Climate Agreement (28/06/19), Government Strategy on Hydrogen (30/03/20)

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Dutch Climate Agreement announces hydrogen programme

- Hydrogen programme aiming for 3-4GW of installed electrolysis capacity by 2030.
- Capex for electrolysis expected to drop by 65% in 2030 on the back of scale-up. According to the Hydrogen Coalition (2018), 3-4GW of electrolysis capacity by 2030 will result in a capex reduction from approx. € 100 million per 100MW in 2019 to € 35 million per 100MW.
- The capacity, usage levels, and locations of the electrolysis plants must all contribute to the embedding of renewable energy into the energy system. The link between electrolysis capacity growth and offshore wind power growth.

The Dutch Government Strategy on Hydrogen announces a policy agenda that ties in with the Dutch Climate Agreement

- The Dutch government wants the Netherlands to lead the way in hydrogen in Europe.
- The Dutch government intends to take charge in kick-starting a sustainable hydrogen supply chain:
  – public role – especially during the start and development phase – for the development of the hydrogen network;
  – current and new financial instruments for research, scale-up, and roll-out of zero-carbon hydrogen to achieve 3-4GW of installed electrolysis capacity. The possibility of linking the development of offshore wind power and hydrogen to an obligation for energy providers to blend a certain minimum amount of renewable energy into their energy offering.

- In the Government Strategy on Hydrogen of 30 March 2020, the Dutch government expresses the ambition for the Netherlands to be at the forefront in hydrogen in Europe. The Dutch Climate Agreement of 28 June 2019 sees a key role for hydrogen; it sets a target of having 3-4GW of electrolysis capacity available by 2030 for example. The table on the left shows the key points from the Dutch Climate Agreement and the Government Strategy on Hydrogen.
- The hydrogen targets were set prior to the tightening of European greenhouse gas reduction targets for 2030. The Netherlands will have to cut emissions even more than initially thought; which may have an impact on the previously set hydrogen targets.
- The Dutch government also stresses the importance of hydrogen in its vision of 15 May 2020 for more sustainable basic industries and in the government response to the advice issued by the Industry Climate Agreement Infrastructure Task Force (TIKI) of 16 October 2020.

Source: Dutch Hydrogen Coalition (2018). Hydrogen Coalition Manifesto

HyWay 27 explored whether, and if so under which conditions, the natural gas network can be reused for the transmission of hydrogen

The study, the results of which are described in this report, was announced in the Government Strategy on Hydrogen

Quote from the Government Strategy on Hydrogen announcing the study
Source: Government Strategy on Hydrogen (30/03/20)

Ministerie van Economische Zaken en Klimaat

- *‘The hydrogen supply chain is likely to develop in the direction of a network sector, such as electricity and natural gas. Any network for the transmission and distribution of hydrogen will have some of the characteristics of a natural monopoly. Part of the existing gas grid can be used for the transmission of hydrogen. As indicated in the Growth Strategy for the Netherlands, the government intends to play a key role in the development of the hydrogen infrastructure. Alongside the national network operators and network companies Gasunie and TenneT, the government will review whether and under which conditions part of the gas grid can be used for the transmission and distribution of hydrogen. The regional network operators and network companies will be involved in this process.*
- *The development of infrastructure will also take into account the development of the north-western European hydrogen market, which is relevant with a view to the potential hub function played by the Netherlands for provision to neighbouring countries. The connections with and in Germany are of particular interest. This study also seeks to identify potential supply, demand, and the required storage capacity. In this context, the Port of Rotterdam will be identifying the potential import supply (from overseas territories).’*

- Given that realising the Dutch government’s hydrogen ambition will require large-scale uptake of hydrogen, connections between producers and consumers of hydrogen will be needed in the short term.
- The Dutch government, therefore, wants to review whether the existing natural gas network can be used for hydrogen transmission. In the Government Strategy on Hydrogen, the Dutch government announced a study in partnership with national transport system operators, and network operators Gasunie and TenneT to look into *whether, and if so under what conditions, part of the gas grid can be used for the transport and distribution of hydrogen.*
- This announced study was conducted in the form of the HyWay 27 project, the results of which are presented in this report. The HyWay 27 project was a joint project of various parties. The analyses in this report were conducted largely in working groups made up of representatives from network operators, government ministries, and other stakeholders. On the instruction of the Dutch Ministry of Economic Affairs and Climate Policy, PwC/Strategy& helped the parties involved structure and analyse the information. PwC/Strategy& also wrote this final report.
- The analyses were conducted based on a combination of public data (such as from the 2030-2050 Comprehensive Infrastructure Survey [II3050]) and data provided by Gasunie (including data on the costs involved in repurposing natural gas pipelines).

Our study focuses on three key topics around the use of the existing natural gas grid for hydrogen transmission

This report will go into the need, possibilities, and the government's role

Chapter		Key questions	
2	The role of hydrogen in a climate-neutral economy	1	**Do we need a transmission network for hydrogen, and if so, when?**
3	The utility of a transmission network for hydrogen		
4	Conversion of existing natural gas networks	2	**Can the existing natural gas grid be used for the transmission of hydrogen?**
5	Policy challenges	3	**What kind of government intervention will be needed to create a transmission network?**
6	Conclusions and recommendations		

- This report is the result of the HyWay 27 project that was set up following the Dutch government's announcement of a review of the use of the natural gas grid for hydrogen transmission. This project analysed under which technical and economic conditions parts of the natural gas transmission network can be used for hydrogen transmission.
- In this study, we will answer the following three key questions:
  1. *Do we need a transmission network for hydrogen, and if so, when?*
  2. *Can the existing natural gas grid be used for the transmission of hydrogen?*
  3. *What kind of government intervention will be needed to create a transmission network?*
- We will be answering these three key questions based on sub-questions that will each be addressed in a separate chapter. These sub-questions are listed in the table to the left.

2 The role of hydrogen in a climate-neutral economy

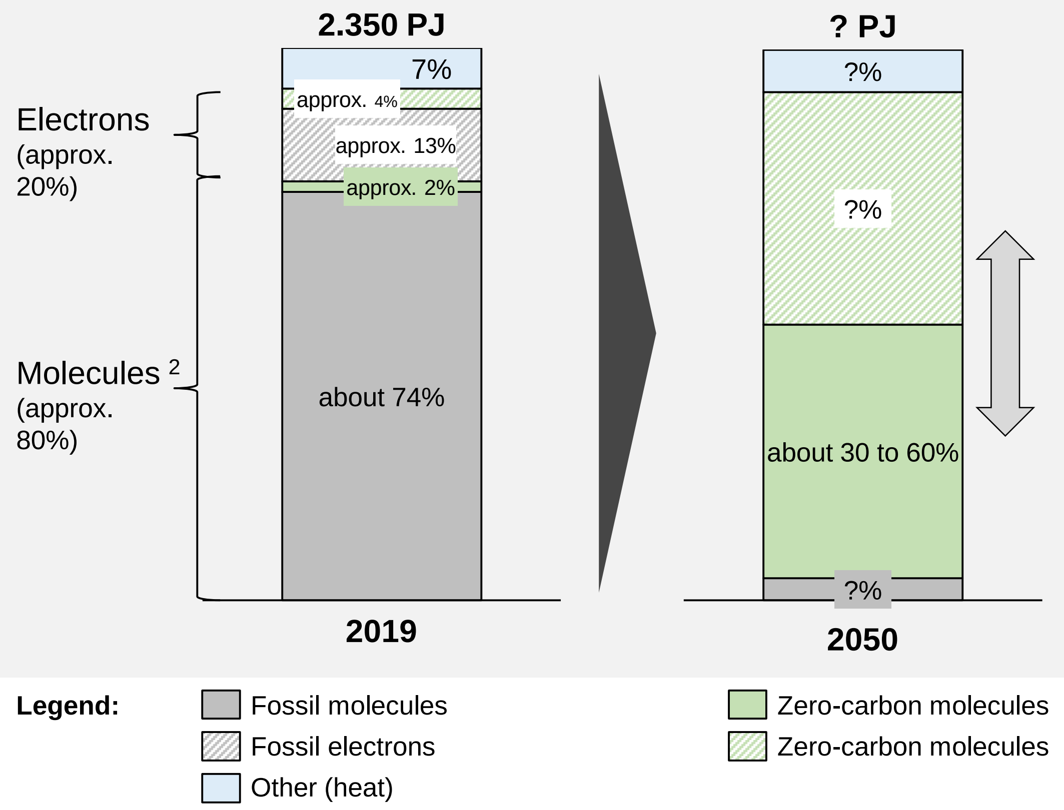
HyWay 27

2.1. The role of zero-carbon molecules

As a zero-carbon molecule, hydrogen is an essential building block in achieving a climate-neutral economy

Zero-carbon molecules are needed to replace fossil molecules like natural gas and petroleum

Total energy usage in the Netherlands by end users by energy carrier and source[1] *(as a percentage of total usage). Source: Statistics Netherlands (2020)*



- Energy and feedstock are needed to keep the Dutch economy running. Energy sources are converted into forms of energy that end users can use, such as heat, electricity and fuels for transport. We also use energy in the form of feedstock (i.e. material input) to make products. Energy is mainly carried by electrons or molecules.
- Currently, the Dutch energy supply uses approximately 80% molecules and 20% electrons (Statistics Netherlands, 2020). Approximately 22% of the electrons originate from zero-carbon sources (Agora, 2020). However, the molecules currently used are almost entirely based on fossil sources, with 42% consisting of natural gas and 57% of petroleum/petroleum products (Statistics Netherlands, 2020). Achieving a fully climate-neutral economic system by 2050 means that carbon emissions will have to be net zero.
- All electrons can be produced with zero carbon in the future by using more of the renewable energy sources like sun and wind, supplementing this with flexibility from power stations that run on zero-carbon molecules (e.g. hydrogen, biomass, biogas) or nuclear energy. Flexibility on the part of energy consumers and large-scale storage is also needed to balance the electricity system. Hydrogen is seen as an important link in the future as a source of flexibility in the electricity system (DNV GL, 2019a).
- For carbon emissions to reach net zero, the current proportion of fossil-derived molecules will have to be largely reduced[3]. A sustainable alternative will need to be sought for every application. Hydrogen is suitable for a wide range of applications, including as a fuel and feedstock, and for storage (RLI, 2021). In addition, hydrogen can be produced and used with zero emissions, and hydrogen is relatively easy to scale up.
- The final ratio between zero-carbon electrons and molecules is uncertain, but estimates show that, with the proportion of electrons increasing thanks to further electrification, the proportion of molecules in 2050 will range between 30% and 60% (TKI Nieuw Gas, 2020; Berenschot & Kalavasta, 2020; IRENA, 2019; Navigant, 2019; Gasunie & TenneT, 2019).

1. Excluding bunkering, power plant's own energy consumption, and losses (in industry, at power plants, during distribution). 2. Use for both energy and non-energy purposes. 3. Fossil-derived molecules can then only be used in combination with CCS, with a large portion (80 to 90%) of the released CO_2 being captured and stored, or in a conversion method (pyrolysis) where carbon emissions are compensated through carbon-negative applications like BECCS (PBL Netherlands Environmental Assessment Agency, 2018, p.23).

In a climate-neutral economy, zero-carbon molecules are needed as fuel, as feedstock, and for storage

Together with electrons, zero-carbon molecules form the foundation of a sustainable energy supply

The role of zero-carbon molecules
Source: several sources; see footnotes

Fuel for applications where zero-carbon molecules will be the most cost-efficient alternative	• High-temperature heat production (+500°C) for industrial high-heat processes[1] • Fuel for certain heavy and long-haul road transport purposes in combination with fuel cell technology[2] • Fuel for aviation and shipping as a replacement for kerosene[3] and bunker fuel[1]
Feedstock for certain products and materials	• Naphtha applications[4], such as for plastics, pharmaceuticals, insecticides, fertilisers and foodstuffs • Natural gas applications (hydrogen) for fertilisers, and for desulphurisation and cracking of crude oil in refining processes • LPG applications like as a feedstock for making plastics in the petrochemical industry
Storage of large volumes of renewable energy over a longer period of time	• Seasonal storage to store energy surpluses over a longer period of time • Strategic storage to store energy for several years

- **Fuel:** To achieve a fully climate-neutral economic system by 2050, a cost-efficient sustainable alternative will have to be found for every energy-consuming application that currently uses fossil-derived molecules. Certain energy applications are best suited to electrification, such as cars, heat pumps and boilers in buildings, but there are also applications where zero-carbon molecules will be the most cost-efficient and/or where electrical alternatives will not be adequate. Furthermore, molecules are expected to be needed as a fuel in power stations to absorb some of the fluctuations in the production of electricity from renewable energy sources (Gasunie & TenneT, 2019).
- **Feedstock:** a number of products and materials that are needed on a daily basis, like plastics and fertilisers, require feedstock (basic materials) in the form of hydrogen/hydrocarbons, which are currently produced mainly using fossil fuel. Most emissions from these products arise during the waste disposal phase (landfill or incineration). In a climate-neutral economy, these products will still be necessary, but the carbon atoms in these products must be treated in a climate-neutral manner so as to be balanced out and ultimately not contribute to emissions. This can initially be done through recycling, although this is not a realistic option for all products and materials. As a second option, a significant portion of these products and materials will need to be produced using climate-neutral synthetic or organic hydrocarbons.
- **Storage:** A temporary storage medium is used to store energy for a shorter or longer period. Various storage methods – mechanical, thermal, electrical and molecular – can be used for this purpose, with each method having its own, distinct characteristics in terms of discharge time, storage capacity and level of efficiency. Which method is most suitable for a given application depends on the circumstances of that application (European Commission, 2017). Capacity and discharge time are particularly important for seasonal and strategic storage. The longer period and scale of storage required for climate-neutral scenarios is technically only possible with the storage of molecules (Berenschot & Kalavasta, 2020; Mulder, 2014; European Commission, 2017; RLI, 2021).

Sources: 1. Knoors et al. (2019). 2. DNV GL (2018a). 3. Clean Sky 2 JU & FCH 2 JU (2020). 4. Technisch Werken (2014).

Hydrogen can be produced with no CO2 emissions through electrolysis, and the CO2 footprint of hydrogen production can be reduced by 50 to 95% through CCS

Both green and blue hydrogen can make a substantial contribution to reducing CO_2 emissions

Hydrogen production methods

	Production method[1]	Carbon emissions (per PJ H_2)
Green hydrogen	Hydrogen produced through electrolysis using sustainably generated electricity	0 Mt CO_2
Blue hydrogen	Hydrogen produced through oxidation of fossil fuels **with** carbon capture and storage (CCS)	0.01 to 0.06[2] Mt CO_2
Grey hydrogen	Hydrogen produced through the oxidation of fossil fuels **without** CCS	0.08 to 0.11[3] Mt CO_2

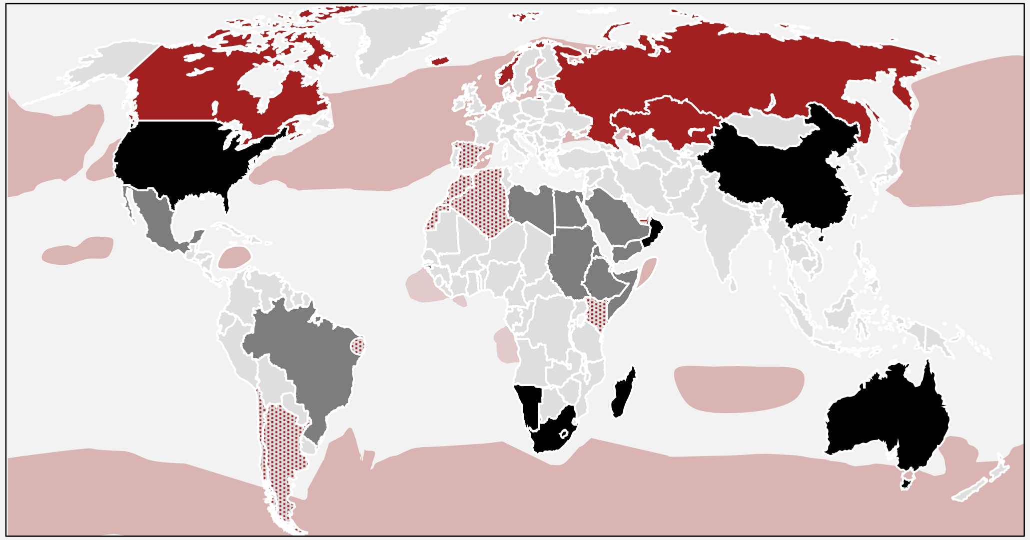
- Hydrogen can be produced in different ways, with 'grey', 'blue' and 'green' methods being the most common ways to produce hydrogen. Each method is distinguished by the feedstock/input for the particular process and the associated CO_2 emissions, which in turn determines the extent to which hydrogen can contribute to reducing carbon emissions (TKI Nieuw Gas, 2020; RLI, 2021).
- Green hydrogen[4] is produced using sustainably generated electricity (from solar and wind energy, for example). Using an electric current (electrolysis) pure water (H_2O) is split into hydrogen (H_2) and oxygen (O_2). This method does not produce any carbon emissions.
- In the production of blue hydrogen, fossil fuels (hydrocarbons) such as natural gas, industrial residual gases or coal are split into carbon dioxide and hydrogen. CO_2 is released during this conversion process. The released CO_2 is captured (though not all) and stored (carbon capture and storage, CCS) in empty gas fields under the North Sea (TNO, 2020c). Because not all of the released CO_2 is captured, this blue hydrogen is also referred to as 'low-carbon hydrogen'. How much CO_2 is captured during production depends on the type of production plant. An existing SMR (steam methane reforming) plant can capture 50 to 70% of the CO_2 emissions; for a new generation ATR or POX plant this is up to about 95% (CE Delft, 2018; TNO & Berenschot, 2017).
- Grey hydrogen has a similar production process to blue hydrogen, where fossil sources (hydrocarbons) are split into carbon dioxide and hydrogen. However, the CO_2 emitted is not captured and reused or stored: it ends up in the atmosphere.

1. TNO (n.d.) also mentions 'turquoise hydrogen', though, according to TNO, this technology is still in the development phase. There are also other hydrogen production methods for which there is no standard term/colour nomenclature; this report does not delve into these technologies however. 2. Depending on the plant used (SMR or ATR) 3. With SMR based on Natural Gas 0.075 Mt CO_2 per PJ H_2 (IEA, 2017) and on average in the Netherlands 0.11 Mt CO_2 per PJ H_2 (TNO, n.d.-a). Via electrolysis using electricity from coal emissions are around 3 times higher. 4. In addition to green hydrogen, hydrogen produced from sustainable biomass or biogas is also zero-carbon, but is not included in this report due to the small scale of production. 5. Utilisation of CO_2 is also possible, but this is only considered carbon neutral if the CO_2 does not end up in the atmosphere later in the disposal phase.

Hydrogen production is very suitable for scaling up and, together with biomass and biogas, can produce the necessary zero-carbon molecules

Hydrogen production can be scaled up well in areas where electricity can be generated on a large scale

Regions in the world with renewable electricity potential
Source: Frontier Economics (2018); Hydrogen Council (2020)



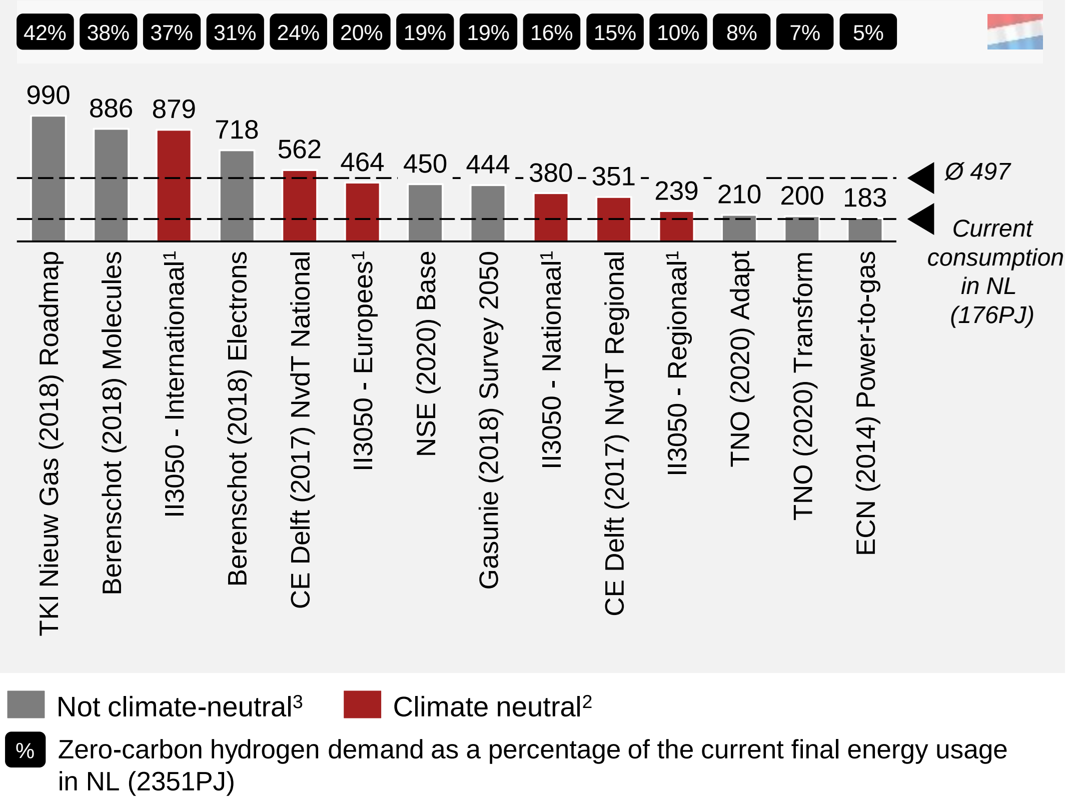
Legend: Onshore wind; Offshore wind; PV + Onshore wind; PV solar; Mainly PV, but partly in combination with wind

- To be able to provide 30 to 60% of the future total final energy use via zero-carbon molecules, both 'synthetic' and 'organic' molecules (from biomass) are required (Berenschot & Kalavasta, 2020).
- Biomass is organic material and therefore biodegradable. As an energy carrier, biomass can be converted into a solid, liquid or gaseous form and can be widely utilised as a fuel and feedstock. The CO_2 emissions released during combustion or biodegradation of certified biomass do not contribute to net CO_2 emissions because, unlike with fossil fuels, this CO_2 is absorbed from the air within the same ecosystem. The production of biomass for use as a fuel/feedstock is highly regulated (PBL, 2020). CE Delft (2020) has shown that the Netherlands cannot be self-sufficient in terms of providing the quantity of biomass it needs by 2050.
- A synthetic molecule is one that is artificially manufactured from other molecules using a chemical process. Such molecules meet the need for zero-carbon molecules as long as they are both manufactured from molecules that occur in nature and produced using renewable energy. Hydrogen, produced from water using renewable electricity, is the most basic synthetic, zero-carbon molecule that can be used to build other synthetic molecules (such as fuels and feedstocks). The required climate-neutral carbon atoms can be obtained from biomass or from CO_2 extracted from the air.
- At locations with availability of substantial quantities of renewable electricity, hydrogen can be produced sustainably in a scalable way (RLI, 2021). There are many locations in the world where sustainable electricity can be generated on a large scale using solar or wind farms. Locations with the most hours of sunshine and wind have the potential for generating inexpensive electricity, and therefore hydrogen, which can then be transported to other countries.

Various scenario analyses confirm that hydrogen will form a larger part of the energy and feedstock system

In climate-neutral scenarios, the demand for hydrogen is forecast to be between 239 and 879PJ by 2050

Scenario forecasts for Dutch hydrogen demand in 2050
Excluding hydrogen for synthetic fuels (in PJ).
Source: TNO (2020a)



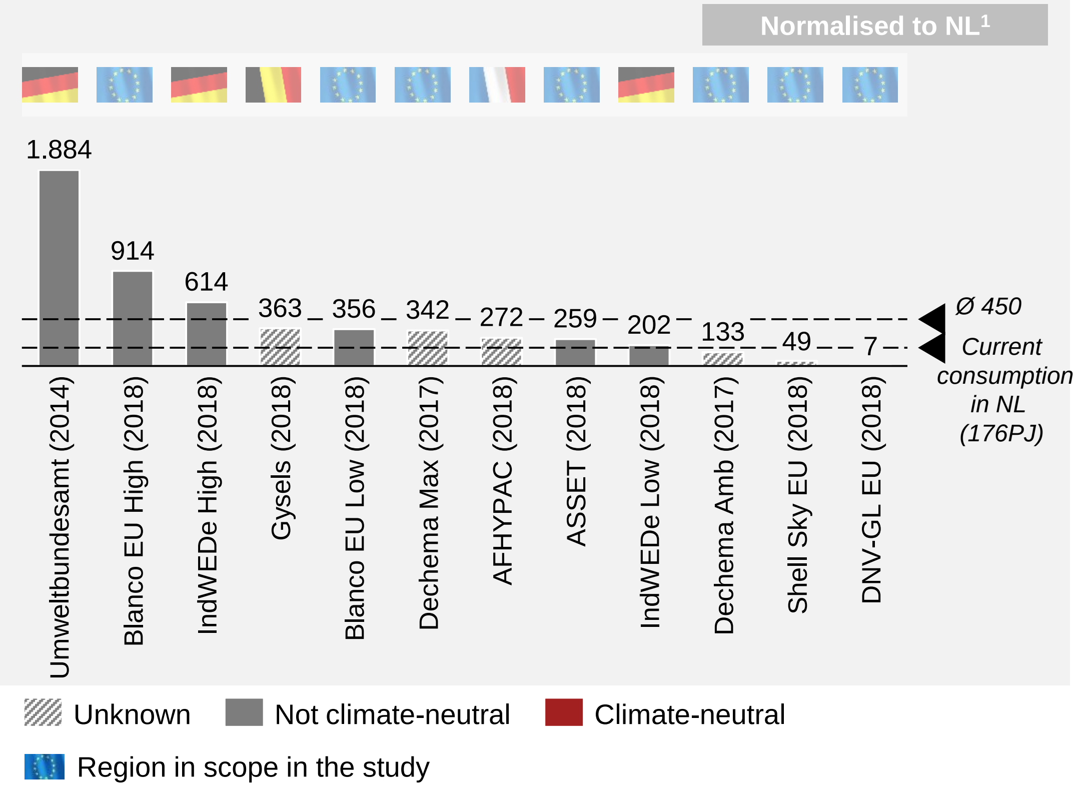
- Various studies provide an idea of what the energy and feedstock mix will look like in 2050. Studies use different assumptions with regard to the total reduction by 2050. The ultimate goal of climate neutrality[2] by 2050 is not achieved in all the studies.
- The figure on the left shows the results of a recent meta-analysis by TNO (TNO 2019; 2020a) into various scenario studies. The volumes in the underlying studies vary widely due to large differences in the assumptions made in each scenario. The main points of discussion from this meta-analysis are as follows:
  - The studies underline a future role for hydrogen as a feedstock for industry, but differ with regard to which products (plastics, steel, etc.) should, in the future, be produced based on hydrogen. There are also various estimates of the future use of hydrogen as an energy source for industry.
  - Some studies include hydrogen use for international aviation and shipping while others do not, given that emissions from these sectors are not included in the national emission targets. To ensure a better comparison, this category is not included in the figure to the left.
  - Scenarios based on a vision or using a simulation model (such as the Energy Transition Model, which is used in the II3050 study to calculate supply and demand for every hour per year) show a higher hydrogen demand than scenarios based on a static cost optimisation model as used, for example, by TNO (2020e) in the Adapt and Transform scenarios. An increasing trend has also been observed in the proportion of hydrogen in studies over time.
- The climate-neutral infrastructure scenarios developed on behalf of the Dutch grid operators in the context of the II3050 study (Berenschot & Kalavasta, 2020) are explorations into various, radically different ways of achieving climate neutrality. These four scenarios are not forecasts. The amount of hydrogen in all four scenarios will increase from the current approx. 180PJ to between 239 and 879PJ in 2050, with the nature of its use also changing.

1. Berenschot & Kalavasta (2020), in which the figures for hydrogen demand deviate from those shown in TNO (2020a) – The authors later updated the figures. The values shown concern hydrogen demand in 2050 excluding transit flows and international aviation and shipping.
2. Scenarios that do not aim for net-zero carbon emissions are not included as climate neutral scenarios.
3. A large number of scenarios assume a cut in CO_2 emissions of 95%, including TNO (2020) Adapt and Transform.

Studies concerning other European countries confirm the notion that substantial volumes of zero-carbon hydrogen will be needed by 2050

Normalised for GDP, for demand in the Netherlands these produce an indicative figure of 259 to 1884PJ

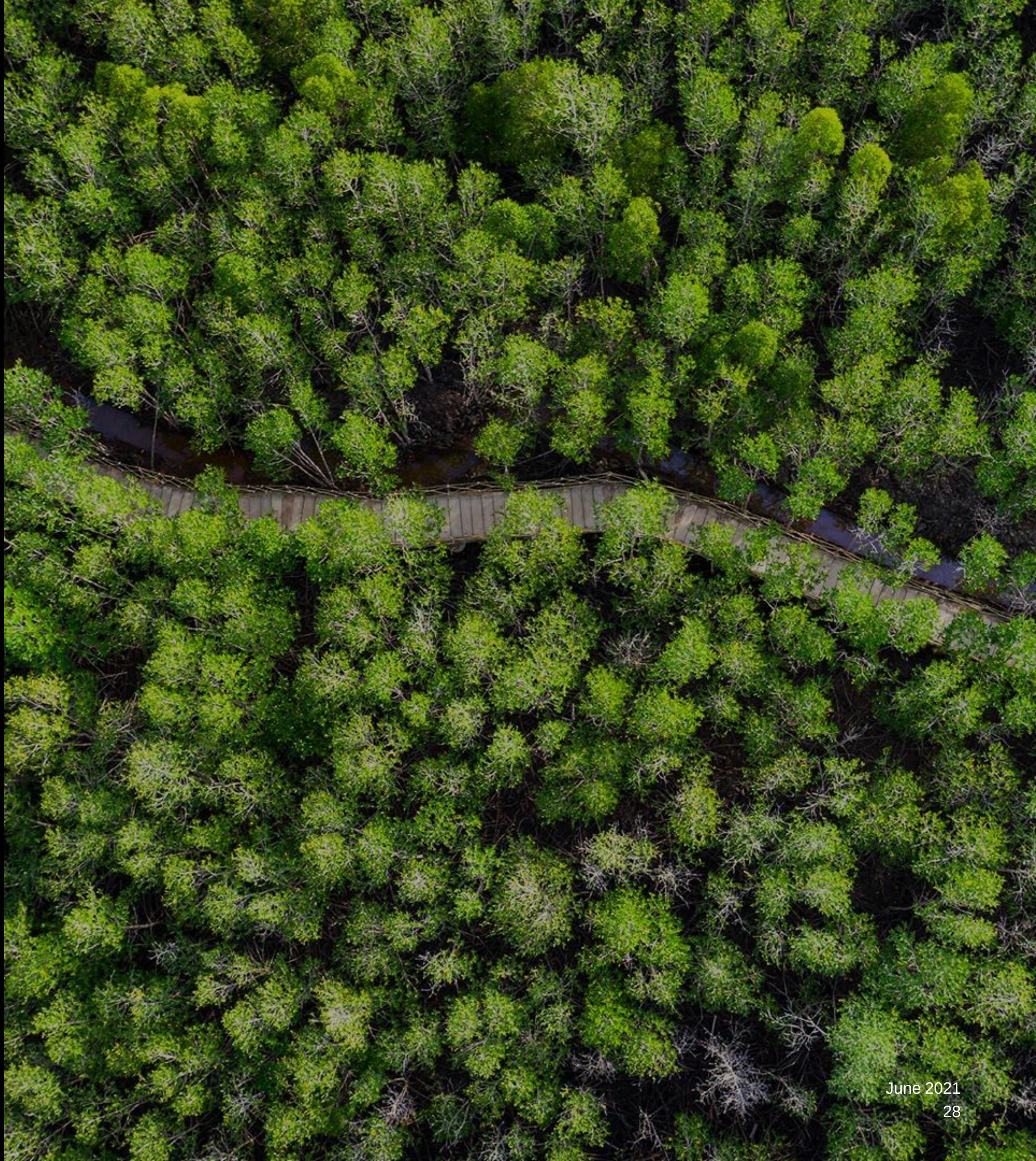
Scenario studies for European countries and the EU hydrogen demand 2050[1]
(PJ per year, normalised to GDP in NL). Source: TNO (2019)



- A meta-analysis of international studies by TNO (2019) also gives an idea of the future hydrogen demand in northwestern Europe. The underlying studies forecast a substantial demand for zero-carbon hydrogen in 2050. For the sake of comparison, TNO has normalised the values for Gross Domestic Product (GDP) to provide an indicative figure for the Netherlands. However, these studies are not based on climate neutrality: they focus on an 85 to 95% carbon emission reduction compared to 1990 levels, in line with the climate targets that applied at the time. Studies that assume around a 95% cut in CO_2 emissions present a normalised value for the Netherlands of between 259 and 1884PJ.
- In the studies with the most conservative estimates for hydrogen demand in 2050 (Shell, 2018; DNV GL, 2018a), the potential of hydrogen is recognised, but it is expected that the hydrogen market will only develop globally starting from 2040 (TNO, 2020a; TNO, 2019).
- As with the scenario studies that focus on the Netherlands, the wide spread in the estimates for hydrogen demand is due to differences in scope, calculation models and underlying assumptions. For example, the scenarios developed by Dechema (2017) only focus on the hydrogen demand within industry. In the Umweltbundesamt study (2014), a significant portion of the hydrogen demand arises from a high demand for the use of hydrogen for producing biofuels and as a feedstock for chemical products and materials (TNO, 2019).
- The underlying assumptions – concerning the availability and cost of hydrogen and other energy sources for example – also differ per country and region. For example, 40% of the petrochemical industry in the European Union is located in the Netherlands, Belgium and Germany[2] (Port of Rotterdam, n.d.). Normalisation based on GDP in the scenario forecasts for hydrogen demand in the EU will, in this specific example, provide a less accurate picture of the expected hydrogen demand in the Netherlands (TNO , 2019).
- The studies in this figure are mainly from 2017 and 2018 and so may be somewhat outdated. As stated on the previous page, TNO (2020a) concluded that more recent studies seem to indicate a higher share of hydrogen.

1. For the sake of comparability with the forecast for hydrogen demand in the Netherlands, the predicted hydrogen demand has been normalised in proportion to GDP.
2. This petrochemical industry is largely located in the ARRRA cluster (Antwerp-Rotterdam-Rhine-Ruhr area).

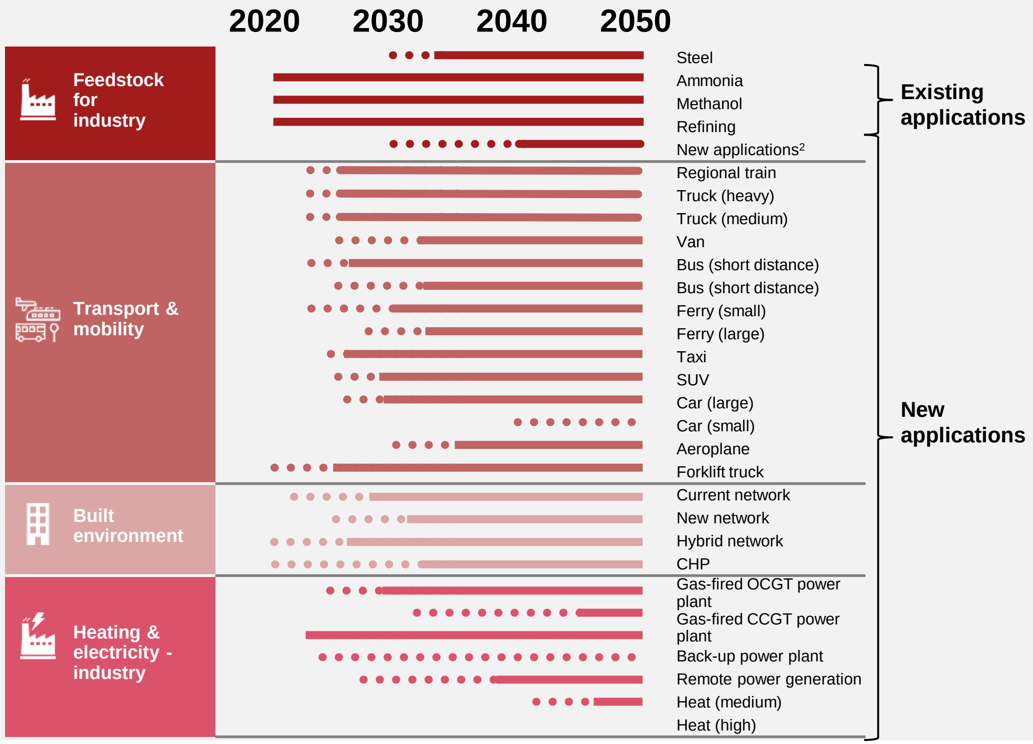
2.2. Development of hydrogen demand



Hydrogen, which is currently being used primarily as a feedstock in industry, has the potential to be utilised for a wide range of applications

It is uncertain for which applications and when hydrogen will become competitive with the alternatives

Possible development paths for hydrogen in relation to alternatives[1]
Source: Hydrogen Council (2020)



••••••• Hydrogen is competitive under optimal conditions and in optimally suitable regions
▬▬▬ Hydrogen is competitive under average conditions and in average regions

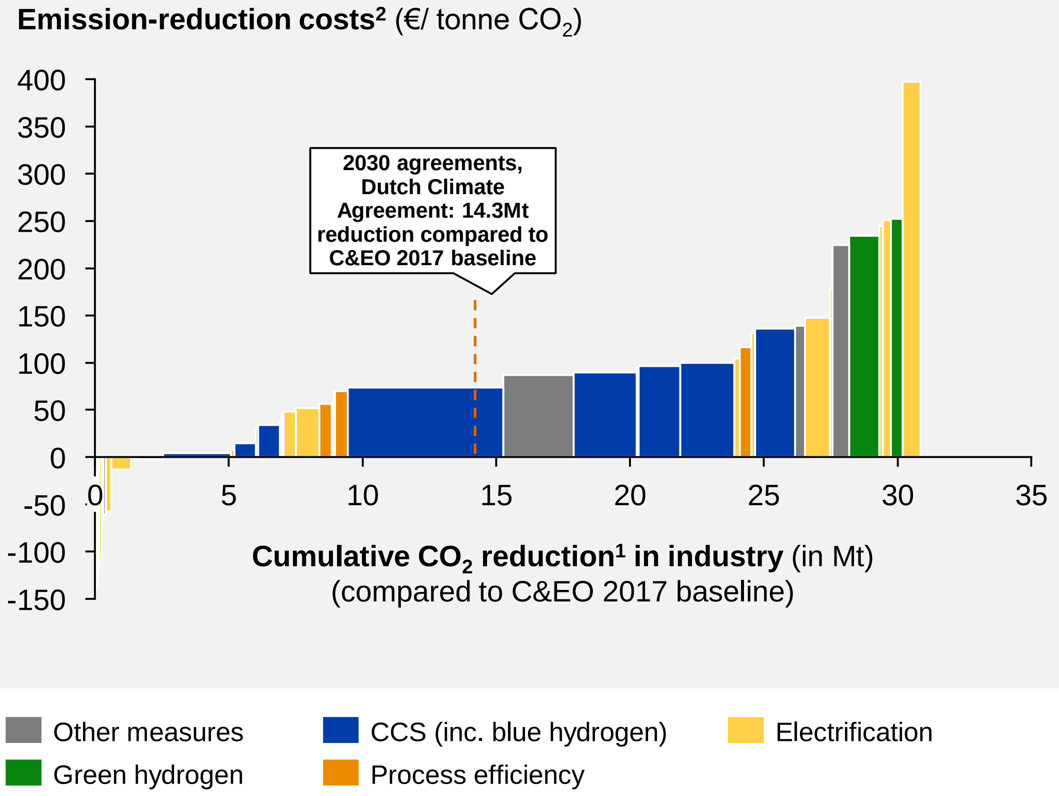
- Hydrogen has the potential to fully decarbonise a wide range of applications in the economy. Hydrogen is already widely used as a feedstock in industry for refining and for the production of ammonia. In industry, other applications for hydrogen as a feedstock are under development (such as in the production of steel and in chemical recycling of plastic), and applications in the generation of heat and electricity are also being considered. There are also a number of applications in transport & mobility and in the built environment.
- Based on its study, the Hydrogen Council (2020) concluded the following:
  - In 2050, hydrogen will be competitive in many of the identified applications with the most economical zero-carbon alternative. When hydrogen will reach this point, however, is highly dependent on the region, each of which has different energy prices, infrastructure options and policies regarding hydrogen development. In regions with good carbon storage options, like in the Netherlands, hydrogen can expect strong competition from fossil fuels from which CO_2 will be captured. Hydrogen will be particularly competitive for applications where there are no sustainable;
  - In **transport & mobility**, the first hydrogen applications are expected in the next ten years for heavy and long-distance road transport, situations where EVs are not cost-efficient. Eventually there will be opportunities for hydrogen in aviation and shipping in the form of synthetic fuels;
  - In the **built environment**, the opportunities for hydrogen lie first in combined applications with other fuels, for example as fuel for the peak load of heat grids in some parts of the country. From 2030, opportunities are also envisioned for hydrogen boilers;
  - From 2030, when production and distribution costs of hydrogen have fallen further, more applications for **heat and electricity** will become interesting for industry. This could include, for example, 'hydrogen turbines' for generating peak-demand electricity capacity and high-temperature process heat.

1. Not specific for the Netherlands but in a global context. 2. For example, chemical plastic recycling where hydrogen is used as a feedstock.

Industry is expected to be the first major consumer of zero-carbon (green) and low-carbon (blue) hydrogen

Making grey hydrogen production more sustainable can cut carbon emissions by around 7.5Mt

Merit order curve for emission-reduction costs 2030: Dutch industry
Scope 1 emission potential from industry clusters. Source: PBL Netherlands Environmental Assessment Agency (2019a)



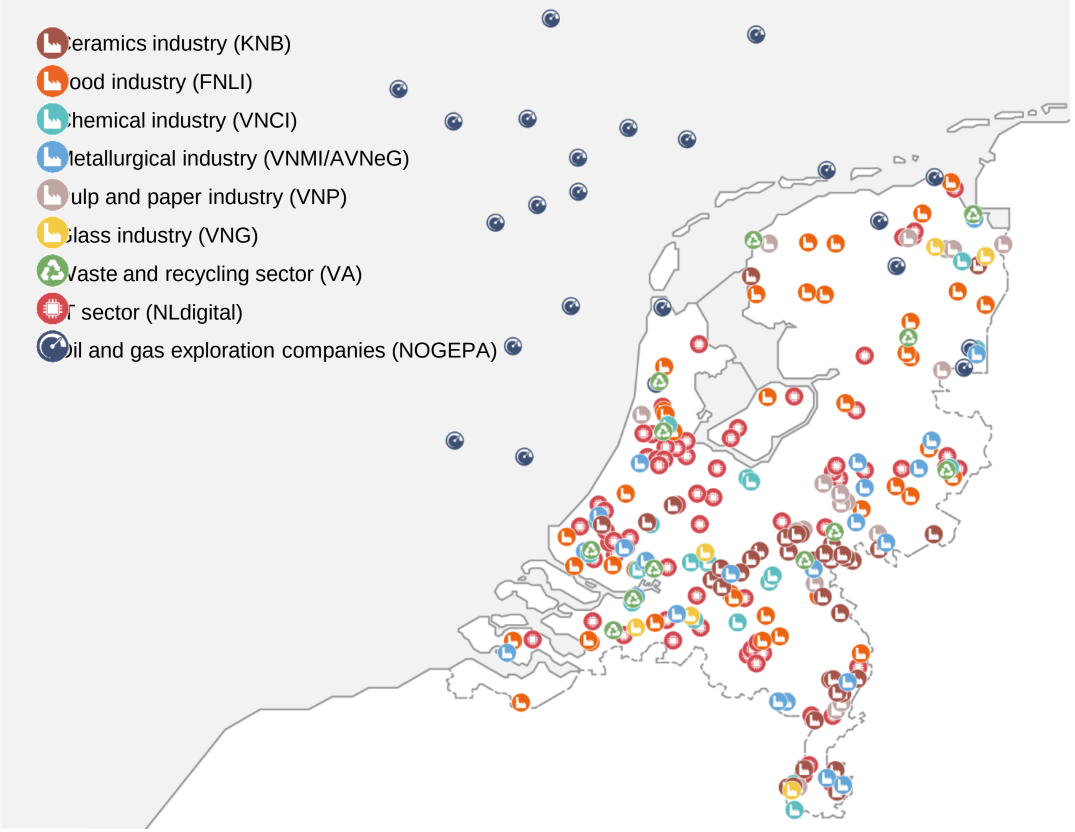
- The Dutch basic industry must become more sustainable if it is to become climate neutral by 2050. The Dutch Climate Agreement (2019) states that basic industry must reduce its CO_2 emissions by 35.7Mt by 2030 Mt, meaning an additional 14.3Mt above the 2017 baseline in PBL's Climate & Energy Outlook. This does not yet take into account the fact that the current target of 49% lower emissions for the Netherlands may be increased as a result of the recent increase of the European target for 2030 to 55%.
- The technological options available to industry are limited. Roughly speaking, the options are increasing process efficiency (meaning lower energy usage), applying CCS (including blue hydrogen), electrification and green hydrogen.
- It is expected that the first application of zero-carbon or low-carbon hydrogen will be to replace the current grey hydrogen that is used as a feedstock in industry. For these users, hydrogen is the only possible way they can make their main process more sustainable. Hydrogen molecules are essential in the manufacture of products such as ammonia and cannot be substituted by anything else. In 2020, the production of roughly 100PJ of pure grey hydrogen generated about 7.5Mt of CO_2 emissions (not including emissions from natural gas extraction) (IEA, 2017). TNO (2020d) estimates that of the 100PJ produced, 50PJ can be replaced relatively easily by zero-carbon or low-carbon hydrogen and can therefore contribute to the reduction of emissions by about 3.8Mt.
- CCS, part of which concerns the capture of CO_2 during the production of grey hydrogen, results in a lower cost per tonne of carbon emissions cut compared to the use of green hydrogen (PBL, 2019a). However, not all CO_2 can be captured in a cost-effective way (for example, at existing SMR plants that produce grey hydrogen only 50 to 70% can be captured), meaning that green hydrogen will ultimately have to play a significant role in reducing carbon emissions in industry.
- Scenario study II3050 therefore assumes that industry will be one of the largest consumers of zero/low-carbon hydrogen by 2050. The figures range from 83PJ in the Regional scenario to 380PJ in the International scenario.

1. This refers specifically to Mt CO_2 equivalent. 2. Including opex and discounted capex; excluding infrastructure costs for electricity and hydrogen; excluding supply of residual heat to the heat grid.

The expected growth in industrial demand for hydrogen also comes from outside the five largest industrial clusters

These hydrogen consumers are spread across the country and require additional infrastructure

Map of 'sixth cluster' industries in Netherlands
Source: VNCI (2020)

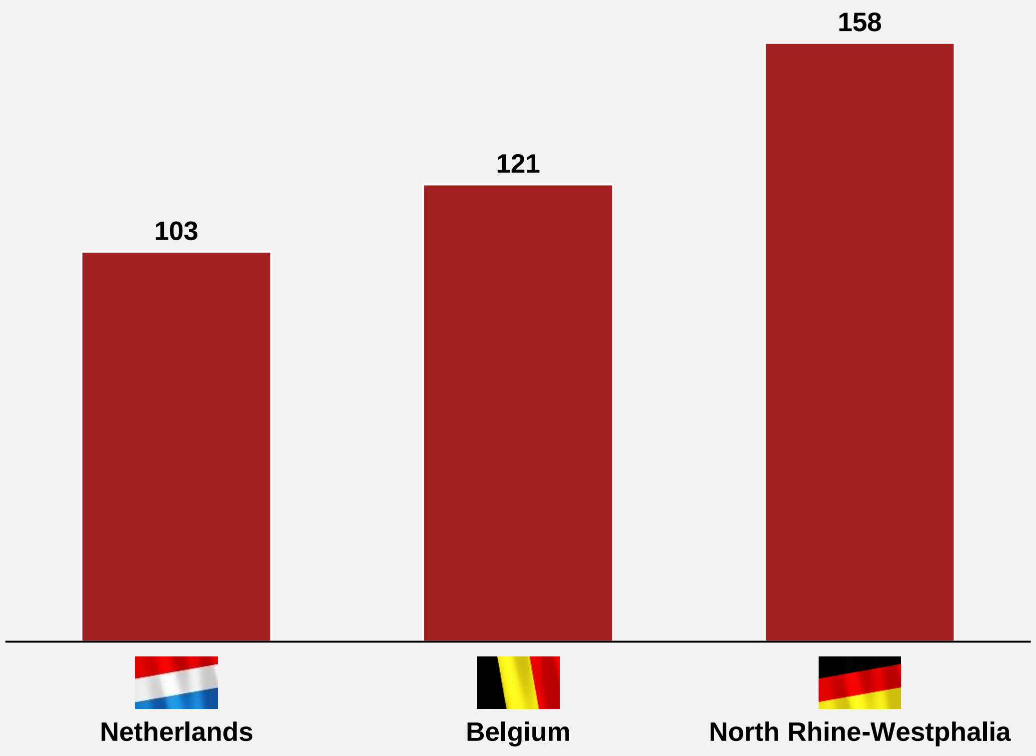


- In addition to the installations (i.e. in-scope stationary technical units) located in the five specific regional industry clusters, there are many more installations in the Netherlands that depend on a hydrogen connection eventually becoming available if they are to make their production processes more sustainable. These installations are spread across the country.
- This includes, for example, installations in the 'sixth cluster' (see the figure to the left), which includes a wide range of industries with diverse characteristics, each of which plays an important role in countless product and production supply chains. These installations can be found in the ceramics, building materials, food and chemical products industries, for example. For many of these installations, sustainability alternatives are limited, because their processes require high temperatures.
- Dutch industry outside the five largest clusters is good for 16.5Mt of CO_2 emissions, 4.3Mt of which must be cut by 2030 (VNCI, 2020). Potential hydrogen demand from these installations is, however, relatively limited in comparison to demand from the five major industrial clusters. The sixth cluster is, however, jointly good for a turnover of approximately €125 billion and creates direct employment of more than 210,000 jobs, with a multiple of this figure in indirect employment (VNCI, 2020).
- A large number of these installations are covered by the EU ETS, and possibly an additional Dutch carbon tax. Access to hydrogen infrastructure, heat grids and/or means of carbon removal is a prerequisite for the continuation of these installations.
- Sixth cluster installations are currently directly connected to the national, high-pressure gas network or a regional transmission network, or are connected via one of the local distribution networks; how these can be connected to the national 'hydrogen backbone' in the future depends on local circumstances.

There are also industrial clusters across the border with, potentially, a high hydrogen demand

The demand for zero-carbon hydrogen in Belgium and North Rhine-Westphalia is estimated at between 120 and 160PJ/year

Hydrogen demand (as a feedstock) for industry in the Netherlands, Belgium and North Rhine-Westphalia in 2050 (in PJ). *Source: Wuppertal Institut (2020)*



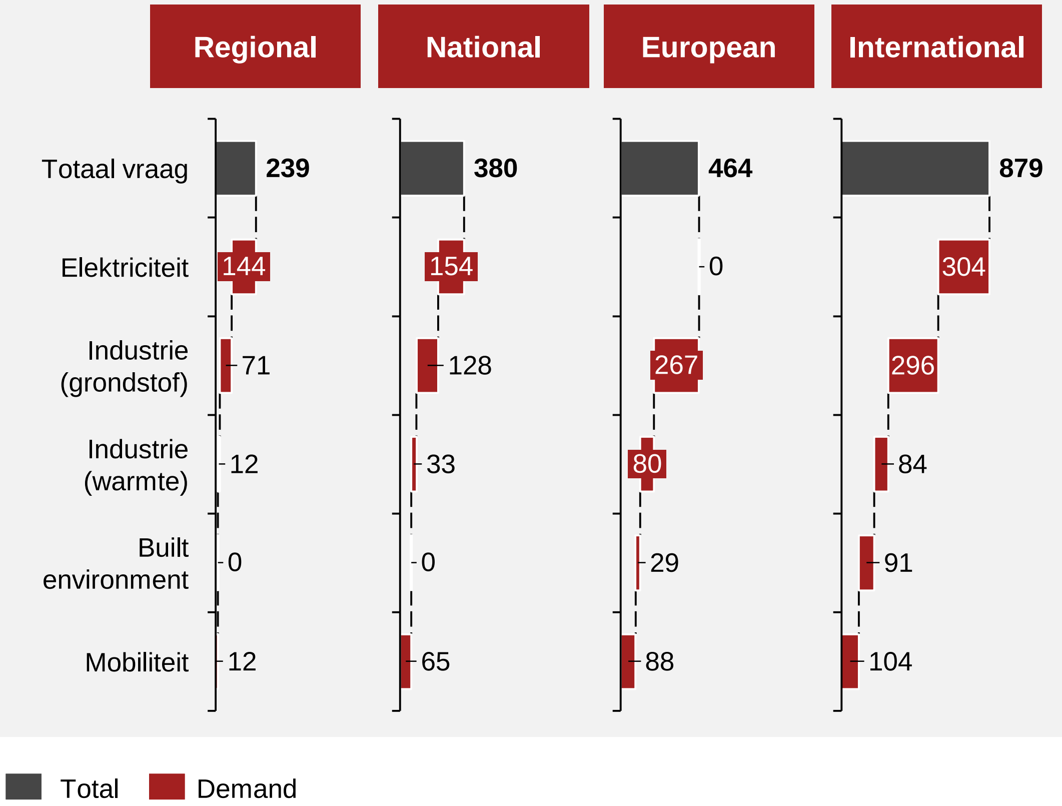
- Countries bordering the Netherlands face similar challenges with regard to making industry more sustainable. Here, too, the focus in the coming years will be on feedstock applications of hydrogen, both for existing applications and for new applications like steelmaking.
- It is estimated that in 2050 the total annual demand for zero-carbon hydrogen as a feedstock in industry in Belgium and North Rhine-Westphalia will be, respectively, 121PJ and 158PJ, which is higher than the forecast demand for hydrogen as a feedstock in the Netherlands.
- It is expected that these quantities of zero-carbon hydrogen will already be partially available by 2030; it is not so much the absolute demand for hydrogen for feedstock applications that will change between 2030 and 2050: it is the demand within specific sub-sectors that will really change. Agora (2021) expects that refining will increasingly shrink over time, but that this will be compensated by steelmaking applications and plastic- that will require increasingly larger quantities of hydrogen. Hydrogen demand for the production of ammonia and methanol is expected to remain stable.
- All three regions are expected to be importers of zero-carbon hydrogen in the longer term. In the Netherlands, Belgium and North Rhine-Westphalia, it is expected that by 2050 the total potential for sustainable electricity will be insufficient to meet the demand for sustainable electricity, including energy for the production of zero-carbon hydrogen. This deficit will be greatest in North Rhine-Westphalia (Wuppertal Institut, 2020). In its hydrogen strategy, Germany describes a national deficit of between 200 and 300PJ, which will need to be filled via imports (BMWI 2020).
- The Netherlands and Belgium have several large seaports that offer import options for zero-carbon hydrogen from areas with great potential for sustainable electricity. To be able to meet the high demand in North Rhine-Westphalia, this region will, in addition to imports via Hamburg, also depend to a large extent on ports in the Netherlands and Belgium, which are located closer to this region.
- Connecting industry in Belgium and North Rhine-Westphalia to the Dutch transmission network can contribute to a higher utilisation rate of the Dutch network, allowing hydrogen to be transported more cost-effectively. It is expected that the balance of exports will go to North Rhine-Westphalia, with a share of around 80%, compared to about 20% for Belgium[1].

1. Estimate of Port of Rotterdam.

In time, hydrogen demand can also arise in the electricity, transport & mobility and built environment sectors

In addition to industry, the main source of demand is for electricity production and transport & mobility

Hydrogen demand[1] II3050 scenarios for weather reference year 2015[2] (PJ).
Source: ETM (2020)



- The widely divergent scenarios for a climate-neutral economy, as set out in II3050 (ETM, 2020), provide a general idea of the future playing field for hydrogen. The total hydrogen utilisation in this scenario study varies greatly, between 239 and 879PJ, and shows a pronounced distribution in the different scenarios according to various applications:
  - **Electricity**: Electrification is an important part of most climate-neutral scenarios, and to guarantee the supply and balance[3] of electricity throughout the year, electricity is produced in hydrogen-powered plants. Hydrogen is used to generate electricity when there is a shortage of sustainable power from solar and wind sources, except in the European scenario, where green gas is used for this;
  - **Industry:** In all scenarios except for the Regional, hydrogen is used, alongside extensive electrification and CCS, to make Dutch industry more sustainable. Hydrogen is mainly used as a sustainable feedstock in the chemical industry, for the production of fertilisers and for refining. In the food industry and pulp and paper industry hydrogen is mainly used for heating;
  - **Built environment**: Hydrogen is used in the built environment to heat homes and buildings. The European and International scenarios assume, respectively, a 20% and 40% share of hybrid heat pumps with an auxiliary hydrogen boiler;
  - **Transport & mobility**: Hydrogen is used for both freight and passenger transport with a hydrogen share of 15 to 50% and 0 to 40%, respectively;
  - **Synthetic fuels:** Though not included in the figures in the figure on the left, the production of synthetic fuels for aviation and shipping would require large volumes of hydrogen. The hydrogen demand for this varies from around 500PJ in the Regional scenario to about 1,000PJ in the European and International scenarios, the National scenario being around 700PJ.

1. Excl. hydrogen transit flows and international aviation and shipping. 2. Based on the weather conditions as these were in 2015. 3. In addition to batteries that cannot (yet) provide the required seasonal balancing.

3 The utility of a transmission network for hydrogen

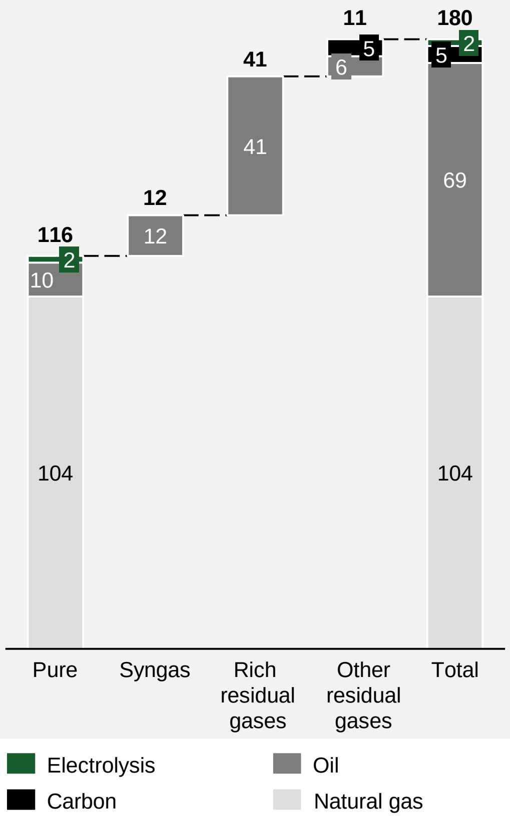
HyWay 27

3.1. The need for hydrogen transport

Currently, hydrogen is only transported on a limited scale because it is produced close to end users

Air Liquide and Air Products use a network to supply hydrogen to customers

Hydrogen supply in the Netherlands per source and type, 2019 *(in PJ). Source: TNO (2020d)*



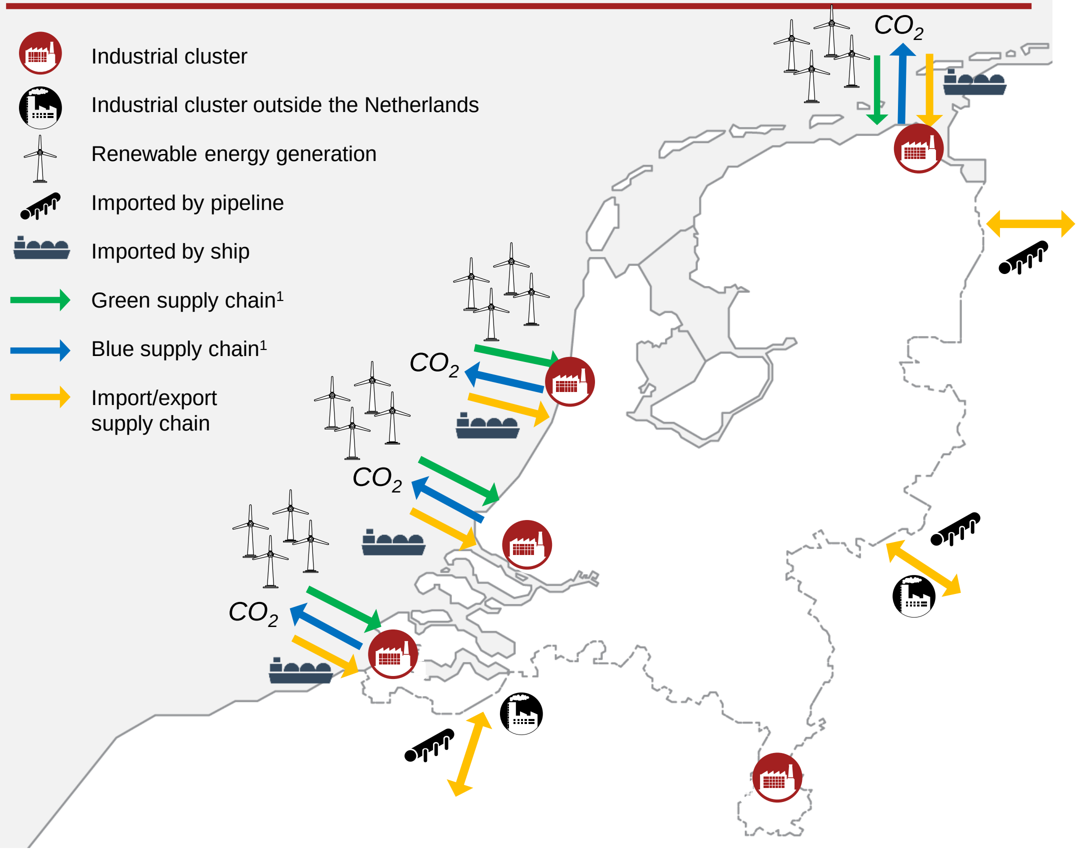
Existing hydrogen pipelines in the Netherlands *Source: DNV GL (2017)*

- Hydrogen is currently only transported on a small scale. The current (2019) demand for hydrogen of around 180PJ is mainly met with grey hydrogen, produced from natural gas and petroleum, with little or no capture of the CO_2 released during the process. Given that the fossil fuels required to make grey hydrogen are available in abundance in the industrial clusters, grey hydrogen can be produced close to where the end users are based, and companies often even produce their own hydrogen.
- At plants where hydrogen, or hydrogen-rich residual gas, is released as a by-product, it is generally transported through local pipelines to other users on the same industrial estate.
- Air Products and Air Liquide are the only producers in the Netherlands who supply pure hydrogen to external customers through their proprietary network of pipelines (TNO, 2020d). In a study these volumes were estimated to be lower than 10PJ/year (Roads2HyCom, 2007):
  - Air Products operates a pipeline system of approximately 140km in the Rotterdam/Moerdijk industrial cluster, which runs from Botlek to Moerdijk and Zwijndrecht;
  - Air Liquide operates Europe's largest hydrogen network, which extends to around 1,000km, is made up of 154mm-diameter pipelines, and runs from the northern France to Rotterdam, connecting various production plants to customers in northern France, Belgium, and the south-western Netherlands. Import and export are possible and currently roughly balanced (TNO, 2020d).
- Aside from that, Gasunie operates a 12km hydrogen network between Dow Benelux and Yara at the Zeeland province industrial cluster. This is a former natural gas pipeline that was repurposed for hydrogen transmission in 2018.
- Small quantities of hydrogen (less than 0.2PJ/year) are also transported by lorry (TNO, 2020d).

A climate-neutral economy requires new transport supply chains to connect hydrogen suppliers to hydrogen users

Transmission capacity is needed to get blue and green hydrogen to end users

Future hydrogen supply and demand clusters[2]



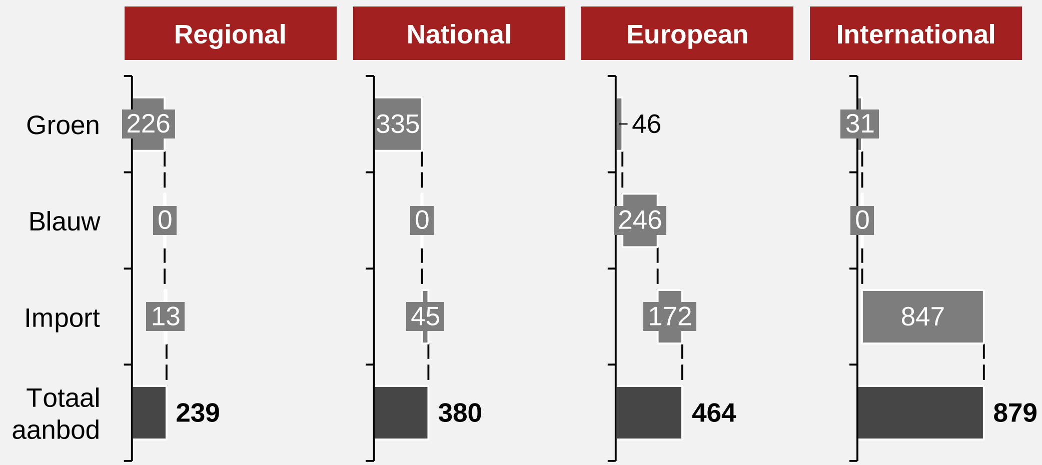
- In order to be able to move towards a climate-neutral energy and resources system in the long term, zero-carbon molecules are needed. Zero-carbon, as well as low-carbon, molecules require new supply chains between energy sources, suppliers, and consumers, meaning that what is needed is hydrogen transport.
- Total supply of zero-carbon and low-carbon hydrogen can be split up into three supply chains (green, blue, import), each of which will require a new form of transport infrastructure:
  - **The green hydrogen supply chain (zero-carbon) requires additional transport of renewable power and/or hydrogen.** For the production of green hydrogen, you need relatively large volumes of renewable power. To illustrate: the production of 1PJ of green hydrogen per year currently requires approx. 10 offshore wind turbines or enough solar panels to cover about 300 football fields. Significant volumes of hydrogen can, therefore, only be produced in the Netherlands using renewable power generated by offshore wind turbines (II3050 from ETM, 2020; RLI, 2021)
  - **The blue hydrogen supply chain (low-carbon) requires additional transport of CO_2 and/or hydrogen.** If existing SMR systems that are currently used to produce grey hydrogen are fitted with CCS, part of the CO_2 can be captured, following which this will need to be transported to empty gas field under de North Sea, which is the only place in the Netherlands where Dutch law permits permanent CO_2 storage (TKI Nieuw Gas, 2020).
  - **For imported hydrogen, which is normally zero-carbon green hydrogen, we need import terminals and domestic hydrogen transport.** Regions such as Southern Europe, North Africa, Chile, the Middle East, and Australia expect to generate such great volumes of renewable power in the long term that their surpluses can be exported in the form of hydrogen (Frontier Economics, 2018). Hydrogen imports can also enter the Netherlands through pipelines from Germany or Belgium (II3050 from ETM, 2020), but these countries do not have any surplus renewable power and actually expect to import zero-carbon or low-carbon hydrogen from or via the Netherlands[3] (BMWI, 2020).
- The figure to the left illustrates how the Dutch coast is a key connection for the various supply chains of zero-carbon and low-carbon hydrogen, thus also confirming that the Chemelot cluster, as well as export locations in Germany and Belgium, depend on connections to other clusters to meet their needs for zero-carbon/low-carbon hydrogen.

1. The green and blue supply chain refer to hydrogen produced in the Netherlands. 2. Other coastal locations with seaports and energy infrastructure, such as Den Helder, also offer opportunities for the development of hydrogen supply chains. 3. The Netherlands could also import blue hydrogen from Norway using existing natural gas pipelines.

The exact extent of transport demand depends largely on future hydrogen sources

It is as yet uncertain how green, blue, and imported hydrogen will relate to each other in the climate-neutral scenarios

Hydrogen supply in II3050 scenarios for weather reference year 2015, not including transit flows and international aviation and shipping *(in PJ).*
Source: Berenschot & Kalavasta (2020) with data from ETM (2020)



Required volume of renewable power or carbon capture for the scenarios

	Bandwidth	Prospect[1]
Green	31 to 335PJ	3 to 43 700MW wind farms
Blue	0 to 246PJ	0 to 28Mt (15 billion m^3) of carbon capture
Imported	13 to 847PJ	1 to 156 700MW wind farms

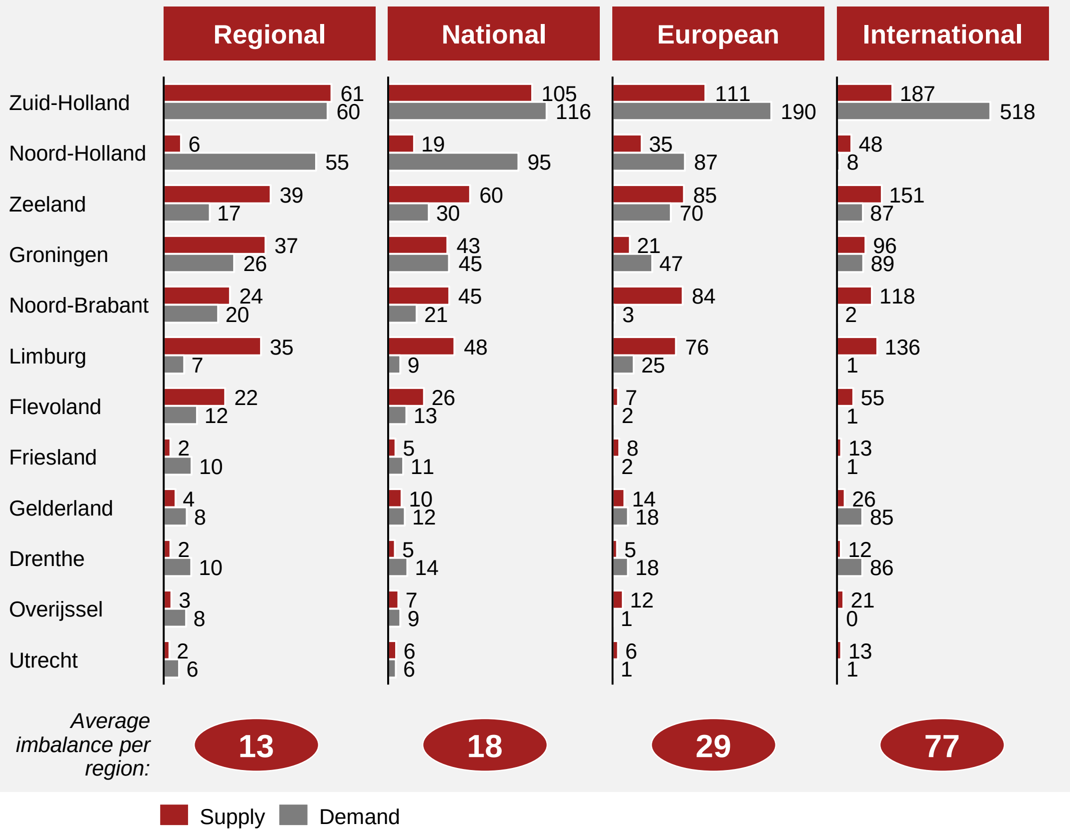
- The exact extent of transport demand depends largely on the various hydrogen supply chains that will be developed in the Netherlands and abroad. Both the total size of these supply chains and how they will relate to each other is, however, still unsure.
- The four scenarios in the II3050 study depict a bandwidth for the total hydrogen supply in the Netherlands of 239PJ to 879PJ in 2050. These values do not include transit flows and hydrogen used for the international aviation and shipping industries. The share of green, blue, and imported hydrogen in the total supply differs significantly from one scenario to the next (green: 4-95%; blue: 0-53%, imported: 5-96%). All the same, a number of important conclusions can be drawn from these four scenarios:
  - To be able reach the required volumes of green hydrogen, we need large-scale development of sources of renewable power, whereby offshore wind has the greatest potential. The 3-4GW required for the European and International scenario can easily be generated using offshore wind, but 20-30GW required for the Regional and National scenario requires extensive development of offshore wind.
  - Although it, still uncertain whether blue hydrogen will ultimately represent a significant share of total hydrogen supply 2050, it is seen as an affordable intermediate step towards fully zero-carbon hydrogen. Seeing as most of the captured CO_2 will have to be transported to the North Sea for permanent storage, and seeing as next-generation systems will be more effective in capturing CO_2, major blue- are expected to materialise close to existing natural gas infrastructure leading to the North Sea. Examples of such projects include H-vision in Rotterdam and H2Gateway in Den Helder.
  - Apart from that, the Netherlands will in any case have to develop the supply chain for imported hydrogen to be able to meet total demand for zero-carbon and low-carbon hydrogen in the Netherlands. Imports are also essential for the ability to develop international transit volumes (especially to North Rhine-Westphalia in Germany). Imported hydrogen can come into the Netherlands through a pipeline or by ship. Given that north-western Europe as a whole, with Germany as its engine, is set to become a net hydrogen importer, most of the hydrogen is expected to come in by ship and will need to be transported inland from the ports (ETM, 2020).

1. Assumptions: 25% loss in green hydrogen production (not included for import); offshore wind capacity factor of 0.47 (4,150 full load operating hours); energy loss for import 30%; 0.1Mt CO2 capture per PJ of blue hydrogen production.

The II3050 scenarios illustrate the importance of transport to eliminate regional hydrogen supply and demand imbalance

The average imbalance volumes within the regions in the four scenarios are between 13PJ and 77PJ

Imbalance between supply and demand in 2050 per province in the II3050 scenarios
(PJ, 2015 weather reference year, not including transit flows). Source: II3050 from ETM (2020)



- An analysis in the II3050 document of where hydrogen supply and demand will develop shows that annual production and import volumes will in each of the regions not be in sync with annual demand volumes, meaning that regions will have either a hydrogen surplus or a hydrogen shortage (imbalance), which they will have to eliminate by supplying their surplus hydrogen to other regions or acquiring hydrogen from other regions.
- The figure to the left shows the annual imbalance volumes per province and per scenario. Total supply and demand for the Netherlands is balanced. The difference between supply and demand on a provincial level is the minimum transport demand from or to each province.
- Based on the analysis, we can conclude that:
  - The provinces with the five largest industrial clusters jointly represent most of the demand. Over all the scenarios, total demand is spread throughout the country;
  - In each of the scenarios, coastal provinces with industrial clusters (South Holland, North Holland, Groningen, and Zeeland) represent the majority of total hydrogen supply because these provinces have access to offshore wind power (for green hydrogen), CO_2 infrastructure (for blue hydrogen) and seaports (for hydrogen import);
  - In all four scenarios, Limburg province (Chemelot), but also Flevoland and North Brabant, are projected to see significant hydrogen shortages, meaning that they will depend on connections to other regions;
  - In the Regional and National scenarios, where there is less dependency on imports, the average imbalance per province is smaller;
  - When factoring transit flows to German and Belgium into the equation, which the II3050 study does not do, the imbalance in each region will increase further.

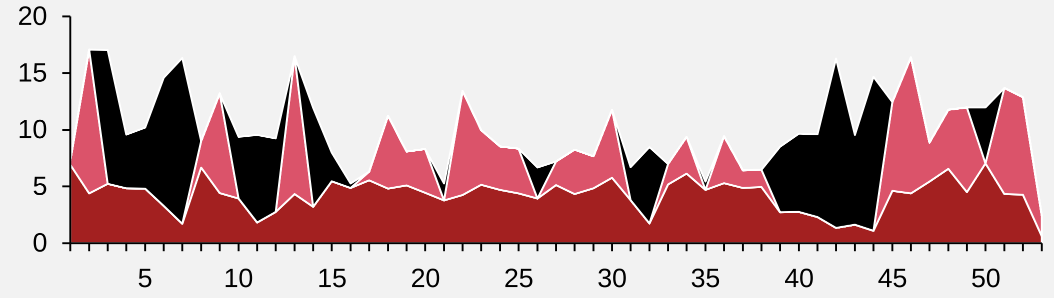
Increasing volumes of zero-carbon hydrogen produced in the Netherlands will also drive up the need for storage capacity

Storage capacity is needed to mitigate season and weather dependency

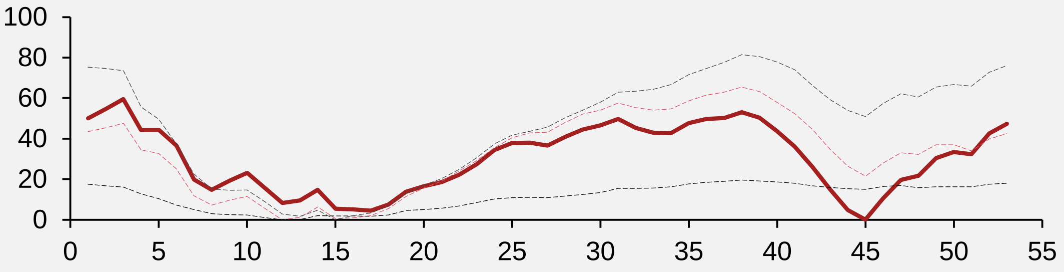
Weekly hydrogen imbalance and storage needs in 2050

II3050 National scenario, for the 2015 average weather reference year.
Source: ETM (2020)

Hydrogen supply and demand (PJ/ week)



Amount of hydrogen stored, cumulative (PJ)



Production deficit Production surplus Production simultaneous with demand

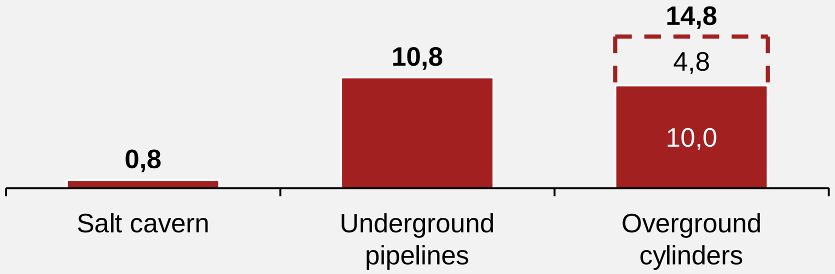
National Regional European International

- As the volume of zero-carbon hydrogen produced in the Netherlands is ramped up, season and weather dependency will also increase. Large-scale storage capacity will then be needed to absorb production fluctuations.
- By way of an illustration of this point, the top-right figure shows the production surplus and shortage for the National scenario from the II3050 document for the average weather reference year (2015). Here, the total demand for hydrogen (380PJ/year) is almost entirely met by green hydrogen production (335PJ/year) using sustainable electricity. About half of this green hydrogen is used for electricity production (154PJ) at times of insufficient supply of electricity.
- To mitigate the effects of seasonal and weather patterns, hydrogen storage capacity of more than 60PJ is required in this scenario. (By comparison, the collective working volume of the three largest Dutch natural gas storage facilities is currently 200PJ [TNO, 2018]). This is because supply and demand in a closed system must be balanced at all times to prevent pressure differences in the system growing to an unacceptable level. Surpluses and shortages have to be discharged or replenished using storage facilities.
- The transmission system can accommodate minor pressure differences and thus achieve flexibility within the time span of one day. Daily hydrogen imbalances will have to be mitigated in another way, such as through large-scale hydrogen storage facilities.
- In the other II3050 scenarios, where total green hydrogen production levels are below those of the National scenario, there is still a substantial need for hydrogen storage to buffer seasonal and weather-related variations.
- In the extreme weather reference year of 1987, which includes a period where renewable energy production dwindles due to lack of sunshine and wind, the storage need in each of the II3050 scenarios would be roughly double the storage need in the case of the average weather reference year of 2015, as shown to the left here.

Transmission capacity , is needed to create access to potential natural storage facilities

Salt caverns in the northern Netherlands appear to be a cost-effective option for hydrogen storage

Large-scale seasonal hydrogen storage cost comparison
Costs *based on 2.5 full-empty-full cycles PJ*[3] *(€/kg H_2). Source: Bünger et al. (2016)*



Storing 0.5PJ of hydrogen requires:

	Salt cavern	Underground pipelines	Overground cylinders
Geometric volume *(m^3)*	500,000	6,800 (10km, 36-inch pipeline)	110
Pressure range *(Bar)*	60-180	20-70	20-50
Net storage capacity *(in PJ)*	Approx. 0.5	Approx. 0.0035	Approx. 0.00004
Investment costs (*€ million)*	107[1]	12	0.08-0.12
Service life *(years)*	30	50	20
Capital costs[2] *(€/year)*	7,500,000	680,000	10,000

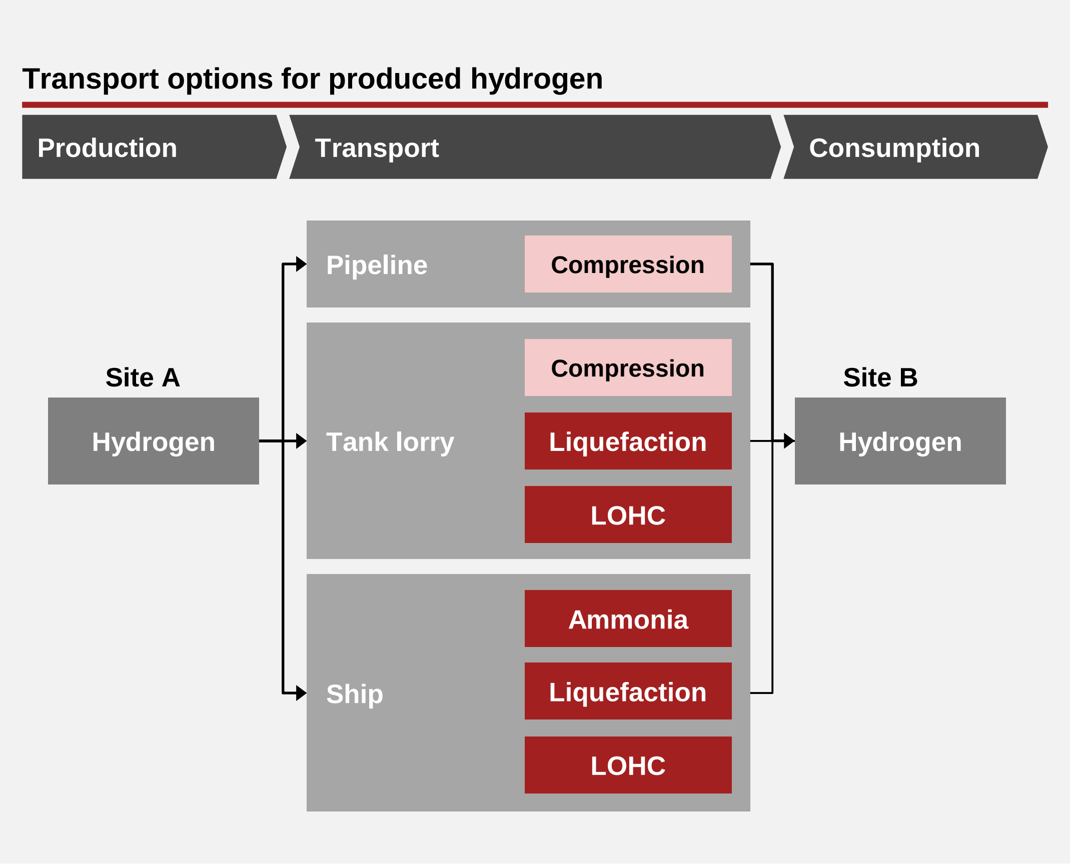
- As shown above, the system will have to include large-scale hydrogen storage to mitigate dependency on the seasons and weather. Large-scale (PJs) and long-term (months to years to bridge seasonal and weather patterns) hydrogen storage, as needed for large-scale green hydrogen production, is only economically interesting if done underground using suitable geological structures (IEA, 2019). However, the fact that all these salt caverns are located in the northern Netherlands means that hydrogen transport is needed to be able to move hydrogen to and from these natural storage facilities.
- Underground salt caverns are the best suited storage medium for hydrogen for various reasons: it is existing and mature technology, the investment involved is relatively low, it offers approx. 98% efficiency and low leakage losses and high inflow and outflow capacity, it involves minimum risk of contamination, and it requires only small volumes of cushion gas (Andersson et al, 2019; IEA, 2019). The main downside is that salt caverns exist only in areas with the right geological structures, which in Europe is mainly in the northern Netherlands and northern Germany. Hydrogen storage in empty gas fields could in the future play a role in scaling up storage capacity, but a number of technical challenges that this involves are currently still being studied (TNO, 2020c).
- Hydrogen in its liquid form can further facilitate large-scale storage, but the high conversion costs make this an economically uninteresting option for stationary storage. When hydrogen is supplied in liquid form (*liquid hydrogen, ammonia, or LOHC*) because it was imported by ship, tank storage in import terminals can also play a key role in meeting the storage/flexibility needs of the hydrogen system, provided that it is economically and technically possible to flexibly set up dehydrogenation, i.e. the process of ‘unpacking’ the hydrogen. A large oil tank with a capacity of 114,000m^3 could theoretically hold 0.8PJ hydrogen in the form of LOHC (50kg H_2/m^3) or 1.9PJ hydrogen in the form of ammonia (120kg H_2/m^3) (Andersson et al, 2019).

1. Including above-ground facility and cushion gas. Investment is highly dependent on the number of salt caverns connected to an above-ground facility. 2. Based on 5.5% interest on capital. 3. A full-empty-full cycle indicates the relationship between flow and capacity of a storage facility and is normally between 2 and 3 in the II3050 scenarios.

3.2. The utility of pipelines as a transport medium

Hydrogen can be transported from production site to end user in a variety of ways

The cost efficiency of various modes is determined by volume and distance



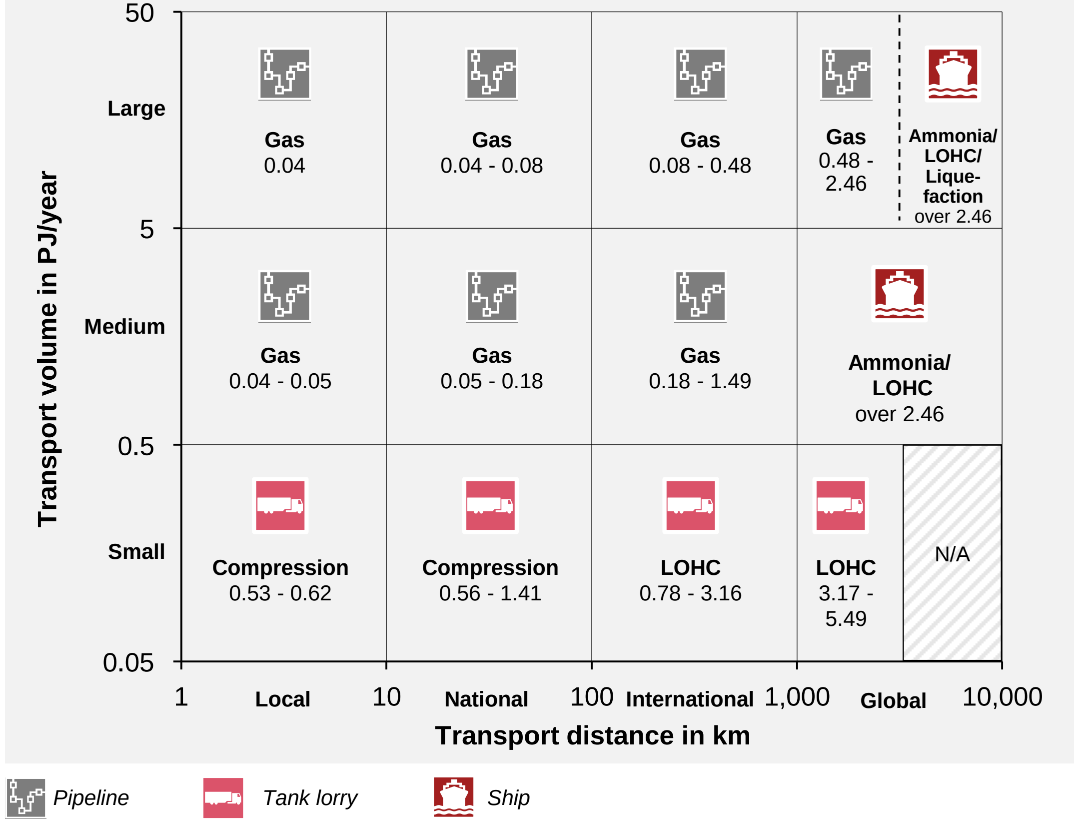
Legend With conversion Without conversion

- Hydrogen transport costs are driven primarily by volumes and distance, whereby different modes of transport are the most cost effective for different combinations of these drivers:
  - *Transmission by pipeline* is profitable mainly when transporting large volumes of hydrogen and, therefore, ideally suited as a transport mode to deliver hydrogen to clusters of large industrial users.
  - *Transport by tank lorry* is profitable mainly when transporting small volumes and when the end user is not based near a pipeline; for shorter distances, high compression in smaller tanks is the most economically attractive option. For longer distances, liquid organic hydrogen carriers (LOHCs) are a cheaper option because of the stability of the carrier (Andersson et al, 2019).
  - *Transport by ship* is the only option when transporting hydrogen over distances where pipelines cease to be profitable. Experiments with three techniques for the storage and transport of hydrogen in liquid form, i.e. ammonia, liquefaction, and LOHCs, are currently ongoing.
- Converting gaseous hydrogen into liquid hydrogen involves extensive energy losses and is, consequently, not very efficient (CE Delft, 2018a). Conversion should, therefore, be avoided as much as possible in the transport of hydrogen between two locations. While the figures below provide an indication of conversion costs, they must always be assessed in the context of the entire supply chain.
  - *Liquefaction*: hydrogen is cooled down to a temperature of approx. -253C. Energy is needed both to cool the hydrogen and to keep it cool in transit. The conversion costs amount to around €0.80 per kg of hydrogen (IEA, 2019).
  - *LOHC:* chemically binding hydrogen to an organic substance (wide range of possible products). The conversion costs are between €1.10 and €2.10 per kg of hydrogen and return flows must also be taken into account (IEA, 2019).
  - *Ammonia:* synthesising liquid ammonia from hydrogen in gaseous form and nitrogen (Haber-Bosch process). The conversion costs are between €1.50 and €1.90 per kg of hydrogen. In addition, because ammonia is toxic extra precautions must be taken (IEA, 2019).

Pipelines are the most cost-effective option for high-volume hydrogen transport within the Netherlands and NW Europe

Pipelines are cost-effective for transport volumes of more than about 0.5 PJ/year and for distances of around 1,000 km and upwards

Costs of conversion and transport mode based on distance and volume
(PJ/year, km, €/kg H_2). Source: Bloomberg NEF (2020)[1]



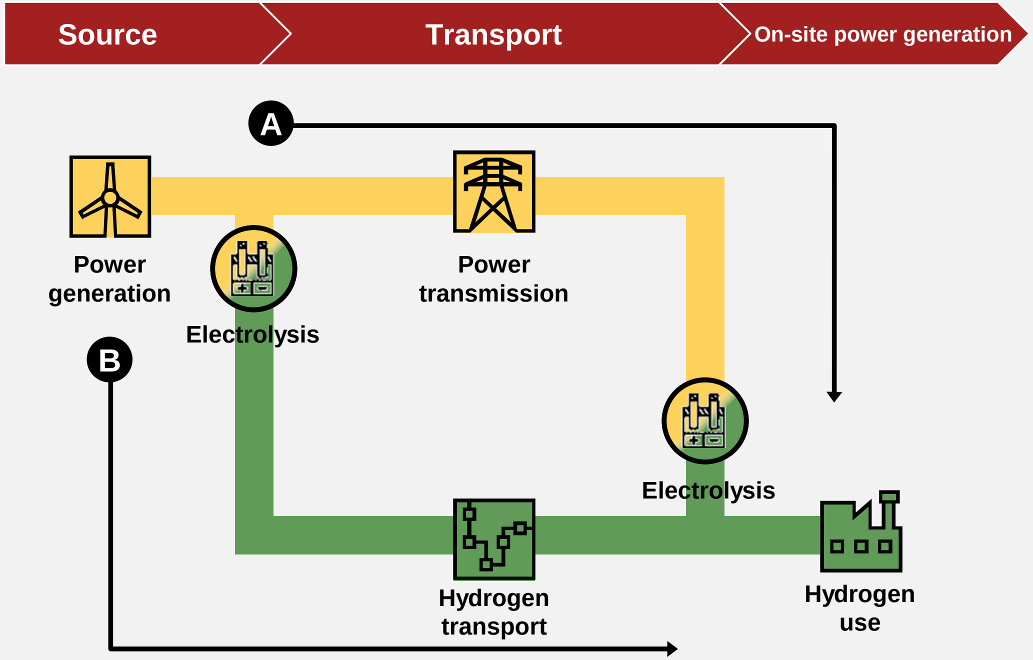
- Hydrogen transport costs are driven primarily by volumes and distance, whereby different modes of transport are the most cost effective for different combinations of these drivers.
- The figure on the left shows that, for medium volumes (approx. 0.5 PJ/year) and above, hydrogen can best be transported in gaseous form by pipeline. Bloomberg NEF (2020) calculated that this is more cost-effective than transport by lorry, which involves hydrogen stored in tanks under great pressure (approx. 500 bar). Transporting 0.5PJ of hydrogen would require approx. 3,500 lorries[2].
- The figure also shows that transport by ship may be a cheaper option when transporting over distances upwards of 1,000km. For large volumes (above approx. 5 PJ/year), this applies especially in the case of intercontinental connections over deep seas and oceans, where pipelines are no longer cost-effective (IEA, 2019).
- By way of comparison: the II3050 study shows that in 2050 regional hydrogen shortages and surpluses per province will be between 13PJ and 77PJ per year. This means that when it comes to eliminating this kind of imbalance, pipelines are the most cost-effective transport option.

1. Gas costs incl. 20% of costs for storage. Summary enriched with data from IEA (2019).
2. A tank lorry can transport around 100kg of hydrogen, where the hydrogen has been highly compressed (to a pressure of approx. 500 bar).

A pipeline transmission network can help limit total transport costs in the supply chain

Electrolysis close to where the power is generated is the cheaper option to supply hydrogen to end users

Illustration of green hydrogen supply chain with two transport alternatives

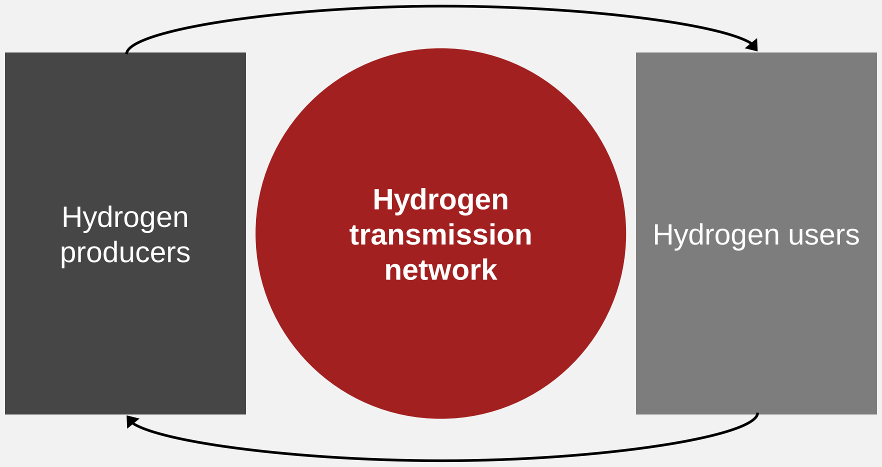


- The figure to the left depicts the green hydrogen supply chain. As pointed out in the previous chapter, the source of renewable power is generally not located near the end users of hydrogen. The hydrogen producer, therefore, will have to choose where to produce the hydrogen. Simply put, there are two options: A) Produce green hydrogen close to the consumer, transmitting renewable power to the location close to the consumer via the power grid; B) Produce green hydrogen close to the source of the renewable power used in the hydrogen production process, transporting the hydrogen to users via a hydrogen transmission network.
- In many cases, producing hydrogen close to the source of renewable power (option B) is the cheaper option. DNV GL (2020a) estimates that the transport costs for molecules are roughly 8 to 15 times lower than electron transport costs, based on the same volume of energy. This is down to the great differences in capacity and costs. Another advantage of this option is that the conversion energy used at the electrolysis plant (20%-40%) does not have to be transported (Hydrogen coalition, 2018). Needless to say, there are exceptions to this rule and specific situations where it would be more logical to produce hydrogen close to an end user.
- Most (industrial) hydrogen users are connected to the power grid. And Dutch network operators are, in principle, subject to an obligation to connect users to their network and to transport power: if a user were to decide to set up an electrolysis plant on its site, the power network operators would be under an obligation to enable that, even if it means that the network has to be upgraded. Developing a hydrogen transmission network will create an alternative way to get hydrogen to end users, an alternative that will in many cases involve the lowest total transport costs in the supply chain.

A transmission network can be a kind of *backbone* to which new users can connect, creating a liquid market

A central transmission network will give both producers and users better options

The potential virtuous circle that may emerge on the back of positive networks effects on the hydrogen market



- Hydrogen pipelines interconnect hydrogen users and hydrogen suppliers, such as hydrogen producers, and storage service providers and users. Increasing numbers of users can be connected to centrally located high-capacity pipelines. More dense (distribution) networks can also be connected to it. The central pipeline then becomes a kind of backbone.
- Such a transport network can have positive external effects that can contribute to creating a virtuous circle. These dynamics work as follows:
  – Producers and users of the transport network benefit from having multiple producers and users connected to the hydrogen network. This is referred to as a positive network effect, which delivers economies of scale (Katz & Shapiro, 1985). A transmission network gives users access to more supply options from different sources at different locations, creating freedom of choice. Also, having a network and centralised storage improves security of supply and reduces the required investment in local storage. The network to which (groups of) users are connected gives producers access to more potential buyers of their hydrogen. It will also lead to variety in sales and utilisation patterns, which means more trading options for producers (Van der Linde & Van Leeuwen, 2019). This combination will provide a positive boost for the use of hydrogen.
  – And as hydrogen uptake grows, hydrogen will become easier to trade (through a virtual trading point [VTP] for example). This, in turn, will foster competition in the market. And the more competition in the market, the more affordable the hydrogen and the greater the security of supply. A transmission network will thus help reduce transaction costs and increase price transparency and trading volumes (Mulder, Perey & Moraga, 2019). These dynamics can ultimately lead to a liquid market for hydrogen.
- The above network effects can become even greater as hydrogen transmission develops further. This is already happening in power grids, where new smart services such as peer-to-peer trading of solar power or storage capacity, for example, or smart charging of electric vehicles are adding to the benefits of increasing uptake among other users for the parties that use the network (Gillingham & Ovaere, 2020). These kinds of developments may also be conceivable for hydrogen transmission.

3.3. The need for transport before 2030

Where and when transmission capacity will be needed before 2030 depends on the government's actions to kick-start the supply chain

To be able to realize 3-4GW by 2030, it is essential that the FID be taken for a number of hydrogen projects in the short term

Possible roll-out path for hydrogen projects
Source: Gasunie, Hydrogen Coalition (2018)

Year	Cumulative electrolysis capacity	Capacity per electrolyser	Electrolysis output	Annual production - volume per unit[1]	Number of tank lorries[2]
	MW	*MW*	*%*	*PJ*	*# per year*
2018	**20**	10	>70%	0.1-0.1	Approx. 700
2021	**60**	20	75%	0.1-0.2	Approx. 1,000
2023	**160-200**	100	75%	0.5 -1.2	Approx. 6,000
2025	**500-600**	250	80%	1.4-3.2	Approx. 16,000
2027	**1300-1500**	500	80%	2.9-6.5	Approx. 33,000
2030	3,500 – 4,000	1,000	>80%	5.8-13.0	Approx. 66,000

- Where and when hydrogen transmission capacity will be needed over the coming years depends largely on the government's ambitions and actions in the hydrogen domain. Supply and demand for zero-carbon hydrogen will over the coming years be driven primarily by public funds. Without additional government policy, including financial support for the supply chain, few zero-carbon hydrogen projects are expected to get off the ground (see chapter 5 for a more detailed analysis of this point).
- The Dutch government's target is to have 3-4GW of installed electrolysis capacity by 2030. In order to hit this target, a roll-out path to build increasingly high-capacity electrolysers will have to be charted for the coming years. This is illustrated by the table on the left, which is based on the Hydrogen Coalition (2018).
- This phasing means that transmission capacity between clusters and storage facilities will also be needed as early as in the period before 2030.
- Within a few years, electrolysers with a capacity of 100-500MW must be built that produce 1 to 6PJ per year. While it may be possible to balance these capacities by downgrading existing SMR systems, transport to storage locations will still be needed at certain locations.
- As soon as the scale exceeds 500 MW, downgrading SMR systems is almost impossible. Zeeland has a total SMR capacity of 1.5GW, which could be downgraded by 60% and thus offer 600MW in flexible supply (Gasunie).

1. Bandwidth determined based on 2,000 to 4,500 full load hours per year.
2. Based on average production of 2,000 and 4,500 full load hours per year and a tank lorry capacity of 1,000kg per lorry (approx. 500 bar).

The first hydrogen projects need transmission capacity to get hydrogen to nearby users

At this point in time, it is not clear yet where the first large-scale electrolysis plants will be built

Current hydrogen projects in the Netherlands
Source: IEA (2019), Topsector Energy (2020), news items

Industrial cluster	Projects and capacity (GW)	Total GW	Green GW	Blue GW	Examples
Rotterdam/ Moerdijk	16 projects	4.2	2.7	1.5	• H-vision • Porthos • Uni500
Northern Netherlands	11 projects	7.3	6.5	0.8	• Djewels • NorthH2 • HyNetherlands
NSCA	4 projects	0.2	0.2	0.0	• H2ermes • P2F Hemweg • Hy4Am
Zeeland	6 projects	2.6	2.6	0.0	• Deltaurus 1-4 • Imported • Rehycle
Chemelot	2 projects	0.5	0.0	0.5	• FUREC • BrigH2
Other projects	3 projects	0.9	0.0	0.9	• H2Gateway • H2 Hub • SCW

Legend Total GW | Green GW | Blue GW

- There are currently about 12GW of green hydrogen projects under development (see figure on the left). To achieve the 3-4GW target, it is necessary to develop a number of projects in a roll-out path similar to that described on the previous page. There are also 3.7GW of blue hydrogen projects under development, some of which will also have to go ahead in order to achieve the industry's reduction targets for 2030.
- Many of these projects will be producing green or blue hydrogen on a large scale, and this hydrogen will subsequently have to be delivered to users. Even if those consumers are located close to the production site, such as in a coastal industrial cluster, transport infrastructure connecting consumers to suppliers is often still lacking.
- What is clear is that hydrogen project initiators need the certainty of having transport infrastructure available. Without such certainty, they are unlikely to make final investment decisions. Given the aspiration to realise the various hydrogen ambitions for 2030, the obvious choice would be to create enabling conditions for promising projects as much as possible by providing transport capacity.
- At this point, it is impossible to say which of these projects will actually materialise over the coming years. And this list is, of course, a snapshot that may change over the coming years. As a result, it is hard to predict now where transport capacity will be needed over the period through to 2030.

Connections between clusters are also likely to be needed in certain cases to connect users and to meet storage needs

Some clusters depend on other clusters for their supply and balancing of zero-carbon and low-carbon hydrogen

Characteristics of industrial clusters in the Netherlands

Source: DNV GL (2020a), TNO (2020c), Netherlands Enterprise Agency (2020), ETM (2020)

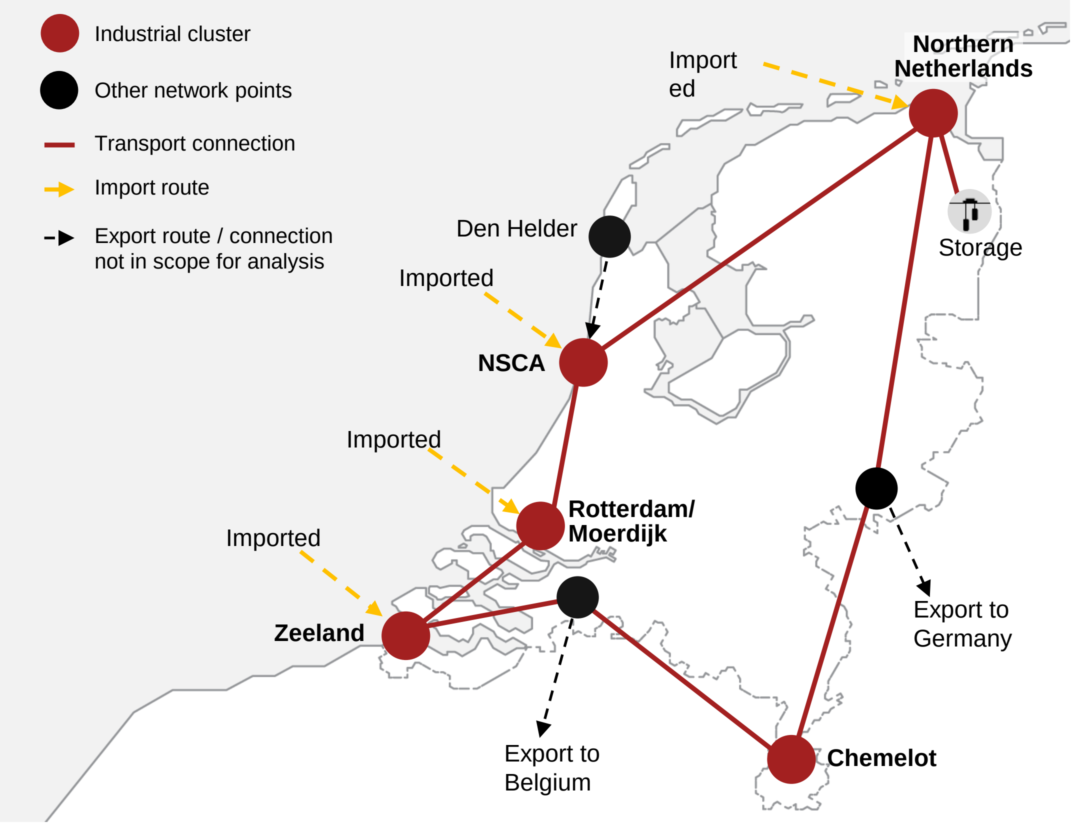
Industrial cluster	**De-mand (PJ)**	**Nearby...** Large-scale renewable energy (off-shore wind power)	Landing places for imports	CO_2 storage or transport options	Hydrogen storage options
Rotterdam/ Moerdijk	**77**	●	◕	●	◔
Northern Netherlands	**13**	◕	◑	◕	●
NSCA	**5**	◑	◕	●	◔
Zeeland	**60**	◑	◑	◔	◔
Chemelot	**25**	○	○	○	○

- Demand for zero-carbon and low-carbon hydrogen is expected to develop first in the industrial clusters, where zero-carbon hydrogen will, for example, have to replace grey hydrogen as a resource to be able to hit climate targets. Transmission capacity is needed within those clusters to interconnect the supply side and the demand side.
- This will also lead to demand for transport connections *between* clusters. There are two primary reasons for that. Firstly, hydrogen users in some clusters depend on a transmission network to be supplied zero-carbon hydrogen. Secondly, storage capacity will be needed as green hydrogen production is ramped up. And that storage capacity needs to be accessible, such as by connecting the salt caverns in the northern Netherlands with places with great electrolysis activity.
- The figure on the left outlines the starting position of a number of clusters in terms of the following:
  - **Access to large-scale renewable energy** is greatest in coastal areas. This concerns access to offshore wind power from the North Sea. Chemelot, for example, has very limited green hydrogen production options and will, therefore, benefit from a connection to an area with ample production potential.;
  - **Landing places for imports** will mainly be Dutch ports where cheap green hydrogen from outside Europe can be imported. While importing hydrogen through Germany and Belgium is technically possible, Germany in particular is expected to be a net importer of zero-carbon hydrogen;
  - **Large-scale hydrogen storage** will in the short term only be available in salt caverns in the northern part of the Netherlands and in the medium to long term also, in combination with imports, in tanks located in port areas;
  - **Carbon storage or transport options$_2$** are available primarily in coastal areas that have access to former gas fields under the North Sea bed (which is currently the only place where Dutch law allows permanent CO_2 storage).
- Industry specifically wants to interconnect clusters to be able to scale up their hydrogen production and usage (DNV GL, 2020a). A central transmission network basically makes one region's starting position also available to other regions.

An illustrative model of a national hydrogen network showing potential transport demand volumes in 2030

We analyse the transport need on the basis of three scenarios for the ambition of 3-4GW in 2030

Illustrative model of the national hydrogen network in 2030
Source: Strategy& analysis



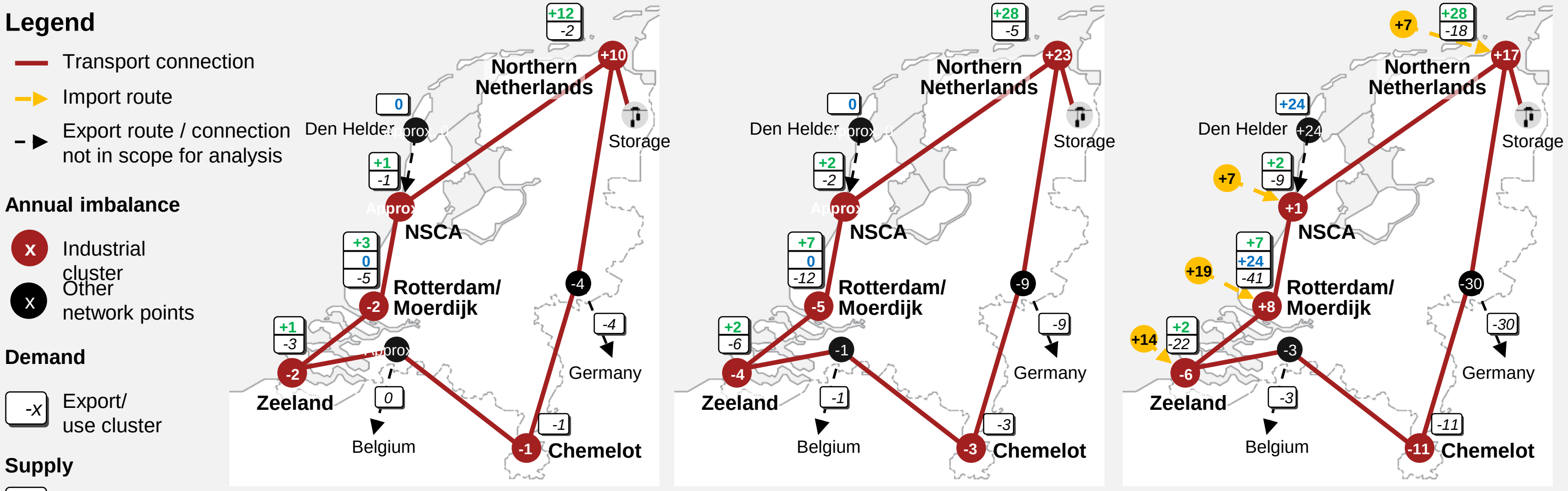
- An illustrative model has been drawn up with the aim of getting a feel for the transport volumes associated with achieving the government's ambition of 3-4GW of electrolysis capacity operational by 2030 (Government Strategy on Hydrogen, 2020).
- This model is made up of various hydrogen supply and demand hubs and pipeline connections between these hubs. The hubs represent the five industrial clusters, two export locations (Germany and Belgium), and one storage location. Den Helder was added as a blue hydrogen production location. The model calculates the transmission capacities and volumes for the connections between the hubs.
- The total volume of hydrogen in the model is supply-driven. In each of the scenarios, we vary the total production and spread the supply over the clusters in the Netherlands and abroad based on projected demand in 2030.
- The model works on an hourly basis. Green hydrogen production is based on a wind profile (2015 weather reference year). The other supply and demand flows are assumed to be constant (base load). Green hydrogen flows are balanced using salt caverns in the northern Netherlands.
- The illustrative analysis shows that realising the 2030 targets will generate demand for hydrogen transport between clusters, which does not automatically mean that all these connections will actually be needed or societally beneficial in the coming years. What is key to realising the ambitions is to help major hydrogen projects, the details of which are as yet unknown, get off the ground over the coming years by interconnecting supply and demand for hydrogen and storage capacity.

The model assumes constant electrolysis capacity of 3.5GW but varies total central hydrogen supply in three scenarios

Demand is always spread over the various clusters in the Netherlands and abroad in the same way

Regionalisation of supply and demand for zero-carbon and low-carbon hydrogen *(annual volumes in PJ).*
Source: Strategy& analysis

Conservative scenario	Middle ground scenario	Progressive scenario (Dutch Climate Agreement IP2022)



Assumptions: Only 1.5GW of the 3.5GW of electrolysis capacity is offered via the central network. The remaining 2GW is locally produced, consumed and balanced by ‘downgrading’ existing SMR installations.

Assumptions: The full 3.5GW is offered via the central hydrogen network.

Assumptions: The full 3.5GW is offered via the central hydrogen network, this in addition to 1.5GW import and 1.5GW blue hydrogen production.

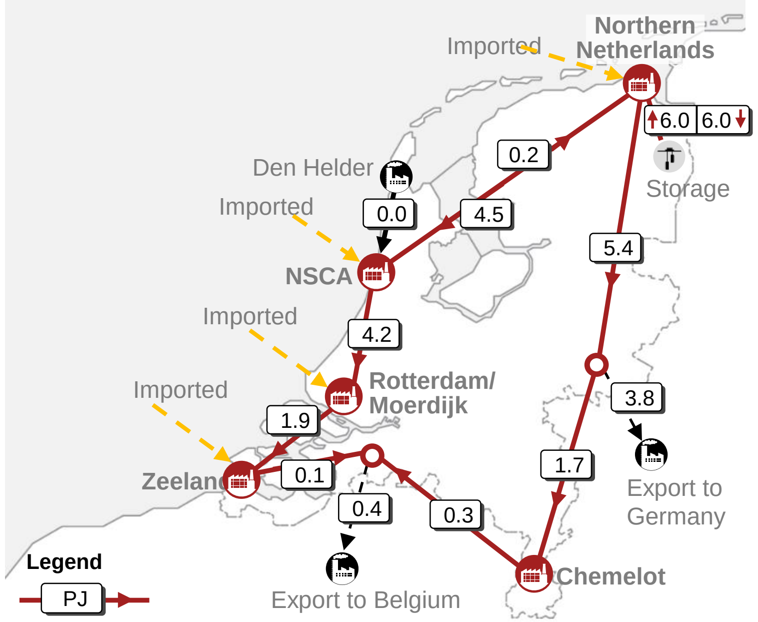
- The analysis compares the three scenarios shown to the left. In each of the three scenarios, 3.5GW of electrolysis capacity – the government’s ambition – has been taken as the starting point. The model only considers the flows of zero-carbon and low-carbon hydrogen and not the current grey hydrogen market of approx.180PJ, which is mainly produced and consumed locally. These volumes will gradually reduce over the period leading up to 2030 as grey hydrogen is substituted by more sustainable hydrogen, albeit that the exact timing of that is as yet uncertain.
- The progressive scenario is based on the Dutch Climate Agreement scenario that Gasunie and TenneT made for the 2022 Investment Plan (IP2022, 2020). This scenario is also used as the basis for the 2030 modelling in the II3050 study. The biggest difference is that the 2022IP does include the grey hydrogen market in its projections.
- The middle ground scenario and the conservative scenario look only at green hydrogen production, and not at blue hydrogen and imported hydrogen, because the government has only set a specific target for 2030 for green hydrogen production.
- The conservative scenario illustrates the most conservative use of a national hydrogen network, though the ambition of 3-4GW of electrolysis capacity is still being achieved.
- See Appendix A-2 for more details of the model parameters.

Based on the 3-4GW ambition, demand for transmission between clusters will arise in 2030 due to local imbalance and storage needs

The model illustrates the transmission volumes per pipeline from 0 to 38PJ for 2030, depending on the scenario

Transmission flows per pipeline per direction for the three scenarios *(Cumulative [on an hourly basis]; annual volume in PJ , 2030).*
Source: Strategy& analysis

Conservative scenario

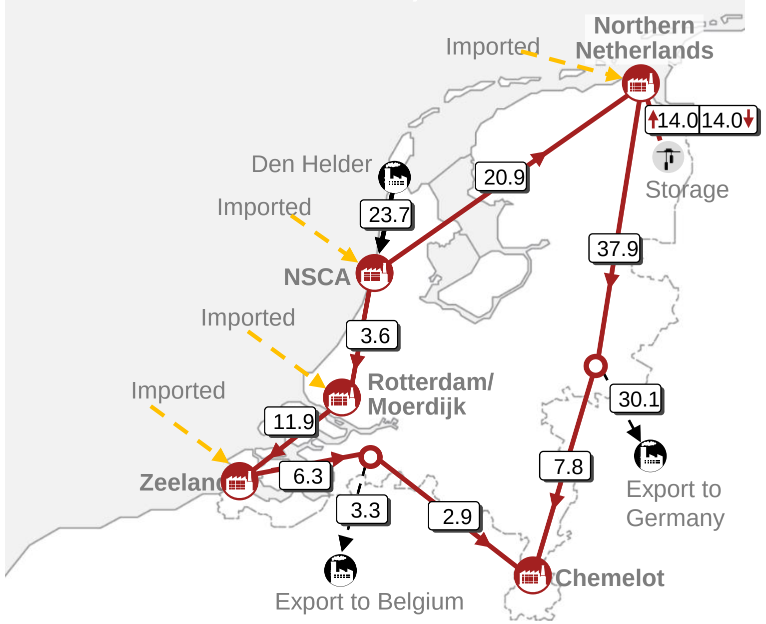


- Sum of transmission volumes of all pipelines: **30.3PJ**
- Average transmission volume per pipeline: **3.6PJ**
- Transport volume for storage/regional imbalance: **41% / 59%**
- Flows run mainly from the northern Netherlands via east and west to the south

Middle ground scenario

- Sum of transmission volumes of all pipelines: **70.7PJ**
- Average transport volume per pipeline: **8.8PJ**
- Transport volume for storage/regional imbalance: **41% / 59%**
- Flows run mainly from the northern Netherlands via east and west to the south

Progressive scenario (Dutch Climate Agreement IP2022)



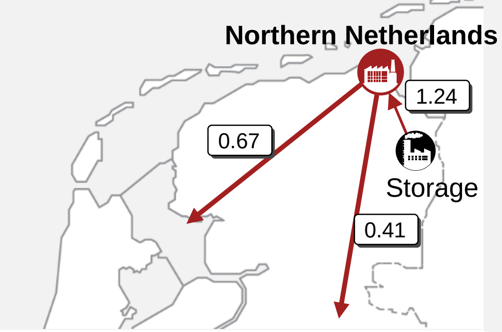
- Sum of transmission volumes of all pipelines: **119.2PJ**
- Average transmission volume per pipeline: **14.9PJ**
- Transport volume for storage/regional imbalance: **26% / 74%**
- Flows run mainly from the north west via the northern Netherlands to the east

Transmission from and to storage locations in the north of the Netherlands is a key transmission demand driver

Weather dependency makes green hydrogen production volatile

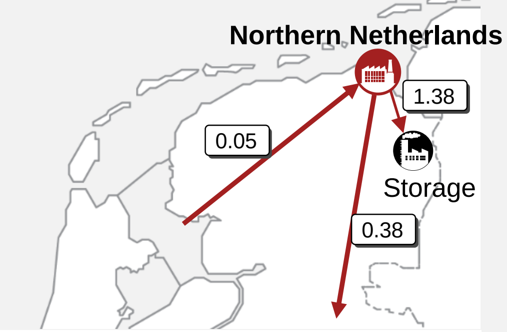
Transmission flows at two specific times (hour) in the basic scenario *(GW, 2030). Source: Strategy& analysis*

0% wind – 0GW produced



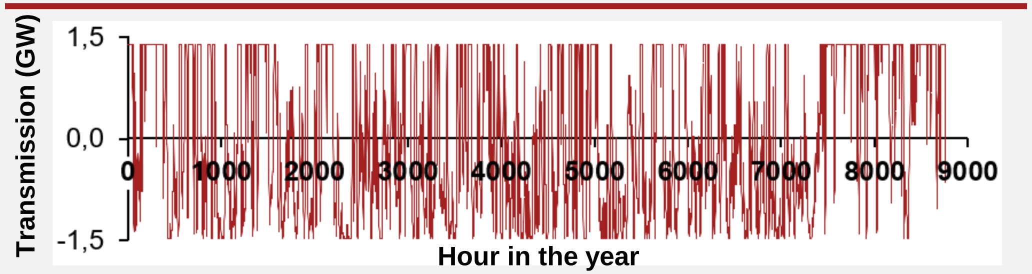
GW **Hydrogen transport for 1 hour**

100% wind – 3.5GW produced



GW **Hydrogen transmission for 1 hour**

Transmission from/to storage as a result of green hydrogen production *(GW)*



- What we can see in the three scenarios is that storage will play a key role because of the weather and season dependency of green hydrogen production. The importance of storage is also confirmed in the literature (DNV GL, 2020a). In the production of green hydrogen, the hydrogen produced is transmitted – at a rate of 1.38GW in one hour that the maximum electrolysis capacity is used – to a central storage location in the north of the Netherlands.
  - In strong winds, the 3.5GW (average of the government target of 3 to 4GW) of electrolysis capacity can be fully utilised thanks to offshore power generated via wind farms in the North Sea. As a result, total production exceeds demand at that specific point in time, creating a temporary surplus supply in the system.
  - This surplus, which is produced in the west and the north of the Netherlands, is to the central storage facility in the northern Netherlands to restore the balance in the system.
- As soon as the wind eases, the direction of these dynamics changes. Then 1.24GW flows from the storage location to the central transmission network to balance the deficit that has arisen in the system.
- This is a continuously recurring cycle. Seeing as green hydrogen production is related directly to power generation from an offshore wind farm, green hydrogen production is equally volatile. During the year, hydrogen is inserted into and withdrawn from storage facilities in step with the weather conditions.
- Both in windy conditions and when there is no wind at all, hydrogen is transported from the northern Netherlands to the south (export to North Rhine Westphalia and Chemelot) because these industrial clusters have very limited on-site green hydrogen production options and will, therefore, continue to depend on imports.
- In the local scenario and the basic scenario, approximately 40% of the need for transport is driven by storage and approximately 60% by geographical differences between producers and consumers. In the Dutch Climate Agreement scenario, approximately 20% is driven by storage, because the assumed constant supply of imported and blue hydrogen does not require storage.

4 Conversion of existing natural gas networks

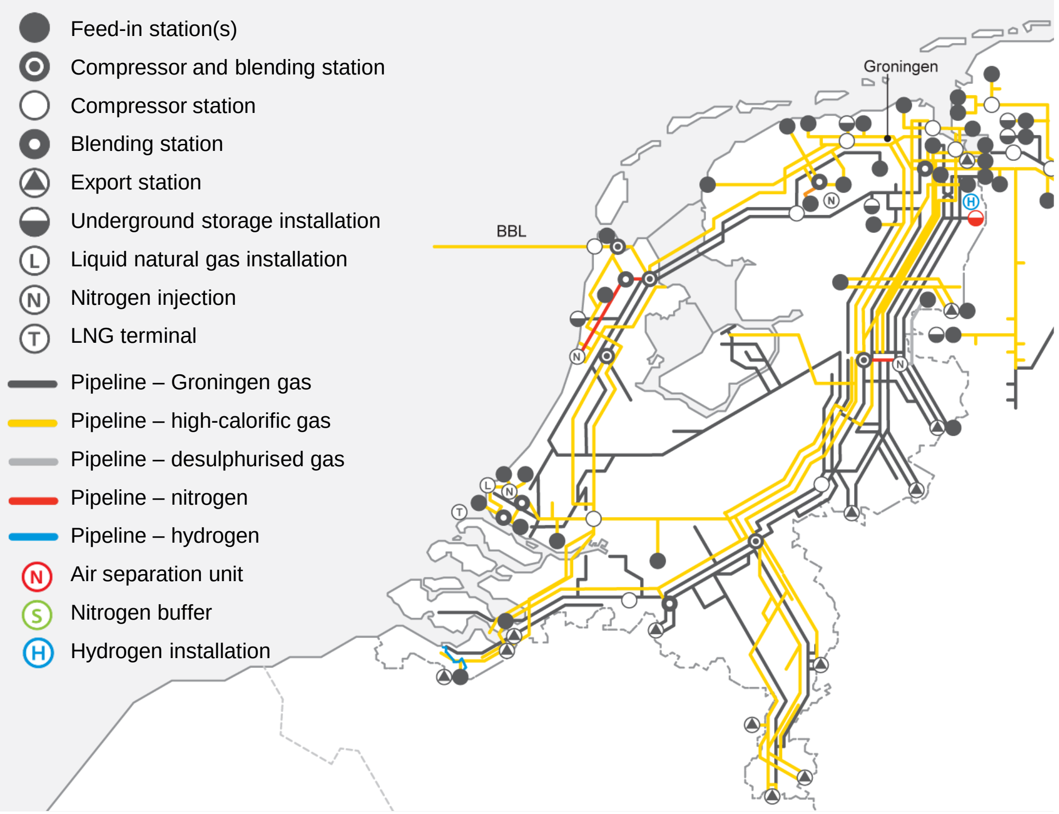
HyWay 27

4.1. Availability of the existing natural gas transmission network

The Netherlands is home to an extensive natural gas transport network made up 12,000km of largely parallel pipelines

The high-pressure gas grid for L-gas and H-gas transmission covers approximately 6,000km of the total network

Illustration of high-pressure gas grid (HTL)
Source: Gasunie (2020a)



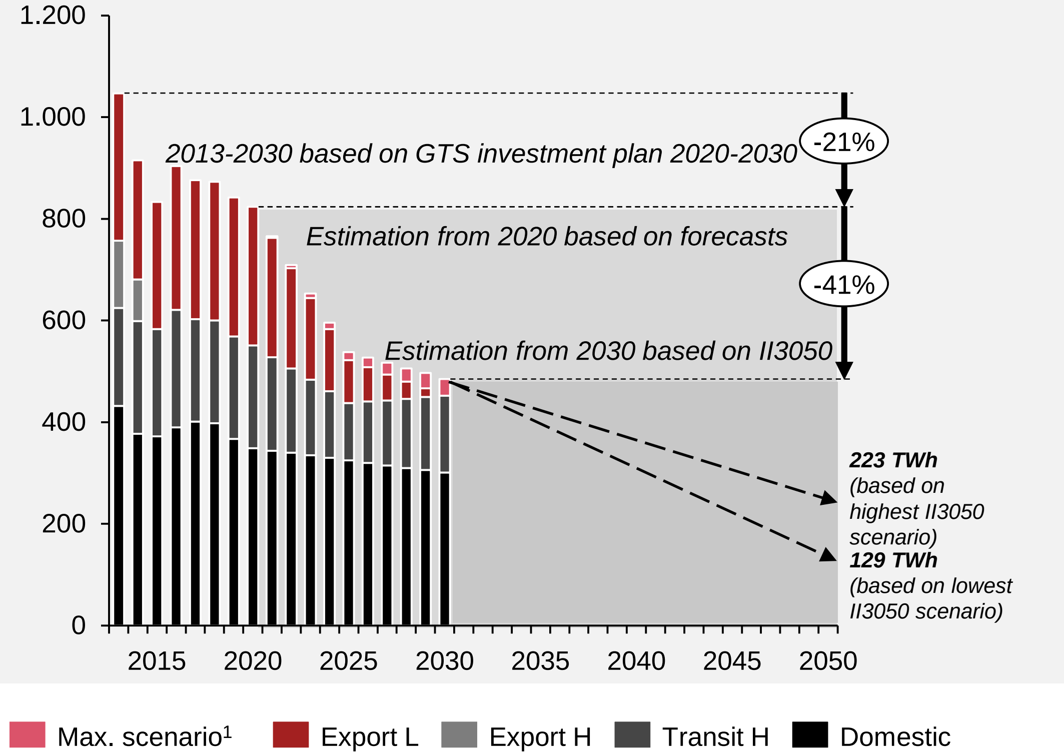
- Gasunie operates the high-pressure natural gas transmission network in the Netherlands. This transport network is made up of approximately 12,000km of natural gas pipelines and is subdivided based on pressure ratings into a high-pressure gas grid (HTL) and an intermediate-pressure gas grid (RTL). Around half of the transmission pipelines are part of the HTL (with a rated pressure of 66.2 and 79.9 bar), while the other half are part of the RTL (rated pressure of 40 bar).
- Gasunie's HTL transports imported gas and gas from Dutch natural gas fields across the Netherlands and the northern part of Germany through (international) connections.[1] This nationwide transmission network branches off into the RTL and regional distribution networks. The regional distribution systems are made up of approximately 130,000km of low-pressure pipelines (generally with a rated pressure of 0.03 to 8 bar) and operated by regional network operators (Netbeheer Nederland, 2019).
- What is special about the Dutch HTL is that it consists of two parallel networks, one for low-calorific gas (L-gas, i.e. G-gas) and one for high-calorific gas (H-gas). This situation arose because the natural gas field in the province of Groningen contains low-calorific gas, while gas extracted from fields under the North Sea and imported from abroad has a higher calorific value.[2] Both types of gas are currently also exported to the Netherlands' neighbouring countries (DNV GL, 2017). The networks for H-gas and G-gas are interconnected through mixing stations where nitrogen is mixed into H-gas to convert it into L-gas. One section of the pipelines can be used both for H-gas and G-gas.
- Another special feature of the Dutch HTL is that it has a large number of parallel pipelines (see figure), while the RTL and the regional distribution systems are more dense and generally lack parallel pipelines. These characteristics make it possible to run natural gas transport flows through the HTL using different routes.

1. Gasunie's national transmission networks are part of the Netherlands' Category A vital infrastructure. 2. Calorific value is a measure that indicates the energy content of gas: the higher the calorific value, the more energy one cubic metre of natural gas releases when burnt. G-gas is used mainly by households and commercial users in the Netherlands; while industry and power plants use H-gas.

Demand for natural gas transmission will decline due to falling exports as gas extraction in Groningen is phased out and the energy transition advances

Gasunie can use the transport capacity that becomes available for alternative purposes

Forecast of falling transmission volumes in the natural gas grid
(in TWh, 2013-2050). Source: Gasunie (2020b), II3050 (2020)



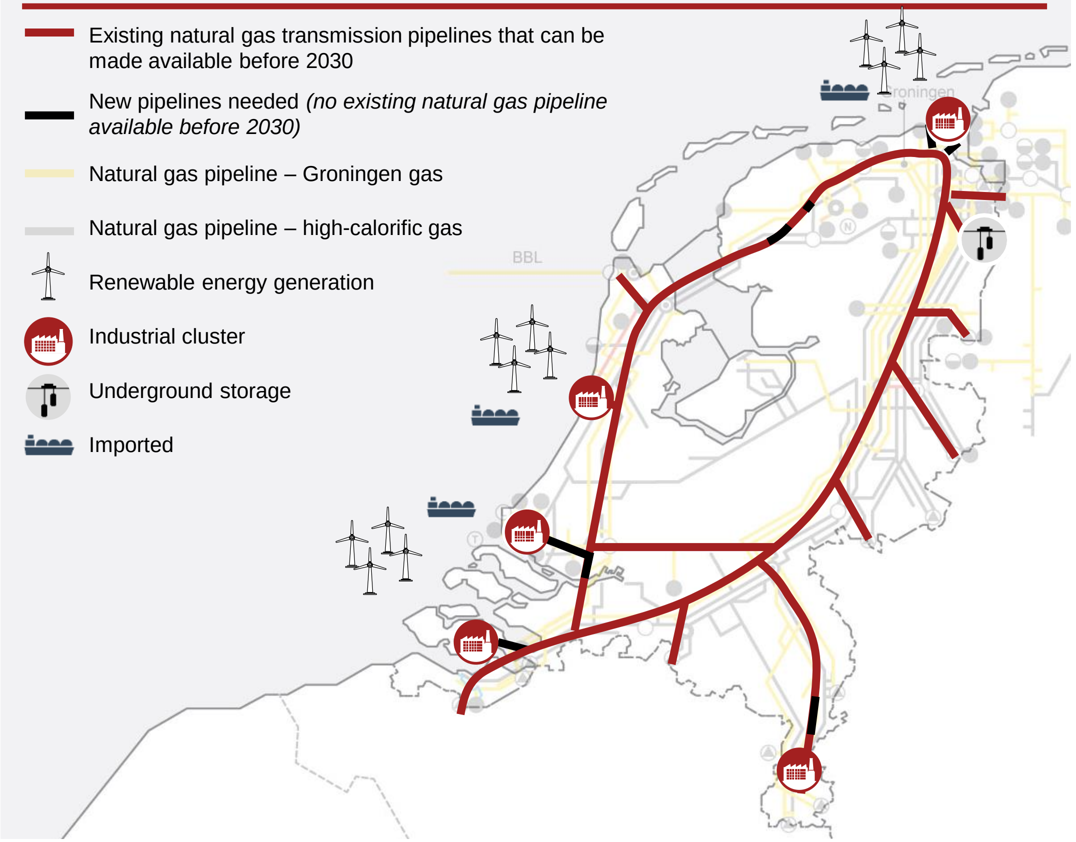
- Natural gas transmission volumes are set to decline as a result of two developments: falling exports as gas extraction from the Groningen field is wound down, which will have an impact in the short term, and falling natural gas consumption as the energy transition advances, which is a long-term development.
- Over the 2013-2020 period, gas transmission volumes in the Netherlands were down approximately 21%, mainly in relation to the gradual phase-out of gas extraction in the province of Groningen. In order to be able to fully cease gas production in Groningen, the Netherlands has asked its neighbours to cut their L-gas imports by 10% every year through to 2030. This will result in a further 41% reduction of transmission volumes over the 2020-2030 period, particularly in pipelines to Germany and Belgium, despite rising import needs in the Netherlands in the short term (part of 'Domestic' in the graph).[2]
- To successfully phase out L-gas, the Netherlands' neighbouring countries will have to switch from L-gas to H-gas (or other alternatives) in time. The phase-out is currently on schedule (Dutch Parliament, 2020; L-gas Market Conversion Monitoring Task Force, 2020).[3]
- Between 2030 and 2050, the required (fossil) natural gas transmission volumes are expected to fall further as the transition to a climate-neutral energy system progresses. Based on the 3050 scenarios, demand for natural gas will fall by approximately 129 to 223TWh per year through to 2050.
- A drop in the required transmission volumes will also mean that there will be less need for transmission capacity. Gasunie can use unused transmission capacity for alternative purposes by freeing up pipelines to, for example, develop a hydrogen network if that would meet the market's and/or the government's needs.

1. There is still a level of uncertainty in the expectation for 'Domestic' and 'Transit H' for the future; this spread has been included separately under 'max scenario'. 2. Part of the L-gas exports that will disappear will from 2025 will reappear as additional H-gas transit flows. 3. The task force monitoring the progress of conversion efforts abroad (*Taskforce Monitoring Ombouw Buitenland*) submits periodic progress reports to Dutch parliament. This task force is made up of representatives from governments, network operators, and regulatory authorities from the four countries in question, alongside representatives from the International Energy Agency and ENTSOG, the European network of gas transmission system operators.

Gasunie can free up existing natural gas transmission pipelines between the five clusters and across the border

These pipelines can be used to interconnect various suppliers and users of hydrogen

Technically possible hydrogen network based on existing natural gas grids in 2030 *Source: Gasunie (2020c)*



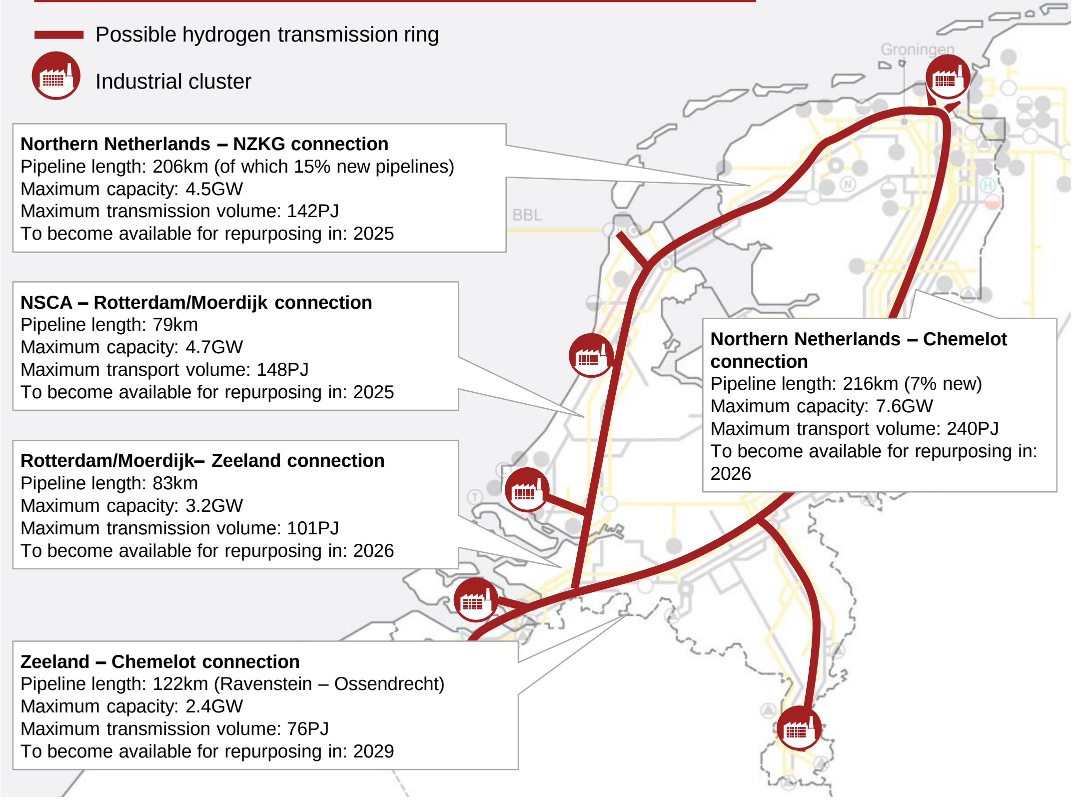
- Gasunie expects to be able to free up existing natural gas transmission pipelines between the five major industrial clusters and on multiple connections to our neighbouring countries. In the long run, existing pipelines can serve as a transport ring that enables suppliers to feed in hydrogen for high-volume users to use. In certain areas, new pipelines (shown in black in the figure) will have to be laid to fill gaps in stretches of pipeline or create connections to industrial clusters.
- If necessary, a large number of pipelines can be freed up before 2030. This means that it is possible, in principle, to have a national hydrogen transmission ring based on repurposed gas pipelines up and running by 2030. The number of new pipelines that would be required is limited, representing roughly 17% of the total number of kilometres of pipeline. After 2030, more existing natural gas pipelines can be freed up.
- The illustration shown here is an illustration of possible pipelines that can be freed up and reused before 2030. Whether pipelines become available is not an exogenous variable, but rather a result of decisions on the routing of natural gas flows. The figure on the right is provided for information purposes only and not a final choice. There are alternatives, including within the previously reserved scope in the government's vision on pipelines (*Structuurvisie Buisleidingen*).[1]

1. Potential export routes are shown graphically in the figure. Gasunie's current plans anticipate initial export connections to Germany along two routes, i.e. Tjuchem-Oude Statenzijl and Ommen-Winterswijk/Zevenaar. When it comes to gas flows to Belgium, Gasunie initially anticipates the Beekse Bergen - Hilvarenbeek export connection. The figure shows two southern east-west connections. While Gasunie initially anticipates a southern connection, a more northern connection from Rotterdam to the east is an alternative for that.

The capacity of existing natural gas pipelines is expected to be more than enough to meet hydrogen transport demand for 2030

On top of that, further existing natural gas pipelines can be freed up after 2030

Key features of possible transmission connections along pipelines between the five major industrial clusters *Source: Gasunie (2020c)*



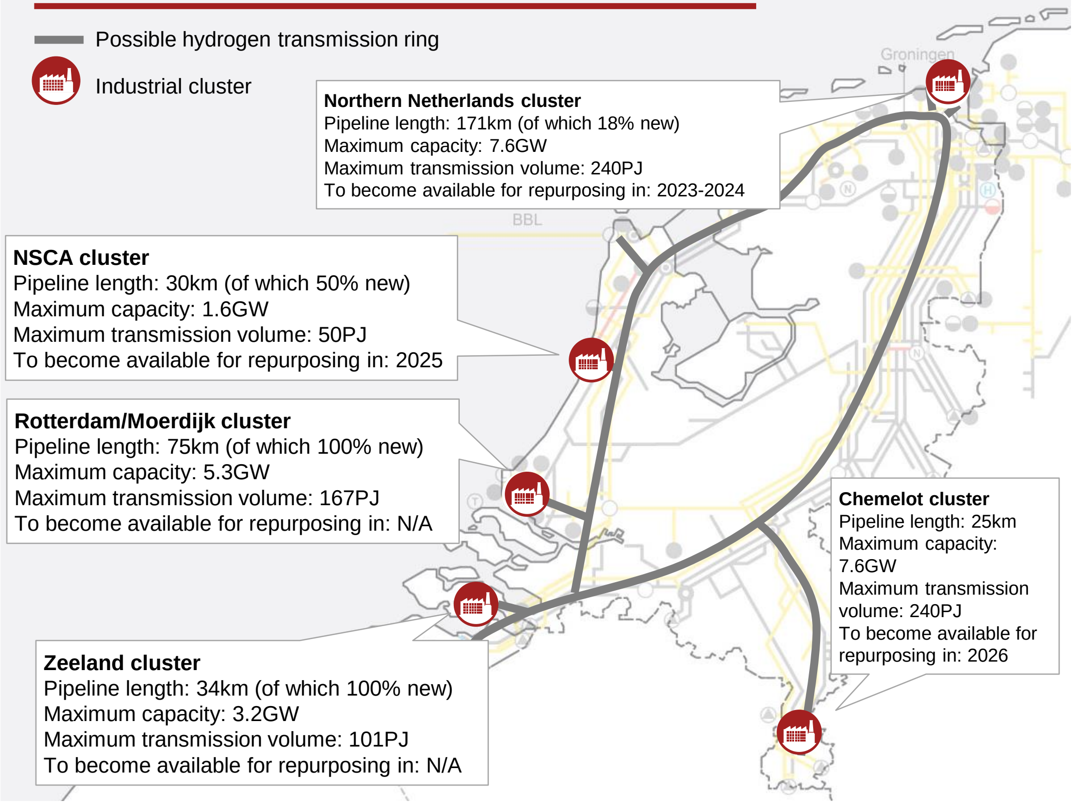
- The figure on the left contains a summary of the main features of the envisaged pipelines between the five major industrial clusters.
- Most of the pipelines that can be freed up have a 36-inch or larger diameter. These pipelines offer a theoretical capacity of around 10 to 15GW. In a gas transmission network, however, supply and demand are balanced, and this balance determines the pressure at any given point in the network. The maximum possible transmission volume between network points is, therefore, determined by the pressure difference between these points. This pressure difference will for most transport routes within a network be (much) lower than the system pressure range. As a result, the maximum capacity of a pipeline included in a network will also be lower than the maximum capacity of the same pipeline if it had the full system range at its disposal as the pressure difference (see Appendix A-4 for further details).
- The capacity that, according to current forecasts, can be freed up on the connections shown in the figure on the left is a provisional estimate by Gasunie based on hydrogen transmission at a maximum operational pipeline pressure of 50 bar, without using compression. If required, the capacity on these connections can be increased at a later stage by operating them at a higher pressure (the maximum operating pressure is 66 bar) and/or using transmission compression.
- The maximum capacities of pipelines that can be freed up, as shown here, more than cover the level of demand projected in the transport scenarios for 2030 outlined in chapter 3, i.e. the local, basic, and Dutch Climate Agreement scenarios. After 2030, further natural gas pipelines can be freed up if additional transport demand were to arise.
- To free up pipelines, Gasunie routes existing natural gas flows through parallel pipelines (or via another route if necessary) to exit points of the high-pressure natural gas grid (HTL). The years shown are the earliest possible years in which Gasunie expects to be able to free up the pipelines in question for repurposing (GTS, 2020c).[1]

1. In 2017-2018, Gasunie conducted an extensive network analysis based on the latest insights, capacity - commitments for natural gas, and the current pipeline configuration. While the actual allocation of a pipeline will always be based on an up-to-date capacity analysis for natural gas, Gasunie considers the features shown to be representative of the current situation.

New pipelines will in particular have to be laid within industrial clusters to create connections

Transport demand is expected to initially arise within these clusters

Summary of the main features of the projected pipelines within the five industrial clusters
Source: Gasunie (2020c)



- Hydrogen demand is expected to initially arise between suppliers and users within the five major industrial clusters. These suppliers and users are not all based at the same location. Gasunie sees only limited scope to free up existing natural gas pipelines within the clusters before 2030, as it would otherwise have insufficient remaining capacity for natural gas. Connecting suppliers and users within the clusters will, therefore, require the laying of new pipelines.[1]
- The figure to the left shows the main features of the projected pipelines within the five industrial clusters. The new pipelines that would have to be laid all fall into the scope previously earmarked in the Dutch government's vision on pipelines (*Structuurvisie Buisleidingen*).[2]
- As soon as the regional clusters have been created, they can be connected to each other, to storage facilities (in the northern Netherlands), and to both of the Netherlands' neighbouring countries.

1. Except for the northern Netherlands cluster. Within this cluster, approx. 140km of existing pipeline is expected to be available as early as in 2023-2024. These pipelines are expected to cover more than 80% of the infrastructure that is anticipated for the northern Netherlands in 2030. For the other clusters, this share is considerably lower.
2. Maximum capacities are an estimate by Gasunie for hydrogen transport at a maximum operational pipeline pressure of 50 bar, without using compression. If required, the capacity of these pipelines can be increased at a later stage by operating them at a higher pressure (the maximum operating pressure is 66 bar) and/or using transmission compression. See Appendix A-4 for further details.

4.2. Technical adjustments required for transmission through existing pipelines

Even though hydrogen and natural gas have different physical properties, natural gas pipelines can, in principle, be used for hydrogen transmission

Various previous studies have concluded that hydrogen transmission through natural gas pipelines is possible

The main physical properties of natural gas and hydrogen
Source: Bilfinger Tebodin (2019), IFV (2020), Gasunie (2019), NEN (2015)

Property	Methane (natural gas)	Hydrogen
Colourless	Yes	Yes
Odourless	Yes	Yes
Flammable	Yes	Yes
Explosive	Yes	Yes
Corrosive	No	No
Molecule size [pm]	200	75
Relative density (air = 1)	0.55	0.07
Flammability limits (lower and upper limit [%])	4.4 - 17	4.0-77
Minimum ignition energy [MJ][1]	0.26	0.02
Calorific value [MJ/m^3]	32	11
Flame colour	Blue	Colourless
Greenhouse gas (infrared absorption)	Yes	No
Hydrogen embrittlement	No	Possible
Required purity	N/A	tbd (≥ 98%) [2)]

- Prior to repurposing a pipeline, such as changing the substance transmitted through it and/or changing process conditions such as pressure and temperature, the 'Decree on the External Safety of Pipelines' requires that an extensive analysis be conducted to confirm that the design and integrity of the pipeline system is suitable for the intended new purpose. When reusing an existing natural gas pipeline for hydrogen, the differences between natural gas and hydrogen in terms of their physical properties must be taken into account.
- Over the past years, various international studies and practical tests have looked into the reuse of existing natural gas pipelines for hydrogen transmission (DNV GL, 2017; Gasunie, 2019; Bilfinger Tebodin, 2019; AVIV, 2019). These studies show that the design factors used for high-pressure natural gas pipelines over the years are in line with the design factors used for new hydrogen pipelines. This confirms that the wall thicknesses of existing pipelines, which are determined by the diameter of the pipeline, as well as the rated pressures and steel quality are adequate for hydrogen transmission as well at a similar rated pressure (Bilfinger Tebodin, 2019). In Zeeland province, a repurposed natural gas pipeline has been in use to transport hydrogen between Dow Chemical in Terneuzen and Yara in Sluisklil since October 2018 (Gasunie, 2019).
- In 2018, the regional distribution system operators commissioned the KIWA testing, inspection, and certification firm to conduct a detailed (international) study of the materials used in existing gas distribution networks and how these materials would be affected by hydrogen flowing through those pipelines (KIWA, 2018). Their study concluded that the current distribution networks would not be affected significantly by hydrogen. Based on the literature consulted and lab and practical tests, none of the familiar pipeline materials are likely to deteriorate (KIWA, 2018), However, like with the reuse of the transport network, measures will have to be taken to be able to safely use existing distribution pipelines for hydrogen.

1. In practice, the ignition energy of a blend of air and hydrogen depends on the hydrogen content. Blends of air and hydrogen with low hydrogen content, up to 8-10%, even have a lower ignition energy than natural gas (DNV GL, 2020b). 2. The government has not yet decided on the hydrogen purity level. For natural gas, quality requirements are laid down in the Ministerial Decree on Natural Gas Quality. See Appendix A-5 for further details.

For hydrogen transport to be as safe as possible, changes will have to be made to the existing grid and procedures

Five focus points that lead to measures to make hydrogen transport as safe as possible

Summary of measures needed to ensure safe hydrogen transmission
Source: Gasunie, Bilfinger Tebodin, AVIV, DNV GL[1]

Focus point	Measure	Type
1. Leak susceptibility	1A Replacing and/or reconditioning valves on account of possible leakage	Adjustments to existing network
	1B Replacing other leak-prone parts (except for valves)	Adjustments to existing network
2. Contaminations	2A Cleaning existing pipelines	Adjustments to existing network
3. Lower (energy) density	3A Configuring or replacing metering equipment to bring it into line with flow speed and gas composition	Adjustments to existing network
	3B Adding compressors (in the long term) on account of the incompatibility of existing compressors	Adjustments to existing network
4. Defect growth	4A Mapping maximum operating pressures, changing operational procedures, and creating pipeline files	Adjustments to procedures
	4B Developing and changing procedures for inline inspections	Adjustments to procedures
5. Ignition risk	5A Training technicians to handle hydrogen	Adjustments to procedures
	5B Changing pipeline modification procedures	Adjustments to procedures
	5C Procuring safe electronic metering equipment for management and maintenance	Adjustments to procedures

= Adjustments to existing network *= Adjustments to procedures*

1. This table was put together based on information obtained from the various HyWay 27 stakeholders and desk research into previous studies (including DNV GL, 2017; DNV GL, 2020b; Gasunie, 2019; Bilfinger Tebodin, 2019; AVIV, 2019). PwC Strategy& did not conduct a technical analysis itself.

1. **Hydrogen may be more prone to leakage due to its smaller molecular size** – The smaller molecular size may increase the risk of leakage through components such as O-rings, gaskets, diaphragm seals, flanges and valves (internal and external) compared to natural gas. This means, for example, that a flange connection that is leak-proof for natural gas may not necessarily be leak-proof when the pipeline is used to transport hydrogen.
2. **Some hydrogen applications are more sensitive to contamination –** Natural gas contains, besides methane and nitrogen, also small to very small amounts of other substances such as natural-gas condensate. As natural gas is transported through steel pipelines for long periods of time, deposits of these substances may form on the inside of the pipeline or accumulate in parts of the network that are deeper under ground (such as underwater pipelines) and in valves. While purity is not really an issue with natural gas, the calorific value is laid down in laws and regulations for the various gas qualities (Ministerial Decree on Natural Gas Quality). For some hydrogen applications at the consumer's end (such as fuel cells), this kind of contamination may not be acceptable. When reusing natural gas pipelines, this existing contamination in pipelines and the cleaning of pipelines are things to take into consideration.
3. **Hydrogen has a lower density and its calorific value is three times lower –** This means that the flow speed for hydrogen transmission will have to be three times higher than that of natural gas to be able to transport similar volumes. This affects the current metering equipment and the use of existing natural gas (centrifugal) compression, also because hydrogen has a lower density than natural gas.
4. **In hydrogen transport, large and frequent pressure fluctuations may accelerate defect growth –** Normally, a thin layer of oxide forms on the inside of pipelines and valves, but there are situations where the steel surface may be laid bare, such as due to inadequate welding. On this clean steel surface, hydrogen molecules may disintegrate into hydrogen atoms and be absorbed into the steel. Once absorbed into the steel, large frequent pressure differences may lead to existing defects in the hydrogen propagating faster than in natural gas. This could lead to small leaks in the long term, anywhere between 20 and 25 years.
5. **Hydrogen ignites more easily and burns in oxygen with a nearly invisible flame –** The ignition energy of hydrogen is lower than that of natural gas, and it has a broader bandwidth between flammability limits. Hydrogen's lower ignition energy, i.e. the greater chance of combustion, may (depending on the amount of hydrogen in oxygen) have other consequences when released during maintenance work or in other situations. What must, in principle, also be taken into account is the fact that when pure hydrogen (100%) ignites, it burns with a colourless flame, but when hydrogen burns because an underground pipeline has burst, the flames will be clearly visible because dust and other particles will also be burning.

Natural gas pipelines are compatible with hydrogen, but leak-prone parts may have to be replaced

Leak susceptibility-related measures 1

Summary of measures needed to ensure safe hydrogen transmission
Source: Gasunie, Bilfinger Tebodin, AVIV, DNV GL[1]

Focus point		Measure	Type
1. Leak susceptibility	1A	Replacing and/or reconditioning valves on account of possible leakage	Adjustments to existing network
	1B	Replacing other leak-prone parts (except for valves)	Adjustments to existing network
2. Contaminations	2A	Cleaning existing pipelines	Adjustments to existing network
3. Lower (energy) density	3A	Configuring or replacing metering equipment to bring it into line with flow speed and gas composition	Adjustments to existing network
	3B	Adding compressors (in the long term) on account of the incompatibility of existing compressors	Adjustments to existing network
4. Defect growth	4A	Mapping maximum operating pressures, changing operational procedures, and creating pipeline files	Adjustments to procedures
	4B	Developing and changing procedures for inline inspections	Adjustments to procedures
5. Ignition risk	5A	Training technicians to handle hydrogen	Adjustments to procedures
	5B	Changing pipeline modification procedures	Adjustments to procedures
	5C	Procuring safe electronic metering equipment for management and maintenance	Adjustments to procedures

= Adjustments to existing network = Adjustments to procedures

- Leak-prone parts will have to checked to make sure they are sufficiently leak-proof for hydrogen applications. If this cannot be confirmed, these parts will have to be reconditioned or replaced with hydrogen-resistant components (Bilfinger Tebodin, 2019).
- Even though this will have to be done for all parts, this point is particularly relevant for valves:

1A *Replacement of the valves*

- The current gas transmission network has a valve every 7 to 10km. Most of these valves are at least 25 years old and have, therefore, reached the end of their technical life. They come with a major risk of inoperability and internal/external leaks, they are mostly contaminated, they were not designed with hydrogen in mind, and repairing them is generally rather costly. Although recent, as yet unpublished, experiments with dismantled valves by the KIWA research firm commissioned by Gasunie seem to show that there is not a significant difference between natural gas and hydrogen in terms of the number of leaks, there is still insufficient clarity on the effects of reusing existing valves for hydrogen transport. For now, Gasunie has decided to replace valves as a preventive measure when reusing pipelines for hydrogen transmission. From a technical point of view this is easy to solve; however, the preventive replacement of all valves has a high impact on the required investments (approx. €1.5 million per valve) and lead time. Further research will have to show whether preventive replacement is really necessary or that reconditioning (or even doing nothing at all to the valves) could suffice without impacting on safety.

1B *Replacing other leak-prone parts*

- Besides valves, there are other (non-welded) connections that may be susceptible to leakage, such as flanges and nipples. Gasunie is looking into the extent to which these joints are prone to leakage when a pipeline is used to transport hydrogen. Given that most underground lines are welded together as standard, replacing these parts is, also in terms of the investment needed, a relatively minor operation compared to replacing the valves. The (above-ground) parts can either be replaced as a preventive measure or inspected periodically as part of regular inspections.

1. This table was put together based on information obtained from the various HyWay 27 stakeholders and desk research into previous studies (including DNV GL, 2017; DNV GL, 2020b; Gasunie, 2019; Bilfinger Tebodin, 2019; AVIV, 2019). PwC Strategy& did not conduct a technical analysis itself.

Existing pipelines are partly contaminated; the cleaning effort depends on the required level of hydrogen purity

Contamination-related measures 2

Summary of measures needed to ensure safe hydrogen transmission
Source: Gasunie, Bilfinger Tebodin, AVIV, DNV GL[1]

Focus point		Measure	Type
1. Leak susceptibility	1A	Replacing and/or reconditioning valves on account of possible leakage	Adjustments to existing network
	1B	Replacing other leak-prone parts (except for valves)	Adjustments to existing network
2. Contaminations	2A	Cleaning existing pipelines	Adjustments to existing network
3. Lower (energy) density	3A	Configuring or replacing metering equipment to bring it into line with flow speed and gas composition	Adjustments to existing network
	3B	Adding compressors (in the long term) on account of the incompatibility of existing compressors	Adjustments to existing network
4. Defect growth	4A	Mapping maximum operating pressures, changing operational procedures, and creating pipeline files	Adjustments to procedures
	4B	Developing and changing procedures for inline inspections	Adjustments to procedures
5. Ignition risk	5A	Training technicians to handle hydrogen	Adjustments to procedures
	5B	Changing pipeline modification procedures	Adjustments to procedures
	5C	Procuring safe electronic metering equipment for management and maintenance	Adjustments to procedures

= Adjustments to existing network *= Adjustments to procedures*

- At this point in time, agreements and/or regulations have not yet been made with respect to the required level of hydrogen purity. However, purity is not a factor in determining whether or not hydrogen can be transported safely in gas pipelines. Based on an international market consultation and several standards for equipment used by hydrogen consumers, Gasunie expects that purity will be required to be at least 98% in the backbone.[2] A decision on purity has yet to be made. The required level of purity will ultimately be up to the international market and laws and regulations.
- Gasunie uses odorisation at metering and regulating stations and at various gas receiving stations to add a distinctive sulphur smell (tetrahydrothiophene, THT) to odourless natural gas, before distributing it to the regional distribution network operators or consumers. In some industrial processes (especially fuel cells and catalysts), the odorant used can lead to problems. As a result, Gasunie anticipates that, like in the HTL, no odorisation will be used in the national hydrogen network. Industrial consumers connected to the HTL are, furthermore, aware of the hazards involved in natural gas and take preventive measures themselves.
- The pipelines that will be used for hydrogen transmission need to be able to deliver clean and dry hydrogen gas. The ultimate use of the hydrogen gas (combustion, fuel cell, resource) determines to what extent the pipeline will have to be cleaned. To prevent corrosion inside the pipeline and reduce erosion as much as possible, it is important that the gas transported be clean and dry (Bilfinger Tebodin, 2019).
- This leads to the following measure:

2A *Cleaning existing pipelines*

- Existing pipelines are partly contaminated. To attain the required level of hydrogen purity, existing pipelines will have to be cleaned before they can be taken into use for hydrogen transport.[2] Large existing pipelines often include facilities for inspection and cleaning, including the cleaning of pressurised pipelines. Pipelines can also be rinsed with nitrogen prior to use.
- The higher the required level of purity, the cleaner the pipeline will have to be. If a specific consumer requires a higher level of purity, there , is also the option to purify the hydrogen on site at the consumer or to add an additional purification step to achieve a higher level of purity, such as by installing a safeguard filter system on site.

1. This table was put together based on information obtained from the various HyWay 27 stakeholders and desk research into previous studies (including DNV GL, 2017; DNV GL, 2020b; Gasunie, 2019; Bilfinger Tebodin, 2019; AVIV, 2019). PwC Strategy& did not conduct a technical analysis itself.
2. Quality will ultimately have to be determined in consultation with the (international) market and recorded in quality specifications with hydrogen purity requirements (for example, ≥98%) and permitted impurities (such as oxygen, water, sulphur). See Appendix A-5 for further details on purity.

Hydrogen's lower (energy) density will require several adjustments to the existing transmission network

Lower (energy) density-related measures 3

Summary of measures needed to ensure safe hydrogen transmission
Source: Gasunie, Bilfinger Tebodin, AVIV, DNV GL[1]

Focus point	Measure	Type
1. Leak susceptibility	1A Replacing and/or reconditioning valves on account of possible leakage	Adjustments to existing network
	1B Replacing other leak-prone parts (except for valves)	Adjustments to existing network
2. Contaminations	2A Cleaning existing pipelines	Adjustments to existing network
3. Lower (energy) density	3A Configuring or replacing metering equipment to bring it into line with flow speed and gas composition	Adjustments to existing network
	3B Adding compressors (in the long term) on account of the incompatibility of existing compressors	Adjustments to existing network
4. Defect growth	4A Mapping maximum operating pressures, changing operational procedures, and creating pipeline files	Adjustments to procedures
	4B Developing and changing procedures for inline inspections	Adjustments to procedures
5. Ignition risk	5A Training technicians to handle hydrogen	Adjustments to procedures
	5B Changing pipeline modification procedures	Adjustments to procedures
	5C Procuring safe electronic metering equipment for management and maintenance	Adjustments to procedures

= Adjustments to existing network *= Adjustments to procedures*

- Hydrogen's energy density is three times lower than that of natural gas. In order for hydrogen to be able to meet the same energy needs as natural gas, the volume of hydrogen transported will have to be three times greater than that of natural gas. Assuming maximum pipeline capacity utilisation, the transport speeds will then also need to be multiplied by three.
- The maximum gas speed in a natural gas pipeline is capped at 20 m/s and the speed for hydrogen will have to be raised to 60 m/s to achieve the same energy transport capacity. From a safety point of view, this is not a problem: prior research has shown that hydrogen transport involves fewer flow-induced pulsations and turbulence and less acoustically induced vibration compared to natural gas transmission, even with a flow speed that is three times greater (Bilfinger Tebodin, 2019; DNV GL, 2018b).
- As a result, hydrogen's lower (energy) density necessitates two measures (in the long term):

3A Configuring or replacing metering equipment to bring it into line with flow speed and gas composition

- Given that minor errors in metering data can have major financial consequences, current gas meters are very accurate, in line with the current standard.
- Seeing as hydrogen has a different composition and will flow through the pipeline at greater speed compared to methane, the metering equipment will have to be reconfigured. Gasunie is currently looking into this together with other gas transmission network operators. The expectation is that gas meters will only have to be reconfigured and not replaced.

3B Adding compressors (in the long term) on account of the incompatibility of existing compressors

- Until 2035, Gasunie does not expect any need for compression in the development of a national hydrogen transport network with an intended pressure range of 30-50 bar. Adding transmission compression is, therefore, currently not included in the investment estimate. If required, capacity in a specific pipeline can be increased at a later stage by adding transmission compression. This would involve the procurement of new compressors of a different type, because existing compressors are not compatible with hydrogen. This may lead to significant additional investments in the long run, i.e. beyond 2035.

1. This table was put together based on information obtained from the various HyWay 27 stakeholders and desk research into previous studies (including DNV GL, 2017; DNV GL, 2020b; Gasunie, 2019; Bilfinger Tebodin, 2019; AVIV, 2019). PwC Strategy& did not conduct a technical analysis itself.

Defect growth can be countered by controlling pressure fluctuations; Inline inspection requires further research

Measures to counter defect growth (4)

Summary of measures needed to ensure safe hydrogen transmission
Source: Gasunie, Bilfinger Tebodin, AVIV, DNV GL[1]

Focus point		Measure	Type
1. Leak susceptibility	1A	Replacing and/or reconditioning valves on account of possible leakage	Adjustments to existing network
	1B	Replacing other leak-prone parts (except for valves)	Adjustments to existing network
2. Contaminations	2A	Cleaning existing pipelines	Adjustments to existing network
3. Lower (energy) density	3A	Configuring or replacing metering equipment to bring it into line with flow speed and gas composition	Adjustments to existing network
	3B	Adding compressors (in the long term) on account of the incompatibility of existing compressors	Adjustments to existing network
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- One of the focus points in repurposing existing pipelines for hydrogen transport is to check whether any (fatigue related) cracks could form in the pipeline. Based on crack propagation calculations and/or inspections, an assessment can be made of whether crack propagation caused by material fatigue could lead to a problem. In this respect, it is key to be able to assess the pipeline's operating conditions, and pressure fluctuations in particular, as accurately as possible and to have safe threshold values for fatigue-related crack propagation.

4A Mapping maximum operating pressures, changing operational procedures, and creating pipeline files

- Gasunie has started to compile the require pipeline files in compliance with the Dutch pipeline standard (NEN 3650), which requires Gasunie to show for each individual pipeline that it is compatible with hydrogen in terms of design and integrity. Gasunie expects to have these files ready in 2021/2022. Tests by Gasunie may show that pressure fluctuations in a specific pipeline will have to be controlled. Gasunie will include the findings from these tests in the documentation for each pipeline and operating procedures, such as by using lower pressures and conducting annual checks of pressure fluctuations (size and number).

4B Developing and changing procedures for inline inspections

- At present, defect growth detection through inline inspections is a measure that is available to meet the requirements from the Decree on External Safety of Pipelines (Besluit Externe Veiligheid Buisleidingen [Bevb]) for transport pipelines. Gasunie is currently in talks with the Dutch Ministry of Infrastructure and Water Management to include external safety for hydrogen transmission in the legislation in a suitable manner.
- Inspecting the inside of a pressurised hydrogen pipeline comes with a number of safety risks that differ from those involved in inspecting a natural gas pipeline. Hydrogen's greater explosive range and lower ignition energy may have different effects, depending on the level of hydrogen in oxygen, when performing inspections. The procedure for safe inspection of the inside of a pipeline will have to be designed accordingly. Inline inspection technology manufacturers have meanwhile started to develop ways to make it possible to inspect pressurised hydrogen pipelines. Such technology is expected to be available in 2023-2024 at the earliest.

1. This table was put together based on information obtained from the various HyWay 27 stakeholders and desk research into previous studies (including DNV GL, 2017; DNV GL, 2020b; Gasunie, 2019; Bilfinger Tebodin, 2019; AVIV, 2019). PwC Strategy& did not conduct a technical analysis itself.

A higher risk of ignition calls for additional management and maintenance measures for hydrogen pipelines

Ignition risk-related measures 5

Summary of measures needed to ensure safe hydrogen transmission
Source: Gasunie, Bilfinger Tebodin, AVIV, DNV GL[1]

Focus point	Measure		Type
1. Leak susceptibility	1A	Replacing and/or reconditioning valves on account of possible leakage	Adjustments to existing network
	1B	Replacing other leak-prone parts (except for valves)	Adjustments to existing network
2. Contaminations	2A	Cleaning existing pipelines	Adjustments to existing network
3. Lower (energy) density	3A	Configuring or replacing metering equipment to bring it into line with flow speed and gas composition	Adjustments to existing network
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- Most of the work performed on the hydrogen grid will be the same as in the current situation with natural gas. A few measures will, however, be required to ensure safe pipeline management and maintenance.

5A Training technicians to handle hydrogen

- Maintenance technicians will have to be aware of and experience the differences between natural gas and hydrogen before they can perform maintenance work on hydrogen pipelines. Gasunie has already developed a course to train technicians in handling hydrogen.

5B Changing pipeline modification procedures

- Technicians need to be able to safely repair leaks on the outside of a pipeline, which requires them to be able to work behind an (almost completely) leak-proof valve. For natural gas, there are various procedures available for this. Gasunie is currently looking into how these same procedures work in combination with hydrogen applications. There are also procedures for working on natural gas pipelines under pressurised conditions, such as welding on gas pipelines. Similar procedures for hydrogen transmission are currently under review.[2]
- Until there is greater clarity on the use of alternative procedures, Gasunie proposes to use (controlled) flaring using mobile flaring equipment as the standard procedure. The downside to flaring is that it takes longer than other procedures, meaning that (part of) the pipeline will be unavailable for longer during pipeline modifications, which affects security of supply and transmission.

5C Procuring safe electronic metering equipment for management and maintenance

- Hydrogen's lower ignition energy means that electronic equipment will have to meet different requirements to (further) reduce the risk of ignition. An assessment will have to be made of whether existing management and maintenance equipment meets these requirements and whether other or additional resources will have to be procured. Infrared detection, for example, is one option that could be used for hydrogen, because the flame produced by pure hydrogen is barely visible.

1. This table was put together based on information obtained from the various HyWay 27 stakeholders and desk research into previous studies (including DNV GL, 2017; DNV GL, 2020b; Gasunie, 2019; Bilfinger Tebodin, 2019; AVIV, 2019). PwC Strategy& did not conduct a technical analysis itself.
2. The Pipeline Research Council International, of which Gasunie is a member, is currently studying these techniques.

The above measures assume amendment of the calculation method in the Decree on External Safety of Pipelines

The current calculation method is more conservative for hydrogen transport than for natural gas transmission

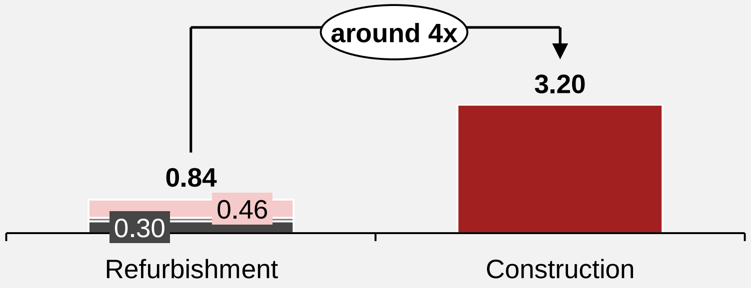
- The Decree on External Safety of Pipelines sets external safety risk standards that operators of pipelines carrying hazardous substances must meet. The current version of this decree breaks pipelines down into three categories: natural gas, oil (k1/k2/k3), and chemicals. In terms of external safety, the decree does not classify hydrogen in the same category as natural gas.
- As a result, assessment of the external safety of a hydrogen pipeline requires the use of a fixed failure rate that is more conservative than the failure rate for natural gas transmission. Assessments using this current calculation method are, therefore, highly likely to identify a need for additional mitigating measures that will end up limiting the use of a hydrogen transmission network, while research has shown that hydrogen transmission involves a similar level of risk to natural gas transmission. When using large-diameter pipelines, as will be used for the national hydrogen ring, the failure rate goes down as these pipelines have thicker walls and are laid deeper under ground, which significantly reduces the risk of excavation damage (AVIV, 2019).
- The Dutch Ministry of Infrastructure and Water Management has meanwhile commissioned a study that will have to produce a new calculation method for external safety assessments of large-diameter pipelines used for hydrogen transport. This calculation method is expected to be ready by mid-2021.
- The Netherlands Institute of Public Health and Environmental Protection (RIVM), which advises the Ministry of Infrastructure and Water Management, proposes to use the failure rates of large-diameter natural gas pipelines (18-inch diameter or larger) for hydrogen pipelines under certain conditions.
- If the Ministry of Infrastructure and Water Management takes RIVM's advice and incorporates it into the new external safety calculation method for hydrogen, Gasunie assumes that the measures outlined in the previous will be adequate to ensure safe and reliable hydrogen transport without further operational limitations.

4.3. Required investment for repurposing existing natural gas transmission network

The refurbishment of existing pipelines is expected to be considerably cheaper than the construction of a new pipeline

Gasunie estimates show that refurbishment would be four times cheaper than construction

Comparison of per-km investment required for reuse and new-build *(millions of € per km, based on*: *36-inch pipeline and route covering 1,183km). Source: Gasunie [1]*



Assumptions for 36-inch pipeline	Refurbishment	Construction
Consideration for existing assets	average Regulated asset value per km [2]	N/A
Cleaning and preparing pipeline	10% of capex value for construction of a comparable pipeline	N/A
Installation of valves (every 32km)	€ 1.5 million each (including removing existing valves)	N/A (already part of construction costs)
Construction	N/A	€2.8 million per km, which is subsequently corrected by a factor of 1 to 1.75 for the type of subsoil along the pipeline or sections of the pipeline. The result is approx. €3.2 million per km.

Consideration for existing assets | Costs involved in laying a new pipeline | Valve replacement | Cleaning and preparing pipeline

- The refurbishment of existing pipelines is expected to be considerably cheaper than the construction of a new pipeline offering the same capacity. This is evident from preliminary estimates by Gasunie and an analysis of publicly available figures for new pipeline construction.
- The new pipeline investments amount to approx. €3.2 million per km, based on a 36-inch pipeline and a comparable route of 1,183km, while the investments for repurposing, according to Gasunie, amount to around €0.84 million per km on average.[3] This makes new construction nearly four times more expensive than repurposing. This factor of 4 times is in line with various recent external (international) studies that also indicate that reuse involves around 10 to 35% of the value of a new pipeline (Guidehouse & Tractebel Impact, 2020; Guidehouse, 2020; Carniauskas et al., 2020).
- Gasunie assumes that the operational costs of a natural gas pipeline repurposed as a hydrogen transmission network will amount to approximately 1% of the investment value, a percentage that is in line with the operational costs of GTS for the gas transmission grid as estimated by ACM. It is therefore assumed that the operational costs of a refurbished pipeline are comparable to the operational costs of a natural gas pipeline.
- Moreover, Gasunie sees no difference in operational costs between a refurbished natural gas pipeline and an entirely new pipeline for hydrogen transmission. After conversion, the pipelines are cleaned and checked for wall thickness, ensuring that these will be suitable for use during the intended lifespan at least. Moving parts, such as the valves, would be replaced prior to the hydrogen transmission pipeline being brought into operation, meaning these will be at the start of their technical service life.

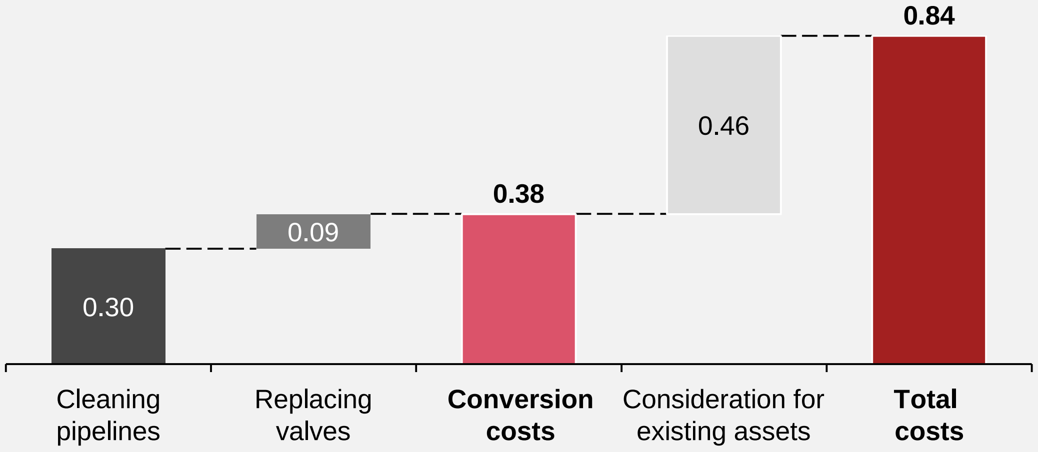
1. Source: Derived from the HyWay 27 investment estimate received from Gasunie. 2. The envisioned 981km of pipeline to be refurbished account for approximately 9.1% of the total number of kilometres of existing GTS transmission pipeline; 9.1% of the regulated asset value (RAV) amounts to approximately €446 million, which leads to an average consideration for the assets of around €0.46 million per km. 3. In addition to the realisation of the pipeline, other investments are also involved in the one-off filling of the pipelines and the performance of quality measurements. These investments (approx. €0.06 million per km) are comparable for both repurposing and new pipeline construction and are therefore not part of this comparison.

Cleaning and preparing the pipelines and replacing valves account for the largest part of the refurbishment investment

The consideration for existing assets is also expected to be a significant cost item

Indicative refurbishment costs for an existing natural gas pipeline

(€ million per km, 2020 price level). *Source: Gasunie*[1]



Assumptions 36-inch pipeline	Refurbishment
Cleaning and preparing pipeline	10% of capex value for construction of a comparable pipeline
Installation of valves	€1.5 million per valve, with a valve required at every start and end point of a pipeline and every 32km in between (price includes removing existing valves)
Consideration for existing assets	average Regulated asset value per km

- Gasunie's estimate for the total investment required for repurposing pipeline is approx. €0.84 million per km. This amount comprises refurbishment costs (approx. €0.38 million per km; around 45% of the total costs) and an consideration paid for existing pipelines (approx. €0.46 million per km; around 55% of the total costs).
- The largest part (some 77%) of the refurbishment costs is in cleaning and preparing the pipelines. Gasunie currently assumes that the costs of cleaning and preparing an existing pipeline are approximately 10% of the capex investment for a comparable (new) pipeline. This assumption also includes the required security analyses, necessary adjustments to the legal framework (spatial planning, real right of superficies, permits), IT adjustments and changes to documentation (roadmaps, SAP, data management, etc.).
- The remaining refurbishment costs (around 23%) are for the replacement of valves. Gasunie currently assumes that a valve will be required at every start and end point of a route and every 32km and further assumes that all existing valves will need to be replaced or removed. Gasunie currently applies €1.5 million per valve (including removal of existing valves) for the replacement of a valve.
- Finally, the existing pipelines will have to be acquired, most of which currently belong to Gasunie Transport Services (GTS).[2] It is expected that, for this acquisition, a consideration for existing assets will have to be agreed. Gasunie is currently using the provisional assumption that this consideration per km is equal to the average RAV determined by ACM per km of the existing natural gas transmission network.[3]

1. Source: Derived from the HyWay 27 investment estimate received from Gasunie. 2. There may also be a limited number of pipelines (approx. 30km) that will need to be taken over from external parties. 3. The actual amount of any consideration for existing assets depends on the status of the entity that will operate the hydrogen transmission network. The final consideration must be determined in consultation with the Ministry of Finance. See the notes on the next page.

Use of existing natural gas pipelines, owned by GTS, for hydrogen transmission would require unbundling or even transfer

The amount of the consideration for existing assets depends on the status of the entity that will serve as transmission operator

Consideration amount to be applied in the case of unbundling and any transfer of existing pipelines from GTS's asset base ***Sources:*** *Gasunie, ACM, Dutch Ministry of Economic Affairs & Climate Policy*

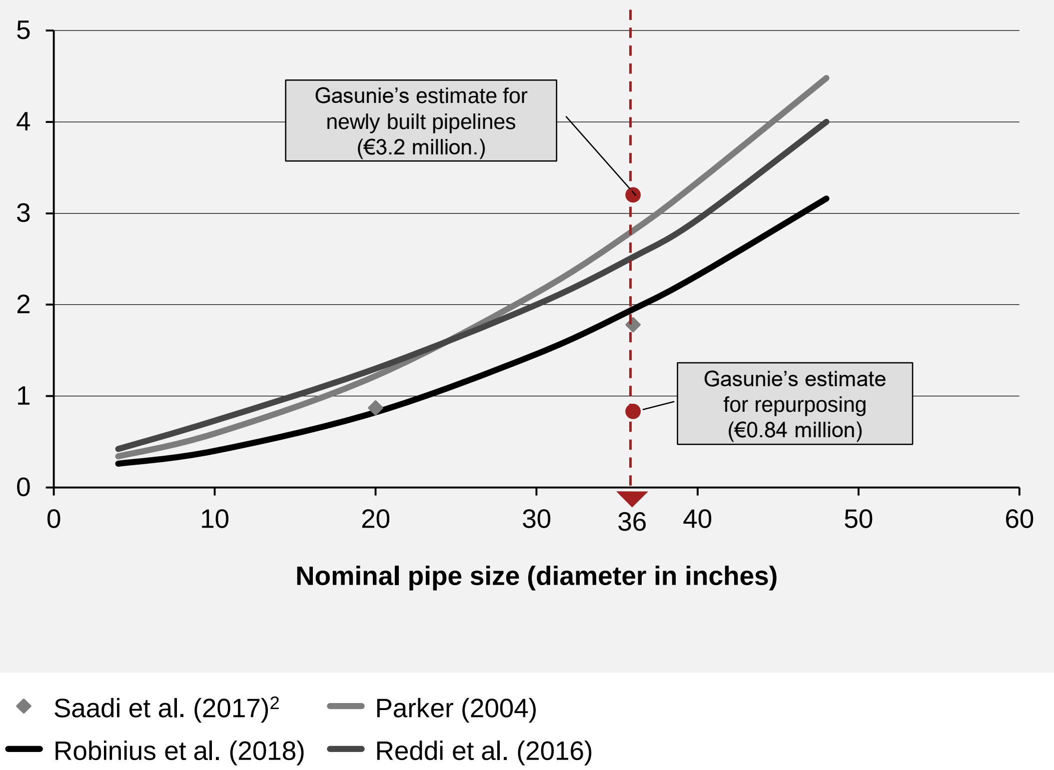
<table>
<tr><th colspan="2">Possible entity that will operate the hydrogen transmission network</th><th>Required transfer and/or unbundling of existing assets</th><th>Value at which existing assets are remunerated</th></tr>
<tr><td rowspan="3">Gasunie</td><td>GTS
(after being given a new task under its statutory remit)</td><td>Unbundling to separate asset base within GTS</td><td rowspan="2">Consideration based on Regulated Asset Value</td></tr>
<tr><td>Other regulated Gasunie entity</td><td rowspan="3">Unbundling and transfer to another entity</td></tr>
<tr><td>Other non-regulated Gasunie entity</td><td rowspan="2">Payment based on market value</td></tr>
<tr><td colspan="2">Other market parties</td></tr>
</table>

- Use of natural gas pipelines that are part of the existing regulated gas transmission grid is only possible under the current legislation and regulations if these pipelines are removed from the regulated asset base of gas transport network operator Gasunie Transport Services (GTS). Under the Dutch Gas Act, GTS may not carry out any activities that do not come under its statutory remit. Currently, managing a hydrogen grid does not fall under this remit. Depending on the status of the entity that manages these pipelines, to be able to use natural gas pipelines for transmission of hydrogen, the pipelines will, at least, need to be unbundled and possibly even transferred to another entity.
- In both cases (unbundling and transfer) under GTS regulations such a transfer is handled as a divestment. The assets sold are removed from GTS's asset base and, after settling the proceeds of the sale, the remaining costs are earned back via the regulated rates. Once these assets have been divested, the users of the natural gas network no longer pay for these pipelines.
- In its cost estimate, Gasunie is currently assuming that this consideration per km is equal to the average Regulated Asset Value (RAV) determined by ACM per km of the existing natural gas transmission network. The envisioned 981km of pipeline to be refurbished account for approximately 9.1% of the total number of kilometres of existing GTS transmission pipeline; 9.1% of the RAV amounts to approximately €446 million, which leads to an average consideration for the assets of around €0.46 million per km.
- If GTS is not given a new task under its statutory remit, Gasunie can decide to sell (transfer) the GTS assets to another Gasunie entity or other (non-Gasunie) party. If the acquiring party is a regulated network operator, the RAV would be used for the transfer. If the future operator is not a regulated hydrogen transmission network operator, however, the transfer would have to be carried out at market value, in which case the value will need to be established by an independent party.

Compared to newly constructed pipelines, even based on the more conservative estimates refurbishing pipelines is cheaper

Although making a comparison is complex, in other studies we see lower figures for new construction than those estimated by Gasunie

Comparison between various figures for construction of a hydrogen pipeline (*€ million per km, 100km route, 2019 price level*). *Source: H-vision*[1]



- It is difficult to make a straightforward comparison with the figures for a newly constructed pipeline. This is because these costs depend on multiple factors, including diameter, route location, subsurface and length. In addition, because construction is very capital intensive, the figures in older sources can often be skewed due to the inflation that has since occurred. This makes it difficult to arrive at a relatively conclusive figure for new pipeline construction.
- In external (international) sources, we see varying figures for pipeline construction. In general we see that these sources apply lower figures for construction than the estimate Gasunie uses:
  - H-vision has made a comparison of figures from various previous studies (see figure to the left). H-Vision has adjusted these figures to the 2019 price level. The costs for a new 36-inch pipeline vary between around €1.8 and €2.8 million per km (H-vision, 2019).
  - FNB Gas in Germany calculates approx. €2.1 million per km for a standard 36-inch natural gas transmission pipeline (FNB Gas, 2020a).
  - ACER applies an amount of approx. €1.5 million per km for the construction of a 36-inch natural gas transmission pipeline over long distances (ACER, 2015); in 2017, ECN stated that ACER's results were representative of offshore costs (ECN, 2017). It should be noted, however, that this figure has been indexed to the 2015 price level. Corrected for inflation, this comes out at approx. €2.3 million per km.
- Gasunie's current estimate for repurposing (€0.84 million per km) based on a 36-inch pipeline (approx. 9.1 GW of capacity) is cheaper than external estimates for construction of new pipelines from a diameter of approximately 10 to 20 inches (with a significantly lower capacity).

1. Figure derived from H-Vision (2019), supplemented with input from Gasunie and Strategy& analysis. In this, H-vision adjusted the figures from previous studies (shown in the legend) to the 2019 price level. 2. Represents two data points of new hydrogen transmission pipelines.

Gasunie estimates that a national hydrogen transmission ring can be created between now and 2030 for around €1.5 billion.

Indication of investment costs for realisation national hydrogen transmission ring

Overview of required investments for realisation of a national transmission ring *(incl. acquisition costs of existing pipelines, if required).* *Source: Gasunie*

Envisioned main routes hydrogen transmission ring	Length of entire route (km)	Length of refurb. pipeline (km)	Length of new pipeline (km)	Required investment for refurb. pipeline (millions of €)	Required investment for new pipeline (millions of €)	Possibly ready for hydrogen
Northern Netherlands cluster	171	140	31	€89 million	€79 million	2024-2025
Rotterdam/Moerdijk cluster	75	N/A	75	N/A	€270 million.	2024-2025
NSCA cluster	30	15	15	€ 16 million	€ 53 million	2026
Zeeland cluster	34	N/A	34	N/A	€100 million	2027
Chemelot cluster	25	25	N/A	€19 million	N/A	2027
Northern Netherlands – NSCA connection	206	175	31	€ 161 million	€ 115 million	2026
NSCA – Rotterdam/Moerdijk connection	79	79	N/A	€99 million	N/A	2026
Rotterdam/Moerdijk – Zeeland connection	83	83	N/A	€71 million	N/A	2027
Northern Netherlands – Chemelot connection	216	200	16	€156 million	€50 million	2027
Zeeland – Chemelot connection[1] (Ravenstein-Ossendrecht)	122	122	N/A	€112 million.	N/A	2030
Export connection to Germany[2]	134	134	N/A	€138 million.	N/A	2027-2030
Export connection to Belgium[3]	8	8	N/A	€12 million.	N/A	2030
Total (km)	**1,183**	**981**	**202**	**€873 million**	**€667 million**	

Total investment, roughly €1.5 billion

- The table shows Gasunie's estimate of the required investment per route. Based on current insights, Gasunie anticipates that these pipelines can be realised between now and 2030 for a total investment of approx. €1.5 billion, comprising:
  - €873 million to repurpose 981km of existing pipeline;
  - €667 million to build 202km of new pipeline.
- The investment amount for refurbishment takes into account, where relevant, a possible consideration for assets for acquiring existing pipelines. The amount is a provisional estimate (based on an average of the Regulated Asset Value as determined by the ACM) for the acquisition. The actual choice of pipeline and any associated asset consideration per pipeline has not yet been determined. These must be determined in consultation with the Ministry of Finance and the Ministry of Economic Affairs and Climate Policy.

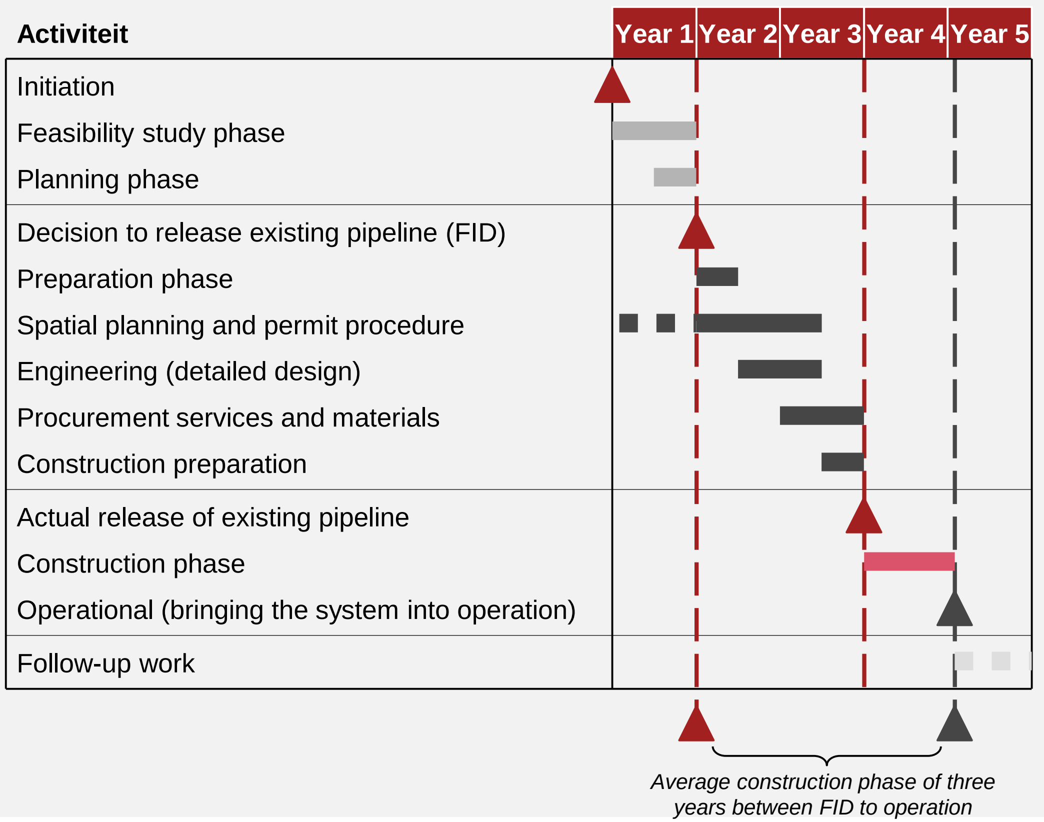
1. The figure on page 59 includes an alternative east-west connection (situated more to the north); this alternative connection is not included in this investment estimate. 2. For export connections to Germany, the Tjuchem-Oude Statenzijl and Ommen-Winterswijk/Zevenaar routes are included in this estimate. 3. For export connections to Belgium, the Beekse Bergen – Hilvarenbeek route is included in this estimate.

4.4. Possible phasing of national hydrogen transmission network

Gasunie estimates that, from the date of final investment decision (FID), it will take about another three years to refurbish a route and bring it into operation

Drivers in the timeline are the permit procedures, material delivery times, and the construction

Timeline for the realisation of an average route[1]
(based on an indicative route of 100km). Source: Gasunie



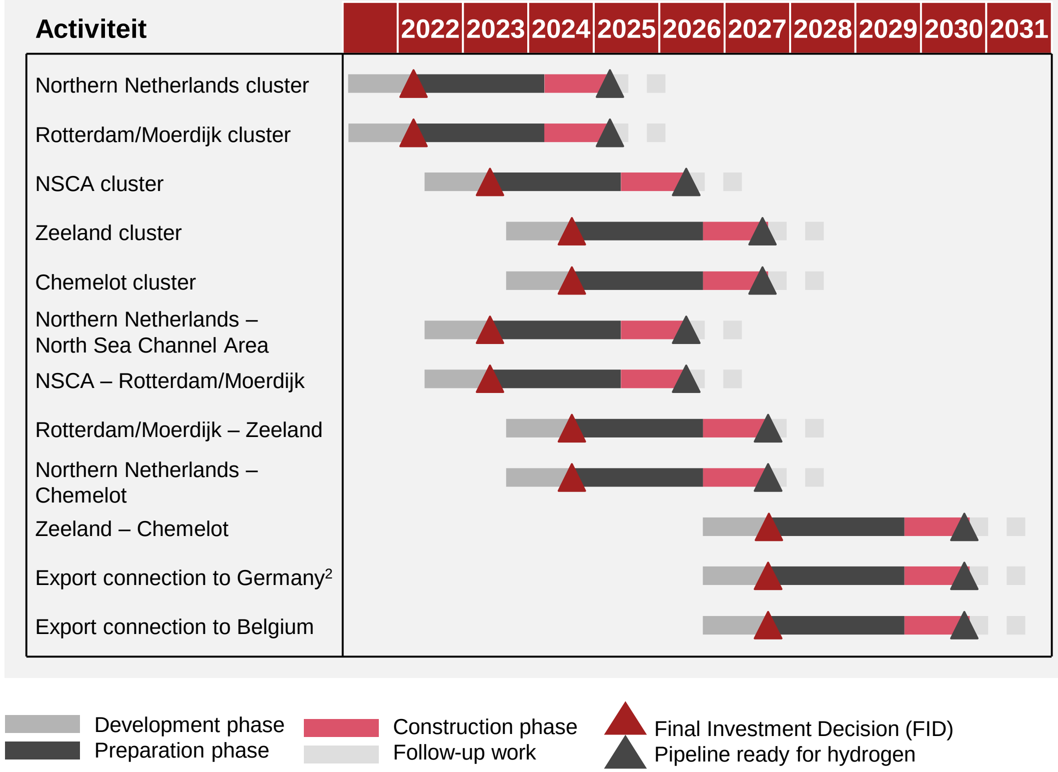
- In terms of the timeline, the date on which the final investment decision (FID) is taken is particularly important for the realisation of a pipeline. This is when the final decision on making an existing natural gas pipeline available and/or constructing a new pipeline for the transmission of hydrogen must be taken. This FID must be taken at least two years prior to the actual construction phase (and release of existing pipeline).
- Prior to decision-making, a development phase will first be required, during which it is investigated whether the pipelines along a route can actually be released for hydrogen transmission and/or where new pipelines need to be constructed. This development phase is divided into a feasibility study phase and a planning phase. Gasunie estimates that such a development phase would take about one year, prior to the FID for a route. Prior to the FID, where applicable the legal transfer of the pipelines must also be arranged.[1]
- Once the decision-making procedure is complete and the decision taken, the project steps to prepare a route for the transmission of hydrogen start. This construction phase comprises all steps required to be able to use a route operationally for hydrogen transmission, including at least preparation, engineering, procurement and construction. Gasunie estimates that, for both refurbishment and construction, such a phase requires an average of three years from FID to a fully operational route.[2]
- In the construction phase, the key drivers in the timeline are the permit procedures, material delivery times, and the actual construction. Key obstacles in this phase are legislation relating to nitrogen emissions and the availability of adequately trained employees.
- The construction phase lasts about a year from the time the pipeline becomes available. During this phase the installation of the valves is the key driver.
- During the year after the route has been brought into operation, follow-up work to analyse whether the system operates in accordance with expectations will still be required.

1. The timeline shown assumes that the pipelines remain the property of Gasunie (possibly under a different entity). There may be longer lead times if existing pipelines were to be unbundled and transferred to another party outside Gasunie.
2. The assumption is that new routes to be realised will be within the area already reserved under the 'Government Structural Vision' [strategic policy document on spatial and functional developments in the Netherlands]. A considerably longer timeline would apply in the event of new routes to be realised outside this reserved space.

According to Gasunie, based on this phasing, per route a national hydrogen transmission ring can be realised in 2030

Providers and large consumers can then be connected to this transmission ring

Possible phasing of routes for a hydrogen transmission network between now and 2030[1]. *Source*: *Gasunie*



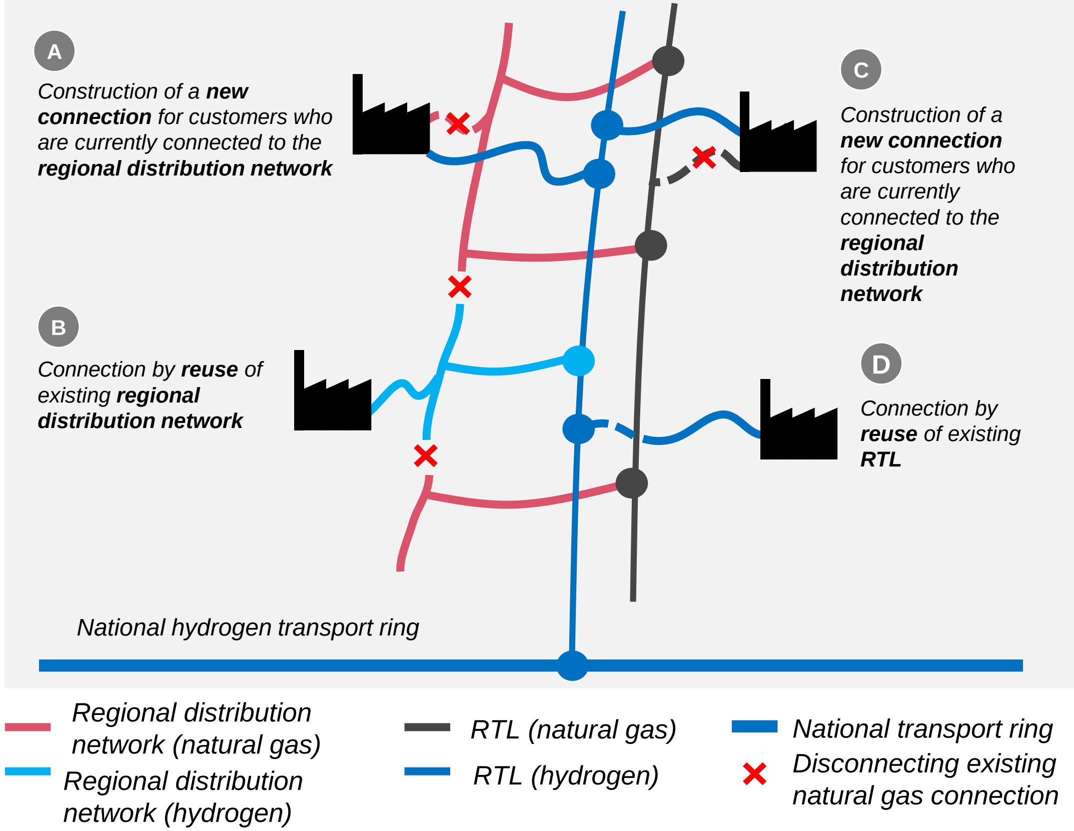
- Gasunie estimates that, if a decision is made in good time, it will be possible to develop a national hydrogen transmission network into which providers can feed in hydrogen and large consumers (the expectation is that this will first be domestic and foreign clusters) can draw hydrogen off by 2030.
- In the left figure, the year in which the existing pipelines along a route can be made available serves as the starting point for the phasing (as shown previously on page 60-61). Subsequently, a construction phase of one year and a preparation phase of two years were included for each route.
- The figure shows what a possible phasing of routes could look like based on the earliest possible availability of existing pipelines. As of yet, no definitive choice of route and/or decision about the phasing has been made.
- For a national hydrogen transmission ring to be realised by 2030, it is important that the current planning is not brought under any additional pressure. To achieve the timeline shown, it is important that the final investment decision be made in good time.
- It is also not expected that all routes can be realised at the same time, mainly due to the market's limited construction capacity. Closer to 2030, there is also expected to be more demand for construction capacity in our neighbouring countries (Germany in particular). This may lead to a further limitation of available construction capacity in the market. If the schedule is brought under more pressure – due to a delay in the necessary investment decisions being made for example – this can have consequences for costs and/or lead time.

1. The timeline shown assumes that the pipelines remain the property of Gasunie (possibly under a different entity). There may be longer lead times if existing pipelines were to be unbundled and transferred to another party outside Gasunie.
2. A first export connection from the Northern Netherlands cluster to Germany may be possible from as early as 2025. The Northern Netherlands – Chemelot route offers various options to realise export connections to Germany between 2027 and 2030, depending on the demand. Transport via the southern route (via Ravenstein-Ossendrecht) would be possible from 2030, according to Gasunie.

A further roll-out of the infrastructure is also possible via the regional transmission network and local distribution networks

Various connection configurations to the national hydrogen transport ring are possible for this

Possible configurations for connection to a national transmission ring via the main or local distribution networks
Source: Gasunie, Liander, Netbeheer Nederland



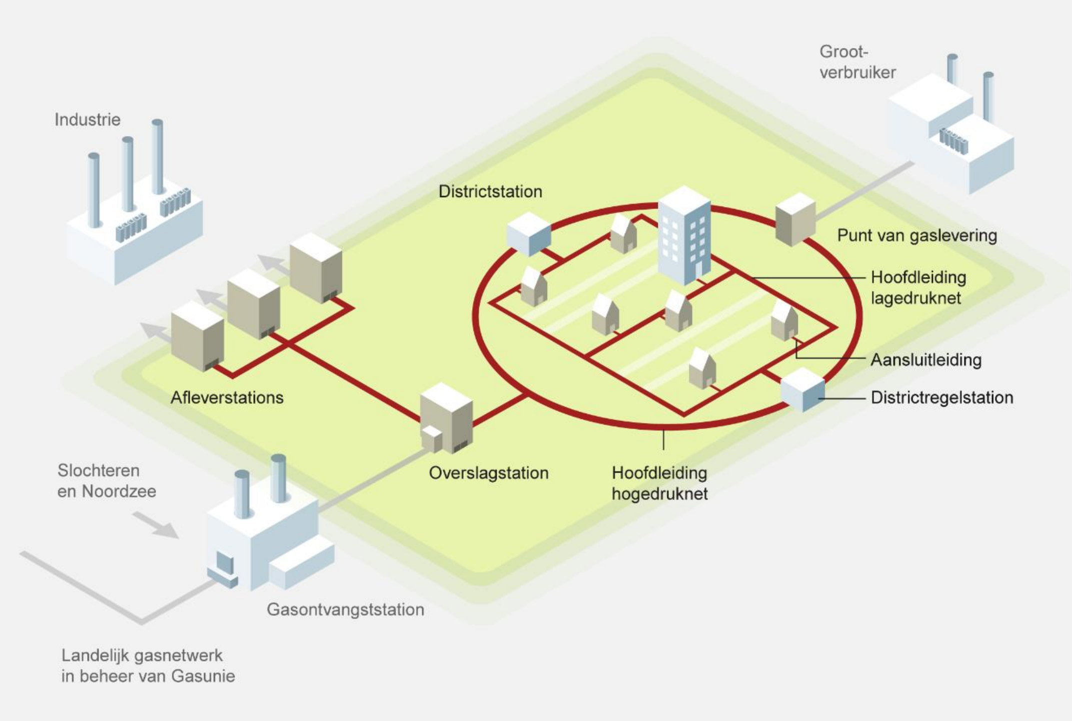
- In time, new connections to the national hydrogen transport ring can be created. This means that hydrogen will also gradually become available to other companies/installations (such as those in the sixth cluster) and sectors, like mobility and the built environment.
- It will then be possible to connect new large customers directly to the national hydrogen transport ring. It will also be possible to connect new customers via (existing or newly constructed) regional distribution networks and/or the intermediate-pressure gas grid (RTL) (see figure on the left). These configurations are comparable to the current situation for natural gas, where large consumers are directly connected to the high-pressure gas grid (HTL) and smaller customers are connected to the intermediate-pressure gas grid (RTL) or to a regional distribution network. [1]
- The choice of configuration depends on the required pressure and capacity, whether and when part of the local distribution network and/or regional transmission network can be disconnected (also considering the effect on security of supply with the remaining natural gas pipelines), the length required for a new connection, etc.
- A point of attention here is that the RTL and the regional distribution networks are more dense and generally lack parallel pipelines. Compared to the HTL, this makes it more difficult to disconnect existing pipelines from the natural gas network. Existing transmission and distribution pipelines can only be used for hydrogen if they can be disconnected from the rest of the natural gas network (see configuration 'B' in the figure). This is a strong dependency, but can also offer connection possibilities for nearby installations and buildings.
- Which customers and configurations are eligible (and when) will need to be investigated further.

1. In addition to Gasunie's transport grid and the distribution networks of the regional network operators, there are also other installations with existing gas pipelines that could possibly be used for hydrogen transport. Given that these pipelines do not necessarily have the same quality and transport capacity as that required for the transport of hydrogen, for each pipeline concerned, its suitability for hydrogen transport will need to be investigated further.

For the further roll-out via the regional transmission network and local distribution networks, decisions about the broader supply chain still have to be made

Supply chain parties must agree among themselves on a number of issues that affect all parties

Current connection of installations and the built environment via distribution networks *Source:* *Alliander (2 011)*



The main issues to be agreed on are:

- *Whether or not to add an odorant in the intermediate-pressure gas grid (RTL) and/or regional distribution networks:* Gasunie uses odorization to add the distinctive sulphur aroma compound (tetrahydrothiophene, THT) to odourless natural gas at metering and regulating stations and at various gas receiving stations before distributing the natural gas to regional network operators or customers. With the addition of this distinctive odour, a large number of faults/leaks are detected at an early stage and safety increased. In connection with possible problems for industrial customers, Gasunie foresees that, as is now the case with the current national, high-pressure transmission network, no odourant will be added in the national hydrogen network. In the further roll-out of hydrogen via the regional transmission and/or local distribution networks, it will have to be determined whether hydrogen will need to be odourised or whether other safety measures are more appropriate. For the central heating boiler, for example, odorization is not a problem.
- *Agreements and/or regulations regarding the required quality of gas:* At this point in time, agreements and/or regulations have not yet been made with respect to the required level of hydrogen purity transmission and distribution networks. agreements about this will need to be made jointly and in good time.
- *Harmonisation of licensing conditions:* Licensing conditions still differ depending on the environmental service/municipality. Harmonising the conditions is important for ensuring efficient progress and safety.
- *Standardisation of networks and end-user installations/devices:* To create clarity and, with this, safety and investment security, standards (ISO, NEN) for connecting networks and end-user installations/devices are needed. These standards have yet to be drawn up across the wider supply chain.
- *The effect of repurposing pipelines on security of supply:* The effect on security of supply (both for the new hydrogen pipelines and remaining natural gas pipelines) as a result of refurbishing existing pipelines for use as hydrogen pipelines will need to be investigated. Agreements on this matter will need to be made with the parties concerned.
- *Possibilities for the feed-in of hydrogen via distribution networks:* In the future, locally produced hydrogen could also be fed into the national hydrogen network. For this, the distribution networks still need to be made suitable for two-way traffic (including compression).

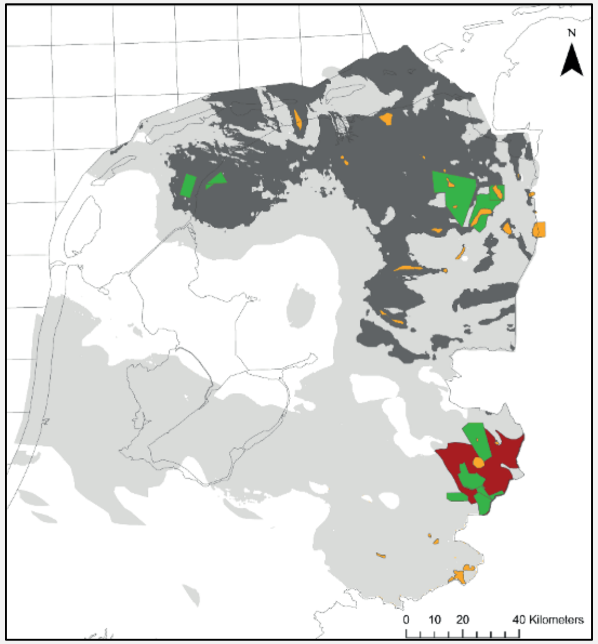
Sources: Liander and Netbeheer Nederland.

4.5. Technical possibilities for underground hydrogen storage

In theory, it would be possible to develop around 320 onshore caverns for hydrogen storage under Dutch soil

Around 3 to 12 caverns are needed to provide the 3 to 6PJ storage capacity required in 2030

Overview of suitability of salt caverns for storage
Source: Gasunie



- Salt solution mining licence
- Suitable for salt solution mining and storage (technical potential)
- Suitable for deep salt solution mining; not suitable for storage
- Suitable for shallow salt solution mining; not suitable for storage
- Unfavourable thickness for salt solution mining
- Salt layer negligible/not present

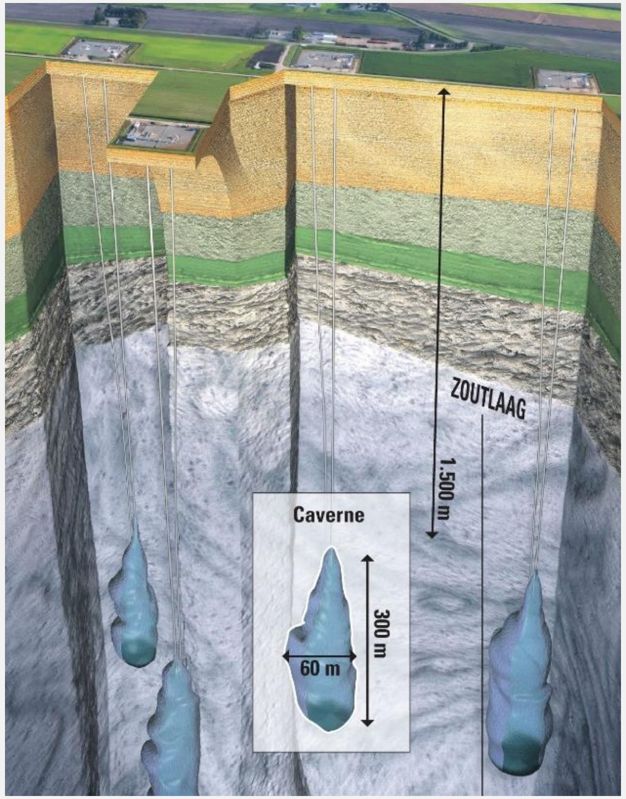
- In theory, there is sufficient space under Dutch soil for the development of around 320 onshore salt caverns for hydrogen storage. These 320 caverns could provide an effective hydrogen storage capacity of 14.5 billion cubic metres (43.3TWh, 156PJ) (Juez-Larré et al, 2019; TNO, 2020c)[1].
- The total size (volume) is determined by the number of caverns; the capacity is determined by the design of the above-ground installation (injection compression and gas treatment). Several caverns can be connected in phases to an above-ground installation. The scaling up possibilities this presents can deliver cost advantages.
- In the IP2022 climate agreement scenarios, a storage capacity of approximately 3 to 6PJ is envisioned for 2030 (as stated previously in chapter 3). Assuming an average storage capacity of 0.5 to 1 PJ per cavern, this need could be met with between 3 and 12 caverns.
- For the development of salt caverns it is important to take into account the available construction capacity (in the short term) and the required development time, which, for an average salt cavern, is around 3 to 4 years. Previous studies assume that with the current construction capacity it would only be possible to construct two to three salt caverns per year in the Netherlands (Juez-Larré et al, 2019). This speed of construction of new caverns is currently driven by the efficient use of the salt mined. For the time being, there is no market demand that justifies the construction of a new salt processing plant (TNO, 2018).
- After 2030, more onshore caverns can be developed in phases. Estimates for the required storage capacity towards 2050 vary widely. The II3050 study assumes storage of between 20PJ to 169PJ to buffer seasonal and weather-related variations, excluding any additional strategic storage. Depending on the storage capacity actually required, the more or less 320 possible onshore caverns can fully meet this need, or (on further research) offshore caverns and/or depleted gas fields will also have to be used.

1. For the most recent insights into hydrogen storage, we refer the reader to TNO (2020c). This report examines in detail what is and is not possible with the various technologies. The report is in turn a summary of four in-depth studies on matters like the role of large-scale energy storage in the Dutch energy system and the risks associated with underground energy storage.

Previous studies indicate that hydrogen storage in underground onshore caverns is both technically possible and safe

Large-scale storage of hydrogen in onshore salt caverns is already taking place in countries outside the Netherlands

Illustration of an underground salt cavern near Epe
Source: Gasunie



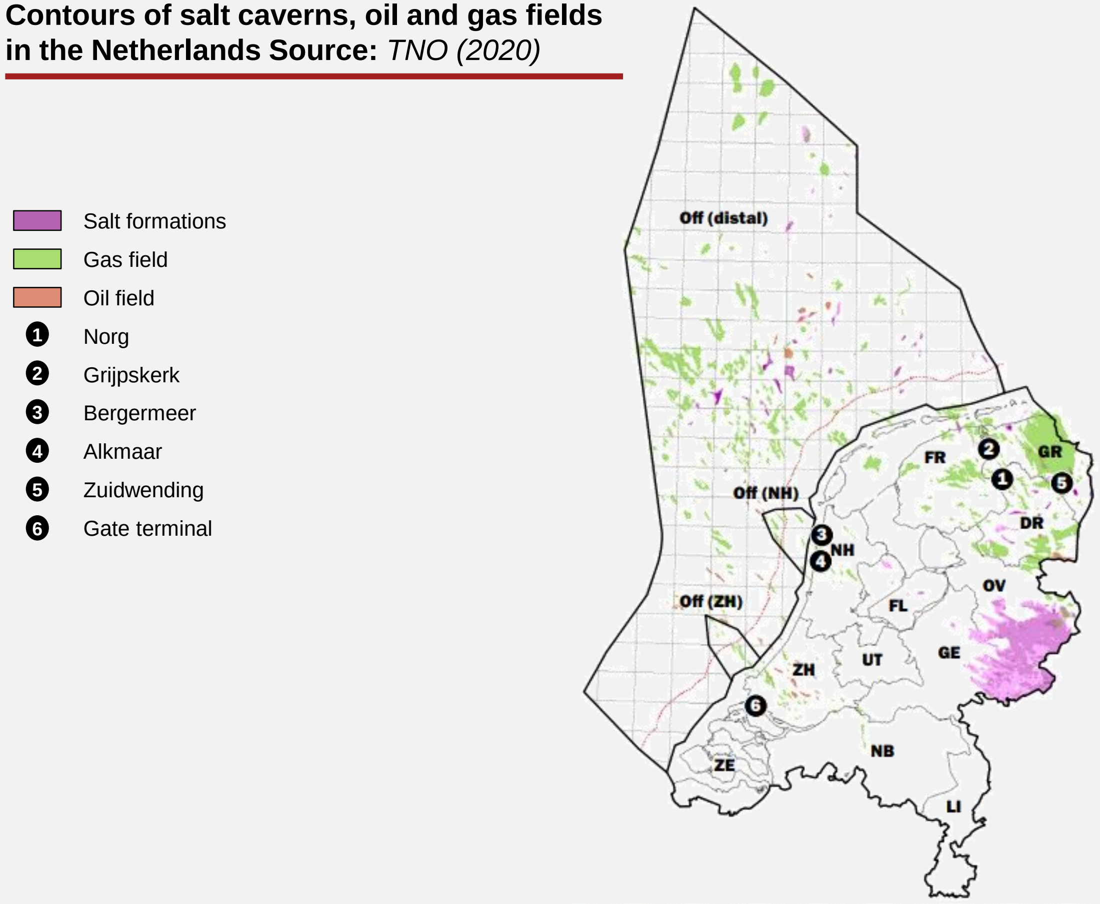
- Storing hydrogen in onshore salt caverns is both technically possible and safe. This form of storage is already being used on a large scale at a number of locations in countries outside the Netherlands, such as in England (Teesside) and in the United States (Texas) (TNO, 2018). The Netherlands itself has many years' experience in storing natural gas in salt caverns. Knowledge about gas storage in caverns is also already available at the Dutch national mines inspectorate SodM, which is important because hydrogen storage will also be covered by mining legislation (under which this inspectorate is tasked with inspecting safety).
- In the north-eastern part of the Netherlands, at Zuidwending in particular, there is a salt dome with caverns for natural gas and nitrogen storage. These caverns are situated at a depth of around 1,000 to 1,500 meters, are hundreds of meters high and have a diameter of approximately 60 to 80 (see figure on the left).
- Rock salt (halite) has very good, proven sealing properties. When hydrogen is stored in salt caverns, it is virtually certain that containment will be adequate and that no mixing will occur (hydrogen purity). Salt caverns must first be created however. This does make it possible though to bring a salt cavern into operation in a scalable manner, so that the capacity of the cavern is tailored to market demand and there is no need for an excessive volume of 'cushion gas' (see next point) to be stored. With the current low demand for hydrogen storage, the better productivity and more favourable ratio of working gas to cushion gas in salt caverns will be a key argument for initially storing hydrogen in onshore salt caverns (TNO, 2018; TNO, 2020c).[1]
- In order to withstand the pressure of the salt, the cavern will first need to be pressurised (80 bar) with hydrogen; this is called the base or cushion gas. The remaining gas that can be stored in the cavern by increasing the pressure (up to a maximum of approx. 180 bar) is called the working gas. The cushion gas/working gas ratio is usually 40/60%.
- On average, for each fully developed cavern (with a geometric volume of approx. 0.5 to 1 million m^3), around 3,500 to 7,000 tonnes of hydrogen can be stored (working gas volume), equivalent to an energy content of approx. 140 to 280GWh (around 0.5 to 1PJ).[2]

1. For the most recent insights into hydrogen storage, we refer the reader to TNO (2020c). This report examines in detail what is and is not possible with the various technologies. The report is in turn a summary of four in-depth studies on matters like the role of large-scale energy storage in the Dutch energy system and the risks associated with underground energy storage. 2. Source: Gasunie.

In the more distant future, there also appears to be storage options for hydrogen in offshore salt caverns, depleted gas fields and aquifers

However, these types of storage have not yet been sufficiently proven and require further research

Contours of salt caverns, oil and gas fields in the Netherlands Source: *TNO (2020)*



- In addition to onshore storage in salt caverns, the Dutch subsurface has great potential, in theory, for onshore and offshore storage in depleted gas fields, aquifers and offshore caverns.
- Due to the costs and a number of technical aspects, the construction of offshore salt caverns is not the most obvious choice in the short term. For storage in depleted gas fields and aquifers, these have not yet been proven as a suitable and efficient storage location for hydrogen. However, these forms of storage may become interesting in the more distant future when a demand for larger (seasonal and/or strategic) buffer capacity (with a lower required purity) emerges and/or when there are no suitable salt structures in the vicinity of a desired storage location. (TNO, 2018; TNO, 2020c).
- The figure on the left shows an overview of onshore and offshore salt caverns, oil and gas fields in the Netherlands deep underground. Large-scale underground storage of natural gas is already being practised in gas fields (no. 1 to 4 in the figure) and in salt caverns in Zoutwending (no. 5 in figure). Oil fields are not expected to be suitable for the storage of hydrogen (TNO, 2018; TNO, 2020c).

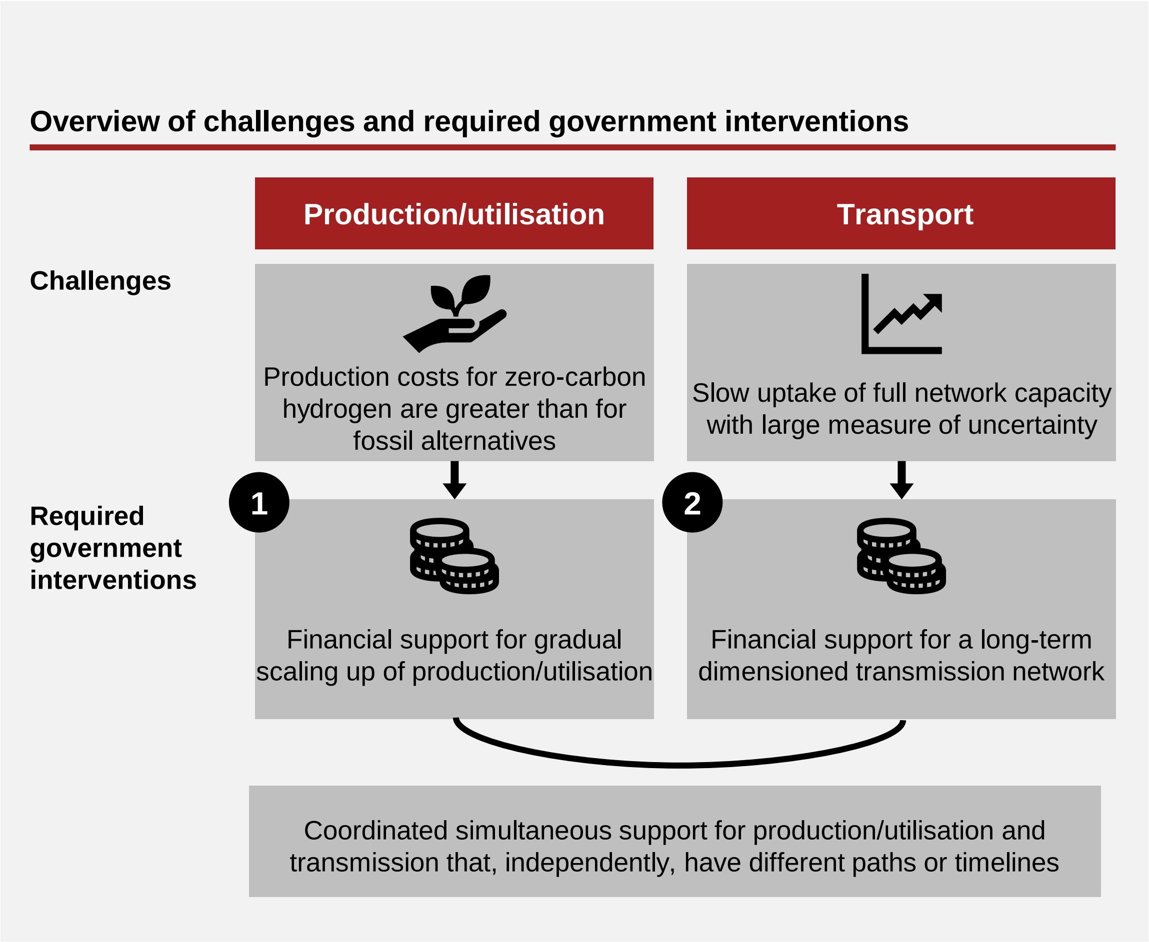
1. For the most recent insights into hydrogen storage, we refer the reader to TNO (2020c). This report examines in detail what is and is not possible with the various technologies. The report is in turn a summary of four in-depth studies on matters like the role of large-scale energy storage in the Dutch energy system and the risks associated with underground energy storage.

5 Policy challenges

HyWay 27

Investments in the repurposing of the natural gas network are not profitable because the supply chain still needs to be developed

Government interventions are needed to realise investments in repurposing



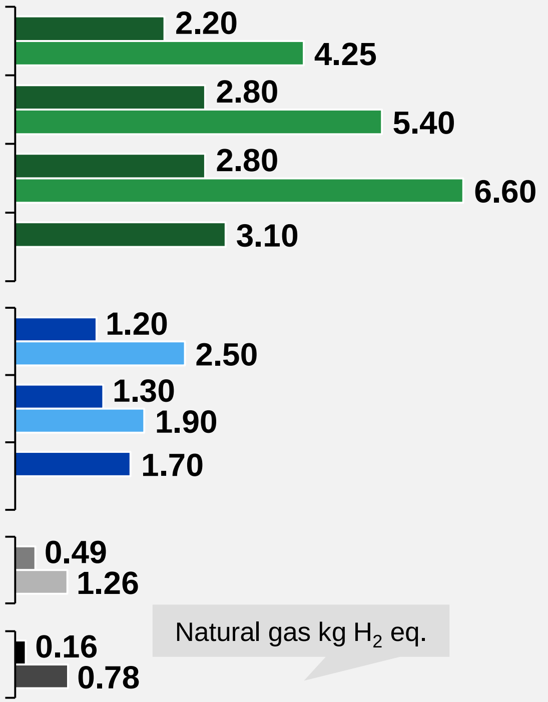
- The previous chapters show that transmission capacity is needed to connect the production and utilisation of hydrogen. The existing natural gas network appears to be suitable for repurposing for use as a hydrogen transmission network. Moreover, refurbishing the existing natural gas network is cheaper than constructing a completely new network.
- In this chapter we demonstrate that government intervention is necessary to mobilise investment in the refurbishment of the existing natural gas network and we discuss two reasons for government intervention, these being:
  1. Green hydrogen is currently much more expensive than fossil alternatives. Without financial support from the government, there will be little demand for green hydrogen.
  2. The optimum approach from a societal perspective is to dimension a pipeline for a transmission network in one go and in such a way that it will be sufficient to meet the expected long-term demand for transmission. Moreover, in the case of repurposing the natural gas network, the dimensions have already largely been determined, namely by the diameter of the pipes (which offer a lot of capacity). Utilisation of the full capacity of the transmission network will take a long time, with a large measure of uncertainty in this regard, which means that less is invested than is socially desirable.
- These two challenges are closely related: a market for green hydrogen cannot be created without a transmission network, and a transmission network cannot be established without market demand for transmission. Government support is needed on both sides of the supply chain. This requires coordination of the speed of support from both sides of the supply chain: at least a part of the transmission network will, preferably, be future-proofed in one go, while the demand for transmission will grow gradually.
- Although this chapter discusses investments in the refurbishment of the existing natural gas networks, the arguments in this chapter also largely apply to investments in new hydrogen transmission networks: we do not expect these investments to come about either without government intervention. It is not expected, in any case, that it would be economically worthwhile to develop several transmission networks in parallel. Typically, the total costs of operating one network are lower than operating multiple networks with comparable combined transmission capacity (subadditivity) (Depoorter, 1999).

Firstly, applications for zero-carbon hydrogen are not yet profitable, so there is no transmission demand

Currently, the costs of zero-carbon hydrogen are higher than those for fossil alternatives

Estimates of current production costs of hydrogen (excl. carbon pricing element)
(€ / kg H_2 [eq.]). Source: Piebalgs et al. (2020), PBL (2019).

Type of hydrogen	Source	Scenario	
Green	IRENA – wind	Low	2.20
		High	4.25
	IRENA – solar	Low	2.80
		High	5.40
	IEA	Low	2.80
		High	6.60
	Bloomberg	-	3.10
Blue	Bloomberg	Low	1.20
		High	2.50
	IRENA	Low	1.30
		High	1.90
	IEA	-	1.70
Grey	Gasunie/Strategy&	Low	0.49
		High	1.26
Natural gas	Gasunie/Strategy&	Low	0.16
		High	0.78



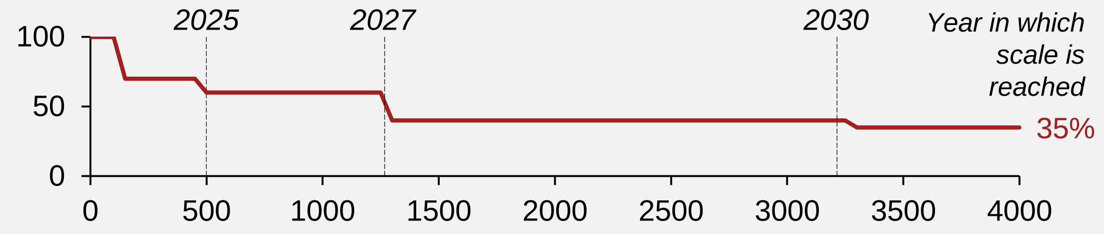
- The need for government interventions is firstly down to the fact that there is currently simply no demand for hydrogen transmission because there are, as yet, no profits to be made from the supply chain for green and blue hydrogen. Green hydrogen is currently between three and as much as ten times more expensive than grey hydrogen.
- The figure on the left shows the 'bare' costs of three colours of hydrogen in Europe in 2020 from different sources. These figures do not include transmission costs, any required modifications to end-user installations, or taxes (including carbon tax payments). Certain estimates include a bandwidth. This is because the price of electricity, natural gas and CO_2, the number of operating hours, and the options for CCS differ per location. As a result, the price for green hydrogen can be lower, for example, in countries with a low electricity price than in countries with a high electricity price.
- To realise investments in the use of green hydrogen, green hydrogen must be cheaper or no more expensive than blue or grey hydrogen. The figure on the left assumes new installations.

Sources: Green and blue hydrogen: Piebalgs et al. (2020). Cost-effective decarbonisation study. Natural gas and grey hydrogen: PBL Netherlands Environmental Assessment Agency (2019). Climate & Energy Outlook. For the sake of reference: the scenarios used in PBL's Climate & Energy Outlook are lower than the prices Gasunie estimates. For the low scenario, Gasunie assumes €15/MWh, which translates to €0.59/kg H2 eq. For the high scenario, Gasunie assumes €25/MWh, which translates to €0.98/kg H2 eq.

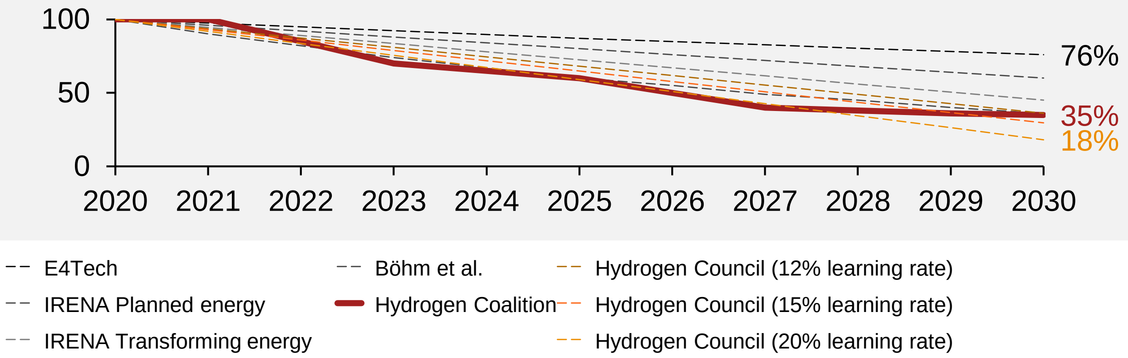
It is expected that the costs of zero-carbon hydrogen can decrease significantly by increasing the scale

Assuming a learning rate comparable to solar panels, electrolysis could be up to 80% cheaper by 2030

Capital cost reduction of electrolyser depending on installed capacity
(% capex per MW). Source: Dutch Hydrogen Coalition (2018)



Scenarios for capital cost reduction for electrolysers between now and end 2030[1] *(% capex per MW); Source:* *Dutch Hydrogen Coalition (2018); E4Tech (2014); Böhm et al. (2020), Hydrogen Council (2021); IRENA (2020)*



- Because electrolysis is currently only applied on a limited scale, the costs of the technology are high. Cost reductions are expected to be achieved through an increase in the average capacity of the electrolysers and the total installed capacity. The top figure on the left shows the expected cost reductions.
- Estimates of the exact potential reduction in costs vary. The bottom figure on the left shows the various estimates. The most conservative estimate is a 24% reduction in capital costs by 2030. At a learning rate of 20%, the capital costs of electrolysis could be as much as 80% cheaper by 2030. In comparison, solar panels have a learning rate of more than 20% (IRENA, 2020) and offshore wind 6 to 8% (TKI Wind op Zee, 2021)[2].
- However, investing in electrolysis is currently not profitable because the alternatives are cheaper, meaning that private parties will invest less in upscaling electrolysis capacity than is socially desirable. Financial support is needed to get investments off the ground and, by means of these investments, achieve the desired increase in scale and reduction in costs.
- In this report, we have aligned ourselves with the Dutch Climate Agreement target of realising 3GW to 4GW installed capacity (we assume 3.5GW) by 2030. In our further calculations we follow the upscaling and cost reduction as set out by the Hydrogen Coalition and the Dutch Climate Agreement (see top at the left)[4].
- In addition to capital costs, the costs of electrolysis are also driven by operational costs, of which the price of electricity is a large part. In addition, government policy contributes to the relative price of green hydrogen compared to alternatives.

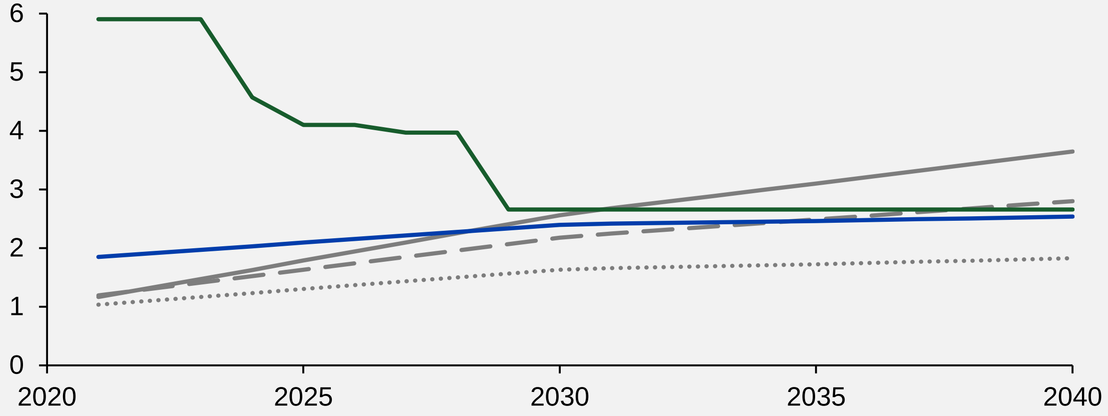
1. This refers specifically to PEM electrolysers. All curves refer to capex, with the exception of the E4Tech curve, which concerns total costs, including electricity costs. The curves are based on different assumptions about the installed capacity. 2. Learning rate (LR) shows the expected cost reduction at a doubling of the installed capacity (globally).

By financially supporting the roll-out and with other supporting policies the application of zero-carbon hydrogen can become profitable

Many studies show that green hydrogen will become profitable in the course of the 2030s

Development costs of hydrogen in various carbon price scenarios

(€ / kg H_2). *Source: Gasunie/Strategy& analyse based on PBL Netherlands Environmental Assessment Agency (2019; 2021), Dutch Hydrogen Coalition (2018), Dutch Climate Agreement (2019)*



Assumptions used in the graph: cost of grey hydrogen based on 'middle' natural gas price scenario in PBL Netherlands Environmental Assessment Agency's Climate & Energy Outlook. Electricity costs based on the 4,360 cheapest operating hours from APX over the last 10 years. Operating hours of electrolysers: 4,360. 65% capex cost reduction for electrolysers in 2030 based on Dutch Hydrogen Coalition (2018). Electrolysers in use for 15 years based on PBL Netherlands Environmental Assessment Agency (2020). The prices are based on production at a new plant. EU ETS 55% scenario follows the same annual increase as used for the national carbon tax.

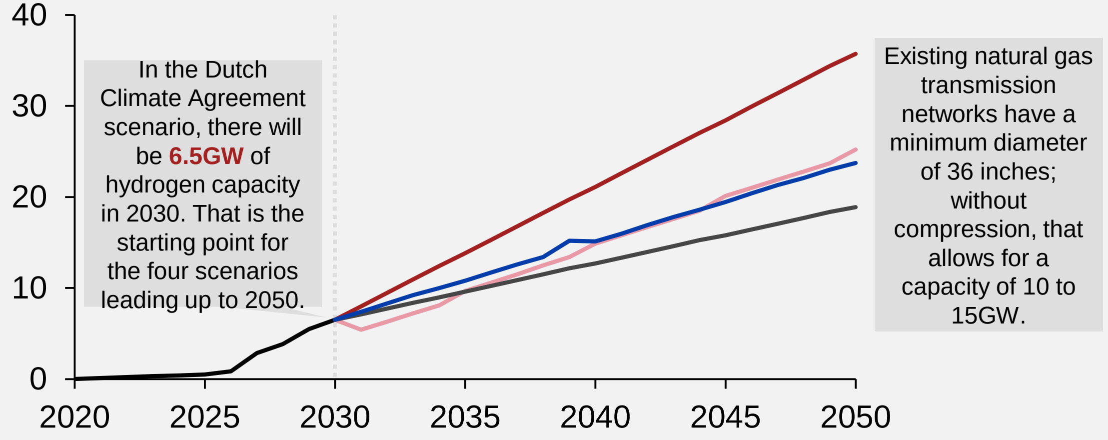
- Through financial support aimed at scaling up and cost reduction, the costs of zero-carbon hydrogen can eventually fall lower than those of fossil alternatives. In addition, putting a price on carbon emissions and other supporting policies regarding matters like standards or blending obligations are important for the relative business cases of the different colours of hydrogen.
- We have calculated the effects of a government-supported roll-out up to 2030, with a target of 3.5GW in 2030 and a cost reduction of 65%. We have taken into account different carbon pricing scenarios. Other supporting policy, such as in the area of standardisation, has not been included. The results are as follows:
  - Green hydrogen will become cheaper than grey hydrogen between 2031 and 2040;
  - Green hydrogen will not become cheaper than blue hydrogen any earlier than 2040.
- The carbon price is an important driver for determining when green hydrogen will become profitable. The higher the EU ETS price, the sooner green hydrogen becomes profitable (meaning less subsidy being required). The carbon price has no impact on the costs of green and blue hydrogen because the methods of producing such emit no (or virtually no) CO_2 into the atmosphere. With blue hydrogen, the level of emissions depends on the emissions that remain after capture. When pricing carbon, care must be taken to prevent 'carbon leakage', where polluting activities are relocated to another country[1].
- Other studies arrive at similar results. According to the Hydrogen Council, in the most optimistic scenario, green hydrogen will be cheaper than grey in 2030; in the most pessimistic scenario this will be in 2038. The World Energy Council predicts that green hydrogen will become profitable around 2030. IRENA's estimate is less optimistic: they anticipate that green hydrogen will be able to compete with grey hydrogen by 2040 (Hydrogen Council, 2021; World Energy Council, 2018; IRENA, 2020).

1. Due to the risk of carbon leakage, free EU ETS allowances are currently allocated for grey hydrogen production. See European Commission (2014). Commission Decision 2014/746/EU.

Secondly, the transmission grid is dimensioned for the long term, while demand arises very gradually

Long-term dimensioning means low utilisation of capacity in the first years as well as high risks

Illustration of the development of connected hydrogen capacity throughout the Netherlands[1] (GW) Source: *Gasunie / Strategy& analysis*



Assumptions used in the graph: Development up to the end of 2030 based on the central production scenario (Dutch Climate Agreement scenario) from IP2022. In addition to green hydrogen, this scenario includes blue hydrogen and imports. Blue hydrogen is not included in the scenarios for regional control and international control up to and including 2030. Growth up to 2050 based on the four scenarios set out under the II3050 project.

- Dutch Climate Agreement scenario from IP2022
- II3050 Europese sturing
- II3050 regionale sturing
- II3050 international control
- II3050 nationale sturing

- The second reason why investments in the repurposing of the transmission network are insufficiently realised is the mismatch between the dimensioning of the pipes and the development of demand (a long period until the full capacity is utilised). Investments must be made in a network of which it is known that the capacity is far too large at the moment, though that capacity will likely be needed at a later time.
- It is economically more advantageous to build an extensive transmission network all at once instead of building several smaller pipelines over time in order to gradually meet the expected long-term demand. This is because the capacity of a pipe increases quadratically with its diameter, while the costs increase nearly linearly. For example, to reach the capacity of one 36-inch pipeline (which is expected to be in full use well before 2050), six 16-inch pipelines are needed. In total, these six 16-inch pipelines will end up costing more than five times what it would cost to refurbish one 36-inch pipeline (Gasunie; Robinus et al., 2018).
- The demand for hydrogen transmission arises very gradually. The graph shows the Dutch Climate Agreement scenario from Gasunie's Investment Plan 2022 (IP2022) up to the end of 2030. This is the middle ground scenario in terms of expected hydrogen capacity. The graph shows the total hydrogen capacity connected to the grid (total of blue, green and imports). If all this capacity were to flow evenly through one pipeline, a 36-inch pipeline, which with compression can reach a capacity of 15GW, would be fully utilised between 2035 and 2045. However, this comparison does not provide a complete picture, because the connected capacity will not entirely flow through the network given that some of it will be consumed locally. Furthermore, the hydrogen may be able to move from the feed-in point to the grid exit point over different pipelines, meaning the capacity can be distributed over several pipelines. And, lastly, not all pipelines have a 36-inch diameter.

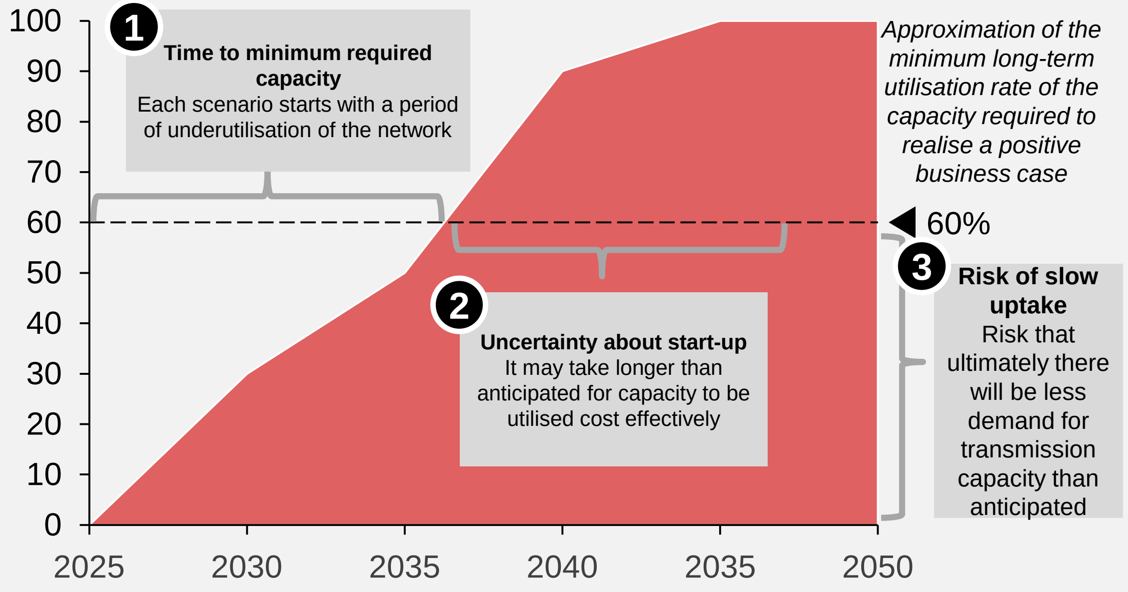
1. This hydrogen does not flow over a single pipeline: this is the total capacity connected to the Dutch grid. The entire volume of hydrogen in the Netherlands will not flow through the pipelines. The hydrogen capacity is derived from the number of PJ, by calculating using 31.54PJ/GW and a load factor of 0.51 for green hydrogen (Source: Gasunie).

To complete the business case for a long-term transmission network, financial support is needed

Without compensation for start-up and slow uptake risks, investments will be ‘too little and too late’ for the good of society

Illustration of start-up and slow uptake risks

Source: Gasunie (2021)



- Uncertainty regarding full uptake of transmission network capacity makes it difficult to start earning a return on investment when repurposing the pipeline. There is uncertainty about the degree of utilisation and about when full utilisation will be reached. Part of the uncertainty about this utilisation is caused by the government’s reluctance to commit: it cannot provide sufficient certainty in terms of whether there will also be sufficient support for the production and/or utilisation of hydrogen in the future, aspects required for creating transmission demand. Because the government is partly responsible for this uncertainty, there is a role for the government in offsetting some of the start-up and slow uptake risks.
- The figure on the left illustrates how the development of the utilisation of the pipelines is associated with risks for the investor in the transmission. There is a great deal of uncertainty about how start-up and utilisation of the pipeline will develop. This can lead to unrecoverable investment costs (in this report called the ‘unprofitable gap’). How much these will be depends on many unknowns, like the tariff the operators will be allowed to charge their customers.
- There are various measures the government can use to absorb some of the start-up and slow uptake risks, for example by providing guarantees, direct grants for capex or opex, loans with flexible terms and conditions, or capital contributions. Guarantees are an efficient solution, given that the government is providing a guarantee for risks that have arisen in part through its own policies. This would to some extent resolve the commitment problem.

6 Conclusions and recommendations

HyWay 27

The conclusions of HyWay 27 justify a decision in principle to use the existing natural gas networks for hydrogen transmission

1 Start with phased repurposing (‘decision in principle’)

Study topics and conclusions

	Key questions	Conclusions
1	**Do we need a transmission network for hydrogen, and if so, when?**	• In a climate-neutral economy, a pipeline-based hydrogen transport network is needed to efficiently connect consumers to suppliers of zero-carbon hydrogen and hydrogen storage facilities. • To achieve the ambitions for 2030, in the coming years transmission capacity aimed at facilitating the first large hydrogen projects will be needed. Transmission demand will also arise as a result of the need for storage.
2	**Can the existing natural gas network be used for hydrogen transmission, and if so, would that be desirable?**	• The existing natural gas network can be used to accommodate the interregional transmission flows that are expected in the long term: key pipelines can be freed up entirely and repurposed for hydrogen transmission. • Reusing existing natural gas grids is more cost-effective than laying new pipelines for hydrogen transmission. A transmission network connecting all industrial clusters to producers and storage locations requires an investment of around €1.5 billion.
3	**What government intervention will be required to create a transmission network for hydrogen?**	• The refurbishment of transmission networks requires a government intervention because investments involve a high risk of slow capital recovery due to slow uptake while also being strongly linked to the development of the hydrogen supply chain as a whole. • Our advice is to decide in principle to use part of the existing natural gas networks for the transmission of hydrogen. To achieve the 2030 ambitions, it is necessary to initiate decision-making now.

- The main question of the HyWay 27 study is whether, and under what conditions, part of the natural gas network can be used for the transmission and distribution of hydrogen. In this report, we argue that reusing the existing natural gas transmission networks would provide a cost-effective basis to accommodate the hydrogen flows expected to materialise in the long term. The table on the left summarises the main conclusions of the research for each secondary question. The analyses in this report justify an answer in the affirmative to the main question of this study.
- The exact nature of the hydrogen transmission network and how it will come about still needs to be determined. All the same, based on the ambitions for 2030, some of the demand for transmission will already arise in the next few years, meaning some choices will need to be made in the short term. Our advice is to decide in principle to use part of the existing natural gas networks for the transmission of hydrogen and to steer the further decision-making process towards working out the specifics (where, when) and implementation (who, how).
- In this chapter we make a number of recommendations for the realisation of a hydrogen transmission network based on the existing natural gas networks. This is structured as follows:
  – Decide where and when to roll out the network (‘what’);
  – Define the required market regulation for transmission (‘who’);
  – Make a plan to kick-start the integrated supply chain (‘how’ and ‘how much’);
  – Bring financial support into line with the ambitions (‘how much’).

There needs to be a roll-out plan that sets out how the transmission network will be rolled out and the principles behind this

2 Decide where and when to roll out the network ('what')

Questions to be addressed in the roll-out plan

1	What investments are needed and what is the required contribution from the government? What are the expected costs and benefits of these investments (societal and otherwise)?
2	Which consumers will be connected, and when can certain groups of consumers expect to be connected? What are the conditions for qualifying for a connection?
3	On the basis of which societal considerations (business case, system optimisation, level playing field) will the roll-out be based?
4	How does the envisioned hydrogen transmission network tie in with existing private hydrogen networks and proposed private investments? What can be done to prevent market distortion?
5	What are the technical prerequisites, for example with regard to availability of the existing pipelines, organisational capacity, etc.
6	How are uncertainties being dealt with? How certain is it that transmission demand will actually materialise and what can be done to influence this?

- The first question the government needs to answer is where and when to repurpose or build the transmission network. There is also a large measure of uncertainty about the pace at which transmission demand will develop. A roll-out plan should describe where and when the government wants to realise the hydrogen transmission network.
- A roll-out plan has several functions. Firstly, it should provide clarity to potential users of the network and, accordingly, offer certainty about investments. In this a balance must be struck between providing clarity on the one hand and leaving scope for including market developments as these emerge on the other.
- A second function of a roll-out plan is to clearly explain the considerations concerning the societal costs and benefits of the roll-out (and each variant of this). Based on the roll-out plan, it must be clear what the motives are for choosing one phasing option over another.
- A final function of a roll-out plan is to prevent market distortion. A number of clear, objective principles should be formulated based on which the roll-out takes place. In this way, market distortion and possible issues relating to state aid can be prevented.
- In this report, in line with the II3050 study, the TIKI report on the required infrastructure in the industry and other reports, we take as our starting point the hydrogen ambitions for 2030 agreed in the Dutch Climate Agreement. To achieve these 2030 ambitions, there needs to be a roll-out plan that describes the targeted contours of the transmission network in 2030, as well as the actions that will be needed for that already over the next couple of years.

A vision of the market regulation is desirable so that choices can be made concerning repurposing the transmission network in tandem with its operation

3 Define the required market regulation for transmission (‘who’)

Relevant market regulation questions for the hydrogen supply chain

***Main question*: what is the desired market regulation in view of the monopoly character in the long term?**

1 *Regulation of access and tariffs: Is it desirable to regulate access to the network (e.g. through tariff regulation)?*
By regulating access and tariffs, a network operator with market power can be prevented from excluding parties from the network. The EU Gas Directive specifies two types of third-party access regimes: regulated third-party access (as applies to natural gas transmission and distribution networks) and negotiated third-party access (as applies to natural gas storage). In Europe, discussions on how hydrogen should be regulated are currently under way. EU legislation will guide future Dutch legislation concerning hydrogen.

2 *Unbundling: Is it desirable to impose requirements with regard to the separation of the transmission operator from other supply chain activities (production and utilisation)?*
Through unbundling, the production and supply of hydrogen are separated from the operation of the pipelines. This can prevent an operator of a hydrogen network – which is essential for all hydrogen producers and consumers – from favouring its own production and supply activities or disadvantaging others. Cross-subsidy by charging the costs of the hydrogen network to the natural gas consumers is currently not permitted, unless the natural gas network users also benefit from the hydrogen network. There needs to be more clarity on this matter.

3 *Ownership: Is it desirable to impose further requirements on the property of the transmission network operator, for example that it be in public hands?*
From a political point of view, it may be desirable, considering the critical infrastructure aspect, to keep ownership of the hydrogen grid in public hands. This can prevent the owner of the network from cost cutting on quality aspects that are not observable/measurable based on commercial considerations. In addition to public ownership, requirements can also be imposed regarding which public party has ownership, such as a network operator.

- The market for hydrogen (zero-carbon or otherwise) is still in its infancy, but it is expected to grow strongly over the years. As the market grows, the demand for transport will increase and the transmission networks will then play an essential role in the hydrogen supply chain. There are two reasons to give consideration to the market regulation of transmission.
- Firstly, it is likely that market power will emerge in the long term, because in the long term it is expected that a single national hydrogen transmission network will be created, and because the networks are crucial for other parts of the supply chain. A comparable situation can be seen with electricity and natural gas transmission. With market power the owner of the transmission network can gain a dominant position and, as a result, charge prices that are too high, lower the quality or exclude consumers from the network. There are three possible instruments to address market power (as shown on the left): regulation of access, unbundling, and public ownership.
- Secondly, it may be desirable for political reasons to have the transmission networks under public ownership. Out of political preference certain critical processes are in public hands; 20% of the processes the Dutch National Coordinator for Counterterrorism and Security [NCTV] deems to be critical, including electricity and natural gas transmission, are in public hands[1]. Public ownership also gives more room to manoeuvre on ‘non-contractable interests’. Activities in which the public interests cannot be defined or monitored as quantifiable targets cannot or are difficult to set out in a contract. In those cases, the government can provide more guidance through public ownership[2].
- It makes sense when it comes to financial support for hydrogen transmission to take into account what the desired market regulation is. The party or parties receiving support for the transmission will be responsible for refurbishing the natural gas networks (and possibly in the longer term operating these).

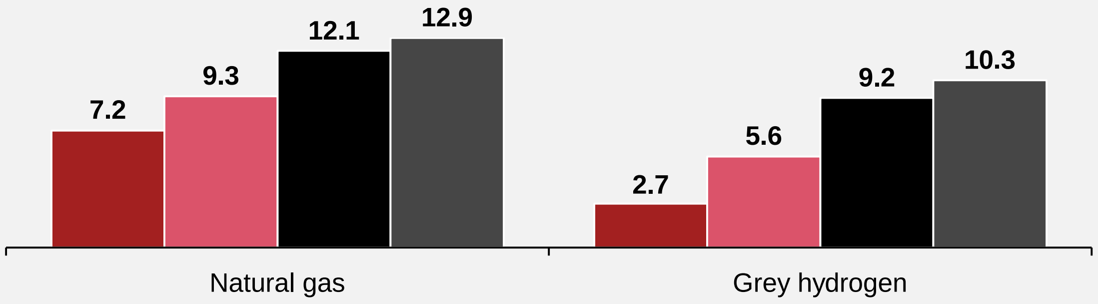
1. NCTV (2021). *Versterkte aanpak beschermen vitale infrastructuur* [Strengthened approach protects critical infrastructure]. 2. Dutch Ministry of Economic Affairs and Climate Policy (2006). Deelnemingenbeleid Rijksoverheid: Brief minister ter aanbieding rapport ‘Publieke belangen en Aandeelhouderschap’ [National government participation policy: letter from the Minister to present the report ‘Public interests and shareholdings’].

Clarity is needed on the available financial support for the entire supply chain

4 Make a plan to kick-start the integrated supply chain ('how' and 'how much')

Indicative amount of subsidy needed for electrolysers installed up to and including 2029 to realise 3.5GW capacity compared to natural gas or grey hydrogen under various carbon price scenarios[1] *(in € billion).*
Source: Gasunie/Strategy& analyse based on PBL Netherlands Environmental Assessment Agency (2019; 2021); Dutch Hydrogen Coalition (2018)

The amounts show the difference in costs between producing green hydrogen compared to producing the same amount of grey hydrogen or natural gas in hydrogen equivalents. The quantity produced is based on the electrolysis capacity, which will increase to 3.5GW in 2029



Assumptions used in the graph: costs of grey hydrogen based on the Climate & Energy Outlook natural gas price scenario 'middle' to 2030 and World Energy Outlook 'middle' from 2031. Cost of electrolysis based on PBL's SDE++ 2021 final opinion document. Electricity costs and capex/opex per kg of H_2 based on 4,360 operating hours for the electrolyser. 65% capex cost reduction for electrolysers in 2030 based on Dutch Hydrogen Coalition (2018). Electrolysers in use for 15 years based on PBL Netherlands Environmental Assessment Agency (2020). EU ETS 55% scenario starts at €30 in 2021 and follows the same increase as for the national carbon tax (€10.50/year).

Legend: Carbon pricing scenario

EU 55% | PBL high | PBL low | No carbon pricing

- It is clear that hydrogen is an essential building block in achieving a climate-neutral economy. Hydrogen also offers economic opportunities, including for industry and for positioning the Netherlands as a feedstock hub for northwestern Europe. To get new, hydrogen-based supply chains off the ground, a broad mix of policy instruments , is required, including pricing and emission standards and financial support. The precise design of this and the level of ambition that leads to the best societal cost-, benefit ratio have not been the subject of this study.
- Ambitions for 2030 have been stated in the Dutch Climate Agreement and the Government Strategy on Hydrogen, including the joint ambition to start a cost reduction programme for electrolysis with a target of 3GW to 4GW installed capacity by 2030. To realise this ambition, depending on the design of supporting policy, a lot of financial support from the government is needed to cover the unprofitable gap. However, it is currently unclear whether that money will actually be made available.
- In the figure on the left, an indicative estimate is made of the subsidy required to realise 3.5GW of electrolysis capacity by 2030. For different carbon prices, the difference has been estimated between hydrogen based on electrolysis and the main alternatives (grey hydrogen or the use of natural gas instead of hydrogen). It follows from this comparison that, in terms of subsidy, a cumulative amount of at least between €2 billion and €13 billion is required (between 100 and 650 million euro per year over a period of 20 years). Costs for modifying consumer installations and transmission costs are not included in these figures.

1. Bandwidth depending on, among other things, carbon price and the application. The comparison with grey hydrogen can be used for applications using hydrogen as a feedstock; the comparison with natural gas can be used for energy applications (in industrial boilers for example). 2. See European Commission (2014). Commission Decision 2014/746/EU.
Sources for the top figure at the left: PBL Netherlands Environmental Assessment Agency (2019). Climate & Energy Outlook, PBL Netherlands Environmental Assessment Agency (2021). *Eindadvies SDE++ 2021* [SDE++ 2021 final opinion] Hydrogen Coalition Manifesto

It is desirable to design the financial support based on a broad vision of kick-starting the hydrogen supply chain

4 Make a plan to kick-start the integrated supply chain ('how' and 'how much')

Relevant questions about financial support for the hydrogen supply chain

Entire supply chain

- What are the objectives of the financial support? Is this intended to reduce costs in the supply chain, to cut carbon emissions, or to promote innovation?
- How are the support of production, transmission and utilisation related? Is it possible to subsidise utilisation (supply chain terminal) only? Why or why not?

Production/utilisation

There are various questions regarding support of production/utilisation:

- *Production or utilisation*: are producers or consumers supported? What are the advantages and disadvantages?
- *Allocation mechanism:* how is it determined which projects receive a grant and how much they receive (phased registration such as SDE ++; other approach)?
- *Competition between technologies:* is competition for grants between hydrogen (green or other) and other technologies desirable, and how does this relate to the roll-out of the 3GW to 4GW target?

Transport

There are two routes for transmission support:

- *Tendering*: are there options for putting parts of the transmission network out to tender? What are the advantages? Is tendering feasible in view of the desired timelines? Is this desirable considering the long-term market regulation?
- *Assigning*: if financial support is not awarded in an open and transparent manner, how can efficient use of public funds be ensured? What role can supervision, regulation and incentives play in this?

- In addition to a decision on the amount of financial support that will be made available, a decision on the 'how' is also needed: what is needed is a plan indicating with which instruments the supply chain can best be supported.
- In theory, subsidy to cover the unprofitable gap of the entire supply chain could be passed on to the end user (demand-side subsidy). In theory, this is an effective instrument because it allows consumers to pay for other parts of the supply chain themselves. However, the development of the production and utilisation of hydrogen proceeds step by step, while a pipeline is preferably constructed in one go and dimensioned for the societal demand in the long term. With this in mind, it is probably necessary to subsidise transmission separately, in addition to subsidising the rest of the supply chain.
- It is therefore desirable to ask the question, for each supply chain component, which instruments best match the objectives (and make clear what the objectives actually are). For example, is it desirable to subsidise the production or utilisation of zero-carbon hydrogen, and which allocation mechanism is suitable for awarding grants? For transmission, some of the questions include whether there are any opportunities for tendering, and to what extent this contributes to the possible objectives. The table on the left provides a sampling of relevant questions.
- Finally, the financial support for the supply chain must be considered in conjunction with other financial and non-financial instruments. For the production and utilisation of hydrogen, this means, in addition to grants, possibly also carbon pricing and possibilities for standardisation (a blending obligation for example).

There are various options for providing support to absorb some of the slow-uptake risks for transmission

4 Make a plan to kick-start the integrated supply chain ('how' and 'how much')

Investment costs of energy transition projects in perspective
Source: DNV GL (2020a) and HyWay 27

	Energy transition initiative	Investment (in euros)
1	Hydrogen transmission: realising the connection of all industrial clusters on the basis of repurposing an existing natural gas network into a hydrogen network	€ 1.5 billion
2	Dutch offshore grid: construction of the infrastructure for the offshore grid by TenneT (by 2030)	€ 7 billion
3	Investments in onshore electricity grid by TenneT	€ 5.5 billion
4	CCS infrastructure for Porthos and Athos projects (CCS)	0.5-1.5 billion euros
5	Construction of infrastructure for high and low-temperature heat (including residual heat)	0.3-2.4 billion euros

The investment amount for initiative 1 is based on research findings in this HyWay 27 study (chapter 4). The amounts for initiatives 2 to 5 are taken from DNV GL.

- The total investment for a national hydrogen transmission network, based on the existing natural gas infrastructure, which connects all clusters with each other, to storage and to other countries, would amount to about €1.5 billion. The table on the left provides a comparison of the total investment costs of a number of infrastructure projects in the energy transition.
- Although the total investments for completing a hydrogen transmission network may be lower than some of the other examples in the table, the risk of slow capital recovery due to slow uptake are relatively high. It is still very uncertain how the demand for hydrogen transmission will develop. As a result of these uncertainties, some of the costs of investment in the hydrogen transmission network will not be recoverable (the 'unprofitable gap'). Gasunie's preliminary findings are set out in Appendix 4.
- To encourage investments, it is necessary to partially assume or compensate for the risks such as the risk of slow uptake. To do that, the government has several options such as:
  - guarantees
  - grants for capital expenditure
  - guarantee + annual totex allowance
  - possibly cross-subsidies with the natural gas transmission network or maximising economies of scale with the natural gas transmission network. These options are only possible if European regulations are amended given that cross-subsidy is currently not permitted
  - combination(s) of the options stated above.

Source for investment amount for initiative 1: Gasunie. Source for investment amount for initiatives 2 to 5: DNV GL (2020a). *Taskforce infrastructuur Klimaatakkoord industrie – meerjarenprogramma infrastructuur energie en klimaat* [Industry climate agreement infrastructure task force – multi-year programme for energy and climate infrastructure] (p. 41).

A Appendices

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(1/4)

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For the illustrative model of the 2030 hydrogen network, assumptions have been made based on the government ambition and IP2022

Overview of hydrogen supply and demand assumptions in an illustrative model for 2030 hydrogen network

Parameter assumptions for an illustrative model of the 2030 hydrogen network
Supporting material for section 3.3. Source: 2022 IP (2020), Gasunie, Strategy&

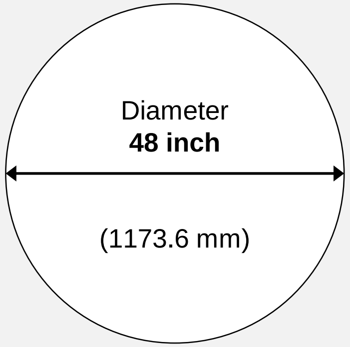
		Capacity (GW) & annual volume (PJ)						Regionalisation								
		Conservative		*Medium*		*Progressive*		*NN*	*Rotterdam*	*Chem.*	*Zeeland*	*NSCA*	*Den Helder*	*DE*	*BE*	*Total*
		(GW)	*(PJ)*	*(GW)*	*(PJ)*	*(GW)*	*(PJ)*									
Central supply	**Green**	1.5	16.8	3.5	39.2	3.5	39.2	71%	17%	-	6%	6%	-	-	-	100%
	Blue	-	-	-	-	1.5	47.3	-	50%	-	-	-	50%	-	-	100%
	Imported	-	-	-	-	1.5	47.3	15%	40%	-	30%	15%	-	-	-	100%
Demand	Domestic	-	12.6	-	29.4		100.4	18%	41%	11%	22%	9%	-	-	-	100%
	Export	-	4.2	-	9.8		33.5	-	-	-	-	-	-	90%	10%	100%
Total demand/supply		**1.5**	**16.8**	**3.5**	**39.2**	**6.5**	**133.8**									

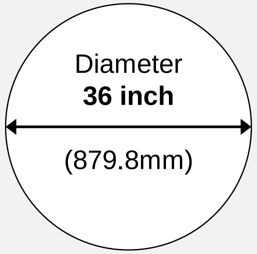
- General assumptions for all scenarios:
  - Green hydrogen: capacity refers to electrolysis capacity. Production based on 2015 wind profile, with 4,150 full load hours, 25% conversion loss and fixed distribution across industry clusters based on a Gasunie forecast that indicates which projects will proceed between now and 2030.
  - Blue hydrogen: 1.5GW outflow capacity only in the progressive scenario (losses have already been deducted from this). Profile: baseload.
  - Imported hydrogen: only in the progressive scenario. Profile: baseload.
  - Export: in all scenarios 25% of the total supply of green, blue and imported. Profile: baseload.
  - Demand in the Netherlands: distribution of remaining supply across industry clusters based on distribution used for IP2022. Profile: baseload.
  - Transmission: the spreadsheet model optimises (i.e. minimises) the total transmitted hydrogen volumes per route. In two-way transmission, each direction is counted separately.
  - Storage: the storage location is modelled as a separate hub so that transmission volumes to and from the storage location can be calculated.

Key figures for theoretical capacity and annual volume of a single hydrogen transmission pipeline

Capacity and maximum annual volumes at different combinations of diameter and pressure

Indicative capacity and annual volume of a single hydrogen transmission pipeline *Source:* *Gasunie*





Pressure range (entry-exit point)	**30-10** bar(a)	**50-30** bar(a)	**65-45** bar(a)
48-inch pipeline			
Capacity	13.6GW	19.2GW	22.5GW
Maximum annual volume (based on 8,760 hours)	428PJ	605PJ	709PJ
36-inch pipeline			
Capacity	6.4GW	9.1GW	10.6GW
Maximum annual volume (based on 8,760 hours)	201PJ	286PJ	334PJ

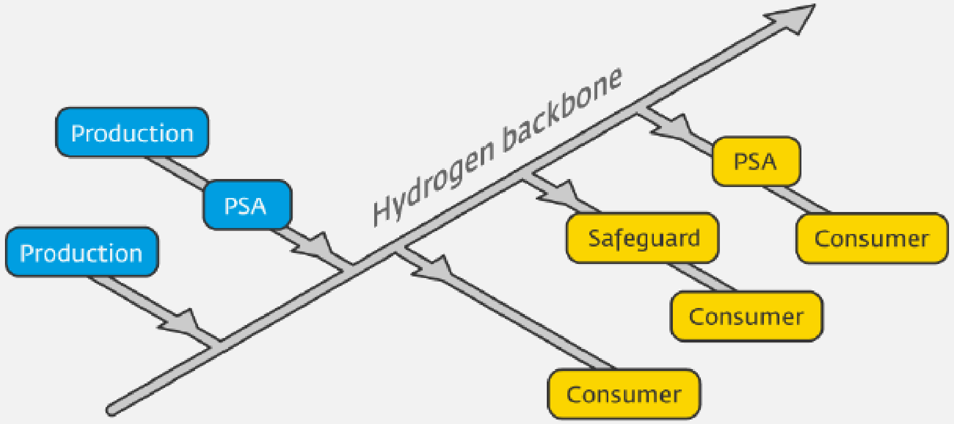
- The figure on the left shows for two pipeline diameters (48 and 36 inches) and three different system pressure scenarios (30-10, 50-30 and 65-45 bar[a]) the maximum transmission capacities and annual volumes for a single pipeline.
- This overview is based on an indicative single pipeline with a length of 100km and a pressure difference at the entry and exit points of 20 bar(a). The values for capacity and annual volumes shown are theoretical and indicative only.
- In a gas transmission network, in practice there is a balance between supply and demand and this balance determines the pressure at any given point in the network. The maximum possible transmission volume between network points is, therefore, determined by the pressure difference between these points. This pressure difference will for most transport routes within a network be (much) lower than the system pressure range (of 20 bar[a]). This means that the maximum capacity of a pipeline included in a network will also be lower than the maximum capacity of the same pipeline were it to have as differential pressure the full system pressure range at its disposal.
- Gasunie’s intention is to operate hydrogen transmission pipelines at a maximum operational pipeline pressure of 50 bar. If desired, the capacity of these pipelines can be increased at a later stage by using a higher operating pressure (the design pressure for the existing transmission pipelines is 66 bar).

Source: Gasunie.

Explanation of the choice and options still to be made for the required quality of hydrogen in the national transmission network

Gasunie's investment estimate provisionally assumes a quality of at least 98%

Illustration of possible installation of quality treatment technologies at producer and/or customer end *Source:* *Gasunie*



- The government has not yet made a choice with regard to the quality of hydrogen as this is currently specified for natural gas in the Ministerial Decree on Natural Gas Quality. The possibilities in the production of hydrogen and the needs of the customers will largely determine the quality of hydrogen that will be required. Certain baselines are essential in this respect; for example it is important to choose a quality with which the largest part of the market can be supplied at the lowest possible cost and which also aligns with the choices made in neighbouring countries.
- Hydrogen can be produced using several technologies, with which a very high purity (at least 99%) – often with the application of downstream technologies – is possible. Different hydrogen qualities are required for different industrial applications. For example, a relatively low quality of hydrogen (at least 95%) is sufficient for combustion processes, while fuel cell applications require a very high quality (at least 99.97%).
- Given that it is not possible to produce and transport 100% pure hydrogen, quality treatment of hydrogen will be required to a greater or lesser extent. This can be done both at the feed-in side of the system (entry point) and at the point of consumption (exit point). Technologies for quality treatment (purifying the hydrogen sufficiently to meet manufacturers' warranty requirements using pressure swing absorption for example) and for quality control (monitoring) are already available.
- In view of the costs for treatment, the central purification of hydrogen is, in general, more cost-effective than bringing the hydrogen 'on-spec' on location at individual customers. However, the need to purify hydrogen will depend on the hydrogen market and developments in this market.
- On the basis of exploratory market research and a few standards for user installations, it appears that there is currently no explicit preference for a specific quality. For the time being Gasunie has assumed a quality of at least 98% in its investment estimate.[1]

1. A couple of examples of existing standards are 'BSI PAS 4444 Hydrogen fired gas appliances Guide' and 'ISO 14687 Hydrogen fuel quality – Product specification'. In the UK, DNV GL has drawn up a draft hydrogen purity specification that assumes a minimum purity of 98% (DNV GL, 2019b). In Belgium, Flyxus is currently also assuming at least 98% in its quality specification proposals (Fluxys, 2021).

Possible methodology to estimate the unprofitable gap component for the transmission grid and preliminary indicative findings

Uncertainty on the development of the hydrogen market makes it difficult to determine how much the unprofitable gap will be

Proposed assumptions for the calculation of the business case by Gasunie
Source: Gasunie

1. Concerns the entire national 'hydrogen backbone'
2. Investment = €1.5 billion; 2021 price level
3. OPEX (maintenance, organisation, dispatch): 1% of the new value of the investment
4. WACC: 6%
5. Indexation: 1.5%
6. Depreciation = 30 years
7. Period of cash flow calculation = 30 years
8. Not taking into account locations of supply/demand
9. Supply (scenarios) = demand (regardless of whether demand comes from outside the Netherlands)
10. Simplification of tariffs by adopting a predetermined uniform tariff (single fixed tariff)
11. Income = volume X simplified fixed tariff per KW
12. The bandwidth of the tariff ensures that the market bears part of the risk

Calculation method

- The unprofitable gap of the transmission network is the difference between the expected return on the investment and the return that an investor should reasonably be able to make given the risks of that investment.
- According to Gasunie, the capital costs of a national transmission network, based on the existing natural gas infrastructure, which connects all clusters with each other, to storage and to other countries, would be around €1.5 billion. The operational costs are approximately 1% of the value of a new pipeline.
- However, the returns on the network are very uncertain. Revenues are a product of the future volume and the tariff applied, both of which are still unknown. The volume depends on an as-of-yet unknown demand for hydrogen transmission. The per-KW tariff depends on the volume over which the costs can be spread. This tariff cannot be higher than the amount users of the network are willing to pay, because otherwise there will be no demand for transmission.
- Revenues can be approximated by using scenarios for the development of hydrogen capacity between now and 2050 and applying a fixed tariff, for example the tariff required to cover the costs at 60% utilisation of the capacity.

Indicative findings

- With the II3050 scenarios used on page 91 for the development of hydrogen capacity, Gasunie estimates that the revenues from the grid should be sufficient to cover the costs. This includes a reasonable return on investment and the assumption that the tariff will be set based on what is required at a capacity utilisation of 60%. In this case, there is no unprofitable gap. However, the materialisation of these scenarios is so uncertain that an investor cannot currently make a positive investment decision on the refurbishment of the existing natural gas network.
- The size of the unprofitable gap depends largely on the actual development of the hydrogen market and is therefore difficult to estimate. Regardless of the size of the unprofitable gap, currently no investments in hydrogen transmission are being made given the large degree of uncertainty. This risk should be shared with the government.

Disclaimer

In July 2020, the Dutch Ministry of Economic Affairs and Climate Policy (hereinafter called the 'client') engaged PricewaterhouseCoopers Advisory N.V., acting under the name Strategy&, (hereinafter called 'PwC', 'we' or 'us') to carry out the assignment in accordance with the engagement letter signed on 24 July 2020.

At the request of the client, PwC has drawn up a public report entitled ‘HyWay 27: hydrogen transmission using the existing gas network?’, dated 30-6-2021 (hereinafter called the ‘report’). The report is addressed to the client for the purpose of being published on behalf of the Dutch House of Representatives.

In compiling the report, PwC has based the content (in part) on documents and information that PwC has received from various parties (including the client) (hereinafter called ‘third party information’). PwC has used the third party information on the assumption that this information is correct, complete and not misleading. The reliability of the third party information has not been verified or established by PwC. PwC has not performed an audit of the third party information, nor a review aimed at determining its completeness and correctness in accordance with international audit or review standards. PwC makes no representation or warranty, express or implied, regarding the accuracy or completeness of the third party information or related references in the report.

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