State of the art, applicability, and potential challenges and benefits

Study on offshore hydrogen blending

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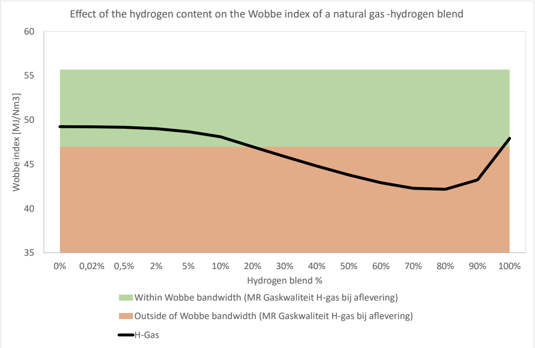
1 Executive summary

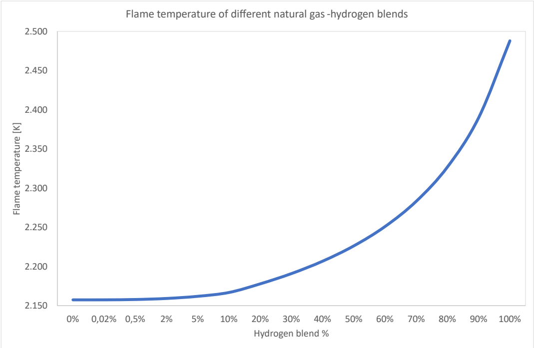
In line with the Dutch ambitions to unlock the potential of offshore hydrogen production in the North Sea, the Dutch Ministry of Economic Affairs (MinEZK) is planning to support two pilot projects for offshore hydrogen production. One of them (called DEMO 1) is expected to have a capacity of less than 100 MW (between 50 and 100 MW). In order to refine the plans of DEMO 1, MinEZK is exploring the possibilities for transporting the hydrogen produced in DEMO 1 to shore.

The goal of this study was to explore the possibilities around transporting hydrogen by blending it in offshore natural gas pipelines. A study was conducted on the following aspects:

1. Hydrogen blending and consequences of using the blends directly
   a. Impact on the properties of natural gas
   b. Impact on the equipment and materials of network operators and end users
   c. Impact on the economic value of natural gas
   d. Impact on existing legislation around natural gas purity
2. Hydrogen blending and deblending onshore
3. Potential locations for hydrogen blending and deblending

On the topic of the properties of natural gas[1], hydrogen blends with a low blend % (e.g., below 10%) are shown to have little impact on the Wobbe index, the flame temperature (thus little impact on the potential NOx emissions), and the burning velocity of natural gas.





Moreover, low hydrogen blend % seem to have little impact on materials and components of natural gas network operators and (most) end users. Special attention needs to be paid on the impact of compressors and gas quality sensors in gas networks. End users that could be impacted by hydrogen blends (even of low %) include feedstock users, gas turbine operators, and compressed natural gas users (e.g., vehicles). On the topic of certification, operation of hydrogen blends in burning equipment could require a new environmental permit depending on parameters such as hydrogen blend % and equipment size. Moreover, use of hydrogen blends require a reassessment according to the ATEX Directive, both as a

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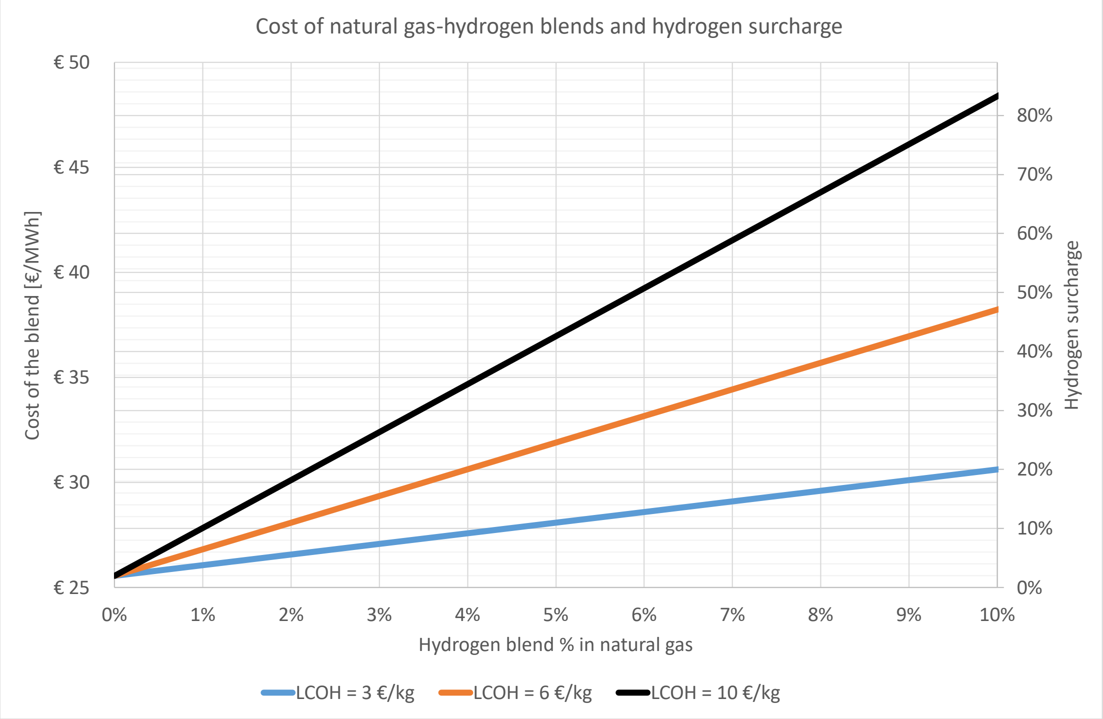
[1] In this report, the basis natural gas composition used as a reference for the calculations was a high-caloric natural gas (H-Gas) used in a report by DNV. The details of the composition are shown in the corresponding section.

result of potential changes in the hazardous zones, and in the equipment used in hazardous areas.

Blending hydrogen in natural gas has an impact on the cost of hydrogen-natural gas blends e.g., per unit energy. For example, we calculated that even low-hydrogen blends (e.g., 5%) could increase the cost of the energy by between 10 and 40% with respect to hydrogen-free natural gas; this depends strongly on the cost of the hydrogen produced (LCOH).



On the topic of hydrogen deblending, we reviewed three technologies: Pressure Swing Adsorption, Membrane Separation, and Cryogenic Distillation. All three are commercially mature and are currently deployed in industry for the separation of hydrogen from mixed gas streams. All three technologies (or a combination thereof) can in principle be used to separate hydrogen from natural gas even at low hydrogen blend %. The costs of hydrogen deblending depend on parameters such as the hydrogen blend %, the required purity of the hydrogen, the required purity of the hydrogen-free natural gas, the pressure at inlet and outlet, and the flow of hydrogen.

Furthermore, we found that hydrogen deblending from low-hydrogen blends is significantly more expensive than the cost of hydrogen-free natural gas, and even potentially higher than the expected costs hydrogen production from DEMO 1.

<table>
<tr><th>Cost of hydrogen deblending under different scenarios

1 million Nm3/day H2 production (~200 MW electrolysis installed capacity)

Inlet hydrogen blend = 5%</th><th colspan="3">2 bar outlet

(Excluding compression needed to reach 50 bar to inject to the Waterstofnetwerk Nederland)</th><th colspan="3">20 bar outlet

(Excluding compression needed to reach 50 bar to inject to the Waterstofnetwerk Nederland)</th></tr>
<tr><td>30 bar hydrogen inlet (expected operating pressure of an electrolyser) – <u>only deblending</u></td><td colspan="3">10-14 €/kg (deblending only)
(254-355 €/MWh)</td><td colspan="3">13-17 €/kg (deblending only)
(330-432 €/MWh)</td></tr>
<tr><td rowspan="2">30 bar hydrogen inlet (expected operating pressure of an electrolyser) – <u>production + deblending</u></td><td>LCOH = 3 €/kg</td><td>LCOH = 6 €/kg</td><td>LCOH = 10 €/kg</td><td>LCOH = 3 €/kg</td><td>LCOH = 6 €/kg</td><td>LCOH = 10 €/kg</td></tr>
<tr><td>13-17 €/kg (330-432 €/MWh)</td><td>16-20 €/kg (406-508 €/MWh)</td><td>20-24 €/kg (508-610 €/MWh)</td><td>16-20 €/kg (406-508 €/MWh)</td><td>19-23 €/kg (483-584 €/MWh)</td><td>23-27 €/kg (584-686 €/MWh)</td></tr>
</table>

Finally, we carried out a survey of the Dutch national database of offshore oil and gas assets (NLOG) in order to identify potentially suitable offshore pipelines and onshore gas processing facilities for hydrogen blending and deblending. We identified six main offshore pipelines where hydrogen blending could take place:

- The W09 pipeline (WGT)
- The NP007 pipeline (LoCal)
- The TP-001 pipeline (NOGAT)
- The NP-001 pipeline (NGT)
- The DPL-15D1 pipeline (TAQA)
- The W41 pipeline (Wintershall)

We estimated the natural gas flows through each pipeline using publicly-available information, and with this information we calculated the expected hydrogen blend % that could result in the case that hydrogen from DEMO 1 is blended in each of the pipelines.

Electrolyser operating capacity	Max. hydrogen blend per pipeline considering a 25% bandwidth of the natural gas flows through each offshore pipeline						
Average expected throughout the year (50%)	Electrolysis capacity	W09 (WGT)	NP007 (LoCal)	TP-001 (NOGAT)	NP-001 (NGT)	DPL-15D1 (TAQA)	W41 pipeline (Wintershall)
	50 MW	1,78-2,93%	8,38-13,22%	0,96-1,59%	1,16-1,91%	28,57-40,00%	14,86-22,54%
	100 MW	3,50%-5,69%	15,46%-23,36%	1,90%-3,13%	2,29%-3,76%	44,44%-57,14%	25,88%-36,78%
Installed electrolysis capacity	Electrolysis capacity	W09 (WGT)	NP007 (LoCal)	TP-001 (NOGAT)	NP-001 (NGT)	DPL-15D1 (TAQA)	W41 pipeline (Wintershall)
	50 MW	3,50%-5,69%	15,46%-23,36%	1,90%-3,13%	2,29%-3,76%	44,44%-57,14%	25,88%-36,78%
	100 MW	6,76%-10,77%	26,78%-37,87%	3,73%-6,07%	4,47%-7,24%	61,54%-72,73%	41,11%-53,78%

2 Introduction

Hydrogen is set to play an important role in the transition towards a carbon-neutral energy system. Countries around the globe are recognizing the potential of this technology to reduce the carbon footprint and start their journey towards energy transition. Offshore hydrogen production is seen as one of the main enablers to unlock the potential of offshore wind energy around the North Sea. Currently, there are several developments, pilots, and demonstrations being performed and reported on the topic of offshore hydrogen production.

The Netherlands has set ambitious goals to decarbonize their energy system through the rapid uptake of green hydrogen in the Dutch energy mix. For example, targets have been set to achieve 500 MW of electrolysis capacity for domestic hydrogen generation by 2025 and 3 – 4 GW by 2030. There are arguments that indicate offshore hydrogen production can be an economic and societal benefit over onshore hydrogen production due, among other reasons, to issues such as land use, permitting, and cost of the expansion of energy (electricity or gas) transport networks.

In line with the Dutch ambitions to unlock the potential of offshore hydrogen production in the North Sea, the Dutch Ministry of Economic Affairs (MinEZK) is planning to have two pilot projects for offshore hydrogen production. The first one (code-named DEMO 1) will have a capacity of less than 100 MW, it is expected to be located somewhere in the West of the Netherlands (near the operating offshore wind park areas Hollandse Kust Noord and Hollandse Kust West); DEMO 1 is expected to be operational in 2027-2029. The second pilot project (code-named DEMO 2) is aimed to have a capacity of 500 MW, is expected to be located to the North of the Netherlands in the area known as TNW (Ten Noorden van de Wadden), and aims to be operational in 2031-2033. According to a recent interest consultation that the Dutch government carried out[2], both pilot projects seem to have attracted positive attention from stakeholders and there are discussions ongoing on what is the best way to carry out both DEMO 1 and DEMO 2 projects.

Once hydrogen is produced offshore, it must be transported to shore. There are two options for transportation: either as pure hydrogen (i.e., in dedicated pipelines offshore), or as a mixture with natural gas (i.e., in the existing offshore natural gas infrastructure). Since there is currently no dedicated offshore hydrogen infrastructure offshore, any pure hydrogen pipeline offshore needs to be built either new or based on repurposing existing natural gas assets. This situation has particular effects on the DEMO projects planned by MinEZK: a decision needs to be made in a short time to select the best option for transporting the hydrogen for DEMO 1 and DEMO 2, where one option is to commission the development of dedicated hydrogen infrastructure that can be connected with the onshore dedicated hydrogen infrastructure i.e., the Dutch Hydrogen Backbone or 'Waterstofnetwerk Nederland', which is currently in construction and is expected to be operational by 2030.

A second option is blending hydrogen with the natural gas produced offshore and transported to shore in existing pipelines. Blending hydrogen into the existing natural gas

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[2] RVO (Netherlands Enterprise Organisation). Interessepeiling: waterstofproductie op zee. https://www.rvo.nl/onderwerpen/waterstof/interessepeiling-waterstofproductie-op-zee

pipeline can be considered as an attractive solution for the transportation of the renewably produced hydrogen in the DEMO 1 and DEMO 2 projects because it could lead to decreased costs of commissioning dedicated infrastructure as well as operation in a shorter time. This could be an attractive solution in the near future as a possibility to transport hydrogen. Once blended, there are two options: either to directly sell the hydrogen-natural gas blends (injecting it in the onshore natural gas network or selling it directly to a consumer), or to deblend the hydrogen from the natural gas stream and e.g., sell the hydrogen directly or injecting it into the Dutch Hydrogen Backbone.

This report focuses on the potential challenges of hydrogen blending and deblending i.e., blending hydrogen with natural gas streams and then (possibly) deblending the mixture at the landing point. In particular, this report addresses the following research objectives and questions:

Research objectives admixing/blending

- Estimate the maximum amount of hydrogen per landfall point (TAQA, NAM, Wintershall, NOGAT, NGT, etc.) and how this will develop over time.
- Provide insight into the necessary adjustments to quality requirements.
- Elucidate the economic value of green hydrogen blended with natural gas.

Research questions admixing/blending

- If a maximum percentage of hydrogen of 2% in the gas network is assumed, what is the maximum amount of electrolysis capacity that can be connected for possible blended access routes? (the 2% is based on potential EU policy for interconnection points as per the decarbonisation package)
- In what time frame would it be possible to adjust the quality requirements of the national gas transportation network? What are the expected costs of this?
- Do future producers of green hydrogen consider offshore blending an interesting option and how can blended gas stream hydrogen be upgraded? What are the implications of blending for a hydrogen producer's business case?

Research objectives gas separation/deblending

- Explore feasibility of both technical options: separation at GBI (*gasbehandelingsinstallatie* or gas treatment plant in English) and full conversion to hydrogen.
- Advice on suitable locations for separating gases.

Research questions gas separation/deblending

- What are the technical possibilities (function of deblending plants) and what is the state of the art?
- Are there already examples of plants in operation at home or abroad (scale + experience)?
- What is the efficiency of the process? What is known about the costs?
- Where would a deblending plant (gas treatment plant) be best located? And which landfall locations are suitable for further focused investigation in a case study?

This document is divided as follows. The **Hydrogen blending** section discusses the impacts of blending hydrogen (the natural gas, the business case, the assets, and the regulations). The **Hydrogen deblending** section discusses the state of the art, technologies, and costs of hydrogen deblending. The **Potential locations for hydrogen blending and deblending** section discusses some hypothetical pipelines where hydrogen could be blended with natural gas, and onshore gas processing facilities where hydrogen could be deblended.

3 Hydrogen blending

3.1 Introduction and challenges

Hydrogen blending is the process of injecting (pure) hydrogen to a pipeline or process that carries another chemical, most commonly natural gas. As such, there are no particular technologies required in order to make the mixture (the so-called 'blend'). That being said, blending hydrogen in natural gas is not without consequence. Figure 1 shows a chart depicting (some of) the potential challenges associated with hydrogen blending; in the next sections, we will discuss in more detail the challenges of hydrogen blending.

Figure 1. Overview of the challenges around hydrogen blending in natural gas.

3.2 Impact of hydrogen blends on the properties of natural gas

The most important impacts of hydrogen blends on the properties of natural gas are the following:

1) Impact on the calorific value of the natural gas
2) Impact on NOx emissions
3) Impact on the burning velocity of the natural gas

3.2.1 Calorific value (Wobbe index)

The Netherlands has a very strict control over the quality of the natural gas that is received by the onshore natural gas infrastructure i.e., the natural gas that comes from feed-in, and the quality of the natural gas that is delivered to off-takers. This is specified in the *Ministeriële Regeling gaskwaliteit* (MR Gaskwaliteit) a ruling of the Dutch Ministry of Economic Affairs and Climate Policy (MinEZK)[3]. Some of the parameters that the MR Gaskwaliteit establishes include the maximum amount of certain components in natural gas: hydrogen, oxygen, other inert and flammable gases, etc.

One of the parameters specified in the MR Gaskwaliteit pertaining to the natural gas quality is the so-called Wobbe index. The Wobbe index is an indicator of the interchangeability of different fuel gases[4]. Such a Wobbe index is required because the natural gas composition can vary as a function e.g., of origin (Groningen gas, North Sea gas, import gas, etc.). The MR Gaskwaliteit defines a range of allowable Wobbe index (i.e., a Wobbe index bandwidth) for the feed-in and the off-take natural gas, both for the high caloric gas (H-gas) and the low caloric gas (G-gas). Below is a summary of the Wobbe index ranges specified in the MR gaskwaliteit:

Table 1. Wobbe index bandwidth (lower and upper ranges) for natural gas according to the MR Gaskwaliteit).

Wobbe bandwidth according to the MR Gaskwaliteit	H-gas feed-in	G-gas feed-in	H-gas off-take	G-gas off-take
Lower Wobbe index [MJ/Nm3]	49,9	43,46	47	43,46
Upper Wobbe index [MJ/Nm3]	55,7	44,41	55,7	44,41

The Wobbe index is related to the HHV (Higher Heating Value, or calorific value) of a fuel gas according to the following formula[5]:

$$Wobbe\ index\left[\frac{MJ}{Nm3}\right] = \frac{HHV\left[\frac{MJ}{Nm3}\right]}{\sqrt{\frac{Molar\ mass_{fuel\ gas}}{Molar\ mass_{air}}}}$$

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[3] Overheid. Wetten Bank. Regeling gaskwaliteit. https://wetten.overheid.nl/BWBR0035367/2019-01-01/

[4] Wobbe Index. https://en.wikipedia.org/wiki/Wobbe_index

[5] The original Wobbe index relates to the HHV using the densities of fuel gas and air instead of their molar masses. Since the EU directives determine that the Wobbe index must be typically evaluated at 15ºC and 1 bar (in accordance with ISO 13443 and ISO 6976), and most gases are expected to behave as ideal gas in these conditions, the simplification to molar mass instead of density can be made without losing significant accuracy.

It is important to mention that the concepts of Wobbe index and HHV are not interchangeable. The HHV is essentially the maximum amount of energy that can be extracted from any fuel; the actual extracted energy from the fuel will decrease according to the efficiency of the process where the fuel is used. The Wobbe index is a measure that depends on the calorific value but also on the relationship between the density of the fuel and the density of air. As such, the Wobbe index is a measure of the 'interchangeability' of a fuel: if two fuels have a similar Wobbe index, they are expected to be interchangeable meaning that they could be used in the same burning process without significantly impacting the operation.

In order to understand how hydrogen can impact the Wobbe index of a hydrogen-natural gas blend, we need to define a natural gas with a reference composition. Below is a table with the composition of three different reference gases, as well the reference properties of hydrogen and air.

Table 2. Molar mass and HHV of the components of a reference H-gas composition as well as hydrogen and air.

Formula	H-Gas[6]	Molar mass [g/mol]	HHV[7] [MJ/Nm3]
CH4 (methane)	91,40%	16	37,71
C2H6 (ethane)	3,00%	30	66,51
C3H8 (propane)	1,50%	44	95,94
C4H10 (butane)	0,50%	58	120,29
C5H12 (pentane)	0,10%	72	148,49
C6H14 (hexane)	0,00%	86	174,08
N2 (nitrogen)	2,00%	28	0,00
O2 (oxygen)	0,00%	32	0,00
CO2 (carbon dioxide)	1,50%	44	0,00
H2S (hydrogen sulphide)	0,00%	34	0,00
Properties of other gases			
H2 (hydrogen)		2	12,62
Air		29	0,00

Table 3. Calculated properties of the reference gases.

Average gas properties	H-Gas	(Pure) hydrogen
Molar mass [g/mol]	17,77	2,00
HHV [MJ/Nm3]	38,65	12,62
Wobbe index [MJ/Nm3]	49,25	47,92

Using the information above, the impact of the hydrogen content of a hydrogen-natural gas blend on the Wobbe index can be calculated, as is shown on Figure 2.

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[6] DNV (2022). H2 removal from natural gas. Technology overview. Report prepared for N.V. Nederlandse Gasunie

[7] The Engineering ToolBox. Fuel Gases – Heating Values. https://www.engineeringtoolbox.com/heating-values-fuel-gases-d_823.html

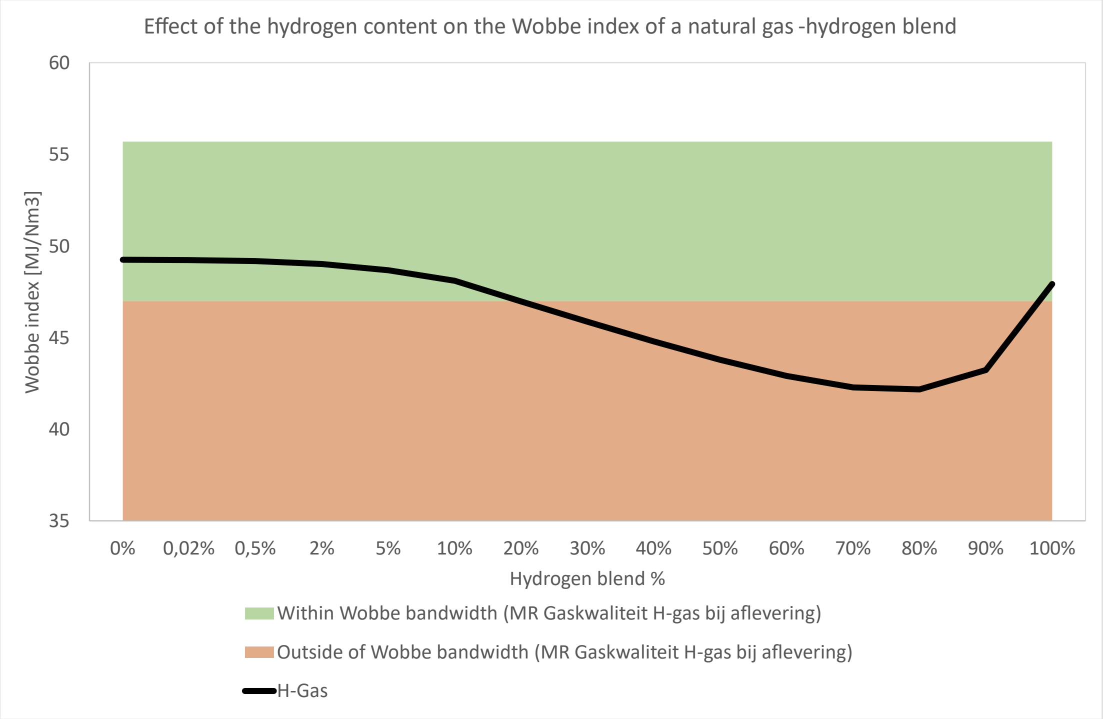

Figure 2. Wobbe index of a hydrogen-natural gas blend as a function of the hydrogen blend %. [Solid line, black] Effect of hydrogen content on a reference H-gas. [Green area] Wobbe index range **within** the parameters of the MR Gaskwaliteit (H-gas bij aflevering). [Orange area] Wobbe index range **outside** of the parameters of the MR Gaskwaliteit (H-gas bij aflevering).

As can be seen on Figure 2, blending hydrogen by up to 2% does not lead to a significant change of the Wobbe index of the gas: according to our calculations, blending up to 2% hydrogen in the reference H-gas leads to a decrease of the Wobbe index of 0,25 MJ/Nm3, which corresponds to ~0,5% change in the Wobbe index of the blend. For this reference natural gas composition, blending up to 10% hydrogen maintains the Wobbe index above the allowed value in the MR Gaskwaliteit. Blends with an increasing hydrogen content led to a sharp decrease of the Wobbe index of the blend, leading to a minimum Wobbe index in a blend with 80% hydrogen, followed by an increase of the Wobbe index towards higher hydrogen contents until reaching the Wobbe index of pure hydrogen.

Although, technically speaking, a 100% hydrogen stream would comply with the Wobbe index range established in the MR Gaskwaliteit (the HHV of hydrogen is low but the molar mas of hydrogen is also low so the two values compensate each other), this does not automatically ensure the interchangeability of pure hydrogen and hydrogen-free natural gas, mainly because pure hydrogen gas has significantly different properties than natural gas. As a result, we should take the Wobbe index comparison with care, and consider that the Wobbe index indicates the interchangeability of hydrocarbon-based (i.e., where hydrogen is not the main component) gaseous fuels.

Table 4 summarizes the effect of selected hydrogen blend % on the Wobbe index and whether or not such hydrogen blends would remain within the Wobbe bandwidth specified in the MR Gaskwaliteit.

Table 4. Summary of the effect of hydrogen blend % on the Wobbe index of a reference H-gas.

Hydrogen blend %	Wobbe index of a hydrogen-natural gas blend [MJ/Nm3]	Percent change with respect of natural gas without hydrogen	Is the gas still within the MR Gaskwaliteit?
2%	49,02	-0,46%	Yes
10%	48,11	-2,30%	Yes
20%	46,99	-4,59%	No

From the analysis above it can be concluded that:

1) Low hydrogen blends (by up to 2%) do not impact significantly the Wobbe index of natural gas.
2) Higher hydrogen content can impact the Wobbe index of the natural gas beyond the quality established by the MR Gaskwaliteit.
3) Whether the resulting blend remains within the specification or not, will depend on the actual composition of the natural gas where hydrogen is being blended. If the natural gas where the hydrogen will be blended is close to the reference gas used in this study, then a hydrogen blend of less than 20% could still remain within specification for the off-takers of H-gas[8].

As a final note, the comparison of the HHV of natural gas and hydrogen is significantly simpler: according to Table 3, the HHV of the natural gas composition used in this section (that would comply with the 'H-gas bij aflevering' specifications of the MR Gaskwaliteit) would be ~38,65 MJ/Nm3, while the HHV of hydrogen is 12,62 MJ/Nm3. This means that natural gas has a ~3 times higher calorific value than hydrogen. As a consequence, replacing the same volume of natural gas with the same volume of hydrogen would lead to a decrease in energy content of the mixture by ~1/3. Table 5 shows the impact of different hydrogen blend % on the HHV of the blend.

Table 5. HHV (calorific value) of different hydrogen blend % and change with respect to hydrogen-free natural gas.

Hydrogen Blend %	Natural gas content %	HHV (calorific value) of the blend [MJ/Nm3]	% change of HHV with respect to pure natural gas
0%	100%	38,65	0%
2%	98%	38,13	-1%
5%	95%	37,35	-3%
10%	90%	36,05	-7%
20%	80%	33,45	-13%
50%	50%	25,64	-34%
100%	0%	12,62	-67%

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[8] The Wobbe index of a 20% hydrogen blend in H-gas that was calculated here has a value (46,99 MJ/Nm3) that is slightly underneath the threshold as per the MR Gaskwaliteit (47 MJ/Nm3). It is to be reasonably expected that if the actual natural gas used in the blend has a higher Wobbe index than the reference gas we used in this calculation, a 20% blend could fall within the Wobbe index band as per the MR Gaskwaliteit.

3.2.2 NOx emissions

A concern over the (co)firing of hydrogen in high-temperature equipment (e.g., gas turbines) is the potential increase in NOx emissions. NOx emissions are primarily a function of the temperature of the combustion process. Figure 3 shows an estimate of the NO (nitrogen oxide) emissions as a function of temperature.

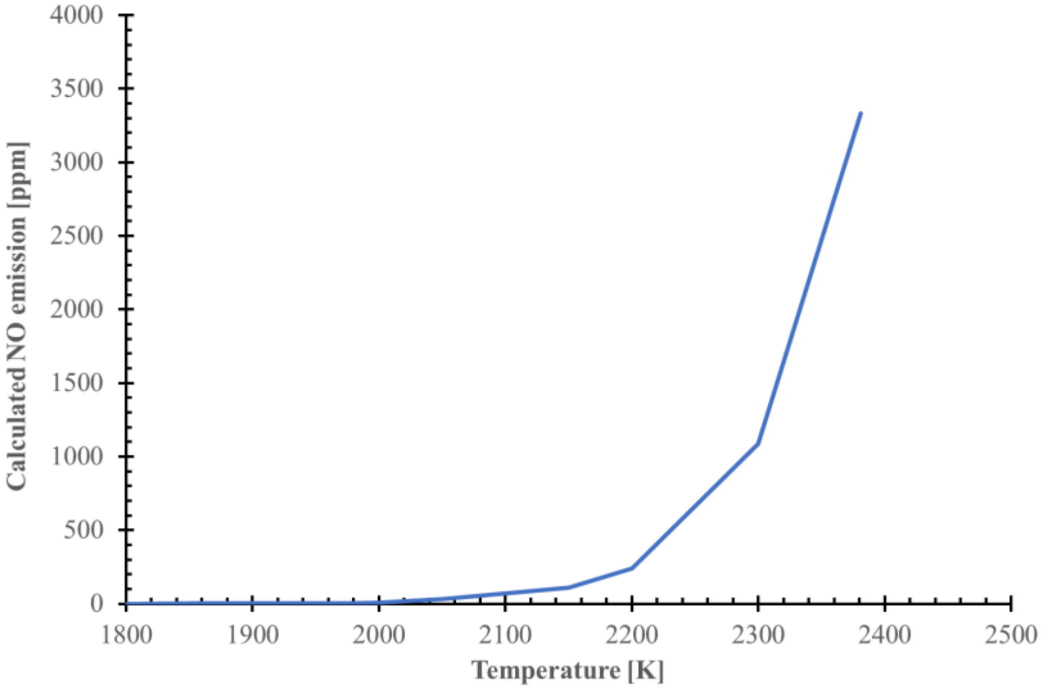

Figure 3. Estimated NO emissions as a function of temperature of a combustion process[9].

Hydrogen has an intrinsic higher flame temperature than natural gas. This means that a mixture of pure hydrogen and a stoichiometric amount of air (i.e., the minimum amount of air needed for all the hydrogen to combust in ideal conditions) would result in a higher temperature than a similar mixture of natural gas without hydrogen. Such increase in the operating temperature could cause an increase in the NOx emissions.

The flame temperature of a fuel is not a direct representation of the actual operating conditions within a combustion process; it is merely an indicator of the maximum temperature the fuel could reach if in ideal conditions e.g., perfect combustion, minimum air needed, perfect mixing of fuel and air. The actual conditions within a burner are a result of other parameters such as the amount of air, the design of the burner, whether or not there is recirculation of the flue gases, etc. How hydrogen blends impact the flame temperature of a hydrogen-natural gas blend is shown in Figure 4.

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[9] Gersen, S., van Essen, M., & Wolff, P. (2023). D9.1 & D9.2 Literature research on low NOx hydrogen burners and developing design rules for low NOx burners. *Zenodo*. https://doi.org/10.5281/zenodo.7956519

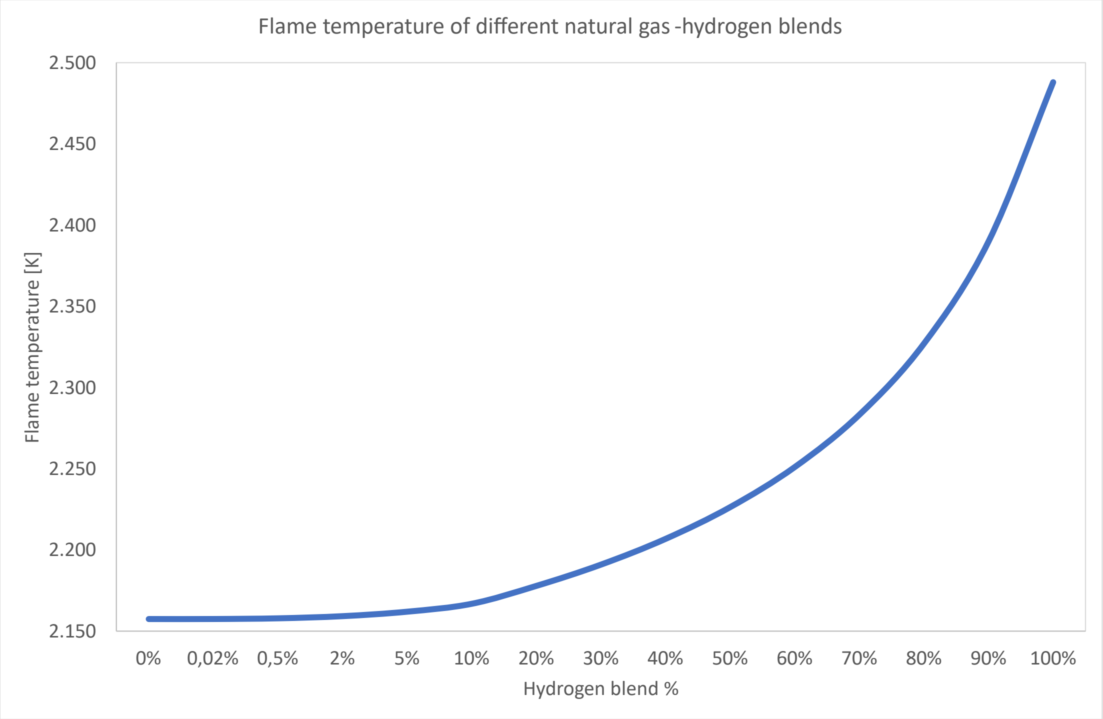

Figure 4. Flame temperature of hydrogen-natural gas blends[10].

According to Figure 4, hydrogen blends of up to 5% do not impact the flame temperature of the blend significantly, whereas blends of a higher hydrogen content cause an exponential increase in the flame temperature. It is therefore expected that, without any adjustments to the heating process (adjusting the burner design, increasing the amount of air or flue gas recirculation, etc.) hydrogen blends (particularly with a hydrogen content above 5%) would increase the flame temperature of the gas.

The specific impact of hydrogen blends in combustion process depends not only on the flame temperature of the fuel used, but also on the operating conditions of the gas. Figure 5 shows the calculated NO emissions in a process for different equivalence ratios i.e., amount of air relative to the natural gas[11].

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[10] Own calculation using an air equivalence ratio of 1, and assuming ideal conditions. Enthalpies of the gases were calculated using the NASA polynomial, see combustion.berkeley.edu/gri-mech/version30/files30/thermo30.dat and https://rmg.mit.edu/tools/evaluate_nasa

[11] A higher equivalence ratio means that there is more air in the fuel-air mixture than would be needed for a complete combustion (also called a ‘lean’ mixture), and a lower equivalence ratio means that there is less air than would be needed for a complete combustion (also called a ‘rich’ mixture).

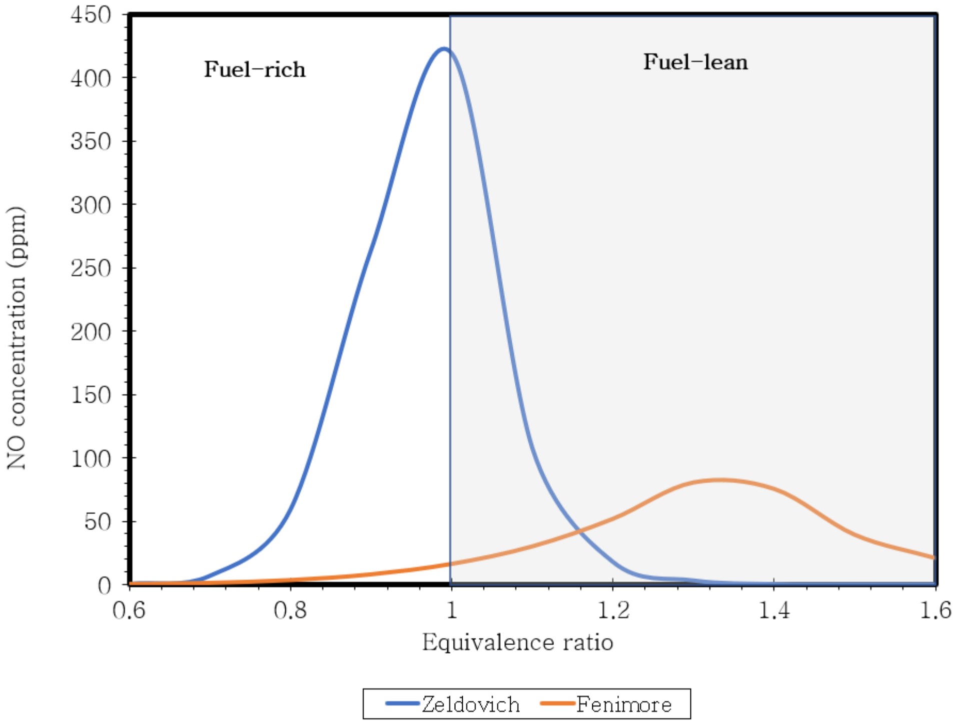

Figure 5. Calculated NO concentrations at different equivalence ratios (i.e., fraction of air in fuel-air mixtures)[12].

As mentioned before, whether or not the increase of the flame temperature leads to an increase in the actual temperature of a combustion process, depends on the actual operating conditions of the process. If blends with high hydrogen content (above 5%) were to be used in burner equipment that is optimized for natural gas without hydrogen, there is a risk that the operating temperature of the burner would increase in accordance with the increase of the flame temperature of the fuel and, subsequently, the NOx emissions of the process could increase. If adjustments were undertaken to minimize the impact of the hydrogen blend in order to keep the temperature of the process at the same level (e.g., by increasing flue gas recirculation or increasing the amount of air) then it is in principle possible to neutralize the effect of high hydrogen blends by keeping the temperature of the combustion process constant. Whether or not this requires a redesign of the burner or adjusting an operating parameter, will depend on the particular process as well as on the hydrogen blend %.

Current design rules for high-temperature burners that are meant to burn hydrogen or co-fire hydrogen-natural gas blends mainly target the reduction of NOx emissions by decreasing the combustion temperature, either by recirculating the flue gas or by making a leaner fuel-air mixture (i.e., a mixture that contains more air with respect to the fuel). As a result, it is possible to minimize or completely neutralize the impact of hydrogen content in NOx emissions by adjusting the combustion process, in particular to change the amount of air in fuel-air mixtures.

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[12] HyDelta D9.1 & D9.2 (referenced above).

3.2.3 Burning velocity of the natural gas

The burning velocity of a fuel is the speed at which a flame propagates relative to gas that is not burning[13]. Generally speaking, there are two main speeds that are of relevance in combustion processes: the speed at which the gas reaches a flame or a point of ignition (the flow velocity), and the speed at which the gas burns (the burning velocity). In fuels such as natural gas, the flow velocity is higher than the burning velocity, meaning that the flow of natural gas to a burner will be limited by the burning velocity of the burner. With such fuels, the result will be a more controlled burning of the fuel.

With fuels such as hydrogen the situation is reversed: the burning velocity is higher than the flow velocity. Compared to natural gas, hydrogen flames have a six time higher burning velocity than natural gas flames[14]. As a result, hydrogen has a less controllable burning, which can lead to situations such as 'flame flashback' i.e., a hydrogen flame can start to flow back in a pipeline, meaning that the flame, instead of being at the tip of the burner (as is normally the case with natural gas flames), slowly creeps back through a pipeline. This situation can cause that the heat generation is not at the exit of the pipeline but rather far from it, generating heat in places where heat is not meant to be generated. As a result, safety hazards can arise. Whether flame flashback occurs in a burner is not only dependent on the type of gas that is being burnt, but also on parameters such as the design of the burner, the gas to air ratio, etc. Figure 6 shows a picture comparing a natural gas and a hydrogen flame, illustrating the flame flashback phenomenon.

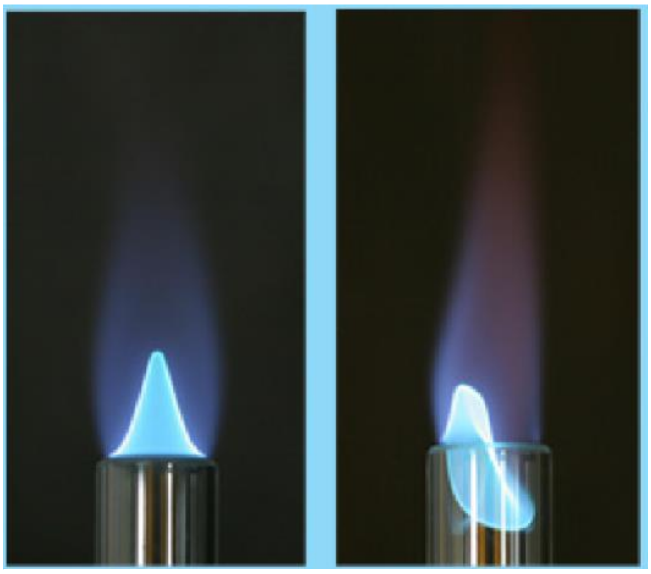
Natural gas flame H2 flame

Figure 6. Comparison of natural gas (left) and hydrogen (right) flames, showcasing the 'flame flashback' phenomenon that hydrogen flames can experience[15].

To prevent flame flashback and guarantee safe situations with hydrogen burning, the design of hydrogen burners can be adapted. One of the potential design changes in hydrogen

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[13] American Institute of Chemical Engineers. Burning Velocity. https://www.aiche.org/ccps/resources/glossary/process-safety-glossary/burning-velocity

[14] Vance et al. (2022). Development of a flashback correlation for burner-stabilized hydrogen-air premixed flames. *Combustion and Flame* 243, 112045. https://doi.org/10.1016/j.combustflame.2022.112045

[15] DNV (2020). Development of high performance (low NOx) domestic hydrogen boilers. https://newenergycoalition.org/custom/uploads/2020/11/Development-of-domestic-hydrogen-boilers.pdf

burners is the addition of ‘flame failure devices’ (FFDs) whose purpose is to shut down the hydrogen supply as soon as flame flashback is detected. Such devices are currently being developed and deployed in domestic appliances i.e., cooking hobs and boilers. Figure 7 shows an example of such devices.

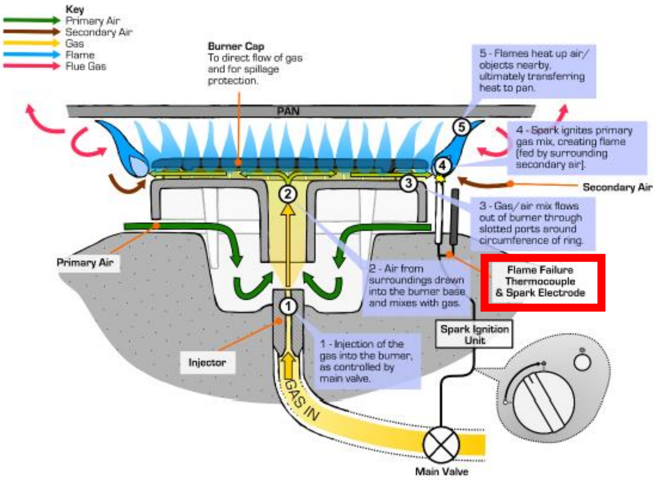

Figure 7. Example of a hydrogen cooking hob with an integrated flame failure device (red rectangle) to guarantee safe operation[16].

The extent up to which hydrogen blends impact the burning velocity of natural gas, is primarily a function of the hydrogen blend %. Figure 8 shows the impact of hydrogen content on the burning velocity of hydrogen-natural gas blends.

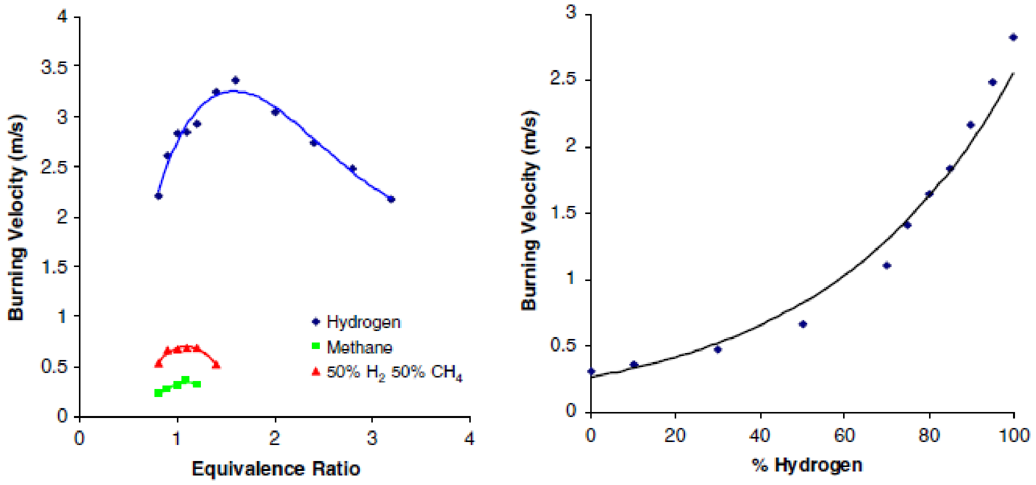

Figure 8. [Left] Burning velocity of methane (green), a 50% hydrogen-natural gas blend (red), and pure hydrogen (blue). [Right] Burning velocity as a function of hydrogen blend %[17]. Equivalence ratio relates to the ratio between the amount of air and the amount of fuel (in volume basis).

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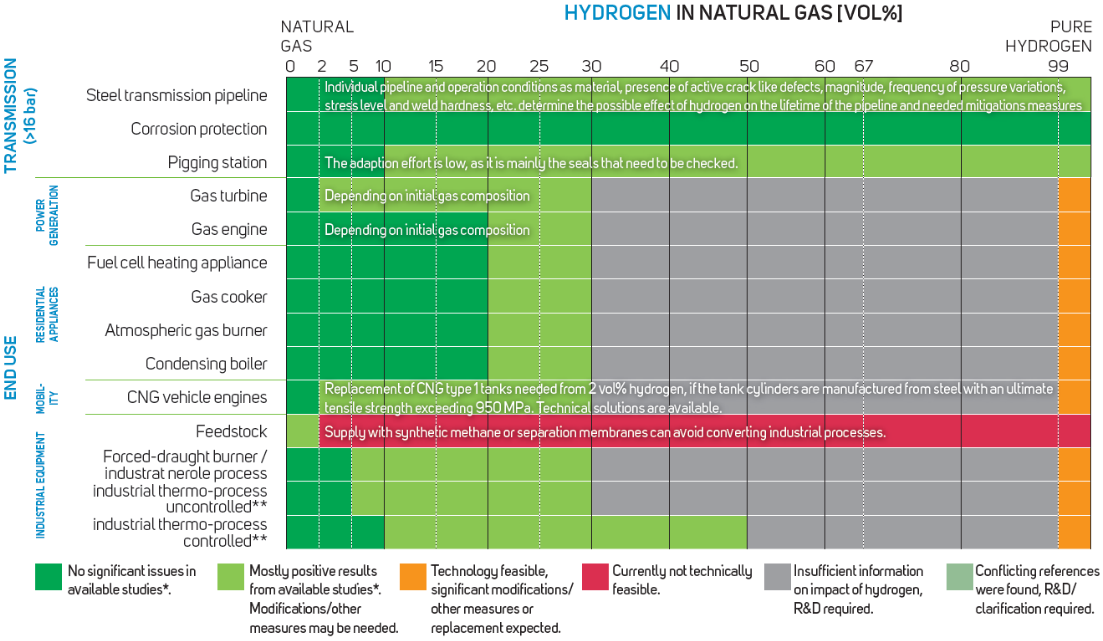
[16] Frazer-Nash consultancy (2018). Appraisal of domestic hydrogen appliances. https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/699685/Hydrogen_Appliances-For_Publication-14-02-2018-PDF.pdf

[17] Ilbas et al. (2006). Laminar-burning velocities of hydrogen-air and hydrogen-methane-air mixtures: An experimental study. *International Journal of Hydrogen Energy* 31, 1768-1779. https://doi.org/10.1016/j.ijhydene.2005.12.007

On Figure 8 we can see the significant differences between the burning velocities of natural gas (represented by pure methane) and hydrogen: the burning velocity of the blend increases exponentially with increasing hydrogen blend %. Regarding the impact of low % blends on the burning velocity, we can see that low hydrogen contents have a small impact on the burning velocity: while a 50% blend would increase the burning velocity of natural gas by a factor 2, blends lower than 10% are expected to behave very similarly to hydrogen-free natural gas. While we generally expect that blends lower than 10% hydrogen are not likely to show a significant change in burning velocity, a more thorough analysis would have to be carried out with particular blends in particular burner equipment in order to provide a more detailed conclusion in a particular process.

3.3 Impact of hydrogen blends on network operators and end-users

Marcogaz, the Technical Association of the European Gas Industry has done recent compilations of the impact of hydrogen blends in the infrastructure of both gas transport and for different kinds of end users. Figure 9 shows a general overview of the compatibility level for hydrogen blends in different networks and end uses.



Individual pipeline and operation conditions as material, presence of active crack like defects, magnitude, frequency of pressure variations, stress level and weld hardness, etc. determine the possible effect of hydrogen on the lifetime of the pipeline and needed mitigations measures

The adaption effort is low, as it is mainly the seals that need to be checked.

Depending on initial gas composition

Depending on initial gas composition

Replacement of CNG type 1 tanks needed from 2 vol% hydrogen, if the tank cylinders are manufactured from steel with an ultimate tensile strength exceeding 950 MPa. Technical solutions are available.

Supply with synthetic methane or separation membranes can avoid converting industrial processes.

Figure 9. Impact of varying hydrogen blends in natural gas in transmission infrastructure and different kinds of end users[18].

An overview of the impact of hydrogen blends per type of infrastructure can be found in the next subsections[19].

3.3.1 Natural gas transport networks (e.g., transmission grids)

It is generally agreed by industry experts and proven in pilots and demonstration projects that hydrogen blends of up to 20-30% can be accommodated in existing natural gas networks and processes with no or only minor changes to the assets. The general recommendations are as follows:

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[18] Marcogaz. Cost estimation of hydrogen admission into existing natural gas infrastructure and end use. November 2023. https://www.marcogaz.org/publications/cost-estimation-of-hydrogen-admission-into-existing-natural-gas-infrastructure-and-end-use/

[19] Marcogaz. H2 infographic 2023 Version. https://www.marcogaz.org/publications/marcogaz-h2-infographic-2023-version/

- The main elements in the transmission infrastructure are expected to be able to accept hydrogen-natural gas blends in the range of 0-10% hydrogen without modification. With modification, concentrations up to pure hydrogen are expected to be accepted.
- Individual pipeline and operation conditions determine the specific mitigation measure for steel pipelines to accept more than 10% hydrogen concentrations in a hydrogen-natural gas blend.

Furthermore, it is expected that small concentrations of hydrogen in natural gas can have impacts on components of natural gas transport networks e.g., compressors and gas quality and flow measurement devices. The recommendation is to verify the maximum allowable hydrogen in the impacted equipment and to elucidate whether the device can be adapted/modified (where a guarantee of correct functioning of the device would be typically needed) or needs to be replaced.

3.3.2 End Use Equipment

Several studies have discussed the issue of hydrogen blends for example, the levels at which no or minor modifications would be needed for end-use systems, including appliances such as household boilers or stoves and industrial or power generation[20]. The conditions determining a maximum hydrogen blend level that does not adversely influence appliance operation or safety vary significantly and include the composition of the natural gas, the type of appliance (or engine), and the age of the appliance. The impact of hydrogen blends on industrial facilities must be addressed on a case-by-case basis. A 5-20% range is often generally acceptable for end-use systems, and most discussions note types of changes, precautions or costs associated with higher blends. For example, there is typically a significant level of inertia i.e., long times needed to bring any required changes to end-user appliances or industrial facilities. As noted in the NATURALHY project[21], end-use requirements are generally the most restrictive conditions on increasing hydrogen blend levels in natural gas.

Furthermore, there have been multiple projects and studies that have explored the effect of hydrogen blends in end-user equipment, in particular in combustion equipment. As an example, projects such as the recently finished EU project THyGA[22] have done extensive research into the matter of the effect of hydrogen blends in burner equipment.

In general, the following recommendations can be given regarding the impact of hydrogen blends in different kinds of end-use equipment:

- Residential appliances are expected to be able to handle hydrogen blends in the range of 0-20% hydrogen without any modification and are expected to reach 30% hydrogen acceptance with minor modifications.
- Many industrial processes (except feedstock) are expected to be able to handle hydrogen blends in the range of 0-5% hydrogen without modification.

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[20] An extensive summary of such projects can be found on: Melania et al., (2013). Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues; https://doi.org/10.2172/1219920

[21] NATURALHY project was a European project that ran between 2004 and 2009 led by Gasunie that explored the tested all critical aspects of a hydrogen system by adding hydrogen to natural gas in existing networks. https://cordis.europa.eu/project/id/502661

[22] Testing Hydrogen admixture for Gas Applications. Horizon Europe project with Grant agreement ID: 874983. https://thyga-project.eu/

- Current power plant gas turbines, industries using natural gas as feedstock and also CNG (Compressed Natural Gas) steel tanks are assessed to be sensitive to even small quantities of hydrogen and need further R&D/mitigation measures when planning to convey higher hydrogen concentrations.
- Higher concentrations (>30% hydrogen) for end use equipment requires R&D and can possibly be reached by mitigation measures or replacement.

Further attention should be given to the impact of hydrogen on 1) the efficiency of e.g., engines, burners, or other kind of industrial components, and 2) on the individual components that appear in small quantities (e.g., gaskets, sensors). In that case, it's important that there is an inventory made on all the materials and components in a particular process or installation and subsequently inquire with the manufacturer(s) on whether the materials or components are suitable for the foreseen hydrogen blend %.

3.3.3 Certification

DNV published a report in 2023[23] that shows the results of a thorough study on the consequences of increasing the hydrogen content in natural gas to 0,6%. According to the study, there are two main impacts of hydrogen blends on the certification of components and infrastructure "behind the meter"[24]:

1. Environmental certification of burner installations (environmental certification)
2. Explosive atmospheres (ATEX certification)

3.3.3.1 Environmental certification

According to Dutch law, processes such as burners require an environmental permit that establishes, among others, upper limits of emissions of substances such as nitrogen oxides (NOx), sulphur dioxide (SO2), as well as particulates. The SCIOS association is the owner of, manager, and developer of quality systems for owners of and contractors of technical installations, for the inspection and the maintenance[25]. According to SCIOS, burner installations can be classified in two main groups relative to their capacity:

- **Small- and middle-sized installations**: burner installations with a nominal thermal installed capacity of more than 100 kW (with gaseous fuels) and 20 kW (with non-gaseous fuels) and no more than 50 MW.
- **Large installations**: installations with a thermal capacity of more than 50 MW.

The applicable environmental law for burner installations as per 01-01-2024 is the BAL (*Besluit activiteiten leefomgeving*[26]). For the application of the BAL the term natural gas is defined as "naturally-occurring methane that has up to 20% in volume of other components"[27]. In this sense, the definition of natural gas (purity) according to the BAL is independent from the definition of natural gas according to the MR Gaskwaliteit; the BAL does not make any references to the MR Gaskwaliteit in its definitions of natural gas.

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[23] Gevolgen van waterstof bijmenging bij hoogcalorisch gas. Studie naar de consequenties van 0,6 mol% waterstof in aardgas voor industriële eindgebruikers. DNV report number 244747-FFA 20-0433. 24-03-2023.

[24] Behind the meter means after the point of connection of an end user with the gas transport network, where the responsibility of the gas network operator ends and the responsibility of the end user starts.

[25] Stichting SCIOS. Over SCIOS. https://www.scios.nl/Over-Scios

[26] Overheid. Wettenbank. Besluit activiteiten leefomgeving. https://wetten.overheid.nl/BWBR0041330/2024-01-01/0

[27] Besluit activiteiten leefomgeving. Bijlage I bij artikel 1.1 van dit besluit (begrippen). A. Begrippen. Aardgas

As such, it is possible that hydrogen-natural gas blends count as natural gas for the application of the BAL as long as the total content of components other than methane does not exceed 20%. For the cases where the total content of other components exceeds 20%, it is possible that the mixture would be considered a gaseous fuel (*gasvormige brandstof*) as per the BAL.

One of the main consequences of a gas being denominated as “natural gas” or “gaseous fuel” as per the BAL is that both natural gas and gaseous fuel denominations have different limits for the emissions of NOx, SO2, and particulate matter. These emissions limits vary per size of the burner as well as the type of application: gas turbine, gas engine, etc.

Since natural gas already contains elements other than methane (ethane, propane, N2, CO2, etc.), adding another non-methane component to natural gas (for example hydrogen) would decrease its methane content. To assess the maximum amount of hydrogen that can still allow the hydrogen-natural gas blend to be classified as natural gas as per the BAL (i.e., where the total methane content is still at least 80%), we used the natural gas compositions (both G-Gas and H-Gas) defined in Table 3 (both compositions would comply with the MR Gaskwaliteit). The calculated maximum hydrogen contents is shown in Table 6.

Table 6. Maximum hydrogen content in a hydrogen-natural gas blend to keep the classification “natural gas” as per the Besluit activiteiten leefomgeving i.e., where the methane content of natural gas is at least 80%.

Reference natural gas compositions	Reference G-Gas composition used in this study[28]	Reference H-Gas composition used in this study
Methane content	81,29%	91,40%
Max. hydrogen content for a blend to still count as “natural gas” as per the BAL	1,59%	12,47%

As per Table 6, if a burner installation operates with G-Gas and it currently has a methane content of 81,29%, then it could only operate with hydrogen blends up to 1,59%; higher blend % would result in the gas no longer being denominated “natural gas” as per the BAL, which could have as potential consequence that the allowed emissions limits change. For the case of operation with H-Gas where the methane content is 91,40%, hydrogen blends of up to 12,47% could in theory still be counted as natural gas for the applicability of the BAL. In the end, the natural gas composition that is used by an off-taker can change over time; the MR Gaskwaliteit establishes the expected bandwidth of potential variations of natural gas compositions e.g., by expressing the allowable Wobbe index as a bandwidth. It is recommended that every installation carries out an individual assessment in order to understand the impact of the hydrogen content in the blend for their particular environmental permit.

Small- and middle-sized installations are required to be certified by SCIOS. As a result, a new permit would be needed for the (co-)firing of a hydrogen blend in such installations. Until the new permit is issued, a temporary solution can be found; for every specific burning

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[28] The example composition of G-Gas used here was taken from the same report as the example H-Gas composition: DNV (2022). H2 removal from natural gas. Technology overview. Report prepared for N.V. Nederlandse Gasunie (cited above).

installation a new *keuringsvoorschrift* (inspection regulations) has to be issued. Such regulations would have to be accepted and approved by the respective agency, which in this instance is the DCMR[29].

Large installations have a maintenance regime based on the recommendations of the manufacturer and potentially also from the insurer. The manufacturer (or retailer) has to give a decision over whether the installation is suitable for the presence of a hydrogen content higher than what the equipment was designed for. Additionally, the NOx emissions have to comply with the requirements set in the respective operating permits that are typically provided by organisations such as the DCMR.

3.3.3.2 ATEX certification

The European directives 2014/34/EU and 1999/92/EC, commonly known as the ATEX Directive (*ATmosphères EXplosibles*, Explosive Atmospheres) determine the minimum safety requirements for workplaces and equipment used in explosive atmospheres[30]. Among other things, it defines two main requirements:

1) How to classify different hazardous zones within a facility where fuel leaks have different likelihood of happening, and the respective distances that have to be kept from such zones.
2) The specifications an equipment should have (for example a sensor) in order to operate safely within a hazardous zones.

The standard IEC 60079-10-1[31] defines the classification of areas where flammable gases or vapour hazards may arise, and it sets the basis to support the proper design, construction, operation, and maintenance of equipment for use in such hazardous areas.

Since the classification of hazardous zones has to be done using the physical properties of the fuel (e.g., natural gas), making any changes to the gas mix (e.g., adding hydrogen) will change the properties of the gas. As such, operating with blends in processes where the hazardous zones were identified using hydrogen-free natural gas, will mean that the calculation of the hazardous zones would have to be verified prior to operation.

Furthermore, the choice of equipment (e.g., sensors) for hazardous zones defined according to the ATEX Directive is done based on two main properties of the fuel: the type of hazardous zone the equipment needs to operate in (called the “equipment group”), and the auto-ignition temperature of the fuel (called the “temperature class”). As a result, any equipment operating in a hazardous zone will have an equipment group and a temperature class.

According to the IEC 60079-0[32], equipment to be used for natural gas/methane is classified as “IIA-T1”, meaning that the equipment to be used needs to be certified for operation in group IIA and temperature class T1. Conversely, equipment meant to be used for hydrogen is classified as “IIB+H2-T1” or “IIC-T1”, meaning that the equipment to be used for hydrogen

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[29] DCMR Milieudienst Rijmond is an environmental protection agency in the Dutch province of Zuid Holland that, among other activities, gives permits and monitors the environmental quality. https://www.dcmr.nl/over-dcmr

[30] European Agency for Safety and Health at Work. Guidelines to Directive 2014/34 EU – ATEX ‘Product’ Directive. https://osha.europa.eu/en/legislation/guidelines/guidelines-directive-201434-eu-atex-product-directive

[31] IEC 60079-10-1:2020. Explosive atmospheres – Part 10-1: Classification of areas – Explosive gas atmospheres. https://webstore.iec.ch/publication/63327

[32] IEC 60079-0:2017. Explosive atmospheres – Part 0: Equipment – General requirements. https://webstore.iec.ch/publication/32878

has to be certified to operate as equipment group IIB-H2 or IIC[33] and also should be certified to operate in temperature class T1. As a result, and according to the same standard, equipment that is suitable for applications requiring groups IIB or IIC (e.g., hydrogen) is also suitable for applications requiring group IIA (e.g., natural gas/methane) but not vice-versa. This means that any ATEX-approved equipment that is suitable for natural gas, would potentially have to be replaced when operating with a hydrogen-natural gas blend.

Furthermore, the standard IEC 60079-10-1 has a special provision pertaining to hydrogen gas. The standard establishes that adding at least 3% hydrogen to the original fuel (natural gas or otherwise) would mean that the temperature class of the equipment needs to be reviewed to consider the auto-ignition temperature of hydrogen. Hydrogen and natural gas have the same temperature class (T1) so this effectively means that no changes would be needed. However, using a fuel that contains at least 30% hydrogen means that the equipment used would have to be of a group approved for use with hydrogen (IIB+H2 or IIC), which has more strict design than the equipment approved for use with natural gas (IIA). In such situation, it is likely that the equipment used for natural gas in the hazardous zones would no longer be suitable for safe operation with hydrogen-natural gas blends of more than 30%.

In summary, adding hydrogen to the fuel (e.g., natural gas) used in an installation that already has a certification according to the ATEX directive will have two main consequences:

1) The hazardous zones would need to be reevaluated and could potentially change, based on the blend %.
    a. It is likely that the higher blend % would result in more changes to the hazardous area classification than lower blend %.
    b. This is independent of the blend %: there is no defined threshold where the hazardous zones do or do not need to be reevaluated. As soon as the composition changes, the hazardous zones need to be recalculated with the properties of the blend.
    c. The lower the blend %, the more similar the blend properties will be respect to hydrogen-free natural gas and the higher the blend %, the less similar the blend and the natural gas properties will be.
2) The equipment that is suitable to operate within the different hazardous zones, could no longer be suitable to operate in an atmosphere where hydrogen is present.
    a. If the current equipment in an installation that uses natural gas is suitable for use in IIA-T1 atmospheres, operating with hydrogen blends of at least 30% could potentially result in having to swap the equipment to install a different one namely, that is suitable for use in IIB+H2-T1 or IIC-T1 atmospheres.

Furthermore, the manager of a burner installation has the responsibility to manage the risks related to the ATEX directive. The EVD (*Explosieveiligheidsdocument*, explosive safety document) is hereby mandatory for installations where explosive atmospheres can occur. In the case that a change in the natural gas composition leads to a change in the current ATEX zone classification, a new risk analysis has to be carried out. This could become a significant endeavour if the ATEX zoning changes significantly e.g., as a result of higher hydrogen blends.

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[33] Guide for hazardous areas, https://www.e2s.com/guide-for-hazardous-areas/apparatus-groups-and-common-flammable-ga

3.4 Impact of hydrogen blends on the economic value of natural gas

3.4.1 The costs of hydrogen blending

The costs of hydrogen blending can be classified in the following generic categories:

1. Physical costs of connecting hydrogen production to natural gas transport infrastructure
2. Planning costs, permitting, safety assurance costs, etc.
3. Cost of a hydrogen blend

3.4.2 Physical costs of connecting hydrogen production to natural gas transport infrastructure

In none of the surveyed literature has there been mention of the costs of hydrogen blending i.e., the costs of physically connecting hydrogen production facilities with natural gas transport infrastructure; it is likely that such costs are considered within the project costs of hydrogen production facilities. Furthermore, several of the activities around hydrogen blending have happened at pilot stage; pilot projects usually have decreased permitting requirements due to the short-duration of the projects and the experimentation that typically occurs (variation of flows, short interruptions of the blending, etc.).

Generally speaking, there could be costs that the physical act of blending hydrogen into natural gas for three main parties: network operators, in-feeders of hydrogen to natural gas networks, and off-takers of natural gas.

- **Network operators:** for the natural gas network operators, the costs of blending are associated with the costs of managing a network that contains an increased amount of hydrogen. These costs can include: costs for adaptation of equipment (compressors, gas quality meters, etc.), increased maintenance of the network, etc. The magnitude of these costs will depend on the number of end users connected to the network where hydrogen is blended: if the connection is 'local' (i.e., where the pipeline will transport the hydrogen blend to a particular consumer), then the costs of managing the network will decrease. Conversely, if hydrogen ends up in the national network or in a pipeline with several off-takers, the complexity of managing such network is more likely to increase. Additionally, it is likely that the costs incurred by gas network operators to adapt their infrastructure for hydrogen blends will result in increased gas transport tariffs.

- **In-feeders of hydrogen to natural gas networks:** the common expectation is that the physical cost of blending for in-feeders will be relatively low. In principle, all is needed to blend is a connection to the natural gas infrastructure, potentially some safety and control measures (e.g., shut-down valves, backflow or check valves) and potentially flow and/or gas quality meters to measure the amount of hydrogen and the resulting blend %. Whether blending hydrogen impacts the rest of the infrastructure of the in-feeder, would have to be determined on a per-case basis.

- **Off-takers of natural gas**: as has been discussed in this report, the impact of hydrogen blends varies depending on the type of end use of the natural gas. As such, the costs of blending for off-takers will be associated with the hydrogen blend % as well as the amount of natural gas that is consumed. Costs will include adaptation of the equipment, additional safety equipment needed, etc.

3.4.3 Costs of permitting

What is not often discussed in literature are costs associated with permitting. An end user equipment that requires a permit to operate with natural gas, will require a permit for operating with hydrogen-natural gas blends. To obtain this permit, there can be costs associated with aspects such as (but not limited to):

- Preliminary studies to ascertain the impact of hydrogen blends on safety and performance.
- Planning of the project.
- Measuring e.g., hydrogen content, gas quality, NOx content, etc.
- Necessary adjustments in the (end user) equipment to comply with potentially different guidelines for operating with hydrogen blends (where the amount of hydrogen could play a role) with respect to hydrogen-free natural gas.
- Notification of a certifying body to issue a permit.

These costs could include for example hiring consultants and researchers, hiring or purchasing equipment, issuing a certificate, etc. These costs would depend on the end user and the hydrogen blend, which is why it is important to ascertain what the maximum hydrogen content in natural gas will be e.g., if the MR Gaskwaliteit is adjusted to accept higher hydrogen content in natural gas. Furthermore, the duration of permitting processes is typically long; there is a general understanding that some permitting processes can take years.

3.4.4 Cost of a hydrogen blend and 'Hydrogen surcharge' calculation

Besides the technical feasibility, costs could be impacted by blending hydrogen in natural gas. A so-called "hydrogen surcharge" i.e., an increase in price of a hydrogen-natural gas blend caused by the presence of hydrogen, could be calculated. Such hydrogen surcharge would depend on three main factors:

1) The calorific value of hydrogen relative to natural gas
2) The price of natural gas
3) The price of hydrogen or, alternatively, the Levelized Cost Of Hydrogen (LCOH)

LCOH is a hydrogen cost value typically used in (pre-)feasibility studies of hydrogen production projects. An LCOH calculation has three main components:

- CAPEX i.e., the cost of the assets to produce hydrogen (electrolysis, balance of plant, etc.).
    - This cost is counted as initial investment.
- OPEX i.e., the cost of the (electricity, spare parts, maintenance, etc.).
    - This cost is counted yearly and in relation to the expected yearly hydrogen production.

- Market variables such as:
    - Cost of capital, often referred to as Weighted-Average Cost of Capital (WACC).
    - Project duration, which depends on the type of assets to be purchased.
    - Potential subsidies, extra funding mechanisms, etc.

With the three main components, a calculation is made to calculate the investment cost and the yearly hydrogen production, which is calculated at "Net Present Cost" (NPC) to consider the compounding interest i.e., the WACC, and add the CAPEX invested at the start of a project (i.e., at year 0) to the hydrogen produced and the OPEX spent at every year of the project operation, using the same year as reference[34]. This is why it is called Net Present Cost, because it calculates the total costs in the present instead of in the future. The LCOH is mainly the result of calculating the total NPC (which would be in millions of €, for example) per unit hydrogen produced during the project's lifetime (in millions of kg, for example). As a result, LCOH is expressed typically expressed as €/kg hydrogen produced.

The total cost of the hydrogen-natural gas blend could be calculated in a simplified manner by the following equation:

$$Cost\ of\ the\ blend_{HHV}\left[\frac{€}{MWh}\right] = (1-X) * NG_{Price}\left[\frac{€}{MWh}\right] + X * LCOH\ \left[\frac{€}{kg}\right] * HHV\ \left[\frac{MWh}{kg}\right]$$

Where X is the hydrogen blend %, NG_{Price} is the natural gas price, $LCOH$ is the Levelized Cost of Hydrogen[35] and HHV[36] is the higher heating value of hydrogen, as seen in Table 2. We can then define the hydrogen surcharge as follows:

$$Hydrogen\ surcharge\ [\%] = \frac{Cost\ of\ the\ blend_{HHV}\left[\frac{€}{MWh}\right] - NG_{Price}\left[\frac{€}{MWh}\right]}{NG_{Price}\left[\frac{€}{MWh}\right]}$$

A hydrogen surcharge, as defined in the equation above, represents the extra amount that the off-taker would need to pay in order to receive the same energy[37]. For example, a 100% hydrogen surcharge would mean that the off taker would need to pay 100% more in order to receive the same amount of energy than if they were to purchase natural gas without hydrogen. A positive hydrogen surcharge means that the cost per unit energy received in the blend is higher than buying natural gas without hydrogen, while a negative hydrogen surcharge would mean that the hydrogen-natural gas blend delivers the same amount of energy at a lower cost than the natural gas by itself.

Figure 10 shows the impact of hydrogen blends on the cost of the blend (per MWh) as well as the corresponding hydrogen surcharge.

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[34] Ebrary.net. Net Present Cost (NPC). https://ebrary.net/32824/environment/cost

[35] The LCOH was used instead of e.g., a hydrogen price, mainly because LCOH is a more widely recognizable parameter.

[36] The choice of using HHV to convert the mass of hydrogen to a unit of energy was done to have a consistent base of calculations throughout this document. There is currently a debate in the hydrogen sector about whether HHV or LHV (Lower Heating Value) is the correct parameter to be used to convert from mass to energy of hydrogen.

[37] The 'hydrogen surcharge' can also be understood as the 'unprofitability gap' or the '*onrendabele top*' in Dutch.

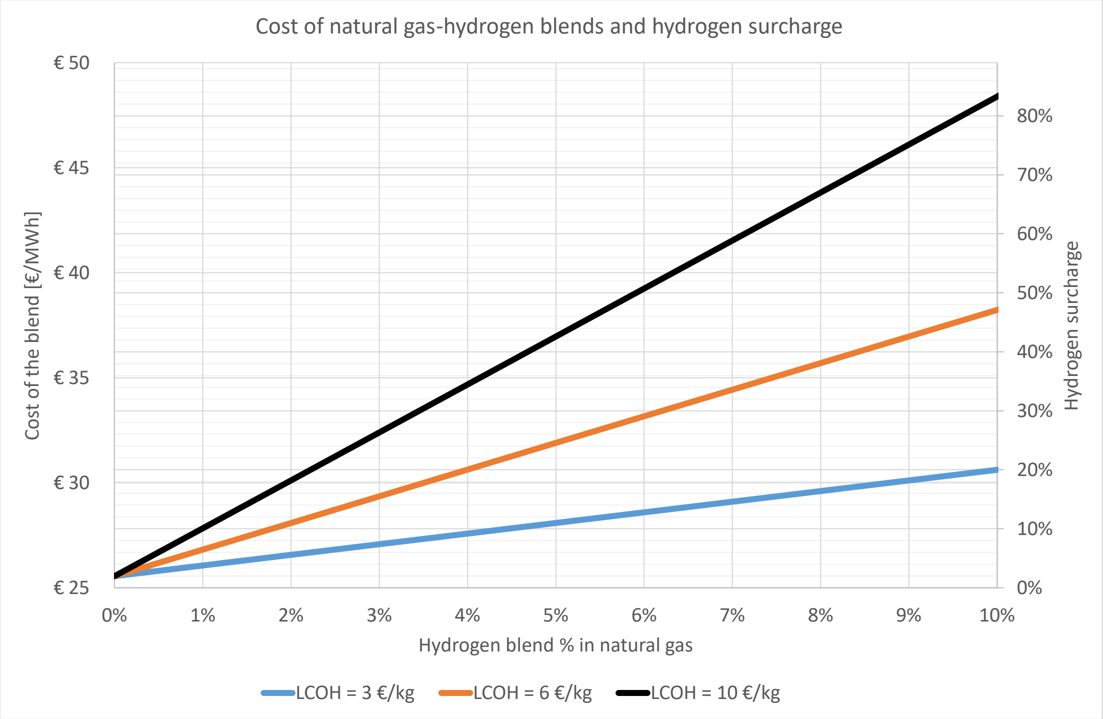

Figure 10. [Left axis] Cost of a hydrogen-natural gas blend for different values of LCOH. [Right axis] Corresponding hydrogen surcharge. The price of natural gas was set at €25,55/MWh, which corresponds to the day ahead price in February 2024[38].

From Figure 10 it can be seen that even with an LCOH of 3 €/kg, the hydrogen surcharge is positive at all blend values, meaning that with the current market conditions a hydrogen-natural gas blend will be more expensive than natural gas without hydrogen. This is partially a result of the recent decrease of the natural gas prices to pre-2022 market conditions. For the specific case of a 2% hydrogen blend, Table 7 shows the corresponding hydrogen surcharge values.

Table 7. Hydrogen surcharge for a 2% hydrogen blend and different LCOH values.

Natural gas cost: 25,55 €/MWh	LCOH = 3 €/kg (76,16 €/MWh)	LCOH = 6 €/kg (152,33 €/MWh)	LCOH = 10 €/kg (253,88 €/MWh)
Cost of a 2% blend [€/MWh]	€26,56	€28,09	€30,12
Hydrogen surcharge	4%	10%	18%

The hydrogen surcharge for a blend with 2%[39] hydrogen varies significantly with the LCOH. With an LCOH of 3 €/kg (which may be lower than the expected LCOH of offshore hydrogen production), the surcharge is 4%; the hydrogen surcharge can easily increase to 10% and 18% for LCOH of 6 and 10 €/kg, respectively. An LCOH of 6 €/kg could be realistically

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[38] CZ VTP Day Ahead price on 20-02-2024. https://www.eex.com/en/market-data/natural-gas/spot

[39] This value is being chosen because the EU is considering implementing 2% as the hydrogen blend % that Member States would need to accept in interconnection points, so MinEZK is considering adopting this 2% measure via adjusting the MR Gaskwaliteit.

expected from offshore hydrogen production[40], meaning that the corresponding 10% hydrogen surcharge could also be a realistic amount. An LCOH of 10 €/kg might be higher than expected for a developed hydrogen market (e.g., towards 2030) but it could well be an accurate reflection of the cost of offshore hydrogen production for DEMO 1.

There can be a case where blending hydrogen will make the cost of the blend lower than the cost of unblended natural gas. Generally speaking, this can happen if the cost of the hydrogen energy is less than the cost of the natural gas energy (Table 8):

$$Cost\ of\ the\ blend_{HHV}\left[\frac{€}{MWh}\right] < 0\ if$$

$$NG_{Price}\left[\frac{€}{MWh}\right] > \frac{LCOH\ \left[\frac{€}{kg}\right]}{HHV_{H2}\ \left[\frac{MWh}{kg}\right]}$$

Table 8. Natural gas costs at which there would be no hydrogen surcharge when blending i.e., the cost of hydrogen energy and natural gas energy are the same.

	LCOH = 3 €/kg	LCOH = 6 €/kg	LCOH = 10 €/kg
Cost of the natural gas where there blending hydrogen will cause no impact to the cost of the blend i.e., where the hydrogen surcharge will be zero.	76,16 €/MWh	152,33 €/MWh	253,88 €/MWh

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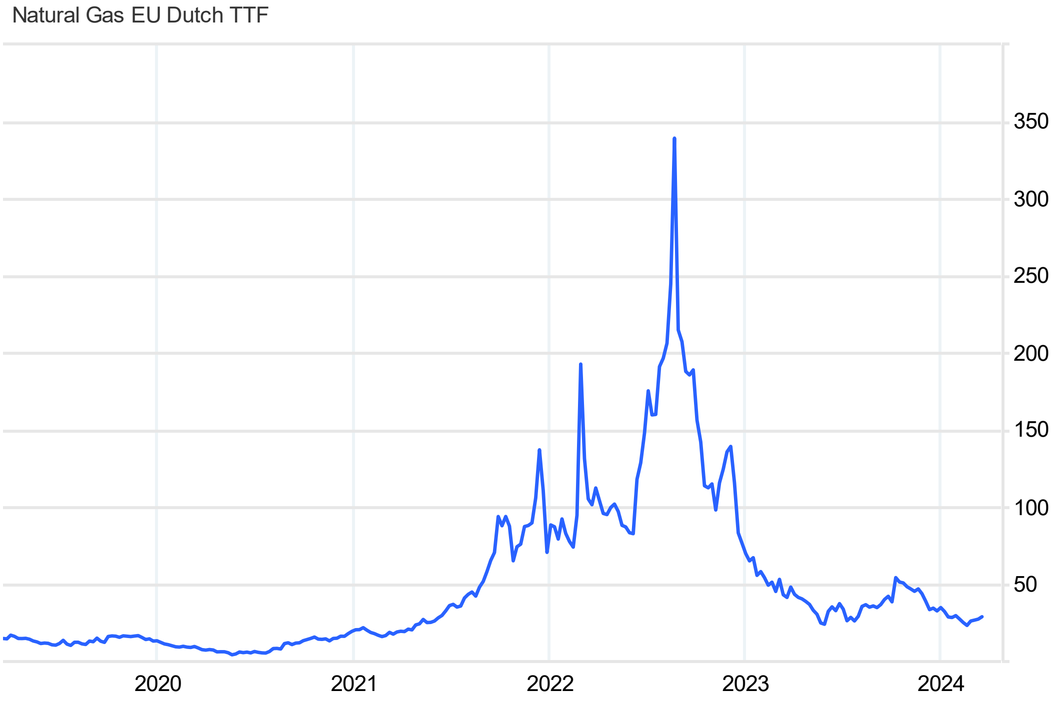
[40] van Zoelen, R., & Kee, J. (2022). D7A.2 Techno-economic analysis of hydrogen value chains in the Netherlands: value chain design and results. Zenodo. https://doi.org/10.5281/zenodo.6477440



source: tradingeconomics.com

Figure 11. Historic TTF (Title Transfer Facility) prices of natural gas of the past 5 years[41].

According to Table 8, the points at which there would not be any hydrogen surcharges (i.e., where the cost of hydrogen energy and the cost of natural gas energy are equal) can vary between 75 and 250 €/MWh for LCOH values of between 3 and 10 €/kg, respectively. How realistic these energy values can be is shown on Figure 11. We can see that 75 €/MWh was reached in the winter of 2021 (before the invasion of Ukraine), meaning that any hydrogen blends produced at that time with an LCOH of 3 €/kg would have resulted in cost-neutral hydrogen-natural gas blends. Between 150 and 250 €/MWh happened at the highest moment of the natural gas prices in 2022, meaning that back then hydrogen blends from LCOH of 6 or 10 €/kg would have resulted in cost-neutral energy situations.

It is important to remember that the energy market situation in 2021 and 2022 was a ‘crisis’ situation; as such, the prices that occurred back then are not likely to occur too often in the future (although it is difficult to predict future energy prices as it was the case back then as well). This analysis merely shows that, if the situation in 2021-2022 were to happen again, blending hydrogen into natural gas would result in a cost-competitive solution with respect to consuming high-cost natural gas.

3.4.5 Cost comparison between LHV and HHV

It is important to clarify that in this section this cost calculation has been done based on the HHV of both natural gas and hydrogen. However, for most customers who use the gas for heat the Lower Heating Value (LHV) will be more relevant. On an LHV basis, the hydrogen surcharge would be a little higher because hydrogen has a larger difference between HHV (141,80 MJ/kgH2) and LHV (119,88 MJ/kgH2) than natural gas (HHV = 51,44 and LHV = 46,40

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[41] Trading Economics. EU Natural Gas TTF (Title Transfer Facility) prices. https://tradingeconomics.com/commodity/eu-natural-gas

MJ/kg natural gas). Table 9 shows a comparative calculation of hydrogen surcharges based on HHV (as was done before) and LHV.

Table 9. Comparison of the hydrogen surcharges for a 2% hydrogen-natural gas blend, calculated on an HHV and LHV basis.

Natural gas cost: 25,55 €/MWh	LCOH = 3 €/kg (76,16 €/MWh)	LCOH = 6 €/kg (152,33 €/MWh)	LCOH = 10 €/kg (253,88 €/MWh)
Cost of a 2% blend [€/MWh-HHV]	€26,56	€28,09	€30,12
Hydrogen surcharge based on HHV	4%	10%	18%
Cost of a 2% blend [€/MWh-LHV]	€26,84	€28,64	€31,05
Hydrogen surcharge based on LHV	5%	12%	22%

Table 9 shows that the hydrogen surcharge of a 2% blend increases when the costs are calculated on an LHV basis instead of an HHV basis. This difference is smaller for the lower LCOH (5% in LHV vs 4% in HHV basis) but starts to increase considerably with the higher LCOH: for the 10 €/kg case, the hydrogen surcharge is 22% calculated on the LHV basis and 18% calculated on the HHV basis. In the end, the net costs will depend on how the natural gas consumption is measured and what the agreements are between the natural gas provider, the off-taker, and the transport company.

3.4.6 Impact on the business case of gas retailers and end users

The calculations shown in this section are relatively generic: they only consider the cost of natural gas in the market and the LCOH. A more accurate reflection of the total cost would have to include the cost of any adaptations needed for the natural gas or oil and gas network in order to accommodate hydrogen blends. This cost can be in principle added to the LCOH, for which a more in-depth calculation of the LCOH in DEMO 1 would be needed i.e., including also the arrangements made in terms of the electricity prices, the cost of the electrolysis unit, etc.

The concept of 'hydrogen surcharge' as shown in the previous section is based on the assumption that the producer of the hydrogen (which may or may not be a natural gas producer as well) would recover their costs by selling the hydrogen at the LCOH value. As such, hydrogen or gas retailers would be passing on their costs to their clients (i.e., the end users). For the end users it is a different story: they would have to accept the increased energy costs of a hydrogen-natural gas blend, where the increase would be at least equal to the hydrogen surcharge. Whether or not the end user is willing to pay for the hydrogen surcharge will depend on e.g., the end user and on the natural gas market.

It is likely that financial support is needed in order for end users to accept the purchase of the hydrogen blends for example to make the cost of the blend the same as the cost of natural gas. As such, we could expect three main scenarios:

- Scenario 1: financial support is given to the project in order to decrease the LCOH e.g., CAPEX support.
- Scenario 2: financial support is given to the producer of hydrogen in order to equate the LCOH with the cost of natural gas e.g., OPEX support.
- Scenario 3: financial support is given to the end user of the natural gas in order to maintain cost-neutrality i.e., to make the cost of energy from the blend the same as with natural gas.

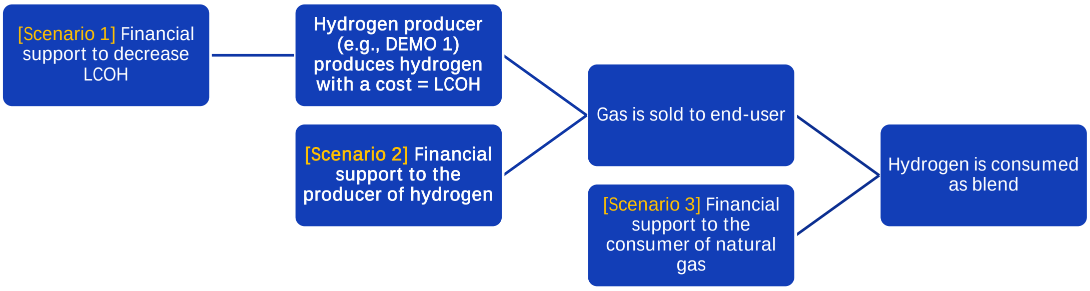

Figure 12. Three possible scenarios for the financial support of hydrogen blends.

In all three scenarios depicted on Figure 12 the total amount of financial support could be the same[42]; the main difference is at which stage of the value chain the market intervention is carried out. In order to calculate the total amount of financial support needed in order to cover the 'hydrogen surcharge' i.e., to equate the cost of the blend to the cost of the natural gas energy, we can use the following equation (Table 11):

$$
\begin{aligned}
&Total\ financial\ support\ needed\left[\frac{€}{year}\right] \\
&= H_2\ produced\left[\frac{Nm^3}{day}\right] * 365\left[\frac{day}{year}\right] * HHV_{H2}\left[\frac{MWh}{Nm^3}\right] \\
&* \left(\frac{LCOH\left[\frac{€}{kg}\right]}{HHV_{H2}\left[\frac{MWh}{kg}\right]} - Natural\ gas\ cost\left[\frac{€}{MWh}\right]\right)
\end{aligned}
$$

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[42] With the reminder that the LCOH considers the cost of capital (WACC) i.e., it expects the project owner to make a profit on its capital. Whether the market intervention wants to compensate for such profit, is for the deciding party (e.g., a subsidy giver) to decide.

Table 10. Total financial support needed yearly to cover the 'hydrogen surcharge' of a hydrogen blend i.e., to have the cost of a hydrogen-natural gas blend equal to the cost of natural gas energy. Values calculated for the average utilisation factor expected of electrolysers operating with direct interconnection with offshore wind turbines (50%).

Total financial support needed to cover the 'hydrogen surcharge' i.e., to maintain a neutral cost of a hydrogen blend. Assuming 50% utilisation factor for electrolysis	LCOH = 3 €/kg (76,16 €/MWh) (Natural gas cost: 25,55 €/MWh)	LCOH = 6 €/kg (152,33 €/MWh) (Natural gas cost: 25,55 €/MWh)	LCOH = 10 €/kg (253,88 €/MWh) (Natural gas cost: 25,55 €/MWh)
50 MW (120.000 Nm3/day or 153.546 MWh/year)	€ 7.771.505/year	€ 19.466.105/year	€ 35.058.905/year
100 MW (240.000 Nm3/day or 307.092 MWh/year)	€ 15.543.011/year	€ 38.932.211/year	€ 70.117.811/year

Table 11. Total financial support needed yearly to cover the 'hydrogen surcharge' of a hydrogen blend i.e., to have the cost of a hydrogen-natural gas blend equal to the cost of natural gas energy. Values calculated for the total installed capacity of electrolysis.

Total financial support needed to cover the 'hydrogen surcharge' i.e., to maintain a neutral cost of a 2% hydrogen blend. Installed capacity electrolysis	LCOH = 3 €/kg (76,16 €/MWh) (Natural gas cost: 25,55 €/MWh)	LCOH = 6 €/kg (152,33 €/MWh) (Natural gas cost: 25,55 €/MWh)	LCOH = 10 €/kg (253,88 €/MWh) (Natural gas cost: 25,55 €/MWh)
50 MW (240.000 Nm3/day or 307.092 MWh/year)	€ 15.543.011/year	€ 38.932.211/year	€ 70.117.811/year
100 MW (480.000 Nm3/day or 614.183 MWh/year)	€ 31.086.022/year	€ 77.864.422/year	€ 140.235.622/year

According to

table 10 and Table 11, total support to maintain a cost neutral hydrogen-natural gas blends (of any %) for electrolysers between 50 and 100 MW depend very strongly on the LCOH and the utilisation rate/capacity factor. A relatively small-scale project offshore connected directly to offshore wind farms might be expected to have an LCOH close to 10 €/kg due to it being one of the first of its kind as well as the current state of the supply chain of offshore projects. As such, an offshore hydrogen project that results in an LCOH of 10 €/kg (without financial support) would require a total financial support of between €35 and €70 million (for an electrolyser of 50 and 100 MW respectively) in order to keep the cost of the energy similar to natural gas. Furthermore, the total financial support will be strongly correlated with the price of natural gas. In this study we are basing the calculations on the spot market price of February 2024; with lowering natural gas prices it is likely that the total financial support has to increase and vice-versa.

3.4.7 Potential opportunities to generate green hydrogen revenue via certificate trading

A potential way to mitigate the negative impact of high hydrogen costs e.g., from DEMO 1, is via certificate trading. In different energy commodity markets (e.g., electricity, gasoline, diesel) in Europe there are obligations to replace part of the fossil energy consumption in a particular industry, to renewable energy[43]. Since the obligations are imposed at an industry level, this means that each company in an obligated industry has to replace a particular % of their fossil energy consumption by renewable alternatives (either green electricity or biofuels); in other words, obligated industries have each to fulfil a ‘quota’ of renewable energy consumption.

There are three main ways that fuel blending obligations are met:

1. By replacing an amount of the fossil energy consumption amount of renewable energy/biofuels i.e., via purchasing from a renewable energy producer or via self-production.
2. By purchasing certificates e.g., from traders or companies who have replaced a higher % than their obligated amount of renewable energy.
3. By paying a penalty if a company didn’t meet their obligations by either of the aforementioned ways.

When a company produces green hydrogen, it can receive a certificate that shows that the hydrogen is green; this is known as the ‘Guarantee of Origin’ (GoOs). GoOs are certificates granted to the producer of a particular renewable commodity for the production of a particular amount of renewable energy (either electricity or biofuels) e.g., per GJ or MWh produced. However, as the name suggests, GoOs only guarantee the origin of hydrogen i.e., they cannot be directly used to fulfil renewable energy consumption obligations. For the fulfilment of renewable energy consumption obligations (e.g., fuel blending obligations), different kinds of certificates are typically needed.

It is expected that voluntary certificate schemes for green hydrogen are created in order to cover the EU’s Renewable Fuels of Non-Biological Origin (RFNBOs) targets, as defined in the

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[43] For an overview of the biofuels blending obligations see https://www.epure.org/about-ethanol/fuel-market/overview-of-biofuels-obligations-in-the-eu/

Renewable Energy Directive's (RED)[44] consumption targets. The main difference between the GoOs and these certificate schemes, is that the certificate schemes consider not only the production side but also the rest of the supply chain of a particular fuel. Figure 13 shows an example of the role of GoOs and voluntary certificates of the RFNBO scheme defined in the RED, for a green hydrogen supply chain.

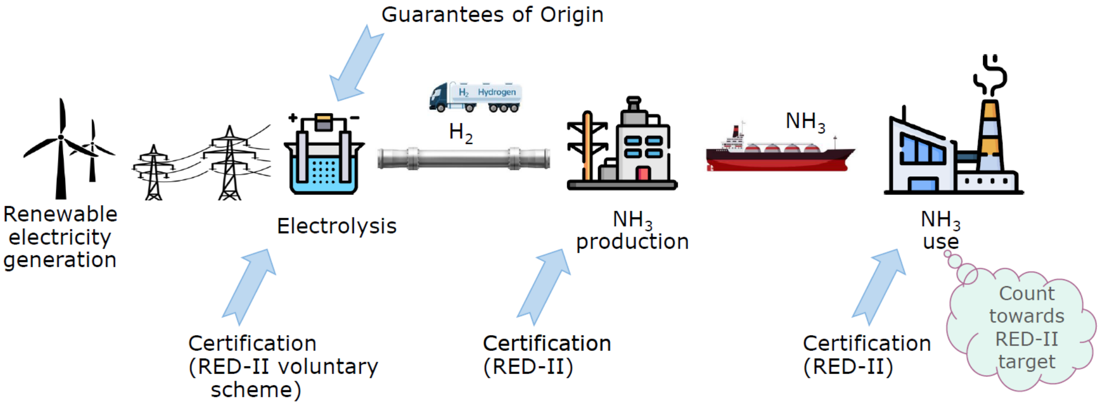

Figure 13. Example of a green hydrogen supply chain (e.g., to produce green ammonia), where the role of Guarantees of Origin and RED-II certificates is elucidated[45].

The process through which an obligated party buys certificates to cover their quota is often referred to as 'cancelling' certificates. Figure 14 shows a simplified overview of how certificates (e.g., RFNBO) are produced and cancelled, as well as the interaction between producers and obligated parties as well as with certifying parties and certificate traders.

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[44] European Union. Renewable Energy Directive. https://energy.ec.europa.eu/topics/renewable-energy/renewable-energy-directive-targets-and-rules/renewable-energy-directive_en

[45] Neeft, John (RVO). Introduction and update on Dutch RFNBO certification pilot. https://nationaalwaterstofprogramma.nl/actueel/nieuws/downloads_getfilem.aspx?id=1475367

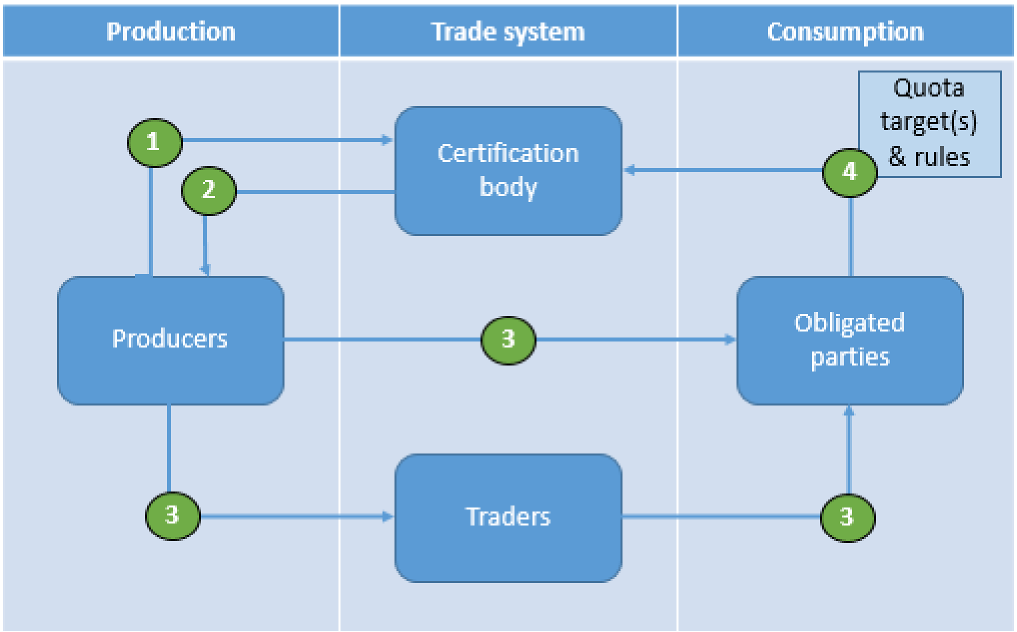

Figure 14. General overview of a mandatory renewable energy consumption quota. 1) Producer shares required production data with certification body. 2) Certification body issues the fitting amount of certificates on the account of the producer. 3) Certificates can be traded between producers, traders and obligated market parties, separate from the physical energy trade. 4) Based on the quota, a specific amount of certificates should be cancelled every period by the obligated market parties[46].

According to the RED, there will be consumption targets for hydrogen in different industries (e.g., refineries, road transport), which will mean that it is possible for a green hydrogen certificate system to be developed. Initiatives such as CertifHy[47] at EU level and HyXchange[48] in the Netherlands have been started to elucidate, respectively, what conditions the GoOs and the supply chain constraints for hydrogen need to fulfil in order to generate certificates from the GoOs, as well as how a potential hydrogen exchange market (that includes certificate trading) will look like, although to the date of this report no concrete schemes for green hydrogen are in operation.

For example, in the Netherlands there are discussions about the use of green hydrogen in industry and the corresponding inclusion of hydrogen in certificates such as HBEs (*Hernieuwbare Brandstof Eenheid* or Renewable Fuel Unit), HWIs (*Hernieuwbare Waterstof voor de Industrie* or Renewable Hydrogen units for Industry), and EREs (*EmissieReductie-Eenheden* or Emission Reduction Units).

In principle, hydrogen production from DEMO 1 would lead to the production of certificates. The claimed certificates could be sold in order to generate an additional income stream that may cover (part of) the income loss due to the increased cost of hydrogen than natural gas in energy units. Some of the questions that would need to be answered before a concrete business case can be developed for green hydrogen certificates of the DEMO 1 hydrogen include:

- What would be the price of green hydrogen certificates?

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[46] van Zoelen, R., Bonetto, J., & Jepma, C. (2021). D8.1 Admixing literature review. Zenodo. https://doi.org/10.5281/zenodo.5142247
[47] CertifHy. https://www.certifhy.eu/
[48] HyXchange. https://hyxchange.nl/

- What would be the relationship or equivalence between GoOs (that only indicate the origin of the green hydrogen) and other certificates that cover the whole value chain (e.g., HBEs, HWIs, EREs) and that can be cancelled to fulfil renewable energy consumption obligations?
- Will there be a distinction in the cost of certificates for green hydrogen (renewable hydrogen) and blue hydrogen (i.e., low-carbon hydrogen)?
- Is there going to be an interoperable certificate trading system in Europe that may allow the sale of certificates to other countries?
- Will there be a difference in how hydrogen is transported i.e., in pure hydrogen pipelines or blended in natural gas, on the certificates that can be claimed and cancelled?

In order to understand whether hydrogen blending can allow for the claiming of certificates of green hydrogen, it is important to understand the concept of 'chain of custody'. Chain of custody is a concept in markets such as the renewable energy certificate trading market[49], where the flow of a material or energy is followed through every step of a supply chain, from production to transport and end use. Having a good understanding of the chain of custody of a particular commodity (for example hydrogen) allows the awareness of the environmental and ethical impacts of the purchased commodities and provides evidence on the sustainability claims of a particular commodity.

There are four main chain of custody models for the certification of commodities in different industries[50]; they are summarised in Table 12.

Table 12. Summary of the four chain of custody models used in industries that feature certification and certificates trading.

Chain of custody model	Description	Industries where this model is used
Identity preservation	This model tracks a commodity throughout a supply chain and doesn't allow the mixture of a certified product with any other products (either certified in a different way or non-certified)	Common in the food processing and agricultural industries
Segregation chain	Similar to Identity Preservation but this model allows mixing with other certified products only if they share the same defined standard	Most notably in certified organic and fairtrade products
Mass balance	Tracks the total amount of sustainable content and allocates the sustainable content appropriately. The main condition is that all producers and all consumers of a particular good are connected through the same infrastructure, as is the case for natural gas and electricity but not for other kinds of fuel commodities (such as diesel, for example)	Common for products and commodities where segregation is very difficult or impossible e.g., the plastics, aluminium, forestry, and petrochemical industries

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[49] The chain of custody concept is also used in other markets for example, the sustainable farming of cotton, cacao, and coffee, and the production of bioplastics.

[50] Circularise. Four chain of custody models explained. https://www.circularise.com/blogs/four-chain-of-custody-models-explained

Book-and-claim	Certificates can be claimed for the volume of certified sustainable commodities that are being generated. No traceability to the rest of the supply chain. It offers the most flexibility and allows certificate/credit trading.	Most often found in the energy commodity world: Sustainable Aviation Fuels (SAF), biofuels, etc.

As can be seen in Table 12, only the mass balance and book-and-claim chain of custody models would allow the claiming of green hydrogen certificates (e.g., HBEs) from hydrogen injected to natural gas pipelines; for HWI certificates, a lot has to be determined still. There are multiple discussions ongoing related to the green hydrogen certificates and how the system would operate, partially because it is likely that production or consumption subsidies would be connected to the certificate system as well[51].

Regarding the potential of hydrogen blending to generate and cancel certificates, it is important to consider that certificates can typically be claimed only by an end user: if the totality of a hydrogen blend is consumed by a single party, then that party would be able to use any generated certificates and cancel them from their potential renewable energy consumption obligation. In contrast, if the hydrogen blend ends up increasing the hydrogen content of the whole of the Netherlands' natural gas supply, there would be no particular company that can claim to be consuming that hydrogen. This means that there would be no way of cancelling such certificates unless there is a fuel blending obligation in natural gas in the Netherlands where hydrogen can be used as renewable fuel; such fuel blending obligation for sellers of natural gas does not exist on the date when this report was written.

Figure 15 showcases a theoretical exercise where the different options for transporting the DEMO 1 hydrogen to land are shown as well as whether the different chain of custody models would allow claiming and cancelling of green hydrogen certificates.

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[51] As it is expected to happen in the first auction of the European Hydrogen Bank that took place in the first half of 2024: all project owners are expected to produce RFNBO-certifiable hydrogen. https://climate.ec.europa.eu/eu-action/eu-funding-climate-action/innovation-fund/competitive-bidding_en

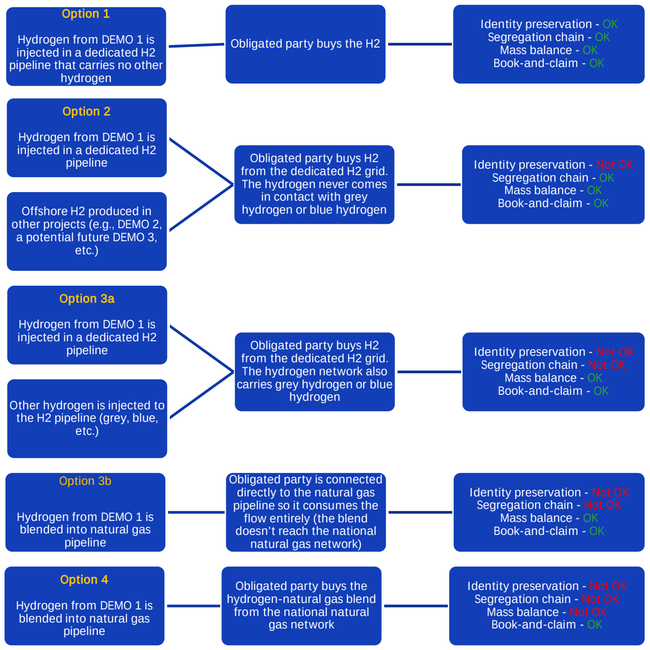

Figure 15. Effect of the various transport options (dedicated pipeline vs blended) of the DEMO 1 hydrogen on the viability to claim and cancel green hydrogen certificates.

As can be seen on Figure 15, whether hydrogen blending can generate certificates is entirely dependent on, among other things, the chain of custody system that is selected to be valid when the certification schemes for hydrogen are defined. By definition, neither identity preservation nor segregation chain would allow certificates cancelling when hydrogen is blended with the natural gas.

For the mass balance chain of custody it is a bit more complex: it depends entirely on where the 'system boundary' is placed by the certification body. As example, if the certification body defines that hydrogen is only certifiable if it is transported in a dedicated hydrogen pipeline, then consuming a blend would not allow certificates to be issued.

The book-and-claim system can be seen as the chain of custody model with the lowest barriers of entry. With such a system, it would be in principle possible to claim green hydrogen certificates. The main question is how would an off-taker prove that they are in fact consuming hydrogen for which they can cancel the corresponding certificates.

All things considered, there are still many questions around the topic of certificates trading, where it is as of the time of writing of this report not very clear what the rules will be. Therefore, it is not yet clear how green hydrogen produced in DEMO 1 would be certifiable and could generate an additional revenue stream via certificates trading.

3.4.8 ETS as another potential revenue source

There could be other potential ways to generate a revenue stream from certificates other than was discussed in this section. As an example, it was recently announced (April 2024) that, as part of the Delegated Regulation of the Free Allowances Act of the EU[52], renewable

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[52] European Union. Commission Delegated Regulation (EU) 2019/331. https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:32019R0331

hydrogen as well as its derivatives (green ammonia, green iron, and green steel) will shortly be eligible to receive free allowances under the EU's Emissions Trading System (ETS)[53], meaning that green hydrogen consumption could be counted within the ETS system. The particularities of this potential revenue stream would have to be considered in detail before it can be elucidated how much impact it can have on the overall revenue stream of offshore hydrogen produced in DEMO 1.

The EU ETS is a 'cap and trade' system. A cap is a limit set on the total amount of greenhouse gases that can be emitted by different obligated parties; such total amounts decrease every year. Such cap is given in so-called emissions allowances (counted in CO2-equivalents)[54]. Such allowances can be traded in an open market: if an obligated party emits less CO2 equivalents than it is allowed, the party can sell the excess allowances e.g., to a party that has emitted more than its allowance.

As an initial estimation of the potential revenue, we can calculate the avoided CO2 costs per unit hydrogen in the blend. To carry out this calculation, we need to establish the reference parameters: the price of the ETS allowances and the emission intensity of natural gas. While the carbon price as per the ETS is a parameter easy to find (since the ETS market is open), the emission intensity of natural gas is a bit more complicated to determine. The reason is that the various obligated industries have different emissions targets (so-called benchmarks), meaning that, as an example, natural gas used for refining has a different emissions allowances than natural gas used in heating applications, since each industry has a different benchmark defined as a function of the end product. To avoid doing a complicated analysis (this is merely a preliminary analysis and a more dedicated one would be needed to achieve accurate results), we will assume that the ETS benchmark used will be that of the "Heat benchmark sub-installation".

To calculate the maximum ETS revenue generated by blending i.e., by substituting some of the natural gas for hydrogen, we can use the following equation:

$$Maximum\ ETS\ revenue\left[\frac{EUR}{MWh}\right] = Emissions\ benchmark\ \left[\frac{ton\ CO2eq}{TJ}\right] * ETS\ reference\ price\ \left[\frac{EUR}{ton\ CO2eq}\right] * \frac{1}{277{,}8}\left[\frac{TJ}{MWh}\right]$$

The equation above would calculate the 'maximum' revenue i.e., that would correspond to substituting 100% of the natural gas with hydrogen and assuming that hydrogen from offshore wind has no emissions[55]. To calculate the potential revenue from blends lower than 100%, we need to consider not only the blend % but also the difference between heating values of hydrogen and natural gas. As has been discussed previously, hydrogen has almost three times less energy than natural gas, so consuming a 1% hydrogen blend (measured by

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[53] The EU ETS is a system that sets an overall limit on the total greenhouse gas emissions in over 10.000 installations around the EU as well as aircraft and maritime transport. It operates in a similar way as fuel blending obligations i.e., there are quotas and trading of certificates. For more information the reader is referred to https://carbonmarketwatch.org/wp-content/uploads/2022/03/CMW_EU_ETS_101_guide.pdf

[54] EU Climate Action. What is the EU ETS? https://climate.ec.europa.eu/eu-action/eu-emissions-trading-system-eu-ets/what-eu-ets_en

[55] The emissions of green hydrogen e.g., from the direct interconnection of electrolysis and renewable power sources (wind or solar) is a current topic of much debate at an international level, and currently we cannot say with certainty whether there will be a reference ETS emissions benchmark reference for green hydrogen production.

volume) would only lead to an effective substitution of ~0,33% of the natural gas in terms of energy. The equation to calculate the ETS revenue from consuming a blend is the following:

$$ETS\ revenue\ of\ a\ blend\ \left[\frac{EUR}{MWh}\right] = \frac{Maximum\ ETS\ revenue\ \left[\frac{EUR}{MWh}\right]}{Hydrogen\ blend\ \% * Hydrogen\ HHV\ \left[\frac{MWh}{Nm3}\right] + (1 - Hydrogen\ blend\ \%) * Natural\ gas\ HHV\ \left[\frac{MWh}{Nm3}\right]}$$

Table 13 shows the reference parameters used in this study as well as the preliminary calculation regarding the potential ETS revenue generated by consuming blended hydrogen.

Table 13. Reference parameters for the ETS revenue calculation.

Reference	Value
Benchmark emissions intensity for the ETS scheme (using the Heat benchmark sub-instalation)[56] [ton CO2eq/TJ]	47,3
Benchmark emissions intensity for the ETS scheme (using the Heat benchmark sub-instalation) [ton CO2eq/MWh]	0,17
ETS reference price[57] [€/ton CO2eq]	€ 67,35
Natural gas price used in this study [€/MWh]	€ 25,55

With the information from Table 13 we can calculate the ETS revenue from hydrogen blending; this calculation is shown on Figure 16.

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[56] https://climate.ec.europa.eu/system/files/2021-10/policy_ets_allowances_bm_curve_factsheets_en.pdf
[57] https://ember-climate.org/data/data-tools/carbon-price-viewer/

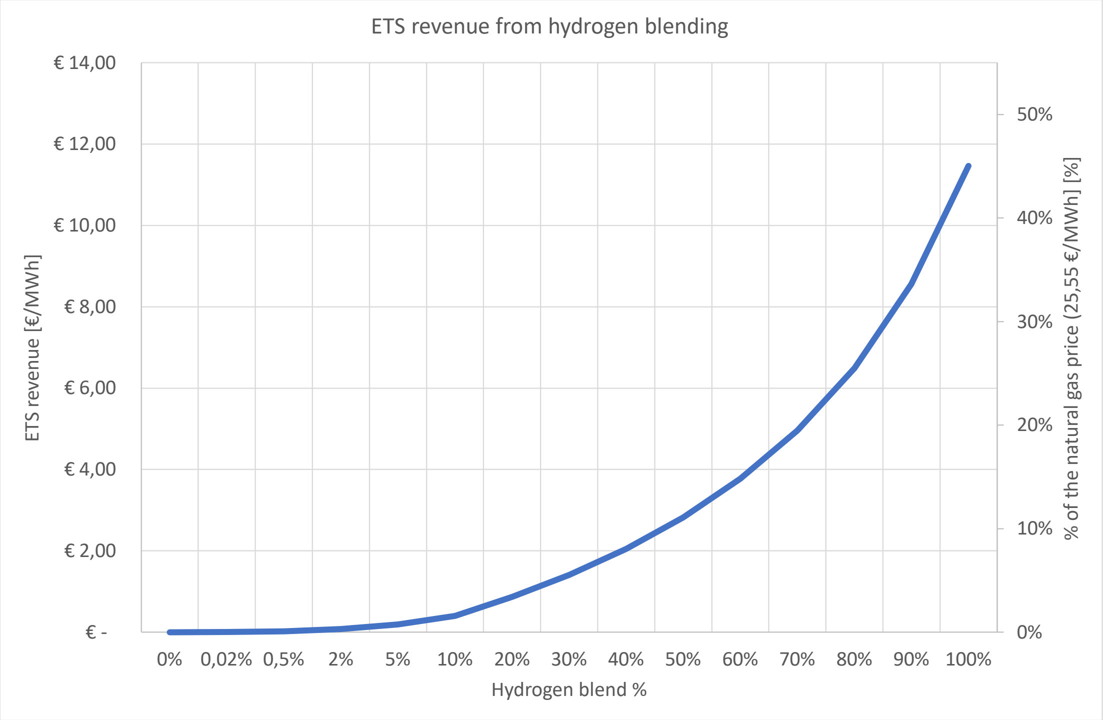

Figure 16. Calculated ETS revenue of different hydrogen blend % and comparison with the natural gas price.

As can be seen on Figure 16, the ETS revenue that can be generated increases dramatically with higher hydrogen blends: the maximum revenue that can be achieved is €11,47/MWh with a 100% blend (which would no longer be a blend but pure hydrogen). With lower blends the ETS revenue is considerably lower: at 2% and 10% the calculated ETS revenue is €0,08/MWh and €0,40/MWh, which represents 0,3% and 2% of the natural gas price, respectively.

Table 14. Summary of the cost of a 2% blend together with the ETS revenue generated.

Natural gas cost: 25,55 €/MWh	LCOH = 3 €/kg (76,16 €/MWh)	LCOH = 6 €/kg (152,33 €/MWh)	LCOH = 10 €/kg (253,88 €/MWh)
Cost of a 2% blend [€/MWh]	€26,56	€28,09	€30,12
ETS revenue generated [€/MWh]	€0,08	€0,08	€0,08
Net cost of the 2% blend including ETS revenue [€/MWh]	€26,48	€28,01	€30,04

From Table 14 it can be seen that the ETS revenue is far from sufficient to compensate for the extra cost of a 2% blend, where the main cause of the price increase is the more expensive hydrogen being blended into a much cheaper natural gas. The ETS revenue is definitely not negligible but by itself is not enough to offset the extra costs of blending hydrogen into a natural gas stream. It is important to consider that the calculation done in thus study should be considered preliminary. In order to have an accurate assessment of the ETS revenue generated, parameters need to be considered such as the type of consumer/obligated party (because different obligated parties have different emissions allowances) and the actual ETS prices when DEMO 1 starts operating.

3.5 Impact of hydrogen blends on the existing gas purity restrictions in Dutch natural gas networks

As has been discussed before, the MR Gaskwaliteit is the law that establishes the purity of the natural gas. According to the MR Gaskwaliteit, there are a total of six different natural gas denominations where each sets the maximum allowed hydrogen content. The allowance of hydrogen differs depending on factors such as the type of gas (H-gas, G-gas, or L-gas), the type of connection to the network (feed-in, off-take, or import/export), and the type of network (high-pressure grid, regional grid, or distribution grid). The MR Gaskwaliteit also makes a distinction for particular end users. Table 15 shows all the natural gas denominations and their corresponding maximum allowable hydrogen content.

Table 15. Summary of all the natural gas denominations defined in the MR Gaskwaliteit and maximum allowable hydrogen contents in each.

Natural gas denomination as per the MR Gaskwaliteit	Type of gas	Type of connection	Network/end user	Maximum hydrogen content
H-gas bij invoeding op een aansluiting	H-gas (high-caloric gas)	Feed-in	HTL (high-pressure transmission grid)	0,02%
G-gas bij invoeding op een aansluiting	G-gas (Groningen gas)	Feed-in	HTL (high-pressure transmission grid)	0,02%
			RTL (regional transmission grid) & RNB (distribution grid)	0,5%
H-gas bij aflevering op een aansluiting	H-gas (high-caloric gas)	Off-take	Refinery[58]	40%
			Maasvlakte system[59]	0,5%
			Rest of the Netherlands	0,02%
G-gas bij aflevering op een aansluiting	G-gas (Groningen gas)	Off-take	HTL (high-pressure transmission grid	0,02%
			RTL (regional transmission grid) & RNB (distribution grid)	0,5%
Grenspunten L-gas: Uitvoer	L-gas (low-caloric gas)	Export	All	0%
Grenspunten H-gas: Invoer en Uitvoer	H-gas (high-caloric gas)	Import/export	All	0%

Additionally, the MR Gaskwaliteit specifies Wobbe index ranges for the import/export natural gas interconnectors with different countries. Table 16 shows the international interconnectors and their corresponding allowed Wobbe bandwidth.

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[58] The MR Gaskwaliteit makes a separate specification for a particular pipeline that services refineries. The pipeline is shown in the Appendix 8 of the MR Gaskwaliteit.

[59] The MR Gaskwaliteit makes a separate specification for a particular pipeline that services the Maasvlakte area. The pipeline is shown in the Appendix 12 of the MR Gaskwaliteit.

Table 16. Summary of the international interconnectors defined in the MR Gaskwaliteit and corresponding lower and upper Wobbe limits. Note that in all import and export stations there is zero hydrogen allowed.

Country	Export stations	Lower limit Wobbe index [MJ/Nm3]	Higher limit Wobbe index [MJ/Nm3]
Belgium	`s Gravenvoeren and Obbicht	49,8	55,7
	Zelzate and Zandvliet	49,2	55,7
Germany	Oude Statenzijl and Vlieghuis	49	55,7
	Bocholtz	49,69	55,7
United Kingdom	Julianadorp (BBL)	49,79	54,23

The timeline to modify the MR Gaskwaliteit e.g., to allow increased hydrogen % in natural gas depends significantly on factors such as (but not limited to):

- **Number of impacted entities**: with a higher number of impacted entities the time to reach an agreement will increase. As rough estimates, past experiences in reaching a decision and the corresponding modification of maximum allowed hydrogen contents have taken between 1,5 years and 10+ years.
- **Changing the MR Gaskwaliteit**: since the changing of the MR Gaskwaliteit is a national decision, the Minister of Economic Affairs and Climate Policy in the Netherlands can change the MR Gaskwaliteit in a relatively short span of time (e.g., a few weeks) if it is deemed that the benefits of changing the MR Gaskwaliteit (by allowing higher hydrogen blend %) outweigh the potential costs (for specific users).
- **International alignment**: the decisions pertaining the natural gas quality in international interconnectors (see for example Table 16) are the result of alignment at the international or EU level, where the standard that determines the limits on hydrogen blend % as well as other maximum values of other components is the EN 16726[60]. Changing this standard[61] (and having it be adopted in each country) could take significantly longer than decisions at national level: it is generally understood that decisions at EU level take longer than decisions at national or regional levels.

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[60] EN 16726:2015. Gas infrastructure – Quality of gas – Group H. https://www.nen.nl/nen-en-16726-2015-a1-2018-en-248937

[61] It is important to note that the EN 16726 does not set a direct limit for hydrogen content in natural gas. The EN 16726 does set a minimum amount of a so-called ‘methane number’, which is a parameter that has to be calculated for each type of natural gas (e.g., that is injected in a particular Member State’s natural gas grid), and has to be calculated based on its composition including hydrogen content.

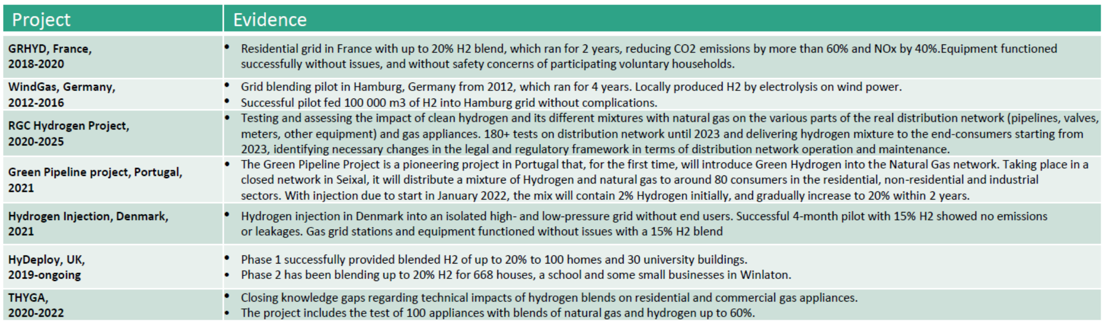
3.6 Other impacts of hydrogen blending

The aim of the previous sections was to assess the impact of hydrogen blends in different aspects: technical, economical, and political. While there was a comprehensive review of different kinds of impacts, there are other impacts that were not studied in detail. These include:

- **Impact of varying blends**. This document based its assessment on fixed blends i.e., where the hydrogen blend % in natural gas is fixed. This is most likely not to be the case in installations where hydrogen is produced via electrolysis directly connected to e.g., offshore wind: the most likely outcome is that a blend produced this way will have varying hydrogen content over time. While most of the impacts described in the previous sections pertain impacts at a design level of a process that produces, transports, or consumes a blend, in reality varying blends could lead to e.g., acceleration of material impacts of blends (e.g., embrittlement or other hydrogen-related effects). That being said, it is likely that natural gas also has a varying composition over time due e.g., to its origin (imports or domestic production with varying production or import amounts during the year) meaning that there is a possibility that process plants that use natural gas are already designed to cope with varying compositions of the gas. As such, the impact of varying blend % may not be any more impactful than varying natural gas. Moreover, little is known regarding the long-term impacts of hydrogen blends on equipment so it is likely that the impact of varying blends is also not very much understood.
- **Other potential new markets and synergies**: potential windfalls that can be established regarding hydrogen (in the context of DEMO 1 or beyond) include the use of CCS (Carbon Capture and Storage) e.g., of hydrogen production via steam reforming. Moreover, first large-scale hydrogen blending projects (e.g., DEMO 1) could potentially accelerate hydrogen production projects via advancements in permitting processes and analysis of safety requirements. Furthermore, hydrogen could have potential value for particular industries that are more severely impacted by emissions allowances or that are seen more strategic to decarbonize first; such industries could include electricity generation, hydrogen as feedstock, etc.

3.7 Real-life tests of hydrogen blending

Hydrogen blending has been explored since the 2000's in Europe[62] and the US[63] including demonstration projects throughout Europe since the 2010's. Figure 17 shows an overview of some of the hydrogen blending (pilot) projects throughout Europe.



Project	Evidence
GRHYD, France, 2018-2020	• Residential grid in France with up to 20% H2 blend, which ran for 2 years, reducing CO2 emissions by more than 60% and NOx by 40%.Equipment functioned successfully without issues, and without safety concerns of participating voluntary households.
WindGas, Germany, 2012-2016	• Grid blending pilot in Hamburg, Germany from 2012, which ran for 4 years. Locally produced H2 by electrolysis on wind power. • Successful pilot fed 100 000 m3 of H2 into Hamburg grid without complications.
RGC Hydrogen Project, 2020-2025	• Testing and assessing the impact of clean hydrogen and its different mixtures with natural gas on the various parts of the real distribution network (pipelines, valves, meters, other equipment) and gas appliances. 180+ tests on distribution network until 2023 and delivering hydrogen mixture to the end-consumers starting from 2023, identifying necessary changes in the legal and regulatory framework in terms of distribution network operation and maintenance.
Green Pipeline project, Portugal, 2021	• The Green Pipeline Project is a pioneering project in Portugal that, for the first time, will introduce Green Hydrogen into the Natural Gas network. Taking place in a closed network in Seixal, it will distribute a mixture of Hydrogen and natural gas to around 80 consumers in the residential, non-residential and industrial sectors. With injection due to start in January 2022, the mix will contain 2% Hydrogen initially, and gradually increase to 20% within 2 years.
Hydrogen Injection, Denmark, 2021	• Hydrogen injection in Denmark into an isolated high- and low-pressure grid without end users. Successful 4-month pilot with 15% H2 showed no emissions or leakages. Gas grid stations and equipment functioned without issues with a 15% H2 blend
HyDeploy, UK, 2019-ongoing	• Phase 1 successfully provided blended H2 of up to 20% to 100 homes and 30 university buildings. • Phase 2 has been blending up to 20% H2 for 668 houses, a school and some small businesses in Winlaton.
THYGA, 2020-2022	• Closing knowledge gaps regarding technical impacts of hydrogen blends on residential and commercial gas appliances. • The project includes the test of 100 appliances with blends of natural gas and hydrogen up to 60%.

Figure 17. Overview of some of the pilot and demonstration projects around hydrogen blending in existing natural gas networks in Europe[64].

Most (if not all) of the projects depicted in Figure 17 have been carried out in onshore pipelines, in both the high-pressure grids (where steel is the main pipeline material) and low-pressure grids (where pipelines are made of polymeric materials). It is widely agreed that from the different pipeline materials, polymers such as Polyethylene (PE) and Polyvinyl chloride (PVC) are more compatible with hydrogen than steel pipelines, mainly due to materials such as iron and steel being more impacted by hydrogen-induced effects than polymers. The following subsections contain a description of some of the aforementioned pilots of hydrogen blending.

3.7.1 HyDeploy – small-scale trial of hydrogen blend for industrial use in the UK

HyDeploy[65] is an ongoing project led by a British consortium consisting of British gas network operators Cadent and Northern Gas Networks, as well as industry players, consultants, and research institutions. The objective of the project is to carry out tests and real-life trials of hydrogen blending (up to 20%) in the British onshore gas network in order to elucidate the safety and compatibility of the existing assets. In 2021, HyDeploy carried out two industrial trials[66]:

- Testing of a 1.2 MW boiler at the Dunphy manufacturing facility
- A five-day trial on the 55 MW operational glass furnace at Pilkington Glass

It is expected that a third trial is carried out namely, on the 7 MW steam-raising boiler at the Unilever manufacturing complex in Port Sunlight.

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[62] For example, the previously mentioned NATURALHY project.
[63] For example see the NREL reports https://www.nrel.gov/docs/fy23osti/81704.pdf and https://www.nrel.gov/docs/fy13osti/51995.pdf
[64] Ready4H2. https://www.ready4h2.com/_files/ugd/597932_0d67d1d9fd3e467ea03d941fcbb6a645.pdf
[65] HyDeploy. https://hydeploy.co.uk/
[66] HyDeploy 2 Project. 3rd Project Progress Report (PPR). December 2021. https://hydeploy.co.uk/app/uploads/2022/06/HYDEPLOY2-THIRD-OFGEM-PPR.pdf

The 1.2 MW boiler testing demonstrated the operational soundness of fuelling a boiler with a hydrogen blend. The testing characterised the thermal and process performance of the boiler to provide robust evidence of performance integrity.

The five-day trial was undertaken at Pilkington Glass in St. Helens. Each day during the trial 2 tonnes of hydrogen –roughly equivalent to the output of a 9 MW electrolyser operating at 50% load– were consumed by the 55 MW furnace. The trial produced a batch of sheet glass, which passed all product quality testing. This was the first use of a hydrogen-natural gas blend within the UK to produce glass. An 18-month engineering and logistics programme was required in preparation for the trial.

3.7.2 Trials by SNAM in Italy

The Italian gas network operator SNAM has carried out in the last years several hydrogen blending pilot projects. These tests have included:

- Supplying 5-10% hydrogen blends to a pasta factory and a water bottling company in 2019[67].
- Testing up to 10% hydrogen blends for a new line of gas turbines designed by Baker Hughes in 2020[68].
- Supplying 30% hydrogen blends as a pilot project to Gruppo GIVA (a steelmaker) in their Rho plant (hydrogen blend was used to heat their furnaces) in May 2021[69].

Furthermore, SNAM has also carried out tests on their infrastructure (pipelines, compressor stations, underground storage) to test the feasibility of operating their infrastructure without major changes[70]:

- Injection of up to 10% hydrogen blends in their transmission network.
- Testing turbocompressors to verify gas turbine operation fuelled with hydrogen blends up to 5% in volume and variable over time, at their compressor stations in Istrana and Sergnano.
- Initial feasibility studies of the physical, chemical, and microbiological phenomena associated with the (underground) storage of hydrogen blends.

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[67] SNAM. Snam: hydrogen blend dubled to 10% in Contrusi trial. https://www.snam.it/en/media/news-and-press-releases/news/2020/snam-hydrogen-blend-doubled-to-10--in-contursi-trial.html

[68] Baker Hughes. Snam and Baker hughes test world's first hydrogen blend turbine for gas networks. https://www.bakerhughes.com/company/news/snam-and-baker-hughes-test-worlds-first-hydrogen-blend-turbine-gas-networks

[69] Reuters. Italy's Snam in World first with test of 30% gas-hydrogen blend in stel forging. https://www.reuters.com/business/italys-snam-world-first-with-test-30-gas-hydrogen-blend-steel-forging-2021-05-19/

[70] SNAM presentation at Wind Meets Gas. 08 October 2021.

4 Hydrogen deblending

A potential downstream process after hydrogen blending can be hydrogen deblending in order to separate hydrogen from natural gas at another point of a gas pipeline e.g., onshore. Being able to recover pure hydrogen from hydrogen blends could enable end users interested in buying pure hydrogen such as refuelling stations and industrial users to utilise the hydrogen produced offshore e.g., during the DEMO 1 and DEMO 2 projects. Deblending can potentially recover pure hydrogen as well as either high-purity hydrogen-free natural gas or hydrogen blends with lower hydrogen content that can be safely integrated to existing assets with minor to no issues.

4.1 Technologies for deblending and state of the art

Deblending is simply gas separation. Gas separation technologies are mature and well-established and have been used in natural gas processes for decades: hydrogen is regularly separated from gas mixtures such as carbon monoxide and carbon dioxide, as well as from other gases such as helium, chlorine, etc. The most relevant technologies for hydrogen deblending are:

1) Pressure Swing Adsorption (PSA)
2) Cryogenic Distillation
3) Membrane Separation (using metallic or polymer membranes, or other materials)

Technologies such as PSA, Cryogenic Distillation & Membrane Separation are globally used to separate and purify hydrogen. Promising technologies including electrochemical separation, palladium membranes, etc., are emerging in the field of hydrogen separation from gas mixtures but have not been used in large-scale applications yet.

As important clarification, there are discussions where chemically separating the hydrogen from e.g., natural gas (through the process known as Steam Methane Reforming or SMR), is considered as ‘deblending’. Technically speaking, SMR is a form of chemical deblending where natural gas is used to produce hydrogen, meaning that in the process inlet there is natural gas but in the process outlet there is no more natural gas (i.e., the gas is consumed to make hydrogen). Such processes are technically speaking a ‘production’ process instead of a deblending process; another term for such processes is ‘chemical’ deblending because the natural gas molecule is transformed into hydrogen. In all the deblending technologies discussed in the following sections, the processes are classified as ‘physical’ de-blending, which means that the natural gas still exists as such in the outlet, only in a separate flow than the hydrogen. As such, no natural gas is consumed during the process.

4.1.1 Pressure Swing Adsorption (PSA)

Pressure Swing Adsorption (PSA) is a mature technology used industrially to purify gases. In the hydrogen context, PSA units are used to purify high hydrogen content gas (>40%). PSA is an economic and reliable method used to separate mixed gas into individual gases while achieving a high purity level. During the process, gases are separated under pressure based on affinity for an adsorbent material.

4.1.1.1 Working principle

The principle of PSA is based on adsorption of the different components of a gas stream (hydrogen, methane, etc.) where some components are physically ‘adsorbed’ (i.e., temporarily adhered to the surface of) a porous adsorbent material contained in a vessel. When a gas stream enters a container full of adsorbent material, the components that have low affinity with the adsorbent (typically hydrogen is one of them) are almost not adsorbed and can pass though. The other components will be adsorbed to the adsorbent until the adsorbent is full, after which the adsorbent needs to be ‘regenerated’. Regeneration of the adsorbent means that the pressure in the vessel is lowered and then the adsorbed components are released (this is known as the ‘pressure swing’). Having two vessels (also called adsorption columns) at the same time will ensure that one bed is operating while the other is regenerated, and when one bed is saturated and the other regenerated, they swap places, ensuring a continuous operation. Figure 18 shows the ‘affinity spectrum’ i.e., the affinity of different components in a typical PSA; PSA is an optimal solution for separating different gases if they find themselves at different ends of the affinity spectrum.

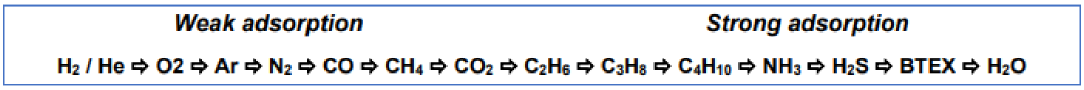


Figure 18. Relative adsorption spectrum of gas components in the adsorbent media typically used in PSA units.

Most of the focus of engineering design of PSA units relates to the optimisation and automatic operation of the regeneration step. To provide a continuous hydrogen supply, a minimum of two adsorber vessels are required to be operated in the following steps:

1. Adsorption
2. Depressurization (via pressure equalisation and purging into another adsorber)
3. Regeneration.
4. Re-pressurisation.

Figure 19 gives an overview of a typical process layout of PSA.

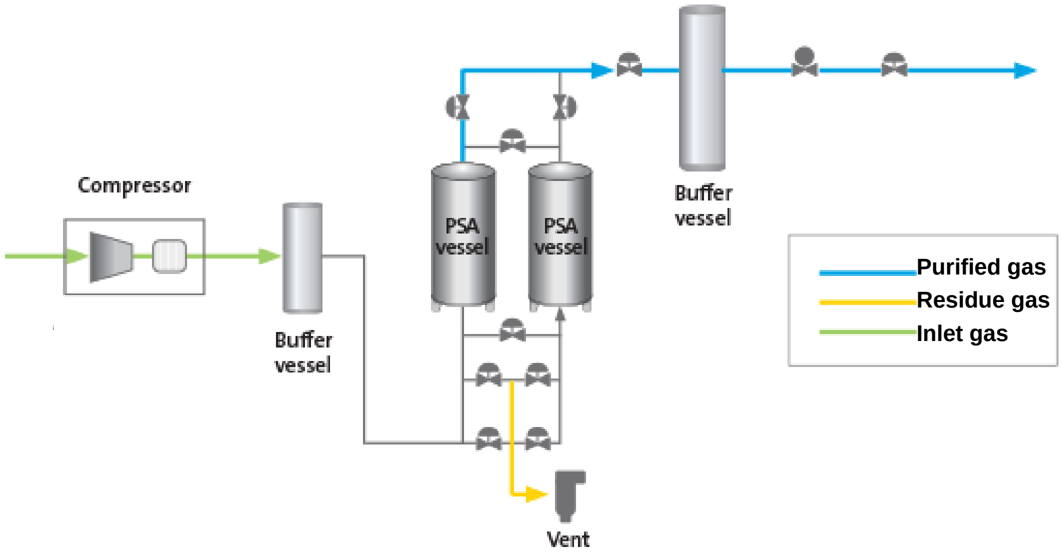


Figure 19. Typical PSA process flow diagram.

4.1.1.2 Technical specifications

Below is a non-exhaustive list of key technology specifications:

- PSA technology is generally suited as hydrogen purification step, achieving high hydrogen purity 99,7% (as high as 99,999%) with frequent cycling, reducing recovery rates or using second stage PSA or membrane separation.
- Hydrogen generally is produced at high pressure, near feed pressure typically (typically between 10–40 bar).
- Recovery rate of the inlet hydrogen typically is around 80–90%.
- No process heating or cooling required.
- Minimum pressure loses can be expected.
- A typical cycle time for a PSA could range from less than 30 seconds to around 10 minutes.
- Generally, PSA is not used for purification of feed gas containing less than 50% hydrogen.

4.1.1.3 Commercial availability

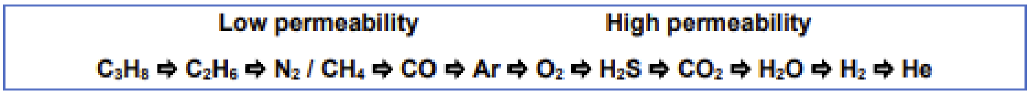
PSA is a global and mature technology with a large number of facilities in operation. Commercial PSA units normally use between 4 and 12 adsorber vessels or modules, but this is strongly dependent on gas flow, required purities, and inlet compositions; more adsorbers are used for higher hydrogen recovery or increasing capacity. Commissioning times vary strongly depending on the type of gas and process conditions, although current design philosophies for hydrogen PSAs lean towards prefabricated modules in order to limit commissioning times and costs[71]. Key suppliers/vendors of this technology include Linde, Air Products, and Honeywell UOP.

4.1.2 (Polymeric) Membrane Separation

Membrane separation is a compelling technology for hydrogen separation. There are quite a lot of membrane technologies available in the market that are in various stages of development. These predominantly include polymer membranes, palladium membranes and carbon molecular sieves. Out of the three mentioned, polymer membrane is currently used in industrial scale processes for hydrogen purification and separation, while the other two are still in development. This report is primarily going to focus on industrial scale processes (i.e., polymeric membranes in this case).

4.1.2.1 Working principle

Unlike in PSA separation where the basis for separation is the affinity of some gases to an adsorbent (‘chemical affinity’), membrane separation consists of separation by size exclusion: membranes act as a filter to separate gas components from a gas mixture. The principle for separation is that membranes are selectively permeable to certain gas components. The mass transfer through the membrane is driven by a pressure gradient across the membrane, which also means that, in order for the outlet gases to exit at the same pressure as the inlet gases, external compression is required. Figure 20 shows the ‘relative permeability spectrum’ of different gases; low molecular weight gases, small gases, and strongly polar gases have high relative permeabilities. Membrane separation is an ideal process to separate a gas mixture if the components are located in opposite sides of the spectrum.



Low permeability **High permeability**

$C_3H_8 \Rightarrow C_2H_6 \Rightarrow N_2 / CH_4 \Rightarrow CO \Rightarrow Ar \Rightarrow O_2 \Rightarrow H_2S \Rightarrow CO_2 \Rightarrow H_2O \Rightarrow H_2 \Rightarrow He$

Figure 20. Relative permeability spectrum of different gases through a polymeric membrane.

A typical membrane separation unit consists of a two-stage membrane process in which a first stage membrane produces the required hydrogen product, and a second membrane producing a low-pressure, hydrogen-rich stream that is recirculated and blended with the inlet gas to increase the hydrogen content. Figure 21 shows a typical process flow diagram of a membrane separation process.

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[71] Hydrogen Recovery by Pressure Swing Adsorption. Linde Engineering. https://www.linde-engineering.com/en/images/HA_H_1_1_e_09_150dpi_NB_tcm19-6130.pdf

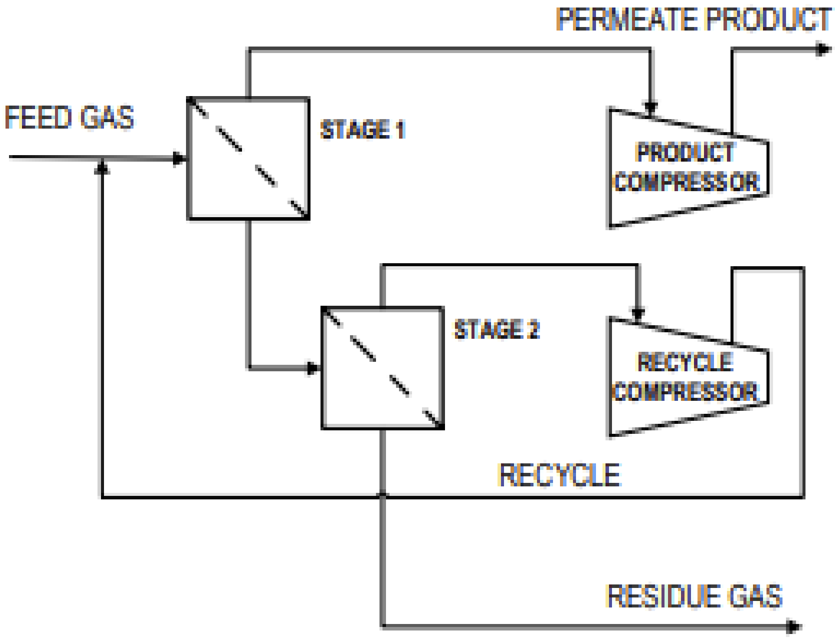

Figure 21. Typical process flow diagram of a membrane separation process.

4.1.2.2 Technical specifications

Polymeric membranes can be based on rubbery or glassy polymers. Rubbery polymers usually have high permeability for gases, but a relatively low selectivity (meaning that gases of different sizes can pass through the membrane unimpeded), while glassy polymers have high selectivity and lower permeabilities. Below is a non-exhaustive list of key technology specifications:

- Maximum hydrogen purity achievable is about 98% with polymeric membranes for feed gas with hydrogen content above ~50% (nominal).
- Maximum hydrogen purity will decrease to about 50–70% for low hydrogen contents (5–10%).
- Recovery rates are typically 80–90%, based on inlet hydrogen contents above 20–50%.
- The technology has an acceptable performance (selectivity and recovery) for inlet gases containing >20% hydrogen.
- Minimum feed gas pressure required is about 20 bar to ensure acceptable flows through the membrane.
- Typical hydrogen purity ranges of 90–95% up to 99% can be obtained (based on typical hydrogen contents above 20-50%).
- For hydrogen purification, membrane separation offers a marginally better performance than PSA at a high feed pressure (~70 bar).

4.1.2.3 Commercial availability

The lead time to commission such a unit is around 12–24 months depending upon the project scale. There is already some industrial deployment of this technology for hydrogen applications, for example the Linde Dormagen hydrogen demonstration site and the Linde/Evonik plant in Mankota, Canada (removal of helium from natural gas). Key suppliers/vendors of this technology include Honeywell UOP, Air Products, Mahler, and Linde.

4.1.3 Cryogenic Distillation

Cryogenic or low temperature separation is a mature technology; the most common process are the Air Separation Units (ASUs) used e.g., in the production of noble gases (helium, argon, etc.) as well as nitrogen for ammonia production. Hydrogen purification via cryogenic distillation is a common in process industries, particularly refineries.

4.1.3.1 Working principle

Separation of gas components is based on differences in the relative volatilities (i.e., different boiling points) of different gases in a mixture. To achieve this, gases are cooled down until condensation, with separation achieved when some of the components are condensed. Hydrogen volatility is very high due to its very low boiling point (-253ºC), and it will (mostly) remain as a gas when most other gases become a liquid (i.e., at temperatures higher than -253ºC). Figure 22 shows the ‘boiling point spectrum’ of different gases; cryogenic distillation is be an ideal process to separate gas mixtures if the components are on different ends of the spectrum.

Low boiling point **High boiling point**
He ⇨ H_2 ⇨ N_2 ⇨ O_2 ⇨ CH_4 ⇨ C_2H_6 ⇨ CO_2 ⇨ C_3H_8 ⇨ C_4H_{10}

Figure 22. Boiling point spectrum of different gases.

Figure 23 represents a typical cryogenic separation process flow diagram.

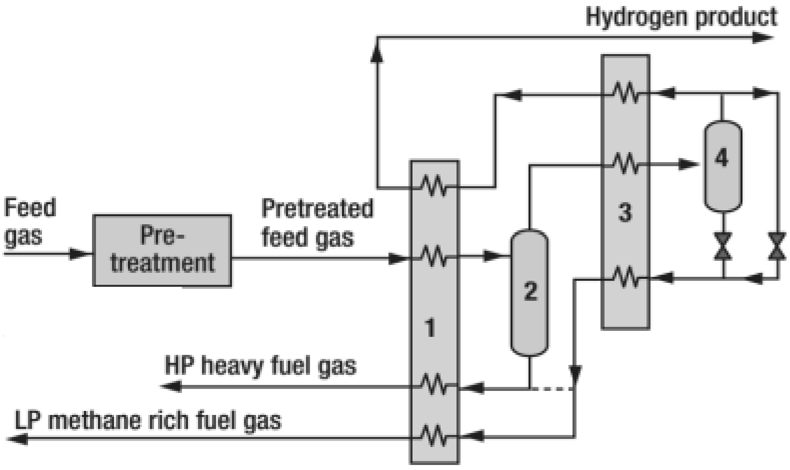

Figure 23. Typical cryogenic distillation process flow diagram.

4.1.3.2 Technical specifications

Cryogenic separation is a proven, well-understood technique for separating gases, for example natural gas and hydrogen at large scale. Currently, it is widely used in midstream gas processing and in the petrochemical sector. Below is a non-exhaustive list of key technology specifications:

- No minimum hydrogen content is needed.
- Typical achievable hydrogen purity is around 90–95%, potentially as high as 98–99% can be achieved.
- Cryogenic separation can produce a high-purity hydrogen stream.
- Cryogenic distillation is typically carried out at -175ºC to -200ºC and requires materials that can withstand cryogenic conditions.
- Typical hydrogen recovery is around 80–90%.
- The start-up and shutdown times of a cryogenic distillation plant are significantly higher than other separation technologies i.e., that operate at lower temperatures.
- Cryogenic separation operates at temperature below -150ºC so any components in the gas that will freeze at these or lower temperatures need to be removed to avoid risks of ice formation. Typical gases that can freeze under such conditions include carbon monoxide, carbon dioxide, as well as sulphur-containing species.

4.1.3.3 Commercial availability

As mentioned before, cryogenic distillation is used widely in industry. Lead times of construction of cryogenic distillation units range between 24 and 36 months i.e., twice as high as membrane separation. Key vendors for this technology include Linde, Air Liquide, and Air Products.

4.2 Required assets to obtain specific qualities of the H2

The previous section of the report focused on different industrially available technologies for purification and separation of hydrogen. All technologies identified in this study can be used to achieve high-purity hydrogen recovery. Moreover, all the technologies mentioned above are currently being used in different industrial sectors.

The costs for hydrogen purification are extremely dependent upon the hydrogen content in the gas, where the 'rule of thumb' is that a lower inlet concentration of hydrogen will generally lead to high purification costs. Some separation technologies may not be able to meet the requirements for both low hydrogen content in the natural gas after separation AND high purity of hydrogen at the same time. Therefore, individual technologies can be coupled to meet the demands in processes with low inlet hydrogen concentrations (e.g., hydrogen-natural gas blends with less than 5% hydrogen).

The biggest challenge and uncertainty are to find the combination of technologies that are economically and technically feasible to achieve high hydrogen purity, low hydrogen content in the natural gas outlet, and a low inlet hydrogen blend %. We have identified two potential combination of technologies that can be used in the case of deblending hydrogen blends with low hydrogen %:

1) **Membrane Separation + PSA**: a combination of Membrane Separation and PSA could be a viable option to attain a high purity hydrogen stream. Membranes can be used as a 'first stage' separation i.e., to increase the hydrogen content that enters the PSA. PSA can be then used as a 'second stage' separation, further purifying the hydrogen to high-purity conditions (higher than 95%).

2) **Cryogenic Distillation**: as mentioned in the previous section, Cryogenic Distillation process can handle practically any hydrogen content in the feed gas. A hydrogen product with a purity higher than 90% can be produced at high pressure, while the 'residue' gas (i.e., natural gas with lower hydrogen content) can exit the process at different pressures.

In the next section, the technologies described above are going to be compared from an economic perspective to determine the costs of hydrogen deblending from natural gas using either the Membrane Separation + PSA or the Cryogenic Distillation route.

4.3 Estimation of the costs of deblending for selected processes

The costs of hydrogen separation will depend on the following parameters:

- Inlet concentration of hydrogen in the blend
- Required purity of the purified hydrogen
- Flow of hydrogen to be separated from the natural gas
- Inlet pressure of the stream
- Recovery rate of hydrogen[72]

Due to the multiplicity of parameter combinations, it is in principle not possible to compare studies done by different publications. To have a recent estimation of the costs of hydrogen deblending for a particular case that we believe to be relatively similar to the situation of DEMO 1, we have selected to discuss the results from a recent calculation done by Costain for a consortium of British gas network operators related to hydrogen deblending from natural gas in different cases.

The Costain study calculated the cost of hydrogen deblending (including CAPEX, OPEX, and cost per kg hydrogen) as a function of parameters such as the hydrogen blend % and the operating pressure, for two different deblending processes (Cryogenic Distillation and a combination of Membrane Separation + PSA). Figure 24 shows an overview of the parameters used for the cost calculation of the Costain study.

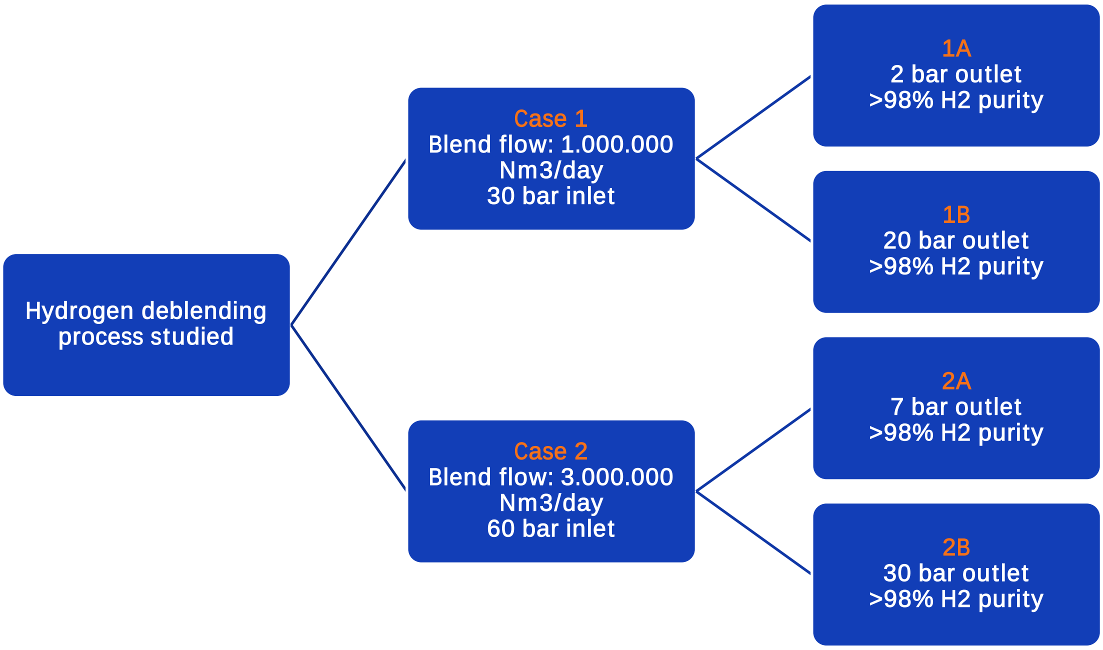

Figure 24. Hydrogen deblending processes studied in this section i.e., in Figure 25, Figure 26, and Figure 28.

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[72] The recovery rate of hydrogen is not an explicit cost of separation but rather a 'missed revenue': since any separation process is inherently not 100% effective at recovering all hydrogen from a hydrogen-natural gas blend, any hydrogen not recovered (i.e., that stays with the natural gas) will lead to a missing revenue unless the natural gas price is adjusted to reflect the missed revenue from the hydrogen that was not recovered.

4.3.1 CAPEX comparison

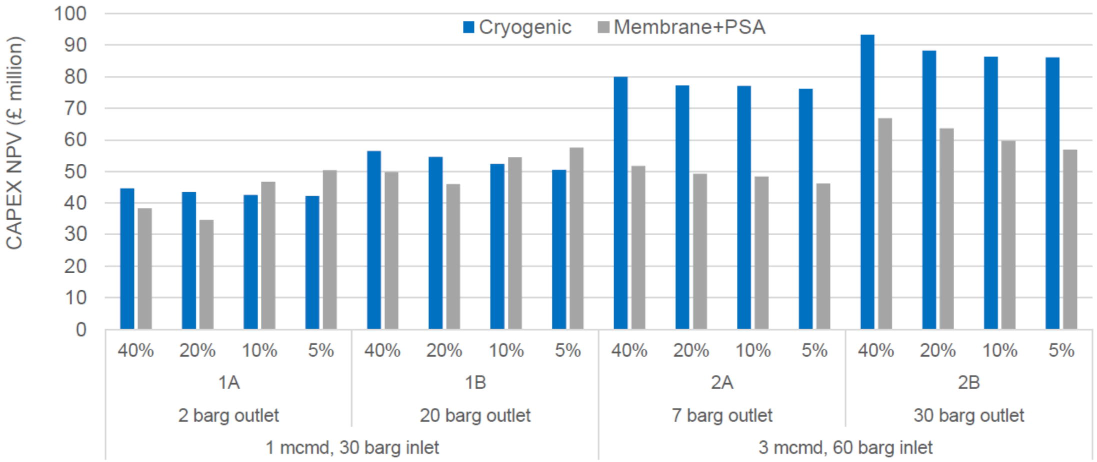

Figure 25. Comparison of the CAPEX (in Net Present Value form) for hydrogen deblending (thus excluding cost of hydrogen production or LCOH) for different technologies, pressures, and hydrogen blend contents, in GBP (British Pounds) per kg hydrogen (1 GBP is approx. 1,17 EUR)[73]. Mcmd = million cubic meters per day. 1 Mcmd ~ 200 MW electrolysis operating at full capacity.

From Figure 25 we can see that the CAPEX of the combination Membrane Separation + PSA has an advantage over Cryogenic Distillation in Case 2 (where the hydrogen flow is 3 million Nm3/day) while the CAPEX is roughly on a similar level in Case 1 (where the flow is 3 times less i.e., 1 million Nm3/day). This could be because PSA is a heavily CAPEX-driven process i.e., the costs decrease significantly for higher flows and vice-versa.

4.3.2 OPEX comparison

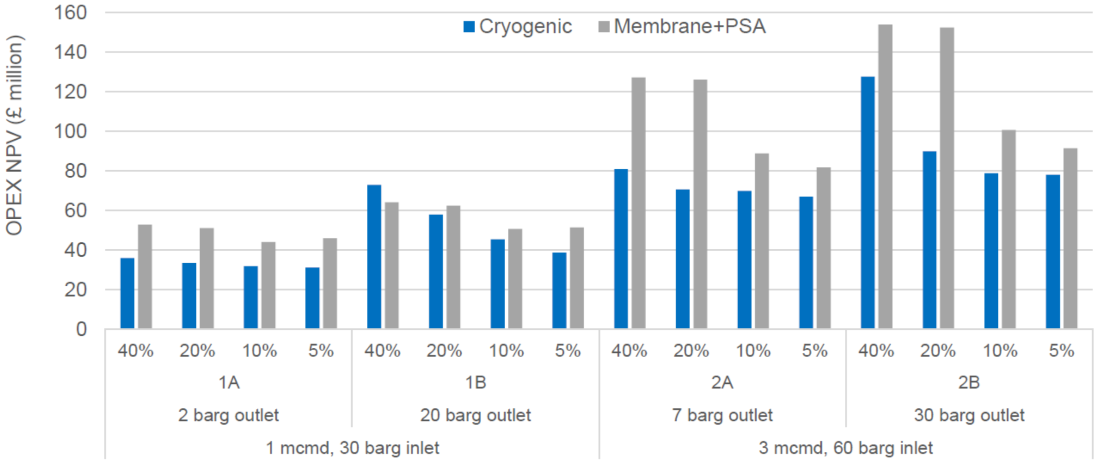

Figure 26. Comparison of the OPEX (in Net Present Value form) for hydrogen deblending (thus excluding cost of hydrogen production or LCOH) for different technologies, pressures, and hydrogen blend contents, in GBP (British Pounds) per kg hydrogen (1 GBP is approx. 1,17 EUR). Mcmd = million cubic meters per day. 1 Mcmd ~ 200 MW electrolysis operating at full capacity.

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[73] Costain. Hydrogen Deblending in the GB Gas Network. NIA Final Report. 2020-2021. https://smarter.energynetworks.org/projects/nia_nggt0156/

Regarding OPEX, from Figure 26 we can see that, generally, Cases 1A and 2A (where the pressure difference is higher) have a lower OPEX than Cases 1B and 2B (where the pressure difference is lower). This is most likely a result of the compression power needed to re-compress the natural gas after deblending e.g., as per pipeline or customer specifications.

4.3.3 Hydrogen recovery comparison

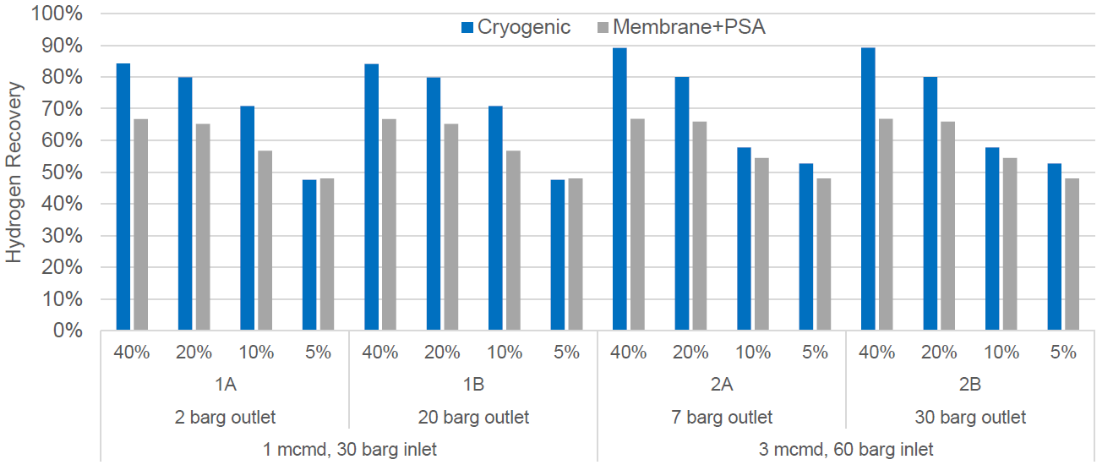

Figure 27. Comparison of the hydrogen recovery (% of the total hydrogen in the inlet that is present in the outlet hydrogen flow) for hydrogen deblending (thus excluding cost of hydrogen production or LCOH) for different technologies, pressures, and hydrogen blend contents, in GBP (British Pounds) per kg hydrogen (1 GBP is approx. 1,17 EUR). Mcmd = million cubic meters per day. 1 Mcmd ~ 200 MW electrolysis operating at full capacity.

Figure 27 shows the hydrogen recovery of the different Cases and technologies. The main drivers of hydrogen recovery are 1) hydrogen that cannot be recovered from the blend (due to the concentration being too low) and 2) hydrogen that needs to be re-injected to the process e.g., for the regeneration of the adsorption bed (relevant only for the PSA process). From Figure 27 it is clear that the recovery of hydrogen in all Cases decreases for decreasing inlet hydrogen blend %, which is logical considering that the it is significantly more difficult to recover hydrogen from a more diluted mixture (e.g., a 5% blend) than a more concentrated mixture (e.g., a 40% blend).

4.3.4 Total cost of deblending hydrogen (excluding the cost of hydrogen production)

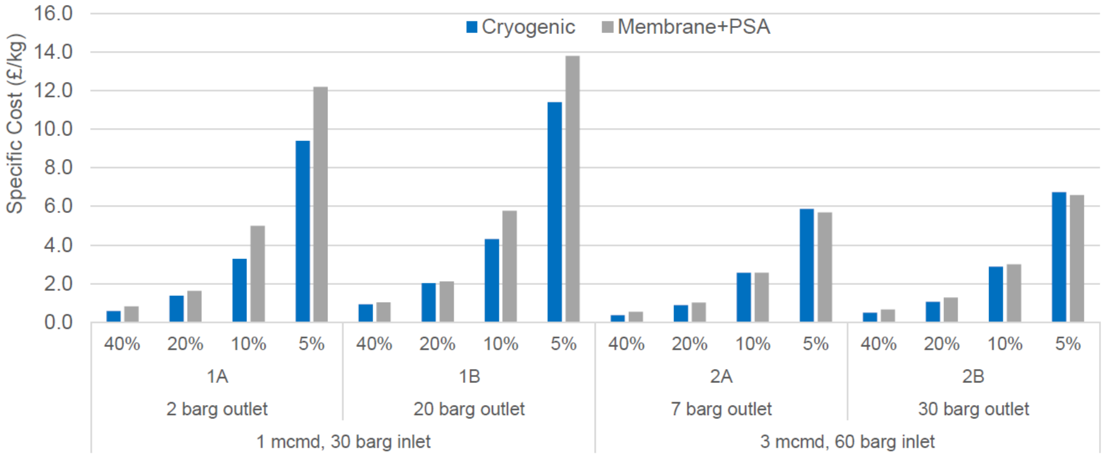

Figure 28. Comparison of the cost per hydrogen deblended (thus excluding cost of hydrogen production or LCOH) for different technologies, pressures, and hydrogen blend contents, in GBP (British Pounds) per kg hydrogen (1 GBP is approx. 1,17 EUR). Mcmd = million cubic meters per day. 1 Mcmd ~ 200 MW electrolysis operating at full capacity.

Figure 28 shows an aggregation of the calculations of CAPEX, OPEX, as well as recovery rate, of different technologies for deblending (cryogenic distillation and a combination of membrane separation + PSA). According to Figure 28, in all Cases a low hydrogen blend % leads to an increase in the specific costs of hydrogen separation. Furthermore, both options for hydrogen deblending perform similarly in costs, with Membrane Separation + PSA having higher costs in the 30-bar inlet case. This might be explained by an increase in both CAPEX and OPEX of the Membrane Separation + PSA combination at low hydrogen blend %.

It is important to emphasize that the costs shown in Figure 28 correspond only to deblending costs i.e., that they do not include any costs of hydrogen production. This means that the total cost of hydrogen including both production and deblending (excluding any extra costs incurred e.g., for blending hydrogen in a natural gas pipeline) are even higher than what is shown on Figure 28. Table 17 shows an overview of the costs of deblending and deblending plus hydrogen production.

Table 17. Summary of the results from Figure 28 for the case of 1 million Nm3/day H2 deblended at 5% hydrogen blend and 30 bar inlet pressure (Cases 1A and 1B), for only deblending and the total cost including production and deblending.

1 million Nm3/day H2 production (~200 MW electrolysis installed capacity) Inlet hydrogen blend = 5%	2 bar outlet (Excluding compression needed to reach 50 bar to inject to the Waterstofnetwerk Nederland)			20 bar outlet (Excluding compression needed to reach 50 bar to inject to the Waterstofnetwerk Nederland)		
30 bar hydrogen inlet (expected operating pressure of an electrolyser) – only deblending	10-14 €/kg (deblending only) (254-355 €/MWh)			13-17 €/kg (deblending only) (330-432 €/MWh)		
30 bar hydrogen inlet (expected operating pressure of an electrolyser) – production + deblending	LCOH = 3 €/kg	LCOH = 6 €/kg	LCOH = 10 €/kg	LCOH = 3 €/kg	LCOH = 6 €/kg	LCOH = 10 €/kg
	13-17 €/kg (330-432 €/MWh)	16-20 €/kg (406-508 €/MWh)	20-24 €/kg (508-610 €/MWh)	16-20 €/kg (406-508 €/MWh)	19-23 €/kg (483-584 €/MWh)	23-27 €/kg (584-686 €/MWh)

From Table 17 it is clear that the total cost of hydrogen deblending is significantly high, in all cases considered the deblending is more expensive than the cost of hydrogen production. This means that the total cost of hydrogen production and deblending could increase up to 600+ €/MWh, which considering the cost of natural gas considered in this study (25,55 €/MWh) effectively means that hydrogen production and deblending is almost 30 times more expensive than natural gas.

It is important to understand that every cost calculation has different assumptions and can lead to different results. The study discussed in this section relates to conditions that may be deemed comparable to the conditions expected in the case of deblending offshore hydrogen: elevated pressures from offshore pipelines make landfall in an onshore gas processing terminal, where hydrogen is deblended. In all four Cases considered in this section, compression of the hydrogen would be needed before injecting to the Waterstofnetwerk Nederland (with a required injection pressure of 50 bar), meaning that compression would be needed, where as a rule of thumb an energy consumption between 2 and 8 kWh/kgH2[74] (depending on the technology used) would be unavoidable.

4.3.5 Deblending as protective measure for feedstock consumers of natural gas

There are organisations that are not considering deblending due to the business case of pure hydrogen but rather as a ‘protective’ measure of natural gas users. As was discussed above, some of the most likely users to be impacted by hydrogen blends are users of the natural gas as feedstock e.g., the ones that produce hydrogen via methane reforming for applications such as hydrocracking of oil, ammonia production, etc. These users could potentially be vulnerable to hydrogen blends of even low %, meaning that in a grid that contains hydrogen intended also for other users (for example that burn natural gas where there could have more flexibility to accept hydrogen blends), the feedstock users would need to have a protective measure so the natural gas that reaches them is hydrogen-free. Other users that can be impacted are vehicles that use CNG (compressed natural gas): hydrogen in the natural gas can lead to embrittlement and potentially failure of the onboard tanks of CNG vehicles (present on both passenger vehicles and cargo vehicles).

Deblending as protection for the feedstock/CNG users could be seen as a viable way to allow hydrogen blends of higher %: at the connection point for the feedstock users (or the CNG tank stations), a deblending unit can be used in order to remove the hydrogen from the natural gas. The removed natural gas can be reinjected in the natural gas grid and the natural gas that reaches the customer can be hydrogen-free. Figure 29 shows a graphical example of two potential consumers of hydrogen blends where one of then requires deblending to get hydrogen-free natural gas.

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[74] The energy consumption of compression is a broad parameter that strongly depends on the pressure inlet and outlet as well as the technology used (centrifugal, reciprocating, diaphragm, etc.). As such, only a broad band of expected energy consumption is presented here instead of a detailed analysis.

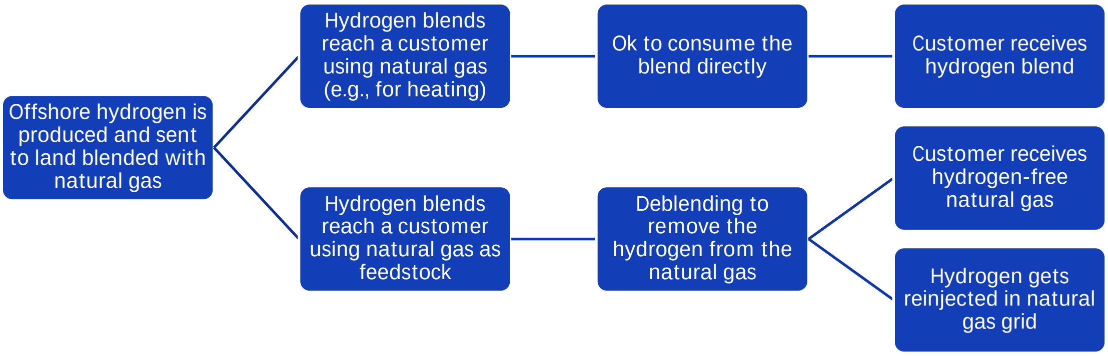

Figure 29. Potential pathways of hydrogen deblending as option to protect consumers of natural gas as feedstock from the effects of hydrogen.

In order to make a quick estimation of the costs of deblending as ‘protective measure’ for e.g., feedstock/CNG users, we can start from the fact that the HHV of hydrogen is almost three times lower than natural gas. This means, for example, that removing the hydrogen from a 5% blend means that 1,7% of the energy of the blend is removed. As a result, and considering the costs of deblending to be as high as 330-432 €/MWh-H2 (Table 17), the real impact in terms of the cost of the blend is 1,7% of that amount i.e., 5,61-7,34 €/MWh-blend, which represents a ~22-28% cost increase for the user[75].

A potential consequence of natural gas consumers having the option to deblend in order not to receive hydrogen is that, as can be seen in Figure 10, the hydrogen surcharge for blends is strongly dependent on the LCOH whereas the deblending costs are not hydrogen market-dependent, meaning that for high LCOH it may be more profitable to pay for deblending than to receive the hydrogen. Table 18 shows a comparison of the different options around hydrogen blending (surcharge or deblending) for a 5% hydrogen blend.

Table 18. Different options for consumers of hydrogen blends (hydrogen surcharge vs deblending costs) with a 5% hydrogen blend.

Different options for consumers and associated cost increases with respect to the natural gas price (25,55 €/MWh)	Hydrogen surcharge (In case customer buys the hydrogen blend)	Deblending costs (In case customer cannot receive hydrogen due to e.g., incompatibility)
5% blend	~10-40% (respectively for LCOH of between 3 and 10 €/kgH2)	~22-28% (independent from LCOH)

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[75] Note that this is a very simple approximation that doesn’t take into account e.g., reduced scales, and this still does not consider the impact of compression to reinject the hydrogen back to pipeline pressure levels.

4.4 Estimated timeline towards realization

As has been discussed above, deblending hydrogen from natural gas implies the installation of deblending technology (for example PSA, Membrane Separation, Cryogenic Distillation). A typical process of construction of industrial assets (thus not only limited to deblending) considers several stages; they are shown in Figure 30.

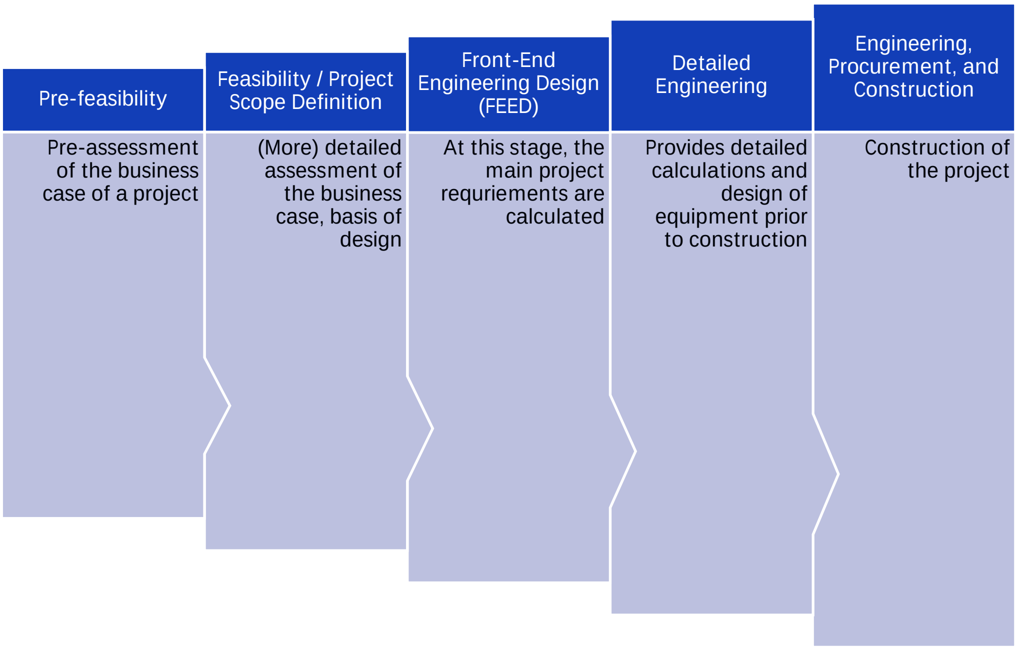

Figure 30. General overview of the project design and engineering phases. The actual number and definition of the stages in a project is typically project or client-specific.

In order to estimate the time before a deblending facility is operational, the following are factors that need to be considered (not an exhaustive list):

- Assessment of the technical implications
- Delivery of the engineering design packages
- Permitting
- Securing financing

As such, it is difficult to provide an estimate for deblending; such estimate will need to be assessed on a case-by-case basis. Furthermore, it is widely recognized that one of the most time-intensive parts of a construction project is the permitting, which can take years depending on factors such as the type of project, the location, the stakeholders involved (e.g., in issuing the permit, providing advice), etc.

5 Potential locations for hydrogen blending and deblending

5.1 General considerations

Where hydrogen blending has been done so far (e.g., in pilot projects and demonstrations), it is generally done at the site where hydrogen is being generated. If the hydrogen production is co-located with an offshore oil & gas facility (e.g., on the same offshore platform), then it is likely that there is an operating pipeline that carries the production from the offshore platform to shore.

Typically, offshore oil & gas platforms in the Dutch North Sea produce either a mixture of oil and natural gas, or just natural gas. As such, co-locating hydrogen production in one of these platforms will mean that there are different potential routes that the hydrogen can take, depending on the connection between the offshore production site and the corresponding landfall point. In general, we can expect three possible routes for the hydrogen; a summary of the routes can be found on Figure 31 and Table 19.

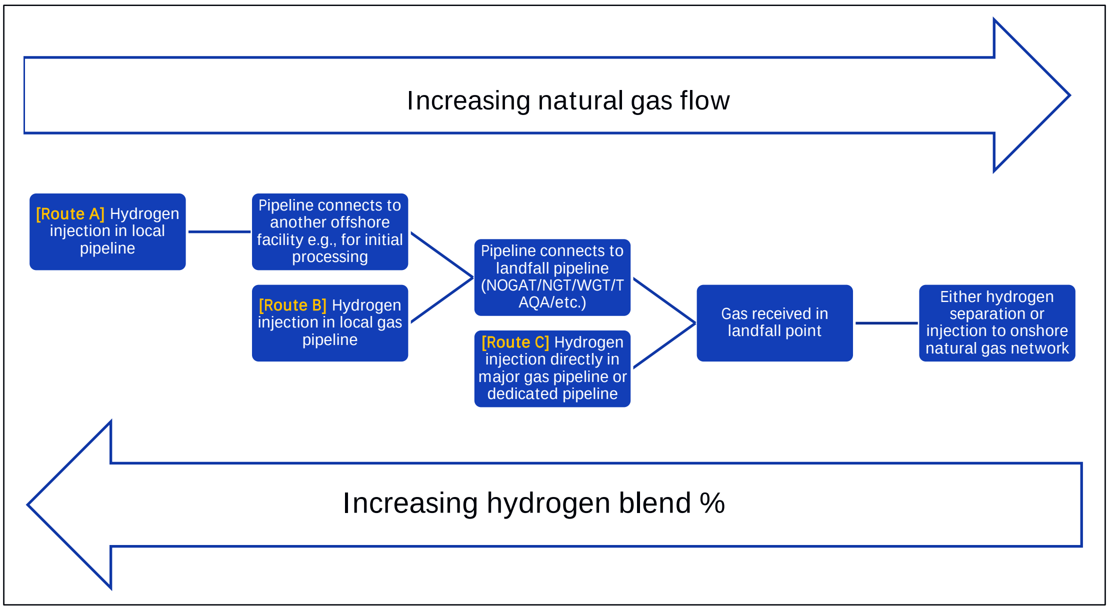

Figure 31. Routes that hydrogen produced and blended in offshore pipelines can take to reach a landfall point.

Table 19. Explanation of the three main potential routes where hydrogen produced offshore can reach land.

Route	Explanation	Expected natural gas flow	Expected hydrogen blend %
Route A	Corresponds to hydrogen that is blended in a local pipeline that produces either gas or oil and gas and is sent to an offshore facility that does initial processing of the mixture (e.g., to separate the oil from the gas). The gaseous mixture would be then either be sent to one of the major gas transport pipelines in the North Sea (a so-called 'trunk' pipeline), where the hydrogen blend would then reach the landfall point, or make landfall directly.	Low	High
Route B	Corresponds to hydrogen that is blended in a local pipeline that produces only natural gas and is connected directly to one of the major gas transport pipelines in the North Sea, where the hydrogen blend would then reach the landfall point.	Mid	Mid
Route C	Corresponds to hydrogen blended directly to one of the major gas transport pipelines in the North Sea, where the hydrogen blend would then reach the landfall point. Alternatively, the hydrogen could be sent via a dedicated pipeline to the landfall point.	High	Low

Except for the direct connection to the landfall point (e.g., in Route C), in all other routes the rule of thumb is that the further away from landfall, the more likely it is that the pipeline is carrying high hydrogen blends, mainly because it is expected that the amount of natural gas carried by smaller pipelines is comparatively low, whereas larger gas transport pipelines carry the natural gas of several production sites. It may also be the case that production from a single platform (e.g., a new platform) is higher than from multiple platforms (e.g., platforms that have been in production for a long time). As such, the potential sites for hydrogen blending (and the potential pipelines to use) could be determined by the following criteria:

1) The route that hydrogen will follow from the offshore production site to landfall.
2) The flow of natural gas at all stages of the route (since this will determine the hydrogen blend %).
3) The landfall connection and available facilities or space e.g., for hydrogen deblending at the onshore gas processing terminal.

5.2 Possible locations to separate hydrogen from natural gas streams

According to the Annual Review 2022 of the Natural resources and geothermal energy in the Netherlands (NLOG)[76], the following all the operational offshore pipelines that carry (natural) gas and have a landing point somewhere in the Netherlands (Table 20).

Table 20. Operational (natural) gas pipelines offshore that have a direct landing point somewhere in the Netherlands.

From	To	Pipeline	Operator	Status	Product	Length (km)	Diameter (inch)
K13-AP	Afsluiter WGT zeeleiding	W09	Wintershall	Operational	Gas	120,5	36
K15-FB-1	LoCal Sidetap onshore Callantsoog	NP007	NAM	Operational	Gas	84	24
L02-FA-1	Sidetap onshore NOGAT Callantsoog	TP-001	NOGAT	Operational	Gas	144,2	36
L10-AR	Uithuizen Gasbehandeling NGT	NP-001	NGT	Operational	Gas	177,6	36
P15-D	Maasvlakte onshore (gas)	DPL-15D1	TAQA	Operational	Gas	40,1	26
Subsea aansluiting Q08	Wijk aan Zee	W41	Wintershall	Operational	Gas	13,7	10

The most likely location identified by MinEZK as the site for the DEMO 1 offshore hydrogen production activities is the area known as Hollandse Kust, where there are currently offshore wind parks operating. Close to this area there are oil and gas assets operated that could potentially be used to transport the offshore hydrogen to land via blending. From Table 20 we can identify six potential pipelines where hydrogen could make a landfall to shore blended in natural gas:

1. [W09] The pipeline connecting K13-AP to the Afsluiter WGT zeeleiding, operated by Wintershall.
2. [NP007] The pipeline connecting K15-FB-1 to the LoCal Sidetap onshore Callantsoog, operated by NAM (Nederlandse Aardolie Maatschappij).
3. [TP-001] The pipeline connecting L02-FA-1 to the Sidetap onshore NOGAT Callantsoog[77], operated by NOGAT (Northern Offshore Gas Transport) and gas treatment plant in Den Helder, operated by NAM.
4. [NP-001] The pipeline connecting L10-AR to the Uithuizen Gasbehandeling NGT and gas treatment plant in Emmapolder near Uithuizen, operated by NGT (Noordgastransport).

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[76] NLOG. Annual Report 2022 - Natural resources and geothermal energy in the Netherlands. https://www.nlog.nl/media/3053

[77] Although technically the pipeline L02-FA-1 is logged in the NLOG database to make landfall in Callantsoog, the pipeline continues from Callantsoog to the onshore gas terminal in Den Helder.

5. [DPL-15D1] The pipeline connecting DPL-15D1 to the Maasvlakte onshore gas terminal, operated by TAQA (the Abu Dhabi National Energy Company, PJSC).
6. [W41] The pipeline connecting the Subsea Aansluiting Q08 and onshore gas terminal in Ijmuiden, operated by Wintershall.

In the next sections, a more detailed overview of the aforementioned assets will be given.

5.2.1 [W09] The WGT pipeline (landfall in Den Helder)

The W09 pipeline, most commonly known as the WGT (West Gas Transport), is a pipeline connecting several production fields in the Dutch North Sea, connecting several of the K-fields.

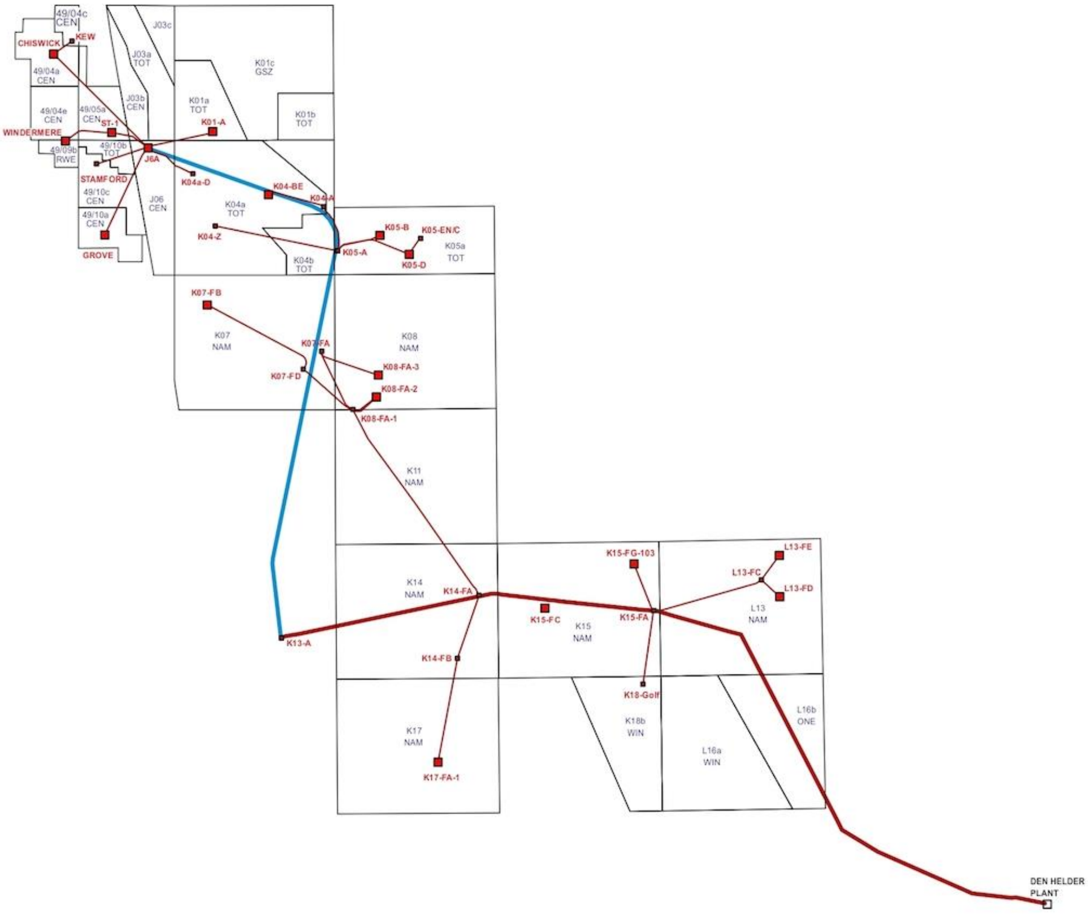

Figure 32. Outline of the W09 (WGT) pipeline, operated by Wintershall[78].

The total natural gas flow in 2022 of the platforms connected to the W09 (WGT) pipeline is shown in Table 21.

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[78] Wintershall. About WGT. http://wgt.wintershall.nl/about

Table 21. Total natural gas flow of the fields connected to the W09 (WGT) pipeline.

Platform	Natural gas production in 2022 (million Nm3/year)
J03b & J06a	37,3
K01a	117,9
K04a	260,2
K04b & K05a	483,8
K05b & K05c	54,1
K07	39,1
K08 & K11a	142,8
K14a	22,6
K15	Connected to the NP007 (LoCal) pipeline[79]
K17a	72,1
K18b	145,3
L13	192,6
Total natural gas production to shore carried by the W09 pipeline	1.567,8 million Nm3/year ~4,3 million Nm3/day

With the information above, we can estimate the resulting hydrogen blends of the W09 pipeline; this estimation is shown in Table 22.

Table 22. Max. hydrogen blend % corresponding to the estimated natural gas flow through the W09 (WGT) pipeline operated by Wintershall.

<table>
<tr><th>Electrolyser operating capacity</th><th colspan="2">Max. hydrogen blend corresponding to the natural gas making landfall via the W09 (WGT) pipeline (4,3 million Nm3/day)</th></tr>
<tr><td rowspan="3">Average expected throughout the year (50%)</td><th>Electrolysis capacity</th><th>Max. H2 blend %</th></tr>
<tr><td>50 MW</td><td>2,71%</td></tr>
<tr><td>100 MW</td><td>5,29%</td></tr>
<tr><td rowspan="3">Installed electrolysis capacity</td><th>Electrolysis capacity</th><th>Max. H2 blend %</th></tr>
<tr><td>50 MW</td><td>5,29%</td></tr>
<tr><td>100 MW</td><td>10,04%</td></tr>
</table>

5.2.2 [NP007] The LoCal pipeline (landfall Den Helder)

Pipeline NP007 (LoCal) transports the low-caloric gas produced in wells K15-FB-1, K15-FC-1, and K15-FK-1. The pipeline is operated by NAM and is connected onshore to the Den Helder

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[79] According to Figure 32 (which can be found on the WGT website), the K15-FA well is connected to the W09 (WGT) pipeline, while the K15-FC is well is connected to the NP007 (LoCal) pipeline. The Annual Review 2022 of the NLOG database only has information about the production of the K15 well in total i.e., it does not have a separate accounting of the part of the K15 well that is connected to the WGT or to the LoCal pipeline.

gas processing terminal. Figure 33 shows the pipeline as well as the assets. The difference between the W09 pipeline (WGT) and the NP007 (LoCal) pipeline, is that the W09 pipeline transports high-caloric gas while the NP007 pipeline transports low-caloric gas.

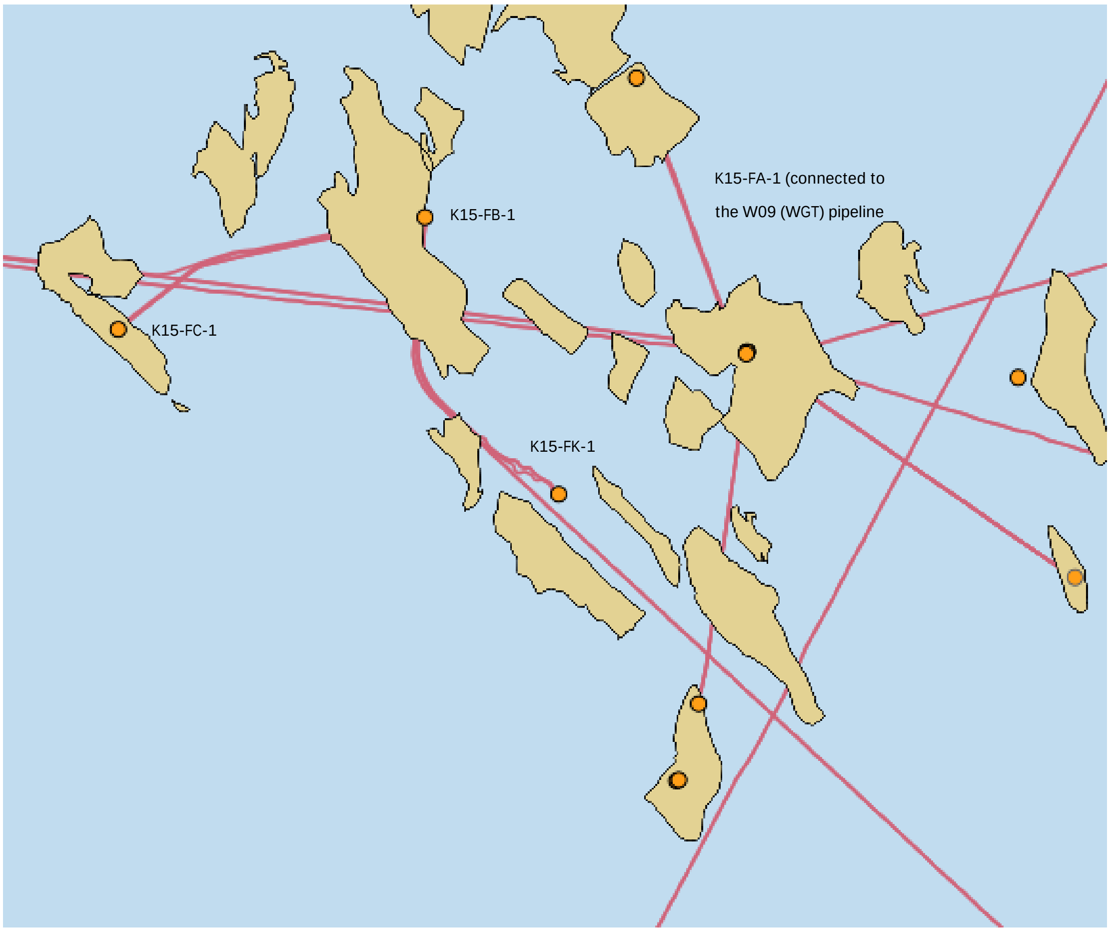

Figure 33. The K-field platforms and the NP007 pipeline operated by NAM (all assets circled in blue)[80].

The total natural gas flows in 2022 connected to the NP007 (LoCal) pipeline operated by NAM are shown in Table 23.

Table 23. Total production of the K-fields operated by NAM and estimation of the total natural gas flow through the NP007 (LoCal) pipeline.

Platform	Natural gas production in 2022 (million Nm3/year)
K15 (K15-FB-1, K15-FC-1, and K15-FK-1)	384,1[81]
Total natural gas production to shore carried by the NP007 pipeline	384,1 million Nm3/year ~1,05 million Nm3/day

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[80] North Sea Energy Atlas. https://north-sea-energy.eu/en/energy-atlas/

[81] As mentioned before, this number counts both the production connected to the W09 (WGT) pipeline (e.g., from the K15-FA-1) as well as the production from the wells connected to the NP007 (LoCal) pipeline. As a result, it is likely that the flow through the LoCal pipeline is overestimated, and the flow through the WGT pipeline is underestimated.

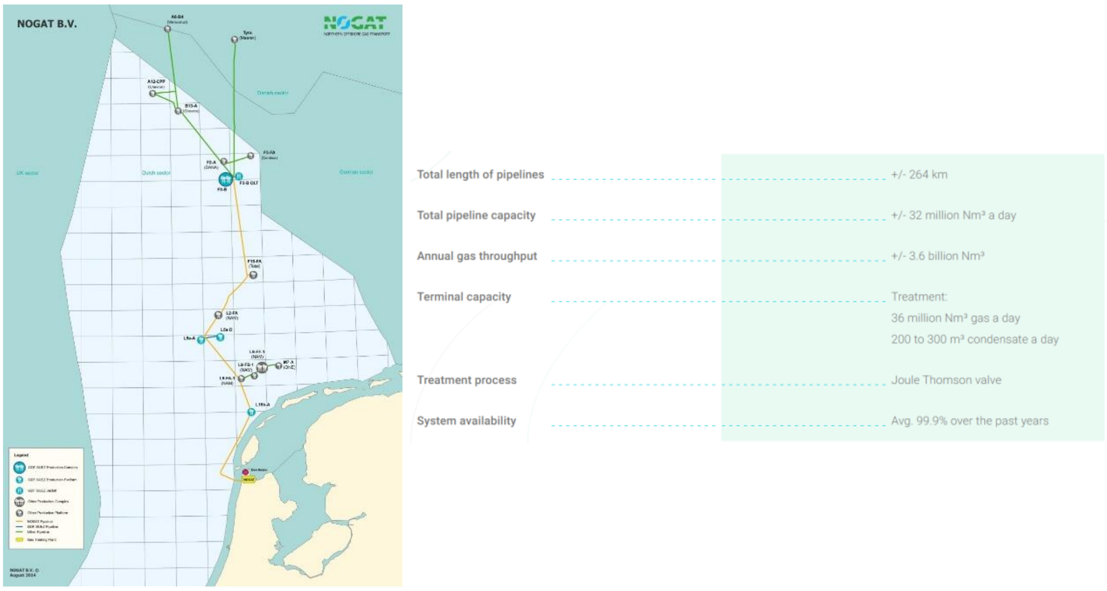
With the information above, we can estimate the resulting hydrogen blends of the NP007 pipeline; this estimation is shown in Table 24.

Table 24. Max. hydrogen blend % corresponding to the estimated natural gas flow through the NP007 pipeline operated by NAM.

<table>
<tr><th>Electrolyser operating capacity</th><th>Max. hydrogen blend corresponding to the natural gas making landfall via the NP007 (LoCal) pipeline (1,05 million Nm3/day)</th></tr>
<tr><td>Average expected throughout the year (50%)</td><td><table><tr><th>Electrolysis capacity</th><th>Max. H2 blend %</th></tr><tr><td>50 MW</td><td>10,26%</td></tr><tr><td>100 MW</td><td>18,60%</td></tr></table></td></tr>
<tr><td>Installed electrolysis capacity</td><td><table><tr><th>Electrolysis capacity</th><th>Max. H2 blend %</th></tr><tr><td>50 MW</td><td>18,60%</td></tr><tr><td>100 MW</td><td>31,37%</td></tr></table></td></tr>
</table>

5.2.3 [TP-001] The NOGAT pipeline (landfall in Den Helder)

A third alternative for the transport of hydrogen via blending (and potential deblending) are the TP-001 pipeline and the onshore gas treatment facility at Den Helder, operated by NOGAT. An overview of the facilities operated by NOGAT can be seen on Figure 34.



Total length of pipelines	+/- 264 km
Total pipeline capacity	+/- 32 million Nm³ a day
Annual gas throughput	+/- 3.6 billion Nm³
Terminal capacity	Treatment: 36 million Nm³ gas a day 200 to 300 m³ condensate a day
Treatment process	Joule Thomson valve
System availability	Avg. 99.9% over the past years

Figure 34. [Left] Map of the pipelines operated by NOGAT. [Right] Facts and figures of NOGAT[82].

According to publicly available information by NOGAT, their Den Helder gas treatment plant can handle up to 36 million Nm3 of gas per day, and the annual natural gas throughput through the TP-001 pipeline can be estimated at 3.600 million Nm3 of gas per year, which corresponds to ~9,9 million Nm3/day. We can calculate the maximum hydrogen blend %

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[82] NOGAT. About us. https://nogat.nl/en/about-us

that could be processed by the NOGAT onshore gas treatment terminal in Den Helder; this calculation is shown in Table 25.

Table 25. Max. hydrogen blend % corresponding to both the installed capacity of the Den Helder gas treatment plant and the average daily throughput of the TP-001 pipeline, both operated by NOGAT.

Electrolyser operating capacity	Max. hydrogen blend corresponding to different parameters by NOGAT		
Average expected throughout the year (50%)	Electrolysis capacity	Max. H2 blend % corresponding to the total terminal capacity of the NOGAT pipeline (36 million Nm3/day)	Max. H2 blend % corresponding to the annual gas throughput of the TP-001 (NOGAT) pipeline (~9,9 million Nm3/day)
	50 MW	0,33%	1,20%
	100 MW	0,66%	2,38%
Installed electrolysis capacity	Electrolysis capacity	Max. H2 blend % corresponding to the total terminal capacity of the NOGAT pipeline (36 million Nm3/day)	Max. H2 blend % corresponding to the annual gas throughput of the TP-001 (NOGAT) pipeline (~9,9 million Nm3/day)
	50 MW	0,66%	2,38%
	100 MW	1,32%	4,64%

5.2.4 [NP-001] The NGT pipeline (landfall in Uithuizen)

Another alternative for the transport of hydrogen via blending (and potential deblending) are the NP-001 pipeline and the onshore gas treatment facility at Uithuizen, operated by NGT. An overview of the facilities operated by NGT can be seen on Figure 35.

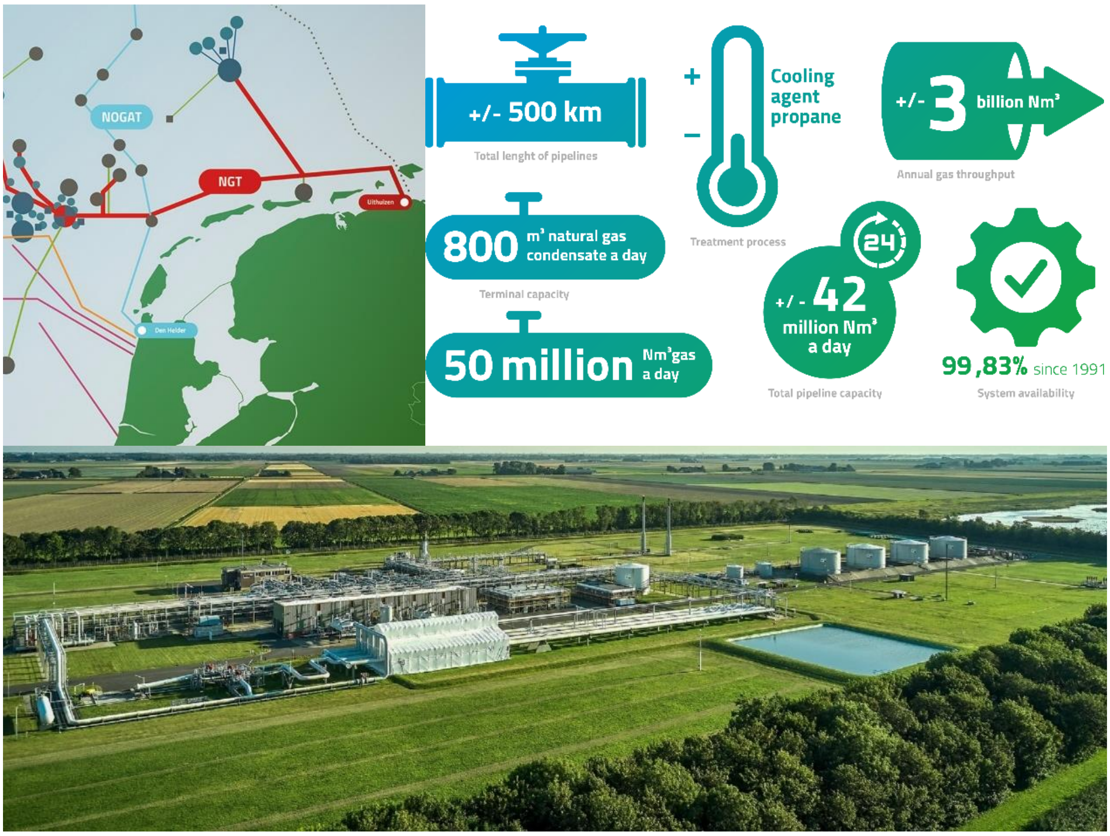

Figure 35. [Left top] Tracing of the NGT pipeline and landfall point in the gas treatment facility in Uithuizen[83]. [Right top] Facts and figures of the assets managed by NGT[84]. [Bottom] Picture of the gas treatment facility at Uithuizen.

According to publicly available information by NGT, their Uithuizen gas treatment plant can handle up to 50 million Nm3 of gas per day, and the annual natural gas throughput of the NP-001 pipeline can be estimated at 3.000 million Nm3 of gas per year, which corresponds to ~8,2 million Nm3/day. We can calculate the maximum hydrogen blend % that could be processed by the NGT onshore gas treatment terminal in Uithuizen; this is shown in Table 26.

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[83] NGT. Our assets. https://noordgastransport.nl/our-assets/
[84] NGT. facts and figures. https://noordgastransport.nl/facts-figures/

Table 26. Max. hydrogen blend % corresponding to both the installed capacity of the Uithuizen gas treatment plant, and the average daily throughput of the NP-001 pipeline, both operated by NGT.

Electrolyser operating capacity	Max. hydrogen blend corresponding to different parameters by NGT		
Average expected throughout the year (50%)	Electrolysis capacity	Max. H2 blend % corresponding to the total terminal capacity of the NGT pipeline (50 million Nm3/day)	Max. H2 blend % corresponding to the annual gas throughput of the NP-001 (NGT) pipeline (~8,2 million Nm3/day)
	50 MW	0,24%	1,44%
	100 MW	0,48%	2,84%
Installed electrolysis capacity	Electrolysis capacity	Max. H2 blend % corresponding to the total terminal capacity of the NGT pipeline (50 million Nm3/day)	Max. H2 blend % corresponding to the annual gas throughput of the NP-001 (NGT) pipeline (~8,2 million Nm3/day)
	50 MW	0,48%	2,84%
	100 MW	0,95%	5,52%

5.2.5 [DPL-15D1] The TAQA pipeline (landfall Maasvlakte)

TAQA operates a pipeline from the P-fields in the Dutch North Sea to the Maasvlakte. Pipeline DPL-15D1 transports the gas produced in many of the P-fields in the offshore natural gas production grid, including the fields P15 and P18 (operated by TAQA Offshore), as well as Q13a, which is operated by Neptune and is where PosHydon (1 MW offshore hydrogen production pilot) is installed. Figure 36 shows the pipeline as well as the assets in relation to the Dutch North Sea and the Hollandse Kust Zuid area as well as PosHydon.

Figure 36. Platforms connected to pipeline DPL-15D1 (red), operated by TAQA.

The total production in 2022 of the platforms connected to pipeline DPL-15D1 is shown in Table 27.

Table 27. Total production of the fields connected to the DPL-15D1 pipeline and estimation of the total natural gas flow through the DPL-15D1 pipeline.

Platform	Natural gas production in 2022 (million Nm3/year)
P15a, P15b, P15d, P15e & P15f	14,8
P18a	65,6
Q13a (operated by Neptune)	5,8
Total natural gas production to shore carried by the DPL-15D1 pipeline	86,2 million Nm3/year ~0,24 million Nm3/day

With the information above, we can estimate the resulting hydrogen blends of the DPL-15D1 pipeline; this estimation is shown in Table 28.

Table 28. Max. hydrogen blend % corresponding to the estimated natural gas flow through the DPL-15D1 pipeline operated by TAQA.

<table>
<tr><th>Electrolyser operating capacity</th><th>Max. hydrogen blend corresponding to the natural gas making landfall via the DPL-15D1 pipeline (0,24 million Nm3/day)</th></tr>
<tr><td>Average expected throughout the year (50%)</td><td><table><tr><th>Electrolysis capacity</th><th>Max. H2 blend %</th></tr><tr><td>50 MW</td><td>33,33%</td></tr><tr><td>100 MW</td><td>50,00%</td></tr></table></td></tr>
<tr><td>Installed electrolysis capacity</td><td><table><tr><th>Electrolysis capacity</th><th>Max. H2 blend %</th></tr><tr><td>50 MW</td><td>50,00%</td></tr><tr><td>100 MW</td><td>66,67%</td></tr></table></td></tr>
</table>

As mentioned before, the DPL-15D1 pipeline is also evacuating the hydrogen produced in platform Q13a (operated by Neptune), where the installed capacity of hydrogen production will be 1 MW. With the estimated daily natural gas flow of the TAQA pipeline (0,24 million Nm3/day), 1 MW installed capacity corresponds to 1,96% max. hydrogen blend.

5.2.6 [W41] The Wintershall pipeline and onshore gas terminal (landfall in IJmuiden)

Some of the potential assets that could be used for hydrogen blending (because the assets are currently transporting natural gas) are at or near one of the “Q” platforms operated by Wintershall. The map of operated facilities by Wintershall is shown on Figure 37 below.

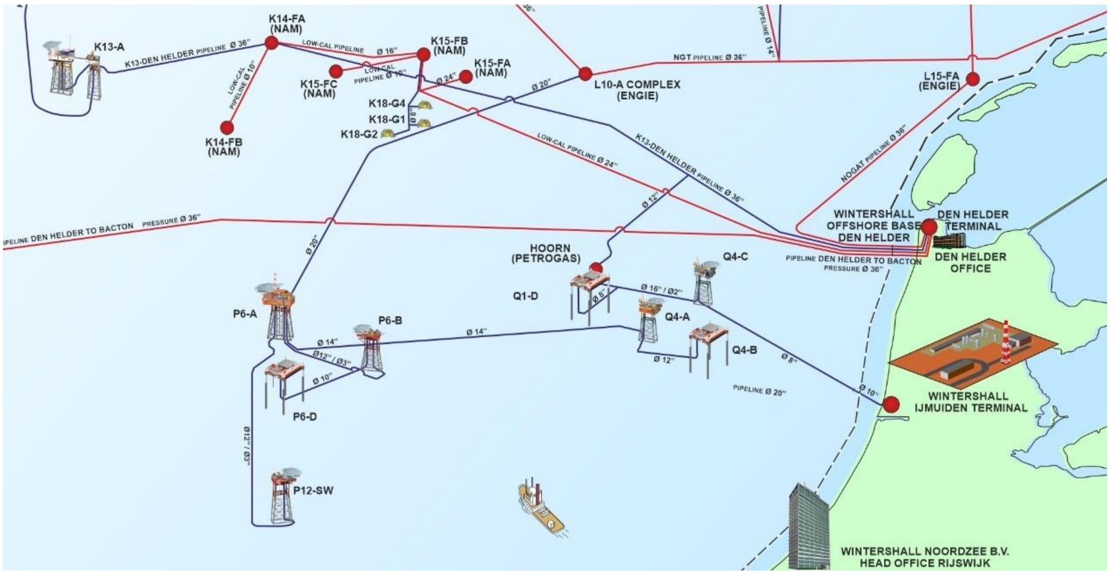

Figure 37. Wintershall Noordzee B.V.’s operated facilities on- & offshore, zoomed in the landfall areas of Ijmuiden and Den Helder. [Blue lines] Pipelines operated by Wintershall. [Red lines] Pipelines not operated by WIntershall[85]. An overview of all the pipelines, offshore wind farms, and offshore rigs in the Dutch North Sea can also be seen in the North Sea Energy Atlas (see Figure 38).

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[85] WINZ (Wintershall Noordzee B.V.) operated facilities On- & Offshore. https://www.wintershall-noordzee.nl/our-assets.html

Figure 38 shows the assets operated by Wintershall in relation to the Hollandse Kust Noord and Zuid areas, as per the North Sea Energy Atlas.

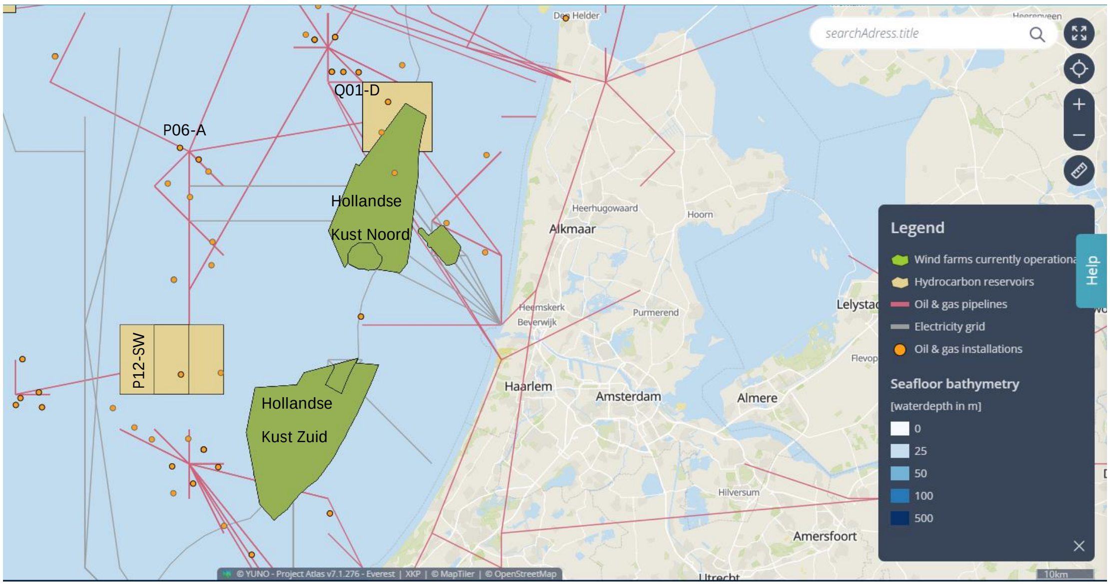

Figure 38. North Sea Energy Atlas, showcasing some of the platforms connected to the W41 pipeline operated by Wintershall.

Wintershall operates an onshore gas processing facility namely, the Q8-Terminal (located on the TATA Steel yard in IJmuiden), where the produced gas from the offshore Q1-D and Q4-C facilities (see Figure 37) is processed. According to Wintershall, their Q8 IJmuiden Terminal can handle up to 1,2 million Nm3 of gas per day. With the information provided, we can estimate the natural gas flow through the W41 pipeline; this information is shown in Table 29.

Table 29. Total production of the fields connected to the W41 pipeline and estimation of the total natural gas flow through the W41 pipeline.

Platform	Natural gas production in 2022 (million Nm3/year)
Q01c-diep	93,5
Q04a	108,1
Total natural gas production to shore carried by the W41 pipeline	201,6 million Nm3/year ~0,55 million Nm3/day

With the information above, we can estimate the resulting hydrogen blends of the W41 pipeline; this estimation is shown in Table 30.

Table 30. Max. hydrogen blend % corresponding to the installed natural gas processing terminal at IJmuiden and the W41 pipeline, both operated by Wintershall.

Electrolyser operating capacity	Max. hydrogen blend corresponding to the installed capacity of the Wintershall IJmuiden terminal (1,2 million Nm3/day)		
Average expected throughout the year (50%)	Electrolysis capacity	Max. H2 blend % corresponding to Wintershall's total IJmuiden onshore gas processing terminal capacity (1,2 million Nm3/day)	Max. H2 blend % corresponding to the total terminal capacity of the W41 pipeline (0,55 million Nm3/day)
	50 MW	9,09%	17,91%
	100 MW	16,67%	30,38%
Installed electrolysis capacity	Electrolysis capacity	Max. H2 blend % corresponding to Wintershall's total IJmuiden onshore gas processing terminal capacity (1,2 million Nm3/day)	Max. H2 blend % corresponding to the total terminal capacity of the W41 pipeline (0,55 million Nm3/day)
	50 MW	16,67%	30,38%
	100 MW	28,57%	46,60%

5.2.7 Summary of the max. hydrogen blend % to be expected at the potential sites

Table 31 shows a summary of the offshore pipelines considered in this study for the blending of hydrogen, the installed capacity of the onshore gas terminals where each is connected to, and the estimated average natural gas throughout as reported in the NLOG database in 2022. Due to the varying production performance of gas fields, the values estimated in this study are likely to fall within a bandwidth of 25%[86]. As such, we have estimated the average throughputs as reported as well as with a ±25% bandwidth.

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[86] The 25% bandwidth comes from a direct communication with experts in the (offshore) natural gas industry.

Table 31. Summary of the pipelines considered in this hydrogen blending study, including the estimated throughput within an uncertainty margin of ±25%.

Pipeline considered	Operator	Installed capacity of the onshore terminal [million Nm3/day]	Estimated average gas throughput[87] based on NLOG data and including a 25% bandwidth [million Nm3/day]
W09 (WGT)	Wintershall	36 (Den Helder)	5,30±1,33
NP007 (LoCal)	NAM	36 (Den Helder)	1,05±0,26
TP-001 (NOGAT)	NOGAT	36 (Den Helder)[88]	9,90±2,48
NP-001 (NGT)	NGT	50 (Uithuizen)	8,20±2,05
DPL-15D1	TAQA	Not surveyed (Maasvlakte)	0,24±0,06
W41	Wintershall	1,2 (Ijmuiden)	0,55±0,14

Table 32 contains a summary of the results from the previous sections i.e., the maximum hydrogen blend % that could be reached in the pipelines surveyed in this section.

Table 32. Summary of the max. hydrogen blend % in the pipelines surveyed in this study, based on the natural gas flows through each pipeline and considering a ±25% bandwidth.

Electrolyser operating capacity	Max. hydrogen blend per pipeline considering a 25% bandwidth of the natural gas flows through each offshore pipeline						
Average expected throughout the year (50%)	Electrolysis capacity	W09 (WGT)	NP007 (LoCal)	TP-001 (NOGAT)	NP-001 (NGT)	DPL-15D1 (TAQA)	W41 pipeline (Wintershall)
	50 MW	1,78-2,93%	8,38-13,22%	0,96-1,59%	1,16-1,91%	28,57-40,00%	14,86-22,54%
	100 MW	3,50%-5,69%	15,46%-23,36%	1,90%-3,13%	2,29%-3,76%	44,44%-57,14%	25,88%-36,78%
Installed electrolysis capacity	Electrolysis capacity	W09 (WGT)	NP007 (LoCal)	TP-001 (NOGAT)	NP-001 (NGT)	DPL-15D1 (TAQA)	W41 pipeline (Wintershall)
	50 MW	3,50%-5,69%	15,46%-23,36%	1,90%-3,13%	2,29%-3,76%	44,44%-57,14%	25,88%-36,78%
	100 MW	6,76%-10,77%	26,78%-37,87%	3,73%-6,07%	4,47%-7,24%	61,54%-72,73%	41,11%-53,78%

It is important to mention that the blend % presented in Table 32 correspond to blends that can be achieved in the local trunk like i.e., as soon as those blends reach the onshore natural gas networks (either the H-Gas or the G-Gas networks), the blend % will be (significantly) lower.

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[87] For NP007, DPL-15D1, and the Subsea aansluiting Q8 pipelines, these are natural gas flows from 2022. For TP-001 and NP-001, these are self-reported annual gas throughputs of NOGAT and NGT, respectively.

[88] Three of the surveyed pipelines, W09 (WGT), NP007 (LoCal), and TP-001 (NOGAT) are processed at the Den Helder gas processing terminal, operated by NAM.

5.2.8 Estimated hydrogen blend percentages for other natural gas flows

As a reference for other potential pipelines or natural gas flows, we can calculate the resulting hydrogen blend percentage for different natural gas flows transported, based on both installed capacity of electrolysis, as well as an estimation of the real hydrogen production considering the capacity factor of a wind farm. Table 33 and Table 34 show the calculated hydrogen flow (installed capacity and assuming 50% capacity factor, respectively) for different natural gas flow scenarios than the ones found for the surveyed pipelines.

Table 33. Estimated hydrogen blend % for different natural gas flows and installed electrolysis capacity, assuming a 50% utilisation factor of the electrolyser due to the typical capacity factor/variable power output of offshore wind farms.

Electrolysis capacity		Natural gas flow [Nm3/day]		
MW	Assuming 50% utilisation factor for electrolysis [Nm3/day]	4.800.000	2.400.000	1.200.000
50	120.000	2,44%	4,76%	9,09%
100	240.000	4,76%	9,09%	16,67%

Table 34. Estimated hydrogen blend % for different natural gas flows and installed electrolysis capacity.

Electrolysis capacity		Natural gas flow [Nm3/day]		
MW	Installed capacity electrolysis [Nm3/day]	4.800.000	2.400.000	1.200.000
50	240.000	4,76%	9,09%	16,67%
100	480.000	9,09%	16,67%	28,57%

For all the calculations of this section regarding the max. hydrogen blend % that can be achieved given a natural gas flow, we used the following equation:

$$Max\ hydrogen\ blend\ [\%] = \frac{Hydrogen\ flow\ \left[\frac{Nm3}{day}\right]}{Hydrogen\ flow\ \left[\frac{Nm3}{day}\right] + Natural\ gas\ flow\ \left[\frac{Nm3}{day}\right]} * 100\%$$

$$\begin{aligned} Hydrogen\ flow\ \left[\frac{Nm3}{day}\right] \\ &= Utilisation\ factor * 4800\ \left[\frac{Nm3}{day * MW}\right] \\ &* Electrolysis\ installed\ capacity\ [MW] \end{aligned}$$

For the calculations of the installed capacity, we set the utilisation factor to 100%, whereas to estimate the average hydrogen output (in a year of operation) from an electrolyser that is directly connected to an offshore wind turbine, we set the utilisation factor to 50%.

It is important to note that the analysis caried out in this document where the achievable hydrogen blend % as a function of electrolysis capacity (both peak and average throughout the year) represents an oversimplified situation and that much more detailed analysis is required to determine the expected hydrogen percentage at every hour throughout the year. A more detailed analysis (for example a case study) using non-averaged values such as the peak of the electrolyser production together with the minimum of the natural gas flow used in the blend, would be needed in order to reach more exact conclusions. We would expect that such analysis would be needed mainly when the detailed part of the engineering of an offshore wind to hydrogen blend is carried out, meaning that the values depicted here can be seen as a reasonable approximation.

5.3 Further selection criteria of the onshore gas terminal for deblending

In case any hydrogen blend coming from offshore needs to be deblended, a deblending installation would have to be constructed onshore. The most likely possibility is that this facility would be located in one of the four onshore gas terminals where the six surveyed offshore pipelines make landfall: Uithuizen, Den Helder, IJmuiden, or the Maasvlakte. The choice of the onshore gas terminal would have to be made considering not only the available gas processing capacity but also other parameters including:

- **Connection of offshore pipeline**: as was discussed in this section, the pipelines where hydrogen can be blended make landfall in a particular onshore gas terminal, meaning that the choice of pipeline goes hand in hand with the choice of onshore gas terminal.
- **Available land in the onshore gas terminal**: it could be the case that the plot of land of the onshore gas terminal cannot accommodate a deblending facility.
- **Available electricity connection**: a topic that is the centre of a national debate in the Netherlands is the topic of congestion of the onshore electricity networks. In summary, the onshore electricity networks (both the high and the low voltage networks) are currently facing significant network congestion, meaning that there is little availability to provide an electricity connection for new process plants[89]. The network congestion varies throughout the country and per connection point, meaning that providing an electricity connection to a deblending facility would have a varying difficulty depending on which onshore gas terminal houses the deblending facility. As an example, there could be less network congestion (and thus higher availability for new electricity connections) in Uithuizen than in the Maasvlakte or vice-versa.
- **Other non-technical considerations**: the selection of a suitable option is not only based on pure technical considerations. Situations such as permitting, involved operators and other parties, etc., also play a crucial role in the selection.

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[89] See for example the most recent network congestion maps published by NEtbeheer Nederland, the association of all electricity and natural gas network operators in the Netherlands. https://capaciteitskaart.netbeheernederland.nl/

5.4 Expected volume of natural gas produced in the Netherlands in the (near) future

The max. hydrogen blend % calculated in this section (Table 32) were obtained either with data from the NLOG Annual Report 2022 or from self-reported data (in the case of NOGAT and NGT). As such, they represent the present situation of natural gas production in offshore fields in the Netherlands. For a project that may be operational in a few years from the date of writing of this report, and that will operate across many years afterwards, it is important to understand how the natural gas flow would evolve over time so there can be an accurate overview of the expected hydrogen blend %.

While estimating the production of each individual well would be a difficult endeavour, the NLOG Annual Report 2022 contains a prediction of the future production from the small fields at sea between 2023 and 2047; this prediction is shown in Figure 39.

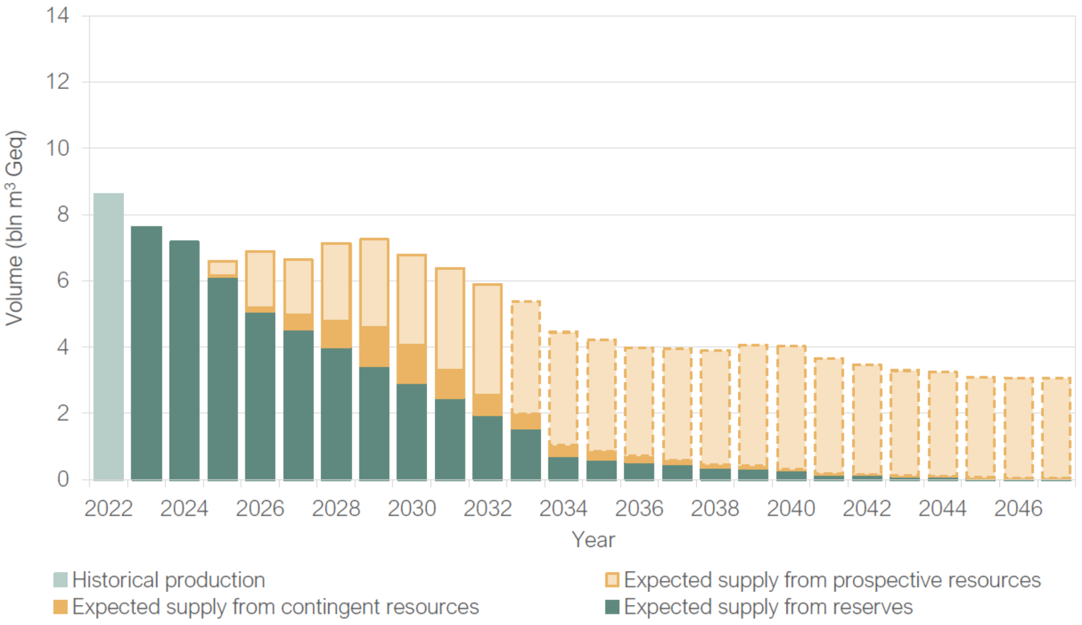

Figure 39. Actual production in 2022 and expected production of natural gas from the small fields from 2023 to 2047 according to the Annual Report 2022 of NLOG.

From the information in Figure 39, we can elucidate a qualitative trend of natural gas production offshore in the next 5, 10, and 15 years, and the corresponding impact on the max. hydrogen blend % that would be obtained (considering that the evolution in natural gas production might differ significantly between fields); this is shown on Table 35.

Table 35. Predicted trend of natural gas production and impact on the max. hydrogen blends in landfall points taking the data in 2022 as the present-day production.

Period	Predicted trend of natural gas production at sea with respect to 2022	(Indicative) Impact on the max. hydrogen blends offshore
2022-2027 (5 years in the future)	Stay similar	Stay similar
2027-2032 (10 years in the future)	Decrease	Increase
2032-2037 (15 years in the future)	Decrease	Increase

Further considerations related to the expected production of natural gas offshore in the Netherlands respond to parameters including changes in the economic situation over time (such as price, cost and profitability) as well as political choices. As DEMO 1 is expected to be ready for operation around 2030, the natural gas production profiles of 2030 and beyond would be needed in order to make a more accurate estimation. As such, the analysis done in the previous section (Table 32) could lead to an overestimation of the natural gas production and hence to an underestimation of the hydrogen blend % in the future.

In order to provide an estimation of the blend % considering a scenario where the offshore natural gas production is expected to decrease annually at a rate of 7-10% with respect to the data discussed in the previous section[90]. Using this information, we can estimate the offshore natural gas flow through each of the surveyed pipelines “n” years from today and considering an 8,5% estimated annual decrease of the natural gas production, using the following equation:

$$Natural\ gas\ production\ "n"\ yearsin\ the\ future\ \left[\frac{million\ Nm3}{day}\right] = \frac{Natural\ gas\ production\ today\ \left[\frac{million\ Nm3}{day}\right]}{(1+\frac{8{,}5\%}{100})^n}$$

Table 36 contains the estimated natural gas flows of the six surveyed offshore pipelines in 5, 10, and 15 years in the future, using the aforementioned equation and considering the 25% bandwidth in production.

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[90] Direct communication with natural gas industry expert

Table 36. Estimated natural gas flows through each of the surveyed pipelines in the present and 5, 10, and 15 years in the future, considering a 25% bandwidth.

Pipeline considered	Operator	Estimated average gas throughput based on NLOG data and including a 25% bandwidth in 2022 [million Nm3/day]	Estimated average gas throughput 2027 (5 years in the future) [million Nm3/day]	Estimated average gas throughput 2032 (10 years in the future) [million Nm3/day]	Estimated average gas throughput 2037 (15 years in the future) [million Nm3/day]
W09 (WGT)	Wintershall	5,30±1,33	3,52±0,88	2,34±0,59	1,56±0,39
NP007 (LoCal)	NAM	1,05±0,26	0,70±0,17	0,46±0,12	0,31±0,08
TP-001 (NOGAT)	NOGAT	9,90±2,48	6,58±1,65	4,38±1,09	2,91±0,73
NP-001 (NGT)	NGT	8,20±2,05	5,45±1,36	3,63±0,91	2,41±0,60
DPL-15D1	TAQA	0,24±0,06	0,16±0,04	0,11±0,03	0,07±0,02
W41	Wintershall	0,55±0,14	0,37±0,09	0,24±0,06	0,16±0,04

With the information above, we can calculated the expected hydrogen blend % in each of the surveyed offshore pipelines considering the estimated future natural gas flows. Table 37, Table 38, and Table 39 showcase the expected hydrogen blend % of each pipeline in 5, 10, and 15 years (respectively).

Table 37. Summary of the max. hydrogen blend % in the pipelines surveyed in this study in 5 years.

Electrolyser operating capacity	Max. hydrogen blend per pipeline considering a 25% bandwidth of the natural gas flows through each offshore pipeline **in 5 years**						
Average expected throughout the year (50%)	Electrolysis capacity	W09 (WGT)	NP007 (LoCal)	TP-001 (NOGAT)	NP-001 (NGT)	DPL-15D1 (TAQA)	W41 pipeline (Wintershall)
	50 MW	2,65%-4,34%	12,09%-18,64%	1,44%-2,37%	1,73%-2,85%	37,56%-50,06%	20,79%-30,43%
	100 MW	5,17%-8,32%	21,57%-31,42%	2,83%-4,64%	3,40%-5,54%	54,61%-66,72%	34,42%-46,66%
Installed electrolysis capacity	Electrolysis capacity	W09 (WGT)	NP007 (LoCal)	TP-001 (NOGAT)	NP-001 (NGT)	DPL-15D1 (TAQA)	W41 pipeline (Wintershall)
	50 MW	5,17%-8,32%	21,57%-31,42%	2,83%-4,64%	3,40%-5,54%	54,61%-66,72%	34,42%-46,66%
	100 MW	9,82%-15,37%	35,48%-47,82%	5,51%-8,86%	6,58%-10,50%	70,64%-80,04%	51,22%-63,63%

Table 38. Summary of the max. hydrogen blend % in the pipelines surveyed in this study in 10 years.

Electrolyser operating capacity	Max. hydrogen blend per pipeline considering a 25% bandwidth of the natural gas flows through each offshore pipeline **in 10 years**						
Average expected throughout the year (50%)	Electrolysis capacity	W09 (WGT)	NP007 (LoCal)	TP-001 (NOGAT)	NP-001 (NGT)	DPL-15D1 (TAQA)	W41 pipeline (Wintershall)
	50 MW	3,93%-6,39%	17,13%-25,62%	2,15%-3,53%	2,58%-4,23%	47,49%-60,12%	28,30%-39,68%
	100 MW	7,57%-12,01%	29,25%-40,80%	4,20%-6,81%	5,03%-8,11%	64,40%-75,09%	44,11%-56,81%
Installed electrolysis capacity	Electrolysis capacity	W09 (WGT)	NP007 (LoCal)	TP-001 (NOGAT)	NP-001 (NGT)	DPL-15D1 (TAQA)	W41 pipeline (Wintershall)
	50 MW	7,57%-12,01%	29,25%-40,80%	4,20%-6,81%	5,03%-8,11%	64,40%-75,09%	44,11%-56,81%
	100 MW	14,08%-21,45%	45,26%-57,95%	8,06%-12,75%	9,57%-15,00%	78,34%-85,77%	61,22%-72,46%

Table 39. Summary of the max. hydrogen blend % in the pipelines surveyed in this study in 15 years.

Electrolyser operating capacity	Max. hydrogen blend per pipeline considering a 25% bandwidth of the natural gas flows through each offshore pipeline **in 15 years**						
Average expected throughout the year (50%)	Electrolysis capacity	W09 (WGT)	NP007 (LoCal)	TP-001 (NOGAT)	NP-001 (NGT)	DPL-15D1 (TAQA)	W41 pipeline (Wintershall)
	50 MW	5,80%-9,31%	23,71%-34,13%	3,19%-5,21%	3,83%-6,22%	57,63%-69,39%	37,24%-49,72%
	100 MW	10,97%-17,03%	38,34%-50,89%	6,19%-9,90%	7,37%-11,71%	73,12%-81,93%	54,27%-66,42%
Installed electrolysis capacity	Electrolysis capacity	W09 (WGT)	NP007 (LoCal)	TP-001 (NOGAT)	NP-001 (NGT)	DPL-15D1 (TAQA)	W41 pipeline (Wintershall)
	50 MW	10,97%-17,03%	38,34%-50,89%	6,19%-9,90%	7,37%-11,71%	73,12%-81,93%	54,27%-66,42%
	100 MW	19,76%-29,10%	55,42%-67,45%	11,65%-18,02%	13,73%-20,97%	84,47%-90,07%	70,36%-79,82%

6 Conclusions

This report has studied the potential consequences of hydrogen blending in natural gas. Hydrogen blending is being considered as a potential option to evacuate the hydrogen produced offshore in the DEMO 1 (less than 100 MW electrolysis installed capacity, somewhere in the west of the Netherlands) and DEMO 2 (500 MW electrolysis installed capacity, in the area known as TNW, Ten Noorden van de Wadden) utilising the existing natural gas infrastructure. The report focused on the impacts of hydrogen blending using the expected electrolysis installed capacity and location of DEMO 1.

Three main topics were discussed in this report:

1. Hydrogen blending and consequences of using the blends directly
2. Hydrogen blending offshore and deblending onshore
3. Potential locations for hydrogen blending and deblending

6.1 Hydrogen blending

We identified four main impacts of hydrogen blending:

- Impact on the properties of natural gas
- Impact on the equipment and materials of network operators and end users
- Impact on the economic value of natural gas
- Impact on existing legislation around natural gas purity

6.1.1 Impact on the properties of natural gas

Hydrogen content in natural gas will have an impact on the properties of natural gas; the most relevant properties of natural gas that hydrogen impacts are 1) the Wobbe index, 2) the NOx emissions that result from firing natural gas, and 3) the burning velocity of a gaseous fuel mixture.

Hydrogen has roughly three times less calorific value than natural gas in a volumetric basis. The Wobbe index is a measure of the interchangeability of a fuel i.e., it considers not only the calorific value difference of two fuels, but also the size of the fuel molecule with respect to air. Since natural gas is not a single molecule but a mixture of different fuels (methane, ethane, propane, etc.) and sometimes contains non-combustible components (such as nitrogen), the Wobbe index is one of the most relevant natural gas parameters in industry because it specifies the properties that a natural gas should have regardless of its composition.

We carried out thermodynamic calculations to measure the impact of hydrogen content in natural gas and found that low hydrogen contents (i.e., less than 20%) have no significant impact in the Wobbe index of a hydrogen-natural gas blend. Higher hydrogen content results in a decrease of the Wobbe index of the blend, while very high (>80%) hydrogen increases the Wobbe index of the mixture. This last phenomenon is caused by the fact that, while hydrogen has three times lower calorific value, hydrogen is also ten times smaller than natural gas, meaning that the Wobbe index of pure hydrogen would be roughly similar to the Wobbe index of hydrogen-free natural gas.

NOx emissions of burning natural gas (or any fuel) is related to the temperature at which a combustion process takes place: increasing the temperature of a flame (e.g., by modifying fuel-to-air ratio) will increase significantly the NOx emissions. In this report we show thermodynamic calculations we carried out to elucidate the impact of hydrogen on the combustion temperature. measured as the flame temperature i.e., the maximum temperature that a flame can reach. We found that low hydrogen content (<10%) has negligible impact on the flame temperature, while increasing hydrogen content can increase the flame temperature significantly.

The burning velocity of a fuel is the speed at which the fuel burns; it is, together with the flow velocity of the fuel, one of the most critical parameters that determine the safe operability of a combustion process. We carried out a literature review to survey the impact of hydrogen blending in the burning velocity of natural gas and found that pure hydrogen has a significantly higher burning velocity than natural gas (six times higher), meaning that a phenomenon known as ‘flame-flashback’ can occur in combustion processes and that redesign of combustion processes of pure hydrogen needs to make place. That being said, we found that low hydrogen blends (<10%) behave similarly to hydrogen-free natural gas, while higher hydrogen contents (>50%) start exhibiting considerably higher burning velocity (a factor of two higher) than hydrogen-free natural gas.

6.1.2 Impact on the equipment and materials of network operators and end users

We distinguish three main potential impacts of hydrogen blends:

- Impact on gas transport networks
- Impact on end users
- Impact on certification

We carried out a literature survey where we found that there is consensus about the fact that low hydrogen contents (<5%) have negligible impact on most materials and equipment of natural gas transport networks. We complemented the literature survey with discussions with industry where the main outcome is that hydrogen blends (even at low %) could impact equipment such as compressors or gas quality analysers, where studies would need to be carried out not only on the integrity of the materials but also on the impact of hydrogen content on the accuracy of instruments such as gas quality analysers or fiscal flow meters.

Furthermore, the magnitude of the potential impact of hydrogen blends would depend on where the hydrogen ends up: if the hydrogen blends are transported directly from a landing point to a particular consumer, then the adaptation of the network would be less impactful than in the case where hydrogen blends reach the national network where many instruments need to be evaluated and eventually adapted or replaced.

The main impacts of hydrogen blends with low hydrogen content is expected to be on end users such as feedstock users i.e., the users that use natural gas as chemical precursor to other substances (either as is or via conversion to hydrogen) as well as operators of gas turbines and compressed natural gas refuelling stations and vehicles.

On the subject of certification, we found that hydrogen blends would have an impact on the permitting of burner installations. Small and medium-sized installations (between 100 kW and 50 MW) need to obtain a new environmental permit for operating with hydrogen blends. Depending on blend %, hydrogen-natural gas blends could be considered as a non-standard gas (a gaseous fuel) as per the *Besluit activiteiten leefomgeving* as opposed to natural gas which is a standard gas. Large installations (>50 MW) need to consult the manufacturer and/or the insurer of the equipment whether they are suitable to operate with hydrogen blends.

Another impact related to safety certification is the ATEX directive. From the conducted literature survey it became clear that adding hydrogen to the process fuel (e.g., natural gas) could lead to a re-evaluation/reclassification of the hazardous zones. Furthermore, equipment suitable to operate within a particular hazardous zone would need to be re-evaluated when hydrogen blends of at least 3% are used. Hydrogen blends would require re-evaluation of the ATEX hazardous zone classification, which may have an impact on the operating permit of end users e.g., new certification would potentially need to be requested.

6.1.3 Impact on the economic value of natural gas

We calculated the impact of hydrogen blends on the cost of energy delivered to an end user, using the current market price of natural gas as well as estimates of the cost of hydrogen of 3, 6, and 10 €/kg. Our calculations show that hydrogen blending has a significant impact on the cost of the hydrogen-natural gas blend (calculated per unit energy i.e., €/MWh). As example, hydrogen blends with 5% hydrogen could increase the cost of the energy by between 10 and 40% with respect to hydrogen-free natural gas.

We also investigated the potential of green hydrogen certificate trading to boost the revenue of the offshore hydrogen. We found that the potential claim of certificates that can be used to claim green hydrogen consumption in either voluntary or mandatory renewable energy consumption obligations, is not only dependent on the origin of the hydrogen but on the complete supply chain. As an example, there are different ‘chain of custody’ concepts that consider not only the origin of a commodity (in this case green hydrogen) but also how it is transported to an end user: whether it is in dedicated pipelines that only carry this particular hydrogen, or also other forms of green hydrogen, or if it is transported via blending. Many things remain unclear about the potential trade and revenue stream of green hydrogen certificates; therefore, it is not possible at this moment to estimate what revenue could be generated by selling green hydrogen certificates from DEMO 1.

Moreover, we provided an initial estimation of a potential revenue in the form of generating and trading ETS allowances, where we found that the maximum revenue from ETS allowances that can be achieved is in the order of €11,47/MWh if a 100% blend were used instead of natural gas in heating applications. For the case of low hydrogen blends (e.g., 2%) we estimated the revenue from ETS allowances to be in the order of €0,08/MWh, which is considerably lower than the cost of hydrogen-free natural gas (€25,55/MWh).

6.1.4 Impact on existing legislation around natural gas purity

We conducted a survey of the current legislation around the purity of natural gas according to the ministerial decree of gas quality in the Netherlands (the MR Gaskwaliteit) and found that the maximum amount of hydrogen allowed in the Netherlands varies depending on factors such as: the type of gas (high-caloric, Groningen, or low-caloric), the type of network (high-pressure, regional, or distribution networks), and type of connection (feed-in, off-take in refineries, off-take in the Maasvlakte, or export connections). In the high-pressure grids, natural gas that enters the grid is only allowed up to 0,02% hydrogen content, while the natural gas in some off-takers can allow up to 40% hydrogen (refineries) and 0,5% (in a defined pipeline in the Maasvlakte area). Furthermore, interconnection points with other countries currently do not allow any hydrogen, while regional and distribution networks (e.g., medium- and low-pressure pipelines) allow up to 0,5% hydrogen in the natural gas of both feed in and off-take.

Potentially updating the MR Gaskwaliteit to allow more hydrogen in the Dutch networks is a decision that per se can be taken in a relatively short notice, where the decision can be made by MinEZK if it is deemed that the benefits of doing so outweigh the cost (e.g., for some users) to adapt their processes to accommodate an increased hydrogen content in their natural gas with respect to the current situation. That being said, the decision will most likely involve discussing and aligning with many different parties at the local and potentially European level (in the case of hydrogen content in international natural gas interconnectors), meaning that the ultimate decision to adjust the hydrogen limits in gas grids could be a long process.

6.1.5 Real-life hydrogen blending trials

A literature survey found that there is some experience at European level on the subject of hydrogen blending in pilots and trials, where the experiences are short (in the order of days or months of operation) and in small hydrogen percentages (<20-30%). Early indications from such projects find that hydrogen blending could be done seamlessly for both the operation of natural gas networks as well as end users, although real-life experience in hydrogen blending still remains relatively limited.

6.2 Hydrogen deblending

We studied three main technologies for hydrogen deblending:

- Pressure Swing Adsorption
- (Polymeric) Membrane separation
- Cryogenic Distillation

All three technologies are mature from the technical perspective, and they are commercially used for the separation of gases including hydrogen. Each technology separates hydrogen from gases based on different properties (chemical affinity, molecule size, and boiling point). Moreover, the potential advantages, cost, and required infrastructure for hydrogen deblending depend on parameters such as the hydrogen blend %, the required purity of the hydrogen, the required purity of the hydrogen-free natural gas, the pressure at inlet and outlet, as well as the flow of hydrogen.

Regarding the costs of hydrogen deblending, we studied the literature and found that the costs of hydrogen deblending depend strongly on the hydrogen blend % and the input and output pressures. In the case of low hydrogen blends (e.g., 5%), hydrogen deblending could cost between 10 and 14 €/kg for a low-pressure outlet (2 bar), and between 13 and 17 €/kg for a higher pressure outlet (20 bar). In both cases the costs found in the literature exclude the cost of the hydrogen production, meaning that the total cost of hydrogen including production in DEMO 1 and deblending (thus excluding any costs for the adaptation of the transport network, or any further compression to inject the pure hydrogen in the hydrogen backbone) can reach between 20 and 27 €/kg, or close to 700 €/MWh, which is significantly higher than the cost of energy from hydrogen-free natural gas (25 €/MWh).

When it comes to the expected time of construction of a deblending facility, we carried out a survey among industry and we concluded that it is difficult to give an estimated timeline. As a general remark, the expected times are not only related to the project planning and execution but also permitting is expected to be a time-consuming endeavour before a project can start construction.

6.3 Potential locations for hydrogen blending and deblending

Finally, we carried out a survey of the Dutch national database of offshore oil and gas assets (NLOG) in order to identify potentially suitable offshore pipelines and onshore gas processing facilities for hydrogen blending and deblending. We identified six main offshore pipelines where hydrogen blending could take place:

- The W09 pipeline (WGT)
- The NP007 pipeline (LoCal)
- The TP-001 pipeline (NOGAT)
- The NP-001 pipeline (NGT)
- The DPL-15D1 pipeline (TAQA)
- The W41 pipeline (Wintershall)

With help from the NLOG database and the North Sea Energy Atlas, we estimated the flow of natural gas through each pipeline based on publicly-available sources such as self-reported information, the offshore platforms connected to each of the pipelines, and the reported natural gas production (in 2022) of the platforms connected to each pipeline. With this information, we were able to provide an estimation of the natural gas flows as well as the expected hydrogen blend % (averaged throughout the year) based on two potential electrolyser installed capacities in DEMO 1 (50 and 100 MW) and considering both the installed capacity and the average expected hydrogen to be produced i.e., considering an utilisation factor of the electrolyser of 50%.

We found that there are pipelines that carry a significant amount of natural gas, where the expected hydrogen flows from DEMO 1 will result in hydrogen blend % of between 1 and 5%. Other pipelines i.e., that evacuate the natural gas produced from a smaller number of fields, carry less natural gas, meaning that the hydrogen blended to those pipelines could result in hydrogen blend % of up to 33% and 67%.

Finally, we used publicly-available projections of natural gas production in the North Sea (and discussed with industry), in order to provide an initial estimation of the expected hydrogen blend % through each of the pipelines in the next 5, 10, and 15 years based on an 8,5% annual decrease in natural gas production offshore. The preliminary calculations show an increase in the hydrogen blend % as a result of the decreasing natural gas production, which could mean that design considerations for blending hydrogen in one of the surveyed offshore pipelines would have to consider an increase in hydrogen blend %.

Signature

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