The Transition of Natural Gas to 100% Hydrogen in an Existing Distribution Network

Case Study: Stad aan 't Haringvliet

Ludger Oprinsen

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by

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Summary

Climate change, earthquakes in Groningen and the desire to become more energy independent in the future are all reasons for the Netherlands to strongly reduce the use of natural gas. To realize this ambitious goal the domestic environment will also have to stop using natural gas and start heating, cooking and using warm water sustainably. The distribution system operator Stedin has developed a method/tool that helps municipalities in identifying a viable energy carrier as alternative to natural gas. Stad aan 't Haringvliet is the first town that approached Stedin about the prospects of hydrogen as an alternative to natural gas. Stedin has made an initial review and concluded that hydrogen could be a promising alternative to natural gas in the case of Stad aan 't Haringvliet.

The objective of this research project is to improve the existing approach for identifying the ideal future energy carrier for different locations within Stedin's operating area by making a technical assessment of all necessary activities and changes when switching from natural gas to 100% hydrogen in an existing distribution network.

All identified relevant aspects of hydrogen are taken into account in the case study of Stad aan 't Haringvliet. The case study shows that the local gas network can be isolated from the larger gas network and function as a hydrogen network. Also, nearly no unfavorable materials (cast iron and asbestos cement) are present in the local network which underscores the suitability. If the town is isolated from the larger network it could be fed from north-west of the town by an alkaline electrolyser. However, a stand-alone system at this scale is not a cost effective scenario in the Netherlands. Therefore, an alternative system comparison was made to verify if hydrogen is indeed a viable option for Stad aan 't Haringvliet. In the chosen system comparison a scenario was sketched in which 'gray' hydrogen was received from a large industrial hydrogen network to the east of Goeree-Overflakkee. This scenario was compared to an all-electric scenario which utilized the current electricity mix which can also be considered 'gray', due to that the majority of the generation is from fossil fuels.

The system comparison shows that with cost-effective insulation, a hydrogen scenario can be nearly as expensive as an all-electric scenario in Stad aan 't Haringvliet regarding annual costs. The average initial investment for a home owner in an all-electric scenario is estimated to be €50,000 and the initial investment in the hydrogen scenario is €11,000 on average. The annual costs are €1,540 and €1,460 for hydrogen and all-electric respectively. The carbon footprint of both scenarios is nearly equal at 4000 kg/CO_2/year. The costs for adapting the local electric and gas distribution network is also significantly less expensive for a hydrogen scenario compared to the all-electric scenario. This is due to the fact that the natural gas network would have to be removed and the electric network would have to be heavily reinforced in an all-electric scenario in contrast to light reinforcements to the electric network in the hydrogen scenario to facilitate electric cooking.

No 'show stoppers' were identified in the general part nor in the case study part of this research. Several requirements and favorable characteristics were determined which could help identify other areas in which hydrogen could be a potential energy carrier. The first characteristic of a suitable area is predominantly housing which is very costly to sufficiently insulate for all-electric heating. Large consumers of natural gas in the area are also not favorable due to the fact that they might not be able to switch to hydrogen yet. The following characteristics relate to the network. Areas at the periphery of the local gas network are favorable due to the fact that they can more likely be isolated without creating capacity issues for itself or other areas. Also, areas which have little to no cast iron or asbestos cement are favorable due to increased risk of fractures inherent to these materials. Finally, a credible source of hydrogen is identified as a requirement for a suitable area.

Preface

This graduation thesis is my deliverable of my graduation research for the Master of Science Energy and Process Technology at Delft University of Technology. The past months I conducted my graduation research in collaboration with Stedin. The past nine months have given me a great insight into the current workings of the natural gas distribution network but also an insight into the challenges and opportunities at which Stedin is looking for the future.

During the final year of my master I realized that large scale energy storage and power to X technology were an essential step in realizing a more sustainable future. During my graduate internship at Stedin I have had the pleasure to really submerge myself into the potential of hydrogen and I am looking forward to a future in which I am sure to see, read and hear increasingly more about it.

This research presents a second iteration of the case study of Stad aan 't Haringvliet and also a more general evaluation of the larger network of Stedin and the issues that are relevant regarding the introduction of hydrogen. It has been very inspiring for me to see the proactive and energetic attitude the people at Stedin have in confronting and tackling the challenges inherent to the energy transition.

I would like to express my gratitude to my professors Ad van Wijk and Wiebren de Jong from the TU Delft for guiding and helping me during my research. Their enthusiasm, understanding and their encouragement to reflect have helped me significantly with my research and have given me the understanding and mindset to complete my research. Furthermore, I would like to thank my third thesis committee member Laurens de Vries from the TU Delft for his time and effort in the final stage of my research.

Finally, I would like to thank Frank van Alphen from Stedin. As of day one Frank has made me feel right at home at Stedin. Throughout my research he has helped me to reflect on my work and keep me up to date on the latest developments around hydrogen throughout all the relevant fields. The past nine months have been a very interesting and exciting journey for me and I would like to thank him with emphasis for his guidance and support.

L.J.F. Oprinsen
Rotterdam, November 2018

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Nomenclature

Abbreviations

AC	Asbestos Cement
AEL	Alkaline Electrolyser
ATR	Autothermal Reforming
CCS	Carbon Capture and Storage
CGS	City Gate Station
CI	Cast Iron
D&T	Distribution and Transmission
DS	District Station
DSO	Distribution System Operator
e-grid	Electric Grid
FFE	Forty Foot Equivalent
g-network	Gas Network
GO	Goeree-Overflakkee
GTS	Gasunie Transport Services
HAS	Huis Aansluit Station
HHV	Higher Heating Value
IR	Infra Red
KNMI	Royal Netherlands Meteorological Institute
LCoH	Levelised Cost of Hydrogen
LHV	Lower Heating Value
MPDS	Medium Pressure District Station
MSIR	Multi Spectrum Infra Red
NG	Natural Gas (Groningen Gas)
NL	the Netherlands
NTP	Normal Temperature and Pressure (20 °C, 1 atm)
PCC	Post-combustion Capture
SatH	Stad aan 't Haringvliet
SH	South-Holland
SMR	Steam Methane Reforming

SOE Solid Oxide Electrolyser

TFE Twenty Foot Equivalent

UV Ultra Violet

WI Wobbe-index

Symbols

η Efficiency

ϕ Relative angle to flow velocity

ρ Density

ρ_r Relative density

ζ Joule-Thompson coefficient

C Proportionality Constant

c Velocity of sound through medium

D Diameter of pipe

E Energy

e Pipeline efficiency

f_r Frequency received

f_t Frequency transmitted

L Length of pipe

P Pressure

P_1 Inlet Pressure

P_2 Outlet Pressure

Re Reynolds number

T Temperature

V Volume

v velocity

Z Compressibility

1 Introduction

Climate change, earthquakes in Groningen and the desire to become more energy independent in the future are all reasons for the Netherlands to strongly reduce the use of natural gas. To realize this ambitious goal the domestic environment will also have to stop using natural gas and start heating, cooking and using warm water sustainably. The distribution system operator Stedin has developed a method (Infrastructural Footprint, 'IF') that can be used in an early stage together with municipalities, housing corporations, residents and other stakeholders to identify what is the best alternative to natural gas for a certain municipality and when is the best moment to transit from natural gas to this alternative.

Roughly one year ago Stedin was approached by the municipality of Stad aan 't Haringvliet to identify the best alternative to natural gas for the town in the future. The town was the first to indicate to Stedin that they were interested in the prospects of hydrogen as an energy carrier. The results of the analysis were that hydrogen could indeed be a favorable energy carrier in the future for Stad aan 't Haringvliet. The next step for Stedin would be to identify if hydrogen could actually be implemented as energy carrier in the town and how a transition to hydrogen would most likely take place.

The objective of this research is to identify all relevant aspects of hydrogen to Stedin. These aspects include properties such as storage capabilities, production options but also the compatibility of the components and materials of the network and end-users. Finally, it should be identified if how an actual transition to hydrogen would have to take place for an area. All identified relevant aspects will be tested with the case study of the town Stad aan 't Haringvliet to identify if hydrogen can actually be implemented as energy carrier in the town. In addition, the goal is to use the identified relevant aspects to better identify areas where hydrogen could also have good potential as an energy carrier in the future.

I

Background Information

2 Research Methodology

2.1. Objective

The objective of this research project is to improve the existing approach for identifying the ideal future energy carrier for different locations within Stedin's operating area - with a focus on case study Stad aan 't Haringvliet - by making a technical assessment of all necessary activities and changes when switching from natural gas to 100% hydrogen in an existing distribution network.

2.2. Research Questions

1. **Which characteristics are relevant for assessing if hydrogen is suitable as an energy carrier?**
   - Which characteristics of hydrogen are relevant for its safe distribution?
   - Which characteristics are relevant for the distribution of energy?
   - Which technology choices (green/blue/gray) for hydrogen generation are feasible and what are their dynamic characteristics?
   - Which technologies for hydrogen storage are feasible and what characteristics are relevant?
   - Which options are feasible for the consumption of hydrogen?
2. **What are the relevant stages to converting a natural gas distribution network to hydrogen?**
   - Which parties are involved in converting an area to hydrogen?
   - What stages does a transition consist of?
   - What determines the duration of a transition?
3. **Is Stad aan 't Haringvliet capable of successfully implementing hydrogen as an energy carrier?**
   - Which production technology is feasible and how large must its capacity be for Stad aan 't Haringvliet?[1][2][3]
   - Is seasonal storage of hydrogen a realistic option for Stad aan 't Haringvliet? What are the limitations in this respect?
   - What is the best form of hydrogen storage for Stad aan 't Haringvliet and why?
   - Which actions are required by the distribution service operator to make the transition to 100% hydrogen?
   - What changes are needed for a residential consumer regarding a switch to hydrogen?[4]

[1] Excluding hydrogen for mobility
[2] Excluding large consumers
[3] If hydrogen were only used as a combustible in the boiler and not for cooking
[4] Assuming no fuel cells are installed

- How does the hydrogen consumption profile of Stad aan ‘t Haringvliet look in a typical year?
- How long will the transition to hydrogen take for Stad aan ‘t Haringvliet?
- What are the costs for the consumers, distribution service operator and production of hydrogen in Stad aan ‘t Haringvliet?

4. **What can be said about the criteria that must be met by Stedin vs. the criteria that must be met by other parties to successfully implement hydrogen as an energy carrier?**
   - What are the relevant technical issues still to be resolved for Stedin?
   - What are the relevant technical issues still to be resolved by other parties?
   - What are the costs with hydrogen as an energy carrier and how are they divided?
   - What are relevant constraints for an area to be suitable for hydrogen as an energy carrier and what are the characteristics for an area for which it is ideal to have hydrogen as an energy carrier?

2.3. Methodology

Literature study and interviews with gas network specialists were done to identify relevant characteristics for a safe energy carrier. Literature and interviews also identified the specific characteristics of how a NG network functions. Hydrogen generation technologies were identified through literature study and compared with NG network requirements to identify the best suitable technologies. Literature study was done on storage characteristics and compared with the demand of the distribution network to identify relevant storage technologies. Different hydrogen consumption possibilities were researched; however, the scope was kept to the combustion of hydrogen which meant that fuel cells were not discussed extensively.
After identifying the relevant aspects for identifying if a network is suitable for hydrogen conversion, the found aspects were compared with the network of SatH. The demand profile of SatH was determined with network capacity program of Stedin. This was done by combining temperature data with the network capacity program, which is the most significant driver of domestic NG demand. With the demand of SatH the production capacity and dynamics for hydrogen could be determined. Literature was used to identify the most feasible production technology. Production of hydrogen was simulated with the help of characteristics found in literature. The differences between the simulated production and demand identified the required storage capacity. Literature and simulated storage were compared to identify the most feasible storage technology.
After considering cost calculations and feasibility, several qualitative system comparisons were made to identify the potential of hydrogen in SatH compared to all-electric heating. After identifying the most promising and relevant system comparison, a quantitative analysis was made of a system comparison better asses the potential of hydrogen in SatH.

2.4. Scope

This research was done in collaboration with the Dutch distribution system operator (DSO) Stedin. The scope of this research will be kept within the scope relevant to a DSO. Specific attention will go to the production, distribution and consumption of hydrogen. To support the work discussed in this report, a case study is made of the town Stad aan ’t Haringvliet (SatH), which is located in Stedin’s operating area.
There were several decisions made to sufficiently narrow down the scope and keep the research relevant for a DSO. The first decision was to not include hydrogen mobility in the scope, even though DSOs do focus their attention on electric mobility. One of the reasons for this decision is because of the complexity of refueling a hydrogen fueled vehicle. This in turn makes it very unlikely that people will be able to refuel hydrogen near their homes, as is possible with electric vehicles. It is therefore more likely that other commercial parties will focus on the hydrogen mobility market.
Another decision reducing the scope, was the choice to not focus on the scenario with domestic fuel cells. The transition to hydrogen will include large investments to be realized in NL, especially if the hydrogen is green. At this moment in time, domestic fuel cell systems are still very expensive and the technology should still mature significantly more for it to come down in price and be a viable option. A scenario with domestic fuel cells also has significant implications with other systems such as a different electric load profile for the electric grid. Altogether, a scenario with domestic fuel cells is a potential research subject by itself and is therefore excluded from this research’s scope.

The scope will also not be able to afford a lot of attention towards large consumers. These consumers consist of a large variety of businesses and the nature of these businesses obviously varies greatly as well. It is therefore hard to verify which consumers will be able to transfer to hydrogen from NG. It is expected that large consumers will be able to transfer to hydrogen for certain processes such as heating in the future; however, for this scope large consumers will only be briefly touched as a subject.
A subject that will be remain within scope is the required modifications for heating with hydrogen and for all-electric. Specific attention will go towards the insulation required for all-electric heating.

2.5. Thesis Framework and Outline

The conceptual design of this report was made following the method developed by Verschuren and Doorewaard [1]. The conceptual design consists of three parts; the research objective, research framework and research questions. Sections 2.1 and 2.2 have already stated the research objective and research questions respectively. This section will explain the framework of the research and it will use this framework to explain the general buildup of this report.

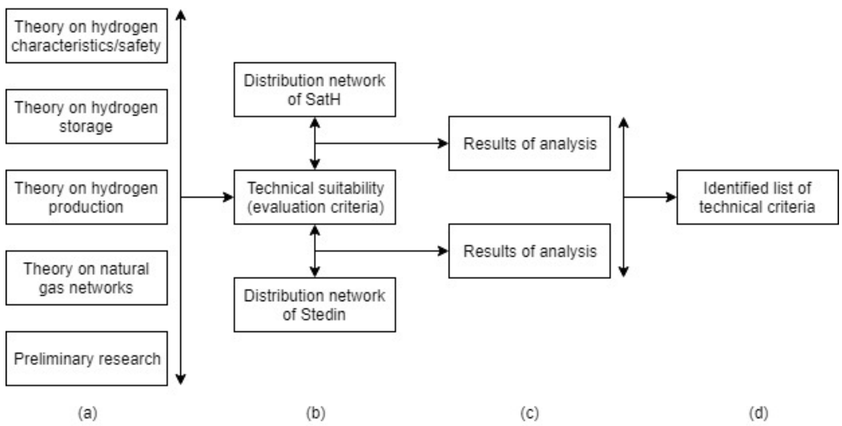


Figure 2.1: Research framework

Figure 2.1 shows the framework of this research and indicates that it has been subdivided into four phases. [1] "The first phase (a) concerns the formulation of the sources from which the research perspective is developed. The second phase (b) indicates to which research objects the research objective is applied. Phase (c) indicates in what way the analysis of the individual research objects may be interrelated. Phase (d) is the research objective."
In this case, phase (a) consisted of a study of hydrogen and the natural gas distribution grid based on talks with experts and relevant scientific literature. The study yielded technical assessment criteria and understanding of the relevant subjects. In phase (b) the natural gas distribution network was evaluated for its technical suitability to hydrogen. Followed by a case study evaluating the technical suitability of Stad aan ‘t Haringvliet in more detail. Phase (c) evaluates and confronts the results of (b) and indicates the similarities and differences between the criteria of the case study of Stad aan ’t Haringvliet and the general distribution network of Stedin. Phase (d) aims to deliver a list of identified technical criteria, helpful in better identifying if hydrogen is an ideal energy carrier for specific area’s.

Part I of this report will acts as the general introduction. The first part of the introduction focuses on the research subject and how the research and report are set up. The second part of the general introduction extensively introduces hydrogen and its characteristics.
Part II discusses the differences between the production of gray, blue and green hydrogen, the different production and storage technologies and the current and estimated future costs of these technologies.
Part III explains how the current NG network works. This part focuses on the lay-out of the network, the different materials and all the relevant components in the network. Finally, this part will discuss the characteristics of domestic consumers connected to the gas grid and the different appliances that are all relevant to the operation and demand of the gas network.

Part IV discusses the actual transition from NG to hydrogen. Attention is paid to the required work (sectioning), costs for the a DSO and consumers and the challanging housing that should be taken into account.
Part V discusses the case study of the town SatH. All relevant aspects of the current gas network, hydrogen production, hydrogen storage and the general transition to hydrogen are now applied to the town of SatH. Step by step the requirements for a hydrogen transition are taken to identify if SatH is indeed capable of switching from NG to hydrogen.
Finally, part VI will conclude with the research results. The research results and method will first be discussed; thereafter, the conclusion to the research questions will be given by answering them. After concluding the research results, recommendations will be given for actions and further research by Stedin.

3
Hydrogen

3.1. Introduction to Hydrogen

The energy transition is slowly starting to take place and the world is still looking for an alternative to fossil fuels. More and more alternatives of green energy technology are being developed and utilized than ever before. For these new energy sources, a need for a sustainable energy carrier is bigger than ever. This ideal fuel should offer ease of use and independence from other nations but at the same time be clean and inexhaustible.
One major candidate for a clean energy carrier is hydrogen. Currently, the prospects for hydrogen are being researched for being a favorable replacement for fossil fuels in many different sectors such as mobility, chemical refining, and heating. Hydrogen gas does not occur in nature and must first be made by any of a variety of processes. It costs energy to make hydrogen and it then acts as an energy carrier. Later, when the hydrogen reacts or burns the energy is released again.
If hydrogen is to be successfully implemented in the energy transition, its properties and safety aspects should be noted and understood. For this reason, this chapter will give an overview of the physical properties of hydrogen and all the properties that are relevant for safety. Hydrogen gas will often be compared to methane (NG) because of the subject of this report.

3.1.1. Previous and Current Uses

Hydrogen is not a new substance that has just been discovered. Its potential has long been known, and has already been used in a variety of industries. In 1927 Norsk Hydro already used the Haber-Bosch process which produces pure hydrogen from electrolysis. The company used the abundant hydro power to produce hydrogen for fertilizer [2]. In 2008, the world demand for hydrogen was 50 Mton, where 28 Mton was used for ammonia production, 5 Mton for methanol production, 12 Mton was used for refining and 5 Mton was for other uses[3]. The large demand for hydrogen in the chemical sector gives industry a great amount of experience with hydrogen.
Hydrogen was already used to heat homes before NG. Hydrogen was the main component in town gas, a gas which was produced from gasifying coals. During the gasification of coals multiple gases were produced, varying in composition between different city gas stations. Hydrogen was the main component in town gas which was typically composed of hydrogen, methane, carbon monoxide, carbon dioxide and nitrogen. From experience, the most dangerous component of town gas was not hydrogen but rather carbon monoxide, which is very poisonous. Carbon monoxide is also formed during the incomplete combustion of NG. City gas stations were often centered in the center of a city from which a local gas network was developed for the heating of wealthy individuals' homes and street lighting. A well known city gas station in NL is the 'Westergas fabriek' in Amsterdam which is currently used as an event location.
Currently, there are 3 main forms of feedstock for the production of hydrogen; NG, coal and biomass/waste. The respective production technologies are steam methane reforming (SMR), coal gasification, and biomass gasification [4]. Hopefully, carbon neutral technologies, such as electrolysis from green energy and biomass gasification, will soon replace SMR as the dominant hydrogen production method.

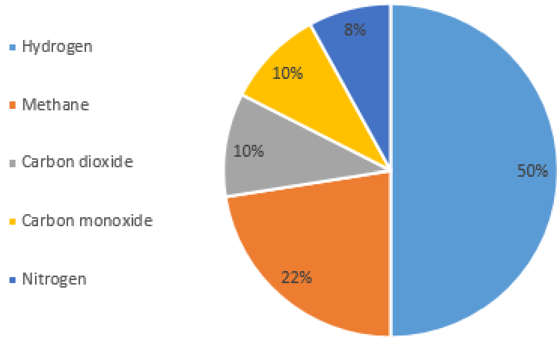


Figure 3.1: Typical composition of town gas [5]

3.1.2. Future Prospects

There are several future markets which show significant prospects for the implementation of (green)hydrogen. One of the most prominent markets which has been mentioned over the past years is the implementation of hydrogen fuel cell technology in the mobility sector. It is suspected that hydrogen can fulfill the requirements of heavy duty / long distance mobility which is not very suitable for battery electric vehicles, differentiated by weight and payload capacity [6].
Another possible future application is the use of green hydrogen for a more sustainable (petro)chemical industry. Due to the vast experience with hydrogen and the existing corresponding infrastructure, this industry could increase its sustainability with little modifications [7].
Last but not least, the implementation of hydrogen for domestic heating is seen as an interesting opportunity. A large portion of houses will ideally be heated by electricity; however, a considerable portion of infrastructure is not suitable and more expensive to heat in an all-electric manner. For these houses and other buildings hydrogen can be an important pathway to becoming carbon neutral in the future [8].

3.2. Physical and Chemical Properties

There are two different types of NG that are transported through the Dutch gas network, H-gas and L-gas/G-gas. H-gas stand for high calorific gas and it consists nearly pure methane gas. L-gas/G-gas stands for low calorific gas or Groningen gas. Low calorific gas and Groningen gas still consists mainly of methane but also has a significant percentage of inert nitrogen (14%) [9], which decreases the calorific value. L-gas is made by adding nitrogen to H-gas, G-gas is found in the Dutch gas fields, predominantly Slochteren in Groningen. The NG found in the distribution network is always L-gas/G-gas, therefore all further mention of NG will refer to L-gas/G-gas.
Table 3.1 compares all relevant physical properties between hydrogen and methane gas. For a comprehensive comparison, a comparison between pure methane and hydrogen will suffice. For certain characteristics an additional comparison will be made with L-gas/G-gas to see how these characteristics relate.

3.2.1. Critical Temperature

The critical temperature of a substance indicates the maximum temperature at which a gas can be compressed to a liquid state. Above this temperature a gas cannot be compressed to its liquid state. For hydrogen, this means that it first has to be kept at 33 K before it can be stored as liquid hydrogen. The condensation temperature of hydrogen however, is 22 K. Methane in comparison has a much higher critical temperature of 190 K, resulting in better prospects for liquid storage.
The low critical temperature demands for a very large amount of energy to cool down hydrogen enough to liquefy it. "The theoretical work required to liquefy hydrogen is 4kWh/kg, but the technical work is about 10 kWh/kg, which is about a third of the lower heating value of hydrogen" [11]. This is why in practice one nearly never stores hydrogen in liquid state. Hydrogen powered cars for example store the hydrogen gas under extremely high pressure instead of cooling it down to its liquid state [12].

Table 3.1: Comparison between hydrogen, G-gas and methane properties [9] [10]

Properties	Hydrogen	G-gas	Methane	Unit
Molar mass	2.02	18.63	16.04	[g/mol]
Critical Temperature	33.2	187	190.65	[K]
Critical Pressure	13.15	44.6	45.4	[bar]
Vapor density (NTP)	0.0899	0.833	0.668	[kg/Nm^3]
Lower Heating Value by mass	120	38	48	[MJ/kg]
Lower Heating Value volume (NTP)	10.8	31.7	35.89	[MJ/Nm^3]
Higher Heating Value by mass	142	42	53	[MJ/kg]
Higher Heating Value by volume (NTP)	12.75	35.1	39.9	[MJ/Nm^3]
Wobbe Index	48	43.5-44.4	52	[MJ/Nm^3]
Explosive limits	18.2-58.9	-	5.7-14	[Vol% in air]
Flammability limits	4.1-74	4.7-16.6	5.3-15	[Vol% in air]
Laminar burning velocity	3.1	-	0.4	[m/s]
Auto-ignition Temperature	833	890	873	[K]
Molecular diffusivity in air	$6.1 \cdot 10^{-5}$	-	$1.5 \cdot 10^{-5}$	[m^2/s]

3.2.2. Critical Pressure

The critical pressure is the pressure required to liquefy a gas at its critical temperature. These pressure are relatively low for both methane and hydrogen. Storage of both hydrogen and methane is possible at much higher pressures in a gaseous state.
As mentioned in section 3.2.1 hydrogen gas is often stored at very high pressures at temperatures well above the critical temperature. Within the setting of the distribution network, the working conditions are well above the critical pressure and temperature for hydrogen.

3.2.3. Vapor Density

The density of hydrogen gas at standard conditions is much lower than the density of air. This results in a much higher buoyancy which makes that hydrogen gas ascends rapidly with great turbulent diffusion, when it is released into air [13]. Methane is also lighter than air in standard conditions; however, it is significantly denser than hydrogen gas, resulting in a lower buoyancy.
The density of hydrogen in its gas form is so low that with hydrogen leakages the hydrogen gas will ascend to the highest part of the environment. For example, if there were a hydrogen leak in the hallway of your house, the hydrogen would quickly rise to the highest part of the house making it very difficult to smell the hydrogen gas even if an odor were added to it. In smaller and better contained rooms such as a garage, it is less likely that a leak would go undetected. This is due to its high diffusivity, further explained in subsection 3.2.7.

3.2.4. Lower and Higher Heating Value

The caloric value of gas is predominantly described in its value per unit of volume. This is in fact the case for most energy carriers (e.g. barrels of oil). The more specific term for energy per unit mass is called the specific energy.
Hydrogen has a lower caloric value per unit volume than methane; however, hydrogen has the highest caloric value per unit mass (excluding nuclear energy). Because hydrogen is often stored under high pressure, volumetric capacity of storage would give an unclear representation of the contained energy. This is why, with hydrogen storage, the stored amount of hydrogen is referred to in value of mass. For certain situations, such as mobility, it is advised to also consider the mass of the storage system. The storage system for compressed hydrogen for example, is significantly more heavy than that of a compressed natural gas tank, due to the higher internal pressures.
When combustion of certain fuels takes place, water can be a product of the reaction. The water that is formed will subsequently 'use' some of the released heat to evaporate. This 'used' heat can be utilized, if the water is later condensed, and the released heat is won back. Many gas boilers have a second stage that utilizes this latent heat. If one wants to know how much heat can be utilized from 1 l of gas in a gas boiler, it makes sense that the higher heating value (HHV) should be used. In other circumstances where the mentioned second stage is not present, the lower heating value (LHV) should be used (e.g. a combustion engine).

The HHV of hydrogen per volume is three times lower than that of methane in NTP conditions. This means that for every cubic meter of methane one needs to heat a house, three cubic meters of hydrogen are needed to provide the same amount of heat.

3.2.5. Explosive and Flammability Limits

Flammability limits indicate which volumetric concentration of a gas in air is required to detonate a flame. The explosive limits indicate a narrower limit in which the gas and air are a more ideal mixture and in which an explosive reaction can take place. Hydrogen has the highest explosive mix range with air of all the gases except for acetylene [13].

The flammability limit can best be explained with an imaginary empty box. If this box were to be filled with 100% hydrogen and it was attempted to start a flame of a lighter inside, nothing would happen. This is because the volumetric percentage of hydrogen within this container was not between the required flammability limits (4 - 75 Vol. %). If the container would contain 5 vol. % of air the flame would ignite and the mixture would burn.

If the hydrogen volume percentage would be within a narrower limit of 18.2 and 58.9 % the hydrogen / air mixture would ignite in an explosive manner. The results of an explosive ignition are more severe because of the pressure wave that is formed at the flame front.

3.2.6. Laminar Burning Velocity

The laminar burning velocity is the velocity at which the flame front propagates. Hydrogen gas has a nearly 8 times higher laminar burning velocity than methane. This burning velocity is directly related to the combustion kinetics and is most significant in two different areas; the pressure generation at the flame front and flame stability [14] [15]. This will be further discussed in section 3.4.

3.2.7. Molecular Diffusivity in Air

The diffusivity of hydrogen is 3.8 times higher than that of methane [10]. This causes the a more rapid decrease in concentration within a large space. The high diffusivity also causes for a higher leakage rates [16].

As mentioned in section 3.2.3 the ascending nature of hydrogen can make it hard to detect the gas at lower heights within certain spaces. The high diffusivity however, does make it possible to notice the gas faster than one would expect due to it drive to diffuse as much as possible [17]. The mixture will be more homogeneous if the hydrogen is released in a rapid turbulent fashion within a non empty area. In an empty area at lower release rates the hydrogen concentration will be more stratified and higher concentrations will be found at the top of the concealed area.

3.2.8. Diffusivity in Solid Materials (Permeation)

Hydrogen is not only very diffusive in gaseous media such as air. The hydrogen molecules are also 5 times more diffusive than methane in solid materials such as metals. The amount of energy that is lost through permeation in gas networks, however, is negligible compared to the energy lost through leaks in connections [18].

What can be identified as an issue is that the hydrogen which diffuses through the material, can build up at locations of imperfections within the material, or between layers. A coating, for example might seem as an ideal way to protect a tube from certain conditions; however, if hydrogen would pass through this tube it would diffuse through the coating and start to build up between the coating and tube material, deteriorating the coating.

It is important to keep the risk of build up by permeation in mind when working with hydrogen. Within the gas network there are several occasions where gas pipes are laid within casings of other pipes. By diffusion hydrogen may build up between these tubes over time and reach explosive limits, if more time goes by the concentration will exceed flammability limit and become unharmful again. Further research should be done to identify if the described risk will form any real danger in real world conditions.

3.2.9. Compression and Reduction

Hydrogen is one of three gases (Helium, Hydrogen and Neon) which have negative Joule-Thomson coefficients at NTP conditions. This means that when hydrogen is compressed it's temperature goes down. Subsequently, when hydrogen's pressure is reduced, its temperature goes up. The Joule-Thomson coefficient of natural gas is 0.5 [°C / bar] and -0.035 [°C / bar] for hydrogen gas [19].

As an example; If natural gas pressure is reduced from 80 bar to 15 bar the temperature of the gas declines with 32.5 °C. When the same pressure reduction takes place with hydrogen gas a temperature increase of 2.275 °C takes place.
Currently gas is often preheated to prevent the formation of ice on piping at Joule-Thomson expansion. With hydrogen the temperature increase would be significantly smaller so that the heating or cooling of the gas will no longer be necessary.

3.3. Safety

Hydrogen varies in a large amount or properties from methane. These differences should be considered carefully, regarding safety. In this section an overview is given of all the relevant properties regarding to safety. Table 3.2 gives an overview of safety aspects of gasoline, methane and hydrogen. Some properties that are relevant to safety have already been mentioned in section 3.2, such as the density and diffusion coefficient. What should be noted is that hydrogen scores the 'safest' score of the three fuels. Hydrogen's ignition limit is higher than that of NG's and Gasoline's, therefore sufficient attention should be paid to understanding the consequences of this and mitigating the consequences.

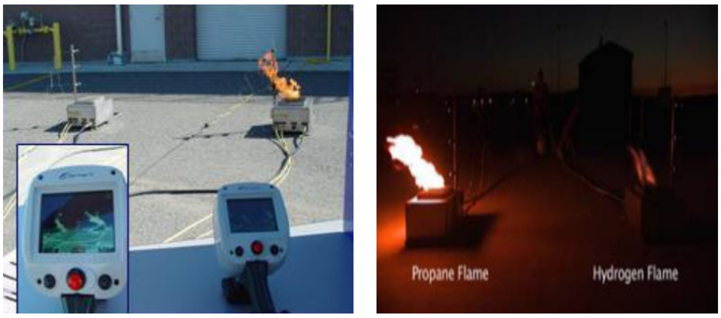
Table 3.2: Safety ranking of fuels [19]

	Fuel ranking		
Characteristics	Gasoline	Natural gas (H-gas)	Hydrogen
Toxicity of fuel	3	2	1
Toxicity of combustion	3	2	1
Density	3	2	1
Diffusion coefficient	3	2	1
Specific heat	3	2	1
Ignition limit	1	2	3
Ignition energy	2	1	3
Ignition temperature	3	2	1
Flame temperature	3	1	2
Explosion energy	3	2	1
Flame emissivity	3	2	1
Total	**30**	**20**	**16**
Safety factors	0.53	0.8	1

1, safest; 2, less safe; 3, least safe

3.3.1. Odorless, Colorless and Tasteless

Hydrogen gas is odorless, colorless and tasteless and can thus not be noticed by the human body [13]. This means that the the gas has to be detected using sensors or odor has to be added, as is done with NG. There already is extensive experience with hydrogen in a number of industrial applications, where it is handled by well-trained experts with excellent safety track record [20].
Natural gas is also, odorless, colorless and tasteless; however, the sulfur-containing odorant mercaptan is added by GTS and green-gas injectors so that people can detect it without sensors. A substitute for mercaptan has to be found because fuel cells (a large potential application for hydrogen) are contaminated by sulfur [19]. Currently steps are being made in realizing sulfur free odorants fit for fuel cell applications. There are already several patents for promising compounds [21] [22] and the realization of their potential should be tracked closely. Another reason why it is difficult to find a fitting odorant is because it is difficult to find an odorant that can 'keep up' with hydrogen's high dispersion rate due to its low molecular weight [23]. Hydrogen's high buoyancy also causes it to rise quickly, which causes it to collect at the ceiling, away from where a person might detect it.
When hydrogen is ignited it is virtually impossible to see it burning in daylight conditions [24]. Figure 3.2a shows a daytime comparison between a between a hydrogen and propane flame. The sensor in the figure shows both flames are burning. At night hydrogen is observable, but it is significantly less visible than a hydrocarbon flame (figure 3.2b). The fact that hydrogen is difficult to observe during the day makes it an increased risk for workers or emergency services. A sensor like in figure 3.2a could be a necessary new addition to maintenance and rescue services' equipment.



(a) Daytime comparison hydrogen (l) and propane (r)

(b) Nighttime comparison hydrogen (r) and propane (l)

Figure 3.2: Flame comparison of propane and hydrogen [25]

3.3.2. Poison / Toxicity

Hydrogen is not toxic nor poisonous. Hydrogen will not contribute to groundwater contamination. In ambient conditions it is in a gaseous state and will not contribute to atmospheric pollution. The product of hydrogen combustion is water, which of course is not a contaminant.

3.3.3. Asphyxiation

Hydrogen (like every other gas except oxygen) can cause asphyxiation. However, due to its high buoyancy and diffusivity it is unlikely that this will happen in realistic conditions, especially for NG of hydrogen of which people are aware of its presence.

3.3.4. Radiant Heat

Hydrogen does not create any carbonaceous species when it is combusted. When a gas containing carbons burns, the carbon atoms in the flame heat up and start to glow. These hot glowing atoms radiate heat which can be felt and seen at a distance from the actual fire. When hydrogen gas is combusted no carbon atoms are present. This is why its radiant heat is significantly lower than that of fossil fuels. This lower radiant heat reduces the chance of secondary fires. Figure 3.3 shows a vehicle fire from a hydrogen container in the back compared to a regular petrol fire under a vehicle. What this figure shows is that after a full minute of hydrogen fire, nowhere throughout the vehicle secondary fires have formed due to radiant heat. The low radiant heat is why blast pressure instead of heat flux is more significant during hydrogen combustion [26].

Figure 3.3: Comparison between a hydrogen (top) and gasoline (bottom) fire in a car

3.3.5. Ignition Energy

Hydrogen has a very low minimal ignition energy of 0.02 mJ [12]. Methane in comparison has a minimal ignition energy of 0.29 mJ which is 14.5 times as high. Such a low ignition energy results in the necessity of isolation of open flames, heating and electrical equipment.
The low minimal ignition energy of hydrogen might be one of the most disadvantageous characteristics of the gas. In practice this means that it will only take a very small amount of energy to ignite a fire or explosion. The justifiable fear is that bad wiring or the impact of a shovel against a metal pipe will be enough to ignite a hydrogen flame or explosion.

3.4. Interchangeability

The interchangeability of methane and hydrogen is of course completely dependent on the function for which the gas is to be used. In this section we focus on the interchangeability of hydrogen and NG in transport through pipes and in burners, as you would see in your household stove or boiler.

3.4.1. Energy Flow Rate

To meet the same energy demand with hydrogen as with G-gas a higher flow rate is required. Table 3.1 indicates the HHV value of NG and hydrogen. Equation 3.1 is used to calculate the flow rate through a pipeline. When multiplied with the HHV the flow rate determines the energy flow rate. The relative density of hydrogen is about 9.26 times lower than that of NG and the HHV of hydrogen is 2.75 times lower than that of NG. The parameters Z and f both vary with pressure and flow rate. Detailed calculations have shown that with an equal pressure drop, 98% of the energy flow can be realized with pure hydrogen compared to G-gas [16].

$$Q = C \cdot D^{2.5} \cdot e \cdot \sqrt{\frac{(p_1^2 - p_2^2)}{\rho_r \cdot Z \cdot T \cdot L \cdot f}} \tag{3.1}$$

3.4.2. Wobbe Index

The Wobbe-index (WI) is used to compare the combustion energy of different gases in appliances. A burner which is designed for a certain gas, will only retain its thermal potential for a new gas if the WI is similar to that of the gas for which the burner was designed. The index is calculated in equations 3.2 and 3.3, in which ρ_r is the relative density of a gas.

$$\rho_r = \frac{\rho_{gas}}{\rho_{air}} \tag{3.2}$$

$$WI = \frac{HHV}{\sqrt{\rho_r}} \tag{3.3}$$

Figure 3.4 shows the WI of hydrogen-natural gas mixture. The WI of pure hydrogen is on the right hand side of the graph. The left hand side shows the WI of G-gas. G-gas has a WI between 43.5 [MJ/Nm^3] and 44.4 [MJ/Nm^3] [27]. What can be noticed is that the WI of hydrogen and G-gas differ considerably (hydrogen has a WI of 48 [MJ/Nm^3]). This means that if 100% hydrogen were to be implemented in the NG network, burners would have to be replaced.

3.4.3. Burning Velocity

In comparison to methane, hydrogen gas has a significantly higher burning velocity. The burning velocity of a fuel is closely connected to the stability of its flame. Issues such as flashback, flame lift and even flame extinction are all due to instability of the flame [15]. Flashback is the phenomenon where the flame speed is higher than the flow velocity of the air-gas mixture and the flame propagates upstream toward the burner (figure 3.5a). The flame can either continue to burn inside of the burner or extinguish, possibly leaking the mixture into the surrounding environment. Flame lift is when the flow velocity of the air-gas mixture is higher than the burning velocity. In this case the burning flame is pushed away from the burner (figure 3.5b). This can result in incomplete combustion, equipment failure and escape of the mixture into the surrounding area. As mentioned above, hydrogen has a higher burning velocity than methane. Therefore the risk of flashback is increased. The risk of flashback can be mitigated by increasing the flow velocity; however, for the implementation of 100% hydrogen in a boiler, the solution will not be so straightforward.

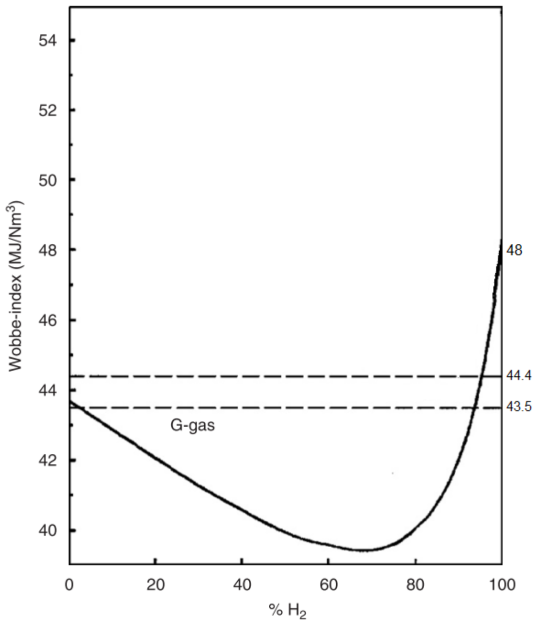


Figure 3.4: The impact of the addition of hydrogen to G-gas on the Wobbe-index [27]

(a) Flashback of a flame with a bunsun burner

(b) Lift of a flame with a bunsun burner

Figure 3.5: Flame flashback and lift due to incorrect tuning of the flow velocity

3.5. Concluding Remarks

At normal distribution network operating pressure and temperatures there are no significant differences between NG and hydrogen which make operation impossible. This should not come as a great surprise, due to the fact that hydrogen has already been transported as a main component of city gas through city gas networks before natural gas was introduced. Hydrogen does however have a variety of characteristics, such as its flammability limits and colorless flame which make it necessary to thoroughly reevaluate and adapt safety standards and procedures. As table 3.2 concludes, hydrogen is not more dangerous than NG but it does have different safety related characteristics. The HHV and density are both very important characteristics of hydrogen. These values are ideal for operating pressure in the current distribution network which makes it possible to transport equal amounts of energy at the same pressure; however, these characteristics also result in hydrogen's Wobbe index to be outside current NG limits. This causes the demand for new burners in boilers and other burning equipment.

II

Current State Hydrogen Production and Storage

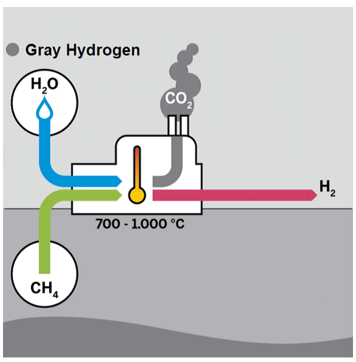
4

Hydrogen Production

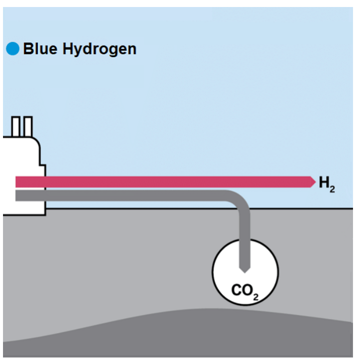
Hydrogen can be produced in a variety of ways. These are often divided into three different categories in which hydrogen is produced; green, blue or gray.
Gray hydrogen is hydrogen which is produced with the use of fossil fuels. The most common form of gray hydrogen production is steam methane reforming (SMR).
Blue hydrogen is also produced with fossil fuels but in this form of production the CO_2 that is produced during the hydrogen production is captured and stored, preventing it from entering the atmosphere. This process is called carbon capture and storage (CCS).
Green hydrogen needs no fossil fuels to be produced. Green hydrogen can be produced by gasifying biomass/waste or by electrolysis of water. The hydrogen from electrolysis is only considered green if the electricity itself was also produced from a sustainable source such as wind or solar energy.

Green, Blue and Gray Hydrogen

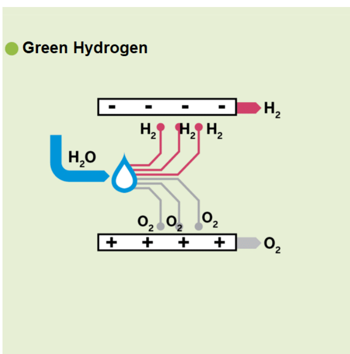
Gray Hydrogen: Hydrogen from fossil fuels without carbon capture and storage (CCS)
Blue Hydrogen: Hydrogen from fossil fuels with CCS
Green Hydrogen: Hydrogen produced from renewable energy or renewable resources



(a) Gray hydrogen production through SMR



(b) Blue hydrogen by CCS of gray hydrogen



(c) Green hydrogen production through electrolysis

Figure 4.1: An overview of the three different categories of hydrogen production (gasifying of biomass/waste not shown) [28]

In the upcoming sections the production methods of hydrogen will be given. Figure 4.2 gives an overview of possible hydrogen production methods. Section 4.4 will pay attention to the characteristics of electrolysers so that an accurate model can be developed.

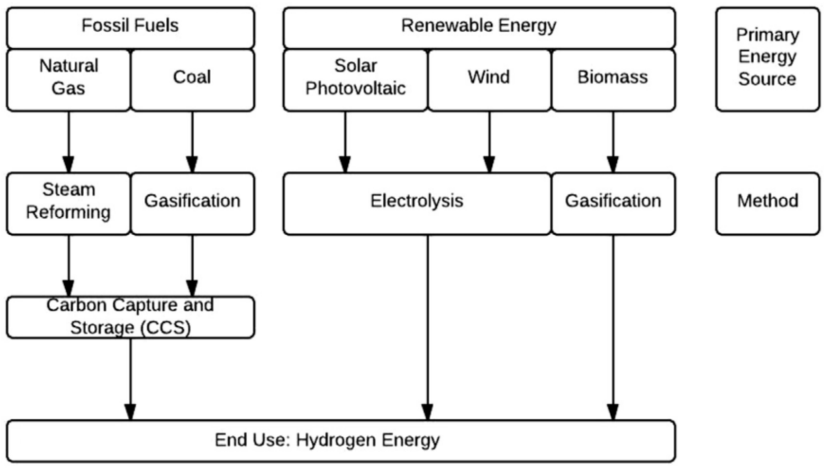


Figure 4.2: Hydrogen production methods (modified from Ref. [29])

4.1. Gray and Blue Hydrogen

The production of hydrogen is currently mostly used for the chemical industry. These companies need a large amount of hydrogen as a feedstock for their processes. As mentioned above, the hydrogen used for their processes is produced via SMR. SMR is a process in which tubes are heated to high temperatures with the burning of fossil fuels. Steam and methane are subsequently flown through the tubes, where a catalytic reaction takes place and hydrogen and carbon monoxide are formed. The carbon monoxide reacts further and creates more hydrogen and carbon dioxide. The hydrogen is later separated from the carbon oxides by pressure swing adsorption and is finally sieved for final purification. Equation 4.1 and 4.2 show the consecutive reactions explained above for the SMR process [10].

$$CH_4 + H_2O + heat \rightleftharpoons CO + 3H_2 \tag{4.1}$$

$$CO + H_2O \rightleftharpoons CO_2 + H_2 + heat \tag{4.2}$$

Another form of hydrogen production through the use of fossil fuels, is the gasification of coal. With gasification of coal, the carbon based material reacts at high temperatures with a controlled amount of steam and oxygen. No combustion takes place in this reaction. The resulting gas is a mixture of hydrogen and carbon monoxide. The carbon monoxide reacts further with steam to form carbon dioxide and hydrogen. The reaction of coal gasification is shown in equations 4.3 and 4.4.

$$3C(Coal) + O_2 + H_2O \rightleftharpoons H_2 + 3CO \tag{4.3}$$

$$CO + H_2O \rightleftharpoons CO_2 + H_2 \tag{4.4}$$

The gasification of coal and SMR are obviously gray hydrogen production processes. These processes can be considered as blue hydrogen if CCS is realized; however, 100% carbon capture from SMR proves to be difficult because part of the CO_2 stream is post-combustion making it difficult to isolate from other gases. 'True' blue hydrogen is therefore harder to realize than sometimes is portrayed. A hydrogen production with NG which does have truly blue potential is the autothermal reforming (ATR) of NG; however, this process requires a pure stream of oxygen making it less common than SMR. In the future, a possible symbiosis could be realized with electrolysis to bring oxygen and ATR together to realize blue hydrogen gas. Companies such as the Norwegian Equinor are looking into the possibilities in sourcing blue hydrogen from NG and selling it to NL through a retrofitted NG pipeline or a new dedicated hydrogen pipeline [30].

4.2. Green Hydrogen

Gasification can be considered as a green source of hydrogen if it is produced from biomass. This process is considered to be carbon neutral because all the carbon molecules that arise from the process, have first been absorbed from the atmosphere by the biomass. The process can be carbon negative if the carbon is captured and stored.

Electrolysis has the advantage that no carbon or sulfur contamination is produced with production of hydrogen. The disadvantage of electrolysis is that it has higher costs and requires more energy to produce hydrogen than fossil based hydrogen alternatives. The process creates hydrogen from water and electricity. As mentioned above, the electricity source should be produced renewably for the hydrogen to qualify as 'green'. Electrolysis is considered as a cost-effective way to produce hydrogen locally due to its compactness and small scale applications.

4.3. Quality

Different production methods of hydrogen come with different hydrogen qualities. This quality of hydrogen is of little concern if hydrogen is combusted. For catalytic uses in fuel cells however, the quality is very important. PEM Fuel cells have shown detrimental effects from gases such as carbon monoxide, ammonia and sulfide compounds. The poisoning in fuel cells due to carbon monoxide has shown to be reversible if flushed with pure hydrogen. Poisoning due to ammonia and sulfides however, has proven to be irreversible at this moment in time. Table 4.1 shows the ISO draft for purity standards for fuel cells. What should be noted is the very low permissible amount of sulfur compounds, including mercaptan. This means that a replacement for mercaptan or sulfur based odorants will have to be found.

The quality of hydrogen from electrolysis is significantly more pure than of SMR because in SMR production there is a chance of sulfides not being cleaned out, which are typically found in NG; however, as will be discussed later, the quality of hydrogen can still deteriorate through its residence time in piping by air diffusing into the pipe.

Table 4.1: The concentration limits for PEM fuel cells of select impurities from the ISO draft standard [31].

Impurity	Concentration [ppm]
Total gases	100
Helium (He), Nitrogen (N_2), Argon (Ar)	Sum: 100
Carbon dioxide (CO_2)	2
Carbon monoxide (CO)	0.2
Total sulfur compounds[1]	0.004[2]
Ammonia (NH_3)	0.1[2]

4.4. Electrolysers

There are currently three types of different types of electrolysers; alkaline, solid oxide and proton exchange membrane (PEM). The solid oxide electrolyser (SOE) currently has a very low technology readiness level (TRL) and only has a proof of concept, for this reason the SOE will not be be discussed. In an alkaline electrolyser (AEL) a DC current is run through a liquid alkaline electrolyte solution (or potassium hydroxide (KOH) or sodium hydroxide (NaOH) in water) between two electrodes. The electrodes are separated by a diaphragm which also separates the two product gases oxygen and hydrogen (figure 4.3a).

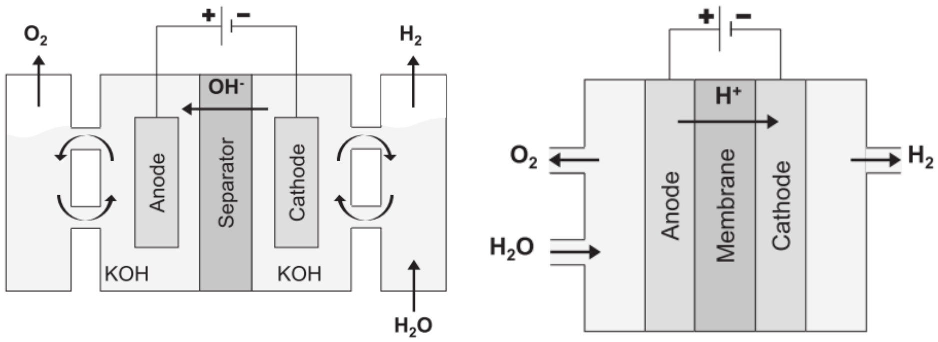
A PEM electrolyser uses a conductive solid polymer. When a potential difference is applied between two electrodes, hydrogen ions travel through the conducting polymer membrane towards the cathode where a neutral hydrogen atom is formed. Hydrogen is separated to one side of the membrane and oxygen and water are left on the other side (figure 4.3b).

AEL systems are the most mature technology for water electrolysis and have been around for nearly a century. Because the technology is so mature, AEL systems are considered to be durable, readily available and exhibit relatively low cost due to the avoidance of expensive noble metals and relatively mature stack components. Low operating pressures and low current density unfortunately negatively effect the system size and hydrogen production costs. In general, the dynamic behavior of the cell is limited in comparison with PEM and has decreased efficiency and purity with dynamic loads [32]. However, when operated adequately, the flexibility may be sufficient to address slow grid services such as fluctuations from wind energy [33]. AEL in 2017 were already to ramp up and down the load up to 20%/s [33].

[1] As a minimum, testing shall include H2S, COS, CS2 and Mercaptans, which are typically found in natural gas.

[2] These values are based on detection limits of available instrumentation and test methods and serve as a basis for subsequent improvements in test methods and instrumentation. Recommended values for these constituents are subject to additional testing under realistic operational conditions and improved analytical procedures suitable for standardization.

PEM systems were first developed in the early '60s by General Electric due to the negative traits of the aforementioned AEL systems. The technology is still less mature than AEL and is still predominantly used for smaller scale applications. The main advantages of the PEM system are its high current density and the high pressure and purity of the produced hydrogen. Also, the system dynamic behavior is far superior because it retains its high efficiency when loaded dynamically. A PEM electrolyser is capable of ramping up and down its load by 100%/s. Unfortunately, the capital cost of the PEM cells are still high. The costs are driven up by the complexity of the system, required due to the high operating pressures, water purity requirements and shorter lifetime than present AEL systems. The technology also requires expensive noble metals such platinum, raising costs [32].



(a) Conceptual set-up of an AEL cell (b) Conceptual set-up of a PEM cell

Figure 4.3: Conceptual set-up of AEL and PEM electrolysis cell technologies [32]

4.4.1. Oxygen Stream

From figure 4.3 one can note that there is one more product stream from an electrolyser beside hydrogen, the oxygen stream. High quality and pressure oxygen is used throughout industries as a high value feedstock [34]. Unfortunately, the oxygen produced from electrolysis is low pressure and 'wet', this makes the stream lose value significantly. There is a variety of processes that can benefit from a cheap oxygen feedstock. In the vicinity of heavy industry, oxygen could be used a feedstock for furnaces. In rural areas the oxygen can be used for biomass gasification. The actual utilization of the oxygen stream can not presumed and the potential would always have to be examined in every specific case/project. If production of hydrogen starts to take place on a large MW scale, the utilization of the oxygen stream could prove to be an interesting business case [8].

4.4.2. Location

There are several aspects that are relevant when deciding on the location for an electrolyser, these aspects are: connectivity, footprint, noise and safety. An electrolysis system needs two feeds and two exhausts. To produce hydrogen from electricity one obviously needs water and power. The water supply can be realized by connecting the installation to the water grid or by having water delivered on site in tanks. Connecting to the water grid would be the best choice due to operating expenses. Water quality from the national network can be shared with the system engineer, who can design the required water purification device accordingly. In certain situations it might also be able to connect to an industrial demineralized water network. Several industries also require very pure water and therefor water system operators also produce and transport large amounts of demineralized water at several locations throughout NL [35]. These networks are typically found near heavy industry.

The power connection is obviously necessary, the preference goes out to connecting to a nearby existing network. As mentioned in subsection 4.4.1 there is often no demand for the oxygen stream. finally, the gas network should be close by so that the hydrogen could be transported through the existing network without the need of installing a significant pipeline.

The footprint of an electrolyser is far larger than that of only the stack. There are several other different components such as cooling and water purification that require space. For a MW scale electrolyser including total system and water purification a footprint of 200 m^2 is realistic [36].

5
Hydrogen Storage

Hydrogen brings a lot of new opportunities to the table as an energy carrier. As mentioned, it is capable of providing energy to the consumer even though there is a mismatch between supply and demand. This flexibility is due to the fact that hydrogen is better capable of storing energy efficiently over longer periods of time (seasonal), compared to energy in the form of electricity.
There is a large multitude of previous and current studies into the technologies of hydrogen storage. One of the drivers of this topic is the mobility sector. Weight is a very important aspect to the mobility sector and this is why many studies are focusing on lightweight storage solutions. For large-scale stationary storage, the weight of the systems is less important. The following forms of storage will mainly focus on larger scale energy storage solutions. Table 5.1 gives an overview of the Technology readiness level (TRL) of the technologies. A TRL of level 4-5, 6-7 and 8-9 indicate a maturity at the level of prototype status, technology in demo/upscaling and mature technology, respectively.

Table 5.1: TRL of researched and mature hydrogen storage technologies [37], [38], [39]

Storage Technology	**TRL**
Compressed	8 - 9
Cryogenic	6 - 8
Metal Hydrides	4 - 9
Ammonia	4 - 7
Salt Cavern	6 - 7

5.1. Established Technologies

Even though there is a lot of research and going into the possibility of storing hydrogen in an efficient, practical and affordable manner, there are currently only few technologies which are able to store hydrogen within acceptable constraints. Compressed and liquid hydrogen storage are currently the two main forms of hydrogen storage being used on a significant scale. This section will briefly touch on the two form of storage and what their inherent characteristics are.

5.1.1. Compressed Storage

Hydrogen compression is the technologically most straightforward form of hydrogen storage. Hydrogen storage containers can stand pressures up to 700 bar [40]. One of the negative effects of compressed hydrogen storage is that a lot of energy goes into getting the hydrogen up to such high pressure, decreasing the storage efficiency. A positive attribute to compressed hydrogen storage is the simplicity of the system and its dynamic load and unload ability.

Figure 5.1: Compressed hydrogen storage cylinder

5.1.2. Liquid Storage

Another proven form of hydrogen storage is the storage of hydrogen in its liquid form. Liquid hydrogen has a higher energy density than compressed hydrogen; however, the processes required to liquefy the hydrogen are costly and not very efficient. The liquefaction of hydrogen takes 10 kWh/kg of hydrogen. In addition to these losses, liquid hydrogen storage has a typical boil-off rate of 0.2%/day [11].
Liquid hydrogen storage is most interesting when hydrogen has to be transported over long distances. The costs made getting hydrogen into its liquid form can be earned back when being able to transport large amounts of hydrogen to more profitable markets. Kawasaki Heavy Industries for example is currently developing a liquid hydrogen tanker which Japan intends to use to import hydrogen for power generation[41]. Figure 5.2 indicates a liquid hydrogen storage vessel, the spherical shape is due to the optimal surface/volume ratio.

Figure 5.2: Liquid hydrogen storage. The sphere shape is chosen due to the minimal surface/volume ratio.

5.2. Researched and Proposed Technologies

Currently there is a lot of research being done into novel and innovative techniques of storing hydrogen. The hope is that new techniques will make it possible to store more hydrogen at more stable conditions with higher efficiency. The technologies discussed in this section are just a selection of the vast amount of different techniques that researchers are looking into.
Hydrogen is a substance which is not easily contained under NTP. This means that a lot of effort has to made to contain hydrogen at commercially interesting energy densities, as one could already conclude from section 5.1. An interesting way to mitigate this issue is by chemically bonding hydrogen to other elements to make it more stable at NTP conditions. The first part of this subsection explains two technologies that utilize a chemical reaction to stabilize hydrogen. There is a multitude of other technologies being developed which utilize this principle but these two have been chosen because they are more commonly known and more relevant than others.

The final technology of this section will focus on physical storage of hydrogen; however, this form of storage is a novel and promising approach to compressed hydrogen and is capable of storing far larger quantities of hydrogen over longer spans of time.

5.2.1. Metal Hydrides

A relatively well known way of storing hydrogen chemically is storing in with the help of metals. The metals absorb the hydrogen forming metal hydrides. The metal hydrides form a very strong bond making it possible to store hydrogen at relatively low temperatures and pressures. The strong bond is unfortunately also the reason why it takes relatively high temperatures to release the hydrogen from the hydrides again. It is possible to use hydrides with weaker bonds making it easier to release the hydrogen again; however, this does make it necessary to bond the hydrogen with the hydrides at higher pressure, canceling out energy savings. Table 5.2 gives an overview of several different metal hydrides. It shows that for good reversible kinetics hydrides require high temperatures and in some cases other extreme conditions.
Hydrides do have a promising potential for stationary storage due to the hydrogen storage capacity, high reversibility and fuel cell friendly temperatures and pressures. The main disadvantage however is the heat transfer that is necessary for absorption and desorption [42]. The process requires heat to be supplied to the system for desorption and heat to be removed from the system for absorption of hydrogen. This heat transfer is often the limiting factor of the system and has great bearing on the system's performance. In addition, metal hydrides suffer damage over time due to mechanical stresses in the matrices due to thermal expansion and compression [43]. The current state-of-the-art for metal hydride storage can be assumed to be 0.4 kWh/kg and 0.4 kWh/L for its gravimetric and volumetric storage capacity. The costs are estimated at 9.6 €/kWh [44].

Table 5.2: Summary of metal hydride materials [44]

Materials	Maximum hydrogen content wt%	Decomposition temperature (K)	Comments
NaH	4.2	698	Good reversible kinetics
MgH_2	7.6	603	Poor reversibility and kinetics
LiH	12.6	~1000	Irreversible kinetics
CaH_2	4.8	873	Relatively good reversible kinetics
AlH_3	10.0	423	Production of AlH_3 requires high pressure and other extreme conditions

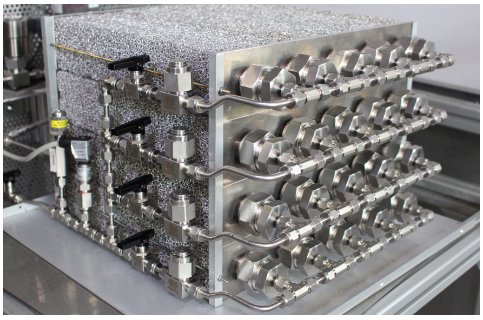


Figure 5.3: Demonstrator model of a metal hydride storage unit

5.2.2. Ammonia

Ammonia is produced by the catalytic reaction between nitrogen and hydrogen. Although the process has improved over the years the underlying reaction is still the identical to the process by Haber and Bosch early in the 1900's . The decomposition of ammonia is essentially the reverse of the production process.
The storage of hydrogen in ammonia has a number of advantageous attributes. The main attribute is ammonia's high capacity for hydrogen storage (Table 5.3).

Table 5.3: Status of storage capacity [45]

	Compressed H_2 (700 bar)	Liquified NH_3 (10 bar)
Gravimetric - capacity (wt%) - energy density (MJ/kg)	3.5-4.2	70-13
Volumetric - capacity (kg/L) - energy density (MJ/L)	0.024-2.9	0.380-7.1

For the production of ammonia and to release hydrogen from ammonia however, significant energy inputs are required as well as large reactor mass and volume. Another issue concerning ammonia is safety, ammonia has high toxicity levels and is a very corrosive substance [45]. Finally, in addition to immediate disadvantages, the storage of hydrogen in ammonia makes it highly incompatible with PEM fuel cells, where even the slightest trace ammonia can cause fuel cell poisoning [46].

5.2.3. Underground Storage

A promising possibility for large-scale hydrogen storage is the use of salt caverns/domes for hydrogen storage. The company ICI has already successfully stored 1 million Nm^3 of nearly pure hydrogen over three salt caverns 400 meters under ground in Teesside in England; near Leeds. The caverns have always operated successfully and are now operated by SABIC [46]. Salt caverns could be used to store hydrogen produced with abundant energy [47]. The size of the caverns makes it possible to store very large amounts of hydrogen over long periods of time. Suitable underground caverns are unfortunately not available everywhere; but when present, underground storage can store far larger amounts of hydrogen than other technologies and at considerably lower prices (1 €/kWh) [48].

There are salt caverns in Groningen that are available for gas storage. Several of these caverns would make seasonal storage possible (92 days at 500 ton G-gas/day). The company Energystock (part of Gasunie) wants to mark one or more of these caverns for future underground hydrogen storage. In NL there are also several NG field available for hydrogen storage; however, further research will have to tell if these locations can be made suitable for hydrogen storage [49].

Exact values about potential hydrogen losses due to leakage from salt caverns are hard to find; however, an old study does indicate that hydrogen in underground storage will behave much like natural gas insofar as integrity against leakage is concerned [50].

5.3. Concluding Remarks

Hydrogen can be stored in a large variety of ways. From the five technologies that this chapter has discussed, salt cavern storage comes out as the most favorable technology for the intended scale. Liquid storage of hydrogen has a low efficiency over longer periods of time due to boil-off and is more interesting for other markets. Storage options such as ammonia seem promising but still have a low TRL. Metal hydrides have been under development for a long period but still show some major drawbacks such as pulverization. In addition, the dynamic load and unload characteristics show significant room for improvement at NTP conditions. Compressed hydrogen currently seems to be the 'best of the rest' option but still considerably more expensive than salt cavern storage.

6

Costs Hydrogen Production and Storage

6.1. Production Costs

TKI Nieuw gas has published a report in which it states production costs of hydrogen, both SMR and through electrolysis [8].

Currently the cheapest form of hydrogen production is gray hydrogen produced from SMR. The cost of hydrogen produced by SMR is strongly dependent on the price of NG. At large scale production about 70-80% of production cost goes to NG.

The two major hydrogen electrolysis technologies are PEM and AEL, as mentioned in section 4.2. The costs of hydrogen through electrolysis are obviously also dependent on the electricity price. Table 6.1 gives an overview of the current hydrogen production prices in three different units, determined in TKI Nieuw gas's literature review. The review bases these costs on electricity prices of 0.07-0.08 €/kWh.

Table 6.1: Current Hydrogen production cost [8]

Production Type	**[€/kg]**	**[€/Nm^3]**	**[€/kWh]**
SMR	1-1.5	0.090-0.135	0.025-0.038
AEL	5-5.5	0.450-0.494	0.127-0.140
PEM	6-6.5	0.540-0.584	0.152-0.165

The investment costs of AEL and PEL are currently typically around 1000€/kW and 1400€/kW respectively [8] [33]. The expected investment cost for PEM electrolysers is expected to drop to anywhere between 700 €/kW and 1000 €/kW in 2025, with a middle value of 850 €/kW [33]. AEL currently have a typical production efficiency of 76% (51.5 kWhe/kg) [33] and are expected to achieve an efficiency of 79% (49.5 kWhe/kg) by 2025 [33]. PEM technology is currently behind in efficiency, producing around 66% (59.5 kWhe/kg) [33] but it is expected to approach the efficiency of the AEL with an efficiency of 75% (52.5 kWhe/kg) in 2025 [33].

6.2. Storage Costs

One of the most interesting characteristics of hydrogen is its ability to store large amounts of energy relatively easily over longer periods of time. The most promising hydrogen storage technologies have already been discussed in chapter 5. Table 6.2 gives an overview of the projected costs for different forms of hydrogen storage. The storage of hydrogen in salt caverns is the most promising technology for large scale seasonal energy storage. Other technologies are interesting for other scales and purposes, therefore the higher prices can often still be justified.

Table 6.2: Estimated hydrogen storage cost for different technologies [37], [48]

Storage Technology	**[€/kg H_2]**
Compressed	344 - 602
Cryogenic	172 - 232
Metal Hydrides	> 430
Ammonia	unk.
Salt Cavern	40

III

Current Gas Network

7 Current Network Components and Lay-out

The Dutch national gas grid is divided into two different sectors. The first sector is the transportation sector. This sector is run by only one company, Gasunie Transport Services (GTS). GTS transports gas from a source, such as the Slochteren gas field over long distances. Figure 7.1 shows the transport network of GTS. In the top right of the figure is the Slochteren gas field. The yellow lines illustrate the G-gas/L-gas network which also exports small amounts to neighboring countries. The gray lines are H-gas lines that import gas from neighboring countries and transport it through NL to other countries or to different locations within NL. From figure 7.1 one can understand why the NG transport network of NL is sometimes referred to as the gas 'roundabout' of Europe. GTS transports NG at pressures of 40 bar (regional transport network) up until 67 bar (high pressure transport network). Within the NL GTS transports its gas to different CGSs.
The second sector is the distribution sector. This sector is run by seven different DSO's which are all responsible for their own areas. These companies are responsible for distributing the gas from the CGSs to the residents and customers in their area.

Figure 7.1: GTS NG Network

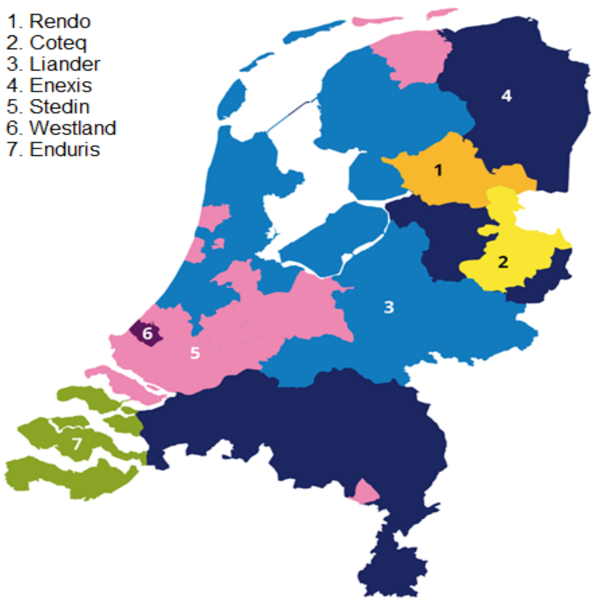


Figure 7.2: NL divided into the designated DSO Gas network areas.

Figure 7.3 gives a clear overview of how the distribution network is set up. The NG is received in the CGS by the DSO from GTS. The NG then enters the high pressure grid of the of the DSO. This high pressure grid is responsible for transporting the NG to the the different DSs in the surrounding area.

A NG distribution network consists of several different components that will be introduced in this section, figure 7.3 gives an overview of the distribution network. Note that there are no compression stations in the distribution grid. Only the transport grid of GTS uses compression to transport NG.
This report's scope does not include the components and materials used for the NG transport network; however, the materials used for the transmission network are largely the same as the materials used in the distribution network. The first part of the section will focus on the different components that are part of the NG distribution network. The effect of switching to hydrogen gas will be discussed for the different components.

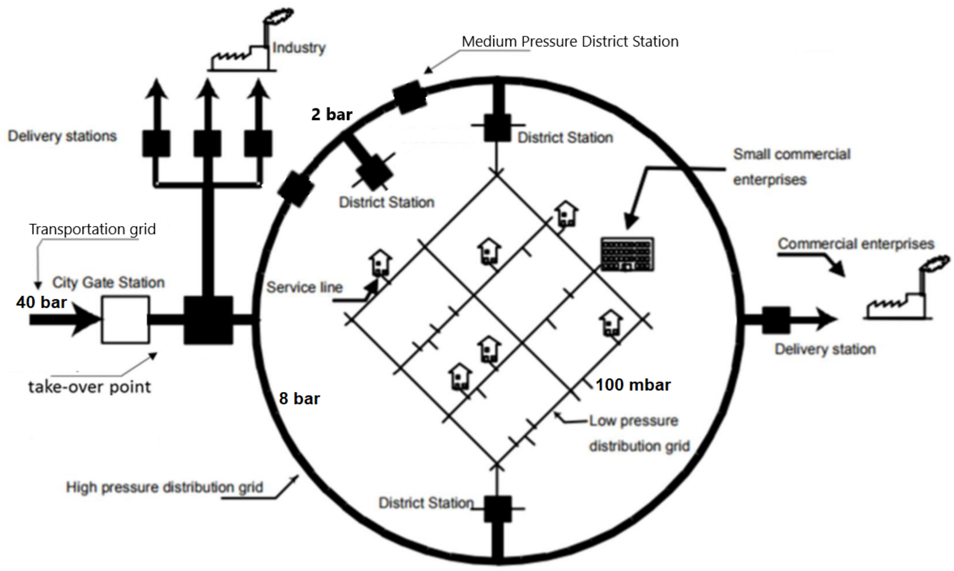


Figure 7.3: Schematic Overview of Gas Distribution Network

In general the transport network is regarded as the high pressure network and the distribution network as the low pressure network. Within the scope of only the distribution network, pressures higher than 100 mbar are regarded as high pressures. Pressures of 100 mbar and 30 mbar are regarded as low pressures within the distribution network. Due tot the scope of this research, all further referral to high and low pressure will be done according to the norms of the distribution network. Table 7.1 shows the operating pressures DSO Stedin retains in its grid. Table 7.1 also indicates the maximum and minimum pressure allowed for each corresponding network.

Table 7.1: DSO Stedin's low and high operating pressures

High Pressure	**Minimum Pressure**
8 bar	1.5 bar
4 bar	0.8 bar
3 bar	0.6 bar
2 bar	0.4 bar
1 bar	0.2 bar
Low pressure	
200 mbar	70 mbar
100 mbar	40 mbar
30 mbar	25.8 mbar

7.1. City Gate Station

Figure 7.3 gives an overview of a gas distribution network. The NG enters the distribution network at the City Gate station (CGS). This station receives the NG at a pressure of 40 bar and reduces it to a pressure of 8 bar.
A CGS is responsible for providing a very large area with gas. Areas with a very large demand of gas are often connected to more than one CGS to ensure sufficient gas security.

Because the CGS is responsible for the supply of NG for such a large area it is paramount that the system always is operational. This is why inside a CGS there are two parallel systems (figure 7.4a), so that maintenance or repairs can be made to the CGS without having to shut down gas supply for a very large area.

(a) Inside of City Gate Station

(b) Outside of a City Gate Station

Figure 7.4: City Gate Station

7.1.1. Joule-Thompson Effect

In figure 7.4a one can see that the actual equipment of the station is contained within a designated building. There are several reasons for wanting to place the CGS equipment within a building. Security and keeping the materials safe from the weather are two of these reasons. Another reason is the need to prevent the CGS material from being covered in frozen condensate. Like other real (non-ideal) gases, NG decreases in temperature when it is decompressed and expanded. This is called the Joule-Thompson effect. The final temperature of the gas can be calculated using equation 7.1. Here ζ is the Joule-Thompson coefficient, which is positive for all real gases except hydrogen, neon and helium at room temperature (figure 7.5). NG has a Joule-Thompson coefficient of 0.5 °C/bar. This means that if the gas pressure is reduced from 40 bar to 8 bar, the NG will decrease in temperature by 16 °C. The temperature of the NG would drop below 0 °C and ice would form on the equipment if the gas was not preheated, this is done inside the CGS. As stated above, hydrogen has a negative Joule-Thompson coefficient at room temperature of -0.035 °C/bar [19]. This means that there would be no need for preheating hydrogen in a CGS. The coefficient is also sufficiently small that no significant temperature increase should be expected.

$$T_2 = T_1 + \zeta(P_2 - P_1) \tag{7.1}$$

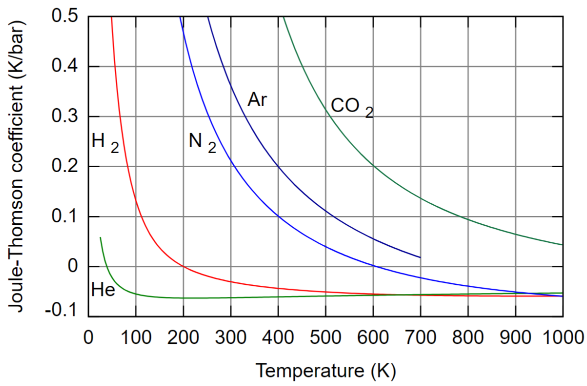


Figure 7.5: Joule-Thompson effect for various gases at atmospheric pressure [51]

7.2. District Station and Medium Pressure District Station

DSs are responsible for reducing the pressure between the high and low pressure network. The high pressure can be any from the noted high pressures from table 7.1 and the low pressure network will have a pressure of 100 mbar or 30 mbar.

There are also medium pressure district stations (MPDS). These stations do not connect the low and high pressure network. These stations reduce the pressure within the high pressure network from any high pressure to a lower high pressure.
What can be noted from table 7.1 is that DSs in the Stedin area never have a higher pressure reduction than 7.97 bar. This results in the fact that no preheating is necessary in a DS to prevent ice formation with NG. With hydrogen, just as with the CGS, also no significant temperature increase will take place.

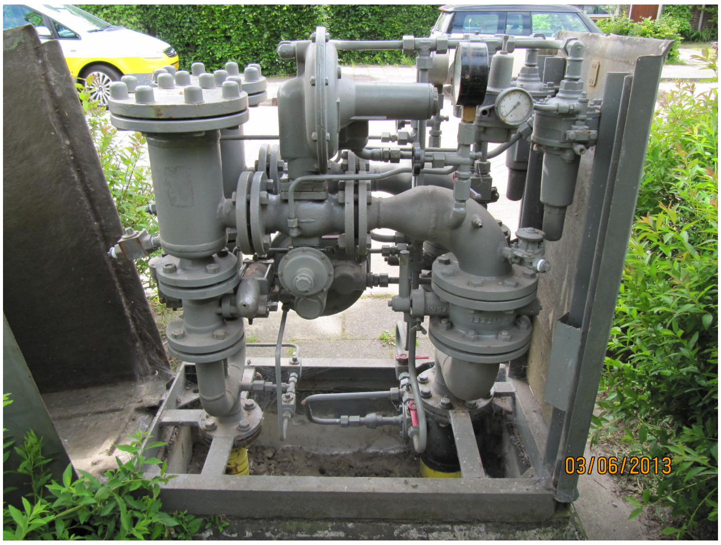


Figure 7.6: Internal Components of a District Station

7.3. Delivery Station

Delivery stations are stations that connect the high pressure distribution network to large customers. Typical customers connected to a delivery station are horticulture or industry.
Another kind of station is the 'huis aansluit station' (HAS, not in figure 7.3), this station connects a house directly to the high pressure grid. These stations can often be found in areas of horticulture. In these area there is often only a high pressure grid in the area. In between the greenhouses there are sometimes single houses which also need to be connected to the grid. A HAS makes it possible to connect these houses to the grid without the need of a low pressure grid.

7.3.1. Flow velocity

Flow velocities in the distribution network have been determined to prevent vibrations, noise disturbance, pulsations, influence on pressure control and erosion [52]. Even though the guidelines and norms for permitted flow velocities are well defined, they are not based on calculations but rather on experience with NG in the distribution network [53].
Guidelines [54] [55] indicate that the maximum flow velocity on either side of a pressure regulation station (CGS or MPDS) be no higher than 20 m/s. The maximum permissible velocity for the outflow of a DS at 30 mbar is 10 m/s
Flow velocities will increase roughly three fold when switching from natural gas to hydrogen due to the lower energy density. This means that flow velocities will sometimes be higher than the permissible NG limit. Without calculations, it is not possible to determine the influence of, for example, the density. With the underlying calculations and argumentation, it can be determined what the maximum permissible flow velocity is of hydrogen. The new permissible flow velocity can also be determined from the knowledge and experience learned from testing. Noise production from a DS for example could easily be tested in advance of actual implementation. Effects of dust or residue being transported due to higher flow velocities will become known during first stages of implementation.

7.3.2. Demand

The NG distribution network of NL is passed its all time maximum NG demand. It is expected that the decline in NG consumption in housing in NL will continue (figure 7.7).
If the same pressures and diameters are maintained in the distribution network the capacity for hydrogen gas will be the same and sufficient following equation 3.1. Because the density of hydrogen is about 9 times lower than that of Dutch NG, at the same pressure drop the flow velocity will be about three times higher. The 3 times higher flow rate cancels out the three times lower HHV, resulting in an equal amount of energy delivered at the same pressure drop. In countries where the HHV of NG is higher than that of NL the pressure drop will have to be increased to deliver the same amount of energy to the consumer. In this case the DSO will have to check if the network can operate at the increased pressure.
The program IRENE PRO [56] used by Stedin can be used to check the capacity of the network. Not just for the capacity of the new hydrogen network but also for the surrounding remaining NG network if present.

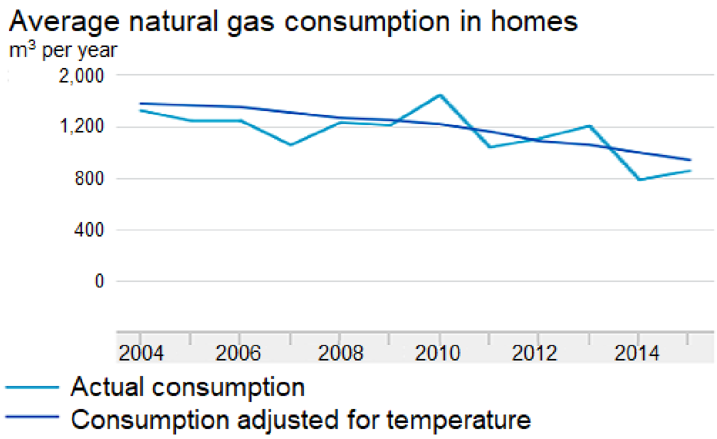


Figure 7.7: Average Natural gas consumption in homes [57]

7.4. Materials

A literature review done by *Kiwa N.V.*, commissioned by *Netbeheer Nederland*, pays special attention to the materials in the NG distribution and transport network. One of the aims of the report was to determine if the current NG infrastructure was capable of transporting hydrogen without any material issues. The report does not only focus on pipe materials but also on rubbers used for seals and connections and on components that can be found in pressure controllers and metering boxes [18]. Figure 7.8 gives an overview of the current composition of materials in Stedins gas network.

7.4.1. Plastics and Rubbers

Plastics and rubbers can be affected by chemically reacting with hydrogen or because their physical properties are effected by absorption or swelling. The sensitivity of the material for hydrogen is dependent on different factors, such as pressure, temperature, gas-composition and duration of exposure to hydrogen. With the help of many different tests a substantiated estimation was made for the lifetime expectancy of the different materials.

PVC & PE

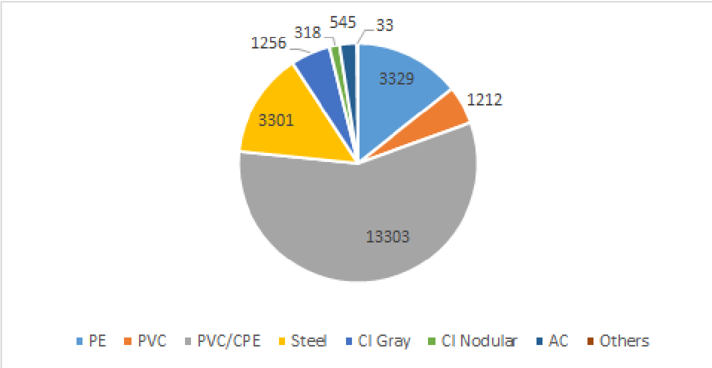
Both PVC (non-ductile PVC and impact resistant PVC/CPE) and PE (PE80 and PE100) are materials that are used as pipe material in the NG distribution network. Tests of up to 10 years were done with PE piping in contact with pure hydrogen. After ten years no degradation was found, indicating that no long term material degradation is expected with PE. In a test done by Stedin, PE100, PVC/CPE and PVC pipes were exposed to 20% hydrogen : 80% NG mixture [58]. After a period of four years there was no degradation. It is Kiwa's expectation that PVC will not show any material degradation over the longer term.

NBR and SBR

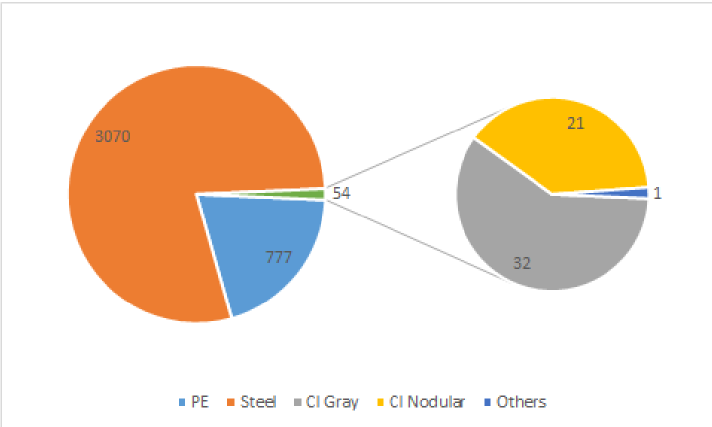
Both NBR and SBR are rubbers that are used for seals and connections between components. For both the rubber NBR and the older rubber SBR no degradation was found in short term tests. Reports of America's national research and energy laboratory also indicate that the rubbers SBR and NBR are both hydrogen proof.

POM

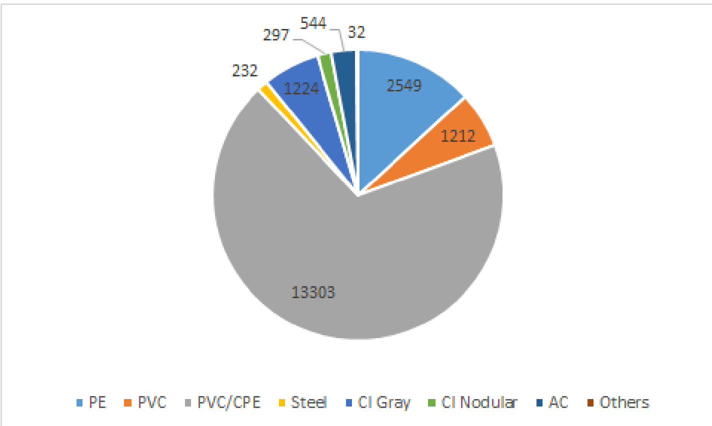
The plastic POM (polyoxymethylene) is often used for coupling components, gas meters and in pressure controllers. POM has been tested over a period of two years for an exposure of 62 vol% hydrogen. Over this period no degradation was observed. There is no conclusive verdict for the long term hydrogen suitability for POM.



(a) Materials in Total Stedin Gas Network [km]



(b) Materials in Stedin High Pressure Gas Network [km]



(c) Materials in Stedin Low Pressure Gas Network [km]

Figure 7.8: Overview of Materials in the Low Pressure, High Pressure and Total Network of Stedin [59]

7.4.2. Metals

Hydrogen can cause metals to deteriorate and lose quality. The fail mechanisms in metals caused by hydrogen are the change in tensile strength, fatigue and hydrogen embrittlement. For the exposure to hydrogen for the metals in the distribution network also many tests have been done and reported. These reports have been used to formulate a life expectancy for the different materials.

For several carbon steels in the distribution network it was determined that no hydrogen embrittlement would occur if hydrogen would be transported under normal temperature and pressure conditions. This is because hydrogen has a high bond dissociation energy (104 kcal/mol). This means that atomic hydrogen is only formed at very high temperatures or at an electrical discharge and atomic hydrogen is required to induce hydrogen embrittlement [18].
Hydrogen has no significant influence on the tensile properties of steels used in the NG network. The flexibility and fracture toughness are decreased but are still considered ample. If there is a small concentration of O_2 (several ppm) in hydrogen, the fatigue is comparable to that when NG is used.
The influence of hydrogen on cast iron is comparable to the influence on steel.
Most commonly used stainless steels in the distribution network (AISI 316L and AISI316Ti) are reported to be resistant to hydrogen under prevailing circumstances. Hydrogen embrittlement has not been observed in tests.
Copper, brass and aluminum also seem to be resistant to hydrogen degradation. Copper pipes and brass couplings can mainly be found in residential connections. Aluminum can be found in home pressure controllers and gas meters. The three mentioned metals have been exposed to 20 vol% hydrogen in a test over a period of four years [58]. After this testing period no degradation was observed and no leakages from the copper piping or brass coupling was observed.

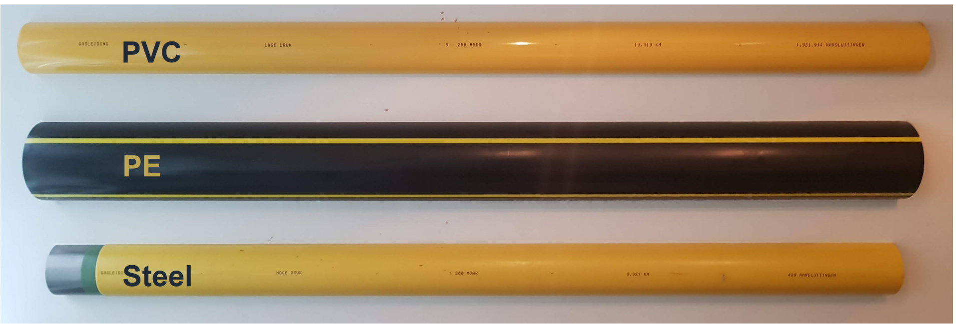
7.4.3. Age of network

The NG network as we know it in NL has been expanding for a long time. The first gas networks that were built were the gas networks in cities which provided city gas to certain neighborhoods. These networks were later used to transport NG after the discovery of the Slochteren gas field in Groningen. After the discovery of Slochteren, throughout NL, NG networks were installed everywhere where possible. Obviously, the undertaking to provide everyone in NL with NG was not done within a single year. In fact, the last part of NL to be connected to the NG grid was the island of Vlieland which was connected in the year 1986, 27 years after the discovery of the Groningen gas field. Ever since, DSO's have been obliged to connect all new houses to the NG grid.
Because of the large period of time in which the network has developed, a large variety of materials can be found in the network. The lifetime of a pipeline that transports NG is currently set to amortize over a period of forty years. However, this does not mean that all pipelines are removed after this period. A significant part of pipelines in NL are older than forty years and show no sign insufficient performance. In some parts of NL there are pipelines that are more than 100 years old, these pipelines are mostly old cast iron (CI) pipelines in cities from the city gas period as can be seen in figure 7.9. CI pipelines are being removed from the distribution grid due to increased risk of fracture in sinking soil. Due to the increased risk inherent to CI the introduction of hydrogen in areas with little to no CI is more desirable than areas with larger amounts of CI.

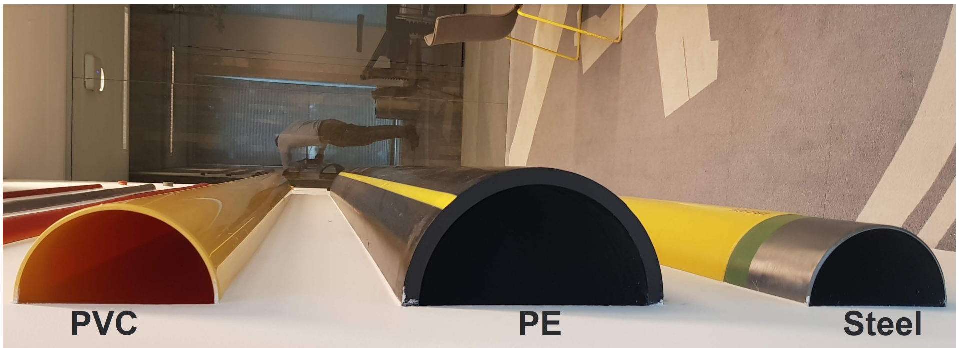
Figure 7.9: Example of an old CI pipe from 1884 recently removed in Schiedam [59]

Later in time steel pipes were replaced with other materials, such as PVC and PE. These materials had the advantage that they did not rust if the gas quality was to low and the city gas carried to much moisture. Figure 7.10 shows current PVC, PE and steel pipes that are currently used.

The diameter of the pipes is determined on the basis of the pipe characteristics. In essence the diameter is determined by the calculated pressure drop. Larger diameters cause lower pressure drops (equation 3.1), so to keep the pressure drop low over long distances, large diameters are often chosen. City gas was transported at low pressure of 30 mbar, this was later increased to 100 mbar for NG. Over a small distance, the diameter doesn't have such a large influence, therefore, in the low pressure grid often smaller diameters are found. Smaller diameters are easier to place underground easier to work with for technicians , especially in a low pressure network environment. It does occur that large diameters are used in low pressure grids (max. 800 mm); however, there is no 'hard' rule for choice of diameters for every situation, only supply security.



(a) Side view of pipes



(b) Front view of pipes

Figure 7.10: An example of pipes which are currently installed in the NG network

The following materials are no longer used for pipelines or grids; nodular and gray CI, asbestos cement (AC) and PVC. Gray CI is expensive and no longer easily available. Nodular CI is also expensive with only marginal advantages over the use of steel.
The use of AC has stopped, since processing of asbestos has been restricted by the government in 1977. PVC is no longer used because the inspection requirements of the material have been withdrawn due to the occurrence of hair tears.
Even though the quantity of the materials is slowly but steadily declining, there is still a large amount of kilometers in use made from these materials. Figure 7.12 shows the distribution of the used pipeline materials in the period of 1965 till 2010 and figure 7.11 shows the relatively recent distribution of materials from 2009. The declining amount of AC, PVC and CI can be seen in this figure. The most used materials for the distribution network are PVC/CPE (Stedin low pressure network) and steel (Stedin high pressure network). The use of steel for lower pressure distribution has been stopped a while back and it seems like it will also stop being used for the high pressure network.

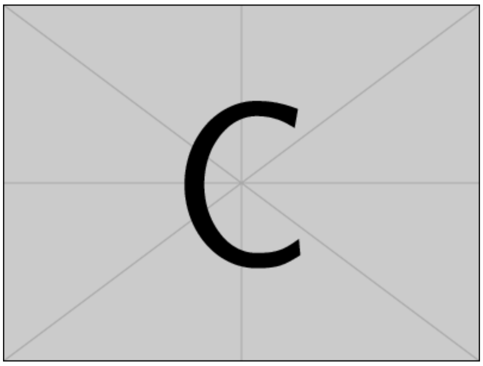


Figure 7.11: Applied materials in Distribution network (2009) [60]

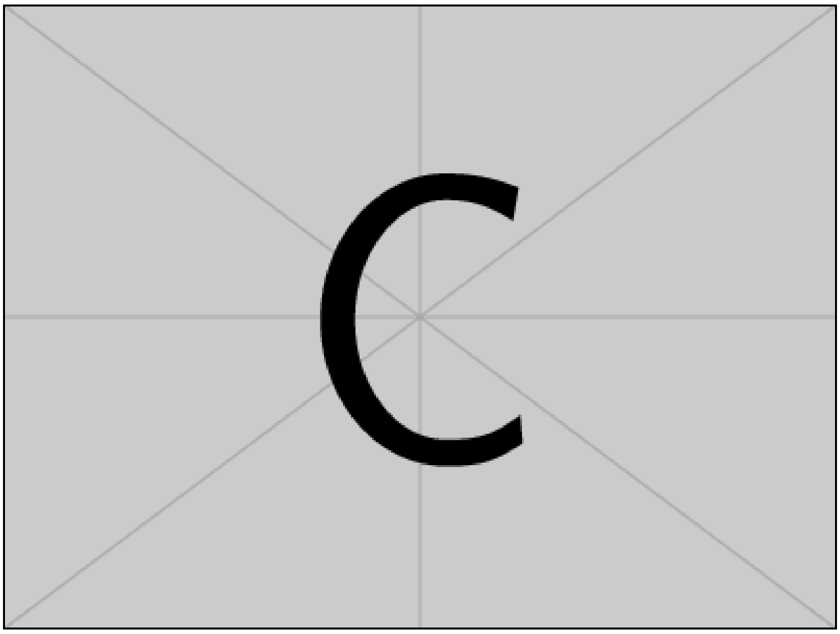


Figure 7.12: Grid length distribution of materials over time [60]

7.4.4. Connections

Pipes are connected to each other in a variety of different ways. For some materials the manner in which they are connected has changed over time.

In the high pressure grid, mostly Steel and PE is used. Currently steel pipes are connected by means of a weld connection. This was not always the case, in the past the steel pipes were connected by flanges but this type of connection is no longer used. High pressure PE pipes are also connected together through a weld. Recently a new technique has been used. This method uses a sleeve that is specially designed to resist the relative object movement caused by tensile strengths. This new method is only used for small diameter pipes.

The low pressure network mostly consists of PVC/CPE and PE. The PVC/CPE pipes are connected to each other through sleeves. The sleeve connections of PVC/CPE pipes are the reason why PVC/CPE pipes can not be used in the high pressure grid. Furthermore, sleeves are ideal for areas where the ground is sinking/setting. In these areas a weld connection is not ideal because of the high stresses that can arise due to relative movement between pipes. PE pipes in the low pressure grid are connected by being welded together or the use of a sleeve.

7.5. Maintenance

The current NG network is subject to maintenance and inspections. The large majority of the network is obviously piping, which is subject to leakage detection (once every 5 years). Once piping has been laid underground, it will only be dug up again when there is new piping being laid nearby or when the pipe is removed. About 20% of gas leakages is caused by excavation damages and 50% of the gas incidents is caused by excavations [61]. This means that it is very important that an excavation crew can detect hydrogen leakages and especially hydrogen flames, in case the hydrogen is ignited. Hydrogen flames can be detected using detection or multi spectrum infra red (MSIR) detectors. The workings of these sensors is explained in more detail in subsection 7.5.1.

To detect if pipes under ground are still working as expected, the ground above the pipes is 'sniffed' for leakages. Components above ground, such as DSs are inspected and are subjected to maintenance. DSO specialists inspect if all valves are still working correctly at regular intervals.

There are two different techniques for sniffing NG leaks in pipes under ground. The first method is driving with a (pilot) car equipped with detection hardware. This hardware can detect methane. If the car detects methane, it registers the location of the detection. The car will come back later to detect the leak again because it is not possible to stop the car in most of the situations where methane is detected. If the car comes back later and the hardware still detects methane it is possible that there is a gas leak. If the hardware does not detect methane again it is possible that the detected methane during the first run was exhaust from a gas powered vehicle.

The mainstream method of detection is done by walking with a 'drag mat' (figure 7.13). This equipment covers the ground and takes a continuous sample of the air under the mat. The sensors used to detect the air are a semiconductor sensor and a chromatographic separation sensor [62]. The chromatographic sensor is added so that the equipment can measure the concentration of both methane and ethane separately. In NG there is both ethane and methane, in biogas there is only methane. This means that if only methane is measured, there is probably a sewage leakage and not a NG leakage.

The 'drag mat' method is currently already used for leakage detection in water pipes. This specific form of detection uses a carrier gas (95% nitrogen, 5% hydrogen) that is pumped into a possible leaking pipe. The hydrogen leaks through the crack in the pipe and sensed by the sensor above ground [63]. This method could also be used for 100% hydrogen leaks. The sensor used for measuring hydrogen is also a semiconductor sensor; however, sensors designed for the detection of methane are not as accurate in the detection of hydrogen. New sensors could have to be purchased to measure hydrogen leakages.

Detection of hydrogen leakages with a car could be more difficult due to the high diffusivity of hydrogen. Tests will have to be done to see if it is possible to detect hydrogen leaks with a moving vehicle. Also, because hydrogen is present in sewage pipes [64], hydrogen will also be detected when one is leaking. If it is unclear if there is a sewage leak or gas pipe leak, methane detection alongside hydrogen detection could resolve the problem.

Figure 7.13: NG leak detection 'drag mat'

7.5.1. Hydrogen Flame Detection

Hydrogen flames are far more difficult to detect than flames from hydrocarbons. This is because there are no carbon atoms radiating light when the hydrogen flame is burning. The absence of the carbon atoms has two main effects. The first effect is that the flame is practically invisible to the human eye. The second effect is that because there is nearly no IR radiation there is far less heat radiating from the flame. Subsequently one can get far closer to the flame without feeling the heat. The flame temperature itself however, is higher than the temperature of hydrocarbon flames. This combination of characteristics makes the it dangerous for people close to the fire because they can't see or feel if they are moving towards or are already close to the flame.
Because the human senses are bad in locating a hydrogen flame, sensors have been developed for safety measures. Normally thermal detectors would be good in detecting heat from a hydrocarbon flame; however, for the hydrogen flame, little thermal radiation is emitted and thermal detectors subsequently do not provide the desired detection. Hydrogen flames do emit UV radiation. This is why in industry UV radiation is already used to help detect hydrogen flames. UV detectors typically have a good range and can sense a 60 cm plume from 15 meters away (figure 7.14). There are however some drawbacks to UV detectors. UV detectors can also be triggered by other rich sources of UV, such as arcs, sparks, welding, and lightning [65]. This false detection could cause people to become less sensitive to hazard alarms in the future. UV detection is preferably used in situations where false detection is less likely, such as in enclosed rooms (often use for battery storage).
An alternative to UV detection is multi-spectrum infra-red (MSIR) flame detection. MSIR flame detectors use a a series of IR filters and software analysis to detect flames and reduce false alarms. MSIR have been designed to specifically detect the low IR radiation profile of hydrogen flames and reduce false alarms that are inherent to UV detectors [65]. The MSIR hydrogen flame detection has a better detection distance for hydrogen flames than UV detectors and have detected hydrogen plumes of 60 cm up to 30 meters away (figure 7.14), twice as far as UV detection. Also, MSIR is not triggered by solar light, artificial light or black body radiation like many other detectors do. A limitation of MSIR detectors is water or ice on the lens. Because of this many MSIR lenses are heated to prevent ice and evaporate water. In effect, water and ice buildup on the lens may change the focal length of the lens causing limited light wave transmission [66] (also relevant for UV detection).
It is important for DSOs to identify the better of the two mentioned technologies for hydrogen flame detection for their specific circumstances. It is for instance possible that the welding of metal high pressure pipes could cause a UV sensor to give a false alarm. Outside conditions in contrast could possibly impair the performance of a MSIR detector due to moisture on the lens. Testing and consultation with experts should identify the best technology for the DSO's circumstances.

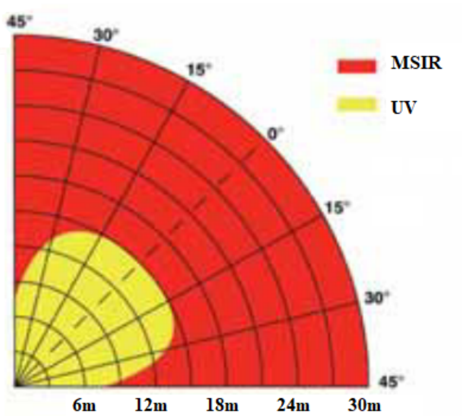


Figure 7.14: Hydrogen fire detection ranges for UV and MSIR flame detectors [65]

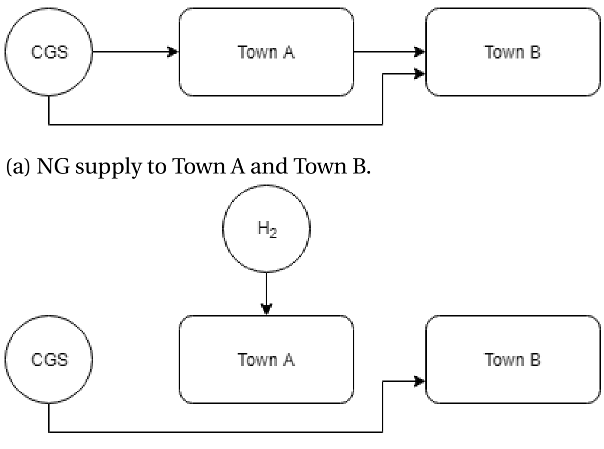
7.6. Electricity Grid Lay-out

Currently there is no real connection between the NG grid and electricity grid. The NG grid supplies the vast majority of energy throughout the country. The electricity grid however, is starting to gain more importance due to electrification, developments in the renewable energy sector and the consumer electronics market.
The production of hydrogen that is of most interest to people who are concerned with pollution and global warming is the production by means of water electrolysis. The production of hydrogen by means of water electrolysis could be the first real link between the electricity and gas network.

If an area would want to fully switch to hydrogen gas instead of NG, it would first have to decide what the source of the hydrogen would be. In the case of hydrogen by electrolysis, the desired location of the electrolyser would have to be decided. Producing enough hydrogen to replace NG for an area as small as a small town can already demand a very high amount of electricity. This means that the local electric network might not be able to sustain such a load.
There are three different approaches to solving the problem of having an inadequate electric network for sufficient hydrogen production. First is re-dimensioning the electric network to be able to carry sufficient electric power. Some areas already have a capable electric network because there is considerable energy production nearby which is already carried by the network.
A second option would be to connect the load of the electrolyser directly to the production of a nearby energy source, such as a windmill or solar field. This would cancel the need to reinforce the electric network of the area, or only for a small part, because the electric energy would be converted to an other form of energy carrier.
The third option would be to not be connected to the electricity network and produce hydrogen directly from an otherwise electric source. An example of this would be a hydrogen windmill of the company *Lagerwey* that converts the electric generated energy directly to hydrogen in an electrolyser within the windmill. The windmill would only produce hydrogen and therefore not produce any electricity on the grid.

7.7. Gas Network Isolation

When aiming to convert a part of the NG distribution network to a hydrogen network one has to consider the larger surrounding grid. The lay-out of the network is important and to a large degree determines the feasibility of a gas transition.
When approached by a municipality regarding a possible hydrogen substitution of NG, a DSO first has to identify which part of the NG network can be transitioned. The layout of the NG network of a town can be very complex so it will take some effort to identify which parts of the town can be converted. The conversion from NG to hydrogen will predominantly depend on the lay-out of the NG network.
The first aspect that has to be regarded is the possible isolation of the intended area. With isolation it is meant that the existing NG gas grid does not functionally connect to the hydrogen network. This way the hydrogen will not enter the NG network and NG will not enter the new hydrogen network.
The first step is to identify if the designated location of conversion is also partly responsible for supplying NG to other locations. For example in figure 7.15a, Town A is partly responsible for Town B's NG supply. If it were to be isolated from the grid, as shown in figure 7.15b, Town B might not receive sufficient NG.



(a) NG supply to Town A and Town B.

(b) NG supply to town B with an isolated Town A.

Figure 7.15: Visualization of isolation constraints regarding NG supply capacity

Town B would be an ideal location for the conversion to hydrogen because it is not responsible for the NG supply of an other area. If Town A would want to convert to hydrogen, a capacity check would have to be done to see if town B could still receive enough NG. The program IRENE PRO allows capacity calculations to determine if isolation of an area creates capacity issues in other areas.

A second point of interest is the capacity of the new isolated hydrogen network. This new network should still be able to supply the new area with sufficient hydrogen. The capacity of the new network can also be checked with IRENE PRO.
It is important to note that is is advised that the hydrogen supply is introduced into the isolated network through the high pressure system. This is to preserve the same network characteristics. The location of DSs within the isolated network could improve the supply security. To further improve the supply security, potential hydrogen supply could be located at a strategic location connected to the high pressure network. Figure 7.16 shows a possible isolated hydrogen network without storage.

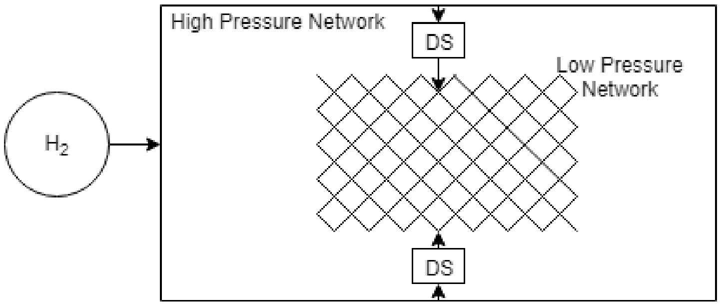


Figure 7.16: Hydrogen entering isolated grid through high pressure network

7.7.1. Hydrogen Production and Storage Location

An important parameter of a gas network is the security of gas supply to an area. If an area is connected to the larger gas network through only one pipe, the security of supply would not be ideal. If anything were to happen to that pipe, the whole area would have a issue with their gas supply. This is why gas grids are looped as can be seen in figure 7.17. If maintenance were needed for a specific part of pipe (parallel red lines), the area normally fed by the pipe would still be able to receive NG through an other route.
Stedin has set target values for gas supply security in their NG network. Table 7.2 shows the values the DSO uses to gauge the supply security. What can be concluded is that the supply security of the NG network is very high. The outage frequency mentioned in the table indicated the ratio between interrupted connections and total connections.
If a town is isolated from the grid because it is converted to a hydrogen network, supply security would still be very important to secure. In the case of a hydrogen network the production location and the storage location could both be identified as individual sources feeding the system. However, because the production of hydrogen could be intermittent, the actual source of hydrogen could be the production location, the storage location or both at the same time. A scenario in which the hydrogen production is not intermittent could benefit from smaller storage at an other location also. There are however drawbacks of storing hydrogen at a location relatively far from production which will be discussed later.
It could be decided to place production and storage of hydrogen far apart from each other. This would decrease the chance that a failure in the system would render both storage and production incapable of supplying the underlying area of hydrogen. Figure 7.18 gives a schematic representation of the described hydrogen network.
The main drawback of not placing the hydrogen storage and production near to each other is the fact that hydrogen will most likely be stored under pressure. If the hydrogen is produced by electrolysis, the produced hydrogen could be produced up to 60 bar. Large hydrogen storage tanks can store hydrogen up to 90 bar. If the hydrogen would have to be transported between the production and storage through the 8 bar network that would produce the necessity of a lot of unfavorable compression and decompression, both demanding large amounts of energy, decreasing system efficiency.

Table 7.2: Realized quality compared to target values of Stedin [61]

Category	Unit	Target value	2014	2015	2016
Annual outage duration	Seconds per year	<60	123.6	97	52
Average outage duration	Minutes per outage	<120	258	215	97
Outage frequency	Outages per year	<0.008	0.01	0.0075	0.0089

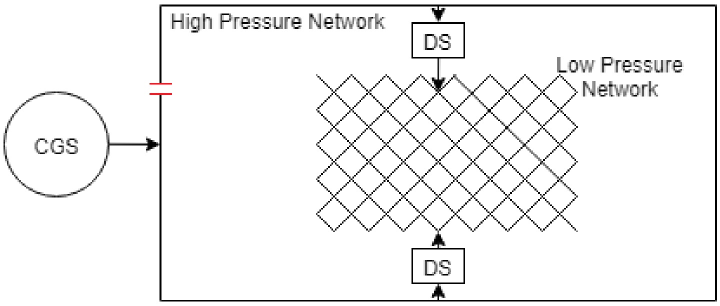


Figure 7.17: Looped Gas network. Maintenance indicated with parallel red lines.

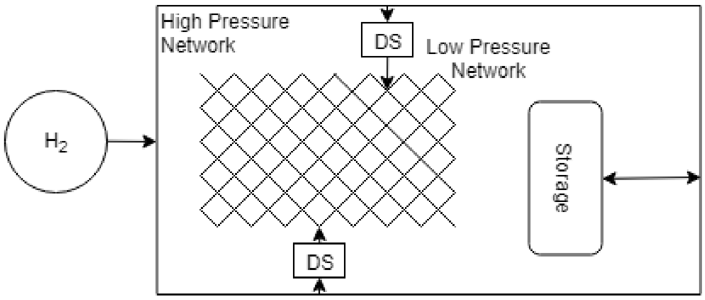


Figure 7.18: Looped hydrogen network with storage capability

7.7.2. Gas Tube Trailer

In certain situations, locations' gas security can be impaired. This can be due to a variety of different reasons, such as a failure in the gas network or scheduled maintenance on a CGS. GTS is the supplier of gas tube trailers and typically has two filled with NG and ready for deployment. GTS has two different types of trailers; a twenty foot equivalent (TFE) trailer and a forty foot equivalent (FFE) trailer. The TFE trailer has a capacity of 4725 Nm^3 and the FFE trailer has a volume of 9975 Nm^3. Tube trailers can be connected to any pressure network of the distribution grid, anywhere between 2 and 40 bar. The peek load of the tube trailer is 2000 Nm^3/hr with a nominal load of 100-1500 Nm^3/hr. Figure 7.19a shows a FFE trailer NG trailer.
Compressed hydrogen trailers have already existed for a long time [67] and it is reasonable to suspect that hydrogen trailers could be deployed in the future for the same functions as the NG tube trailers are today. It is unfortunate that the amount of energy that a tube trailer can provide is three times lower with hydrogen compared to NG. GTS is currently involved with a hydrogen project in Groningen, for which they are already utilizing hydrogen tube trailers (figure 7.19b).

(a) Compressed NG trailer

(b) Compressed hydrogen trailer

Figure 7.19: Compressed gas tube trailers

8

Current Consumers and Appliances

The conversion from a NG network to hydrogen network is quite a substantial transition for end users; however, alternatives such as heat networks and all-electric heating also require large changes. This chapter will shine light on the considerations one has to take to determine which transition path is the best option for a town, city or area to become carbon neutral. Also, changes and modifications that that will have to be made at the end users will be discussed.

8.1. Housing Type

NL has roughly 7.7 million households [68] and obviously there is a large variation in housing. Over the years, the quality and energy efficiency of houses has increased considerably. The energy efficiency does not only depend on date of build, but also on the type of housing. A stand alone house for example has considerably higher energy use than an apartment that has neighbors on all sides. The shear size of the building also influences the amount of energy that is required to keep a building habitable all year round.
The Netherlands Enterprise Agency (RVO) has developed a brochure with 30 different housing types, with which policy advise for energy savings can be made. This brochure distinguishes in type of housing, date of build and location of the household with respect to the larger building it is situated in (e.g. corner house or between two neighbors).
There is large variety of ways to make a house more sustainable regarding its energy efficiency. There are two main aspects that should be regarded when inspecting efficiency, insulation and the source of heating.

8.1.1. Source of Heating

The most obvious way to make a building more sustainable, is making the source of its energy more sustainable. There are several different forms of sustainable energy sources that can be used for housing. To come to a bespoke solution for an area, a thorough comparison between several promising options has to be made by means of a transition strategy.
The first step in developing a transition strategy away from NG is the formation of a stakeholder group. In this stakeholder group are the major parties that can give substance to a transition plan. Typical parties of a stakeholder group are; the municipality, operator of a heat network, housing cooperatives and sometimes representatives of the areas residents.
After the formation, the stakeholder group indicates which sustainable energy transition paths they are most interested in. Typical options are a heat network or a form of all-electric heating. These options could be based on several factors, such as an existing heat network nearby, a high capacity electric network nearby or relatively modern housing in the area.
At Stedin the next step is to developed a detailed report indicating the total costs that are associated with each path. This can be done in greater detail due to the access to electric and NG demand in the area. Also, more detail can be attained because information from housing cooperations and municipality can be shared with the DSO.

8.1.2. Insulation

There is large variety of options one can take in making a household more energy efficient. Even the options 'all-electric' and 'heat network' are actually a multiple of many different options. For example, an all-electric solution could be; an air heat pump, a water heat pump or an air/water heat pump. A heat network could be a low-temperature heat network with with a local heat source or a high temperature heat network from possible industry nearby.
All the mentioned options above could be considered sustainable; however, every form of heating comes with its own pro's and cons. For example, for all-electric heating options, a household would first have to be insulated considerably. The house should be insulated significantly because the amount of power a heating system has to deliver is very high. If all this power has to be delivered in the form of electricity the electric grid would simply not be able to support the demand and would have to reinforced, with obvious financial investments.
Unfortunately, heavily insulating existing houses can be very expensive. The prices vary significantly with different types of housing, but a household should definitely expect an investment of several ten thousand euro's. This is an extremely large amount of money if one considers the amount of houses that would have to make this investment.
Noteworthy is the fact that many housing cooperatives are insulating their properties to higher energy labels. This is greatly due to the agreements between the government and the rent sector. The agreements state that housing cooperatives are required to have a B-label for all their properties in the year 2020 [69]. Many housing cooperatives are in fact improving the insulation to A-label standards because they expect that new agreements will ask for higher insulation standards.

8.1.3. Heating System

When switching from NG to a different energy source, the heating system should be changed or adjusted. This subsection will give an insight to the adjustments necessary for different technologies.
When energy for heating enters a house it can do so in several different forms. The energy can enter the house in the form of thermal energy, such as with a heat network in the form of chemical energy as is the case with NG or hydrogen gas or the energy can be in the form electricity. These different forms of energy all come with their own heating system.
A low temperature heating network will enter the house through the house's connection to the network. The maximum temperature of a low temperature heating network is 55 °C [70]. The lower temperature in comparison to the surroundings makes it necessary to have radiators or other heating elements with a larger surface area. A typical example of a low temperature heating is underfloor heating. Converting to low temperature heating will come with the cost of installing the appropriate heating system. High temperature heating from a nearby industry area does not require the installation of a new system.
Heating from chemical energy in the form of molecules with sustainable gases, such as hydrogen instead of NG will not need adjustments to the larger heating system of the home, this prevents long term investments locking investors in a certain technology. Adjustments to or replacement of the boiler will be necessary depending on the sustainable gas. Subsection 8.4.1 will elaborate on the adjustments needed for the boiler.
Heating with electricity requires several modifications. All-electric systems, such as a heat pump produce their heat from the surrounding environment from the house. The heat which is produced by the heat pump is at a relatively low temperature and therefore also needs low temperature radiators etc.
Finally, hybrid solutions are also possible. An example of a hybrid solution is the hybrid heat pump. The heat pump is powered by electricity throughout most of the year to create low temperature heat inside the house. In very cold days, when the heat pump would need to produce a very large amount of thermal power, the heat pump can burn additional hydrogen to supply enough heat to the household.

8.2. Meter Box

In modern houses in NL the meter box is often a closet within three meters from the entrance of a house; however, in older houses there is often no meter box. This is due to the fact that over time new utilities have been been introduced to the domestic environment. The meter box is the place where the network companies transfer their product to the responsibility of the residents of the household. there can be up to five different utilities entering the meter box. These utilities are telecom, water, CAI (cable television), gas and electricity. Clear regulations for the lay-out and location of the meter box are stated in the Dutch entry norm document NEN2768 'meterruimten' [71].

These regulations are only mandatory for the buildings being built now. As mentioned, old buildings have been connected to the several different networks over a long period of time. This results in the fact that in many houses in NL there is sometimes no meter box at all. In these situations replacing the gas meter can be sometimes be quite laborious. For example, there have been situations where the gas meter was installed behind a wall and could only be read through a small hatch. In this case changing a meter is not a simple task and can take substantially more time and effort from the mechanic.
In 1960 the gas field in Slochteren, Groningen was discovered. After the discovery of the gas field, towns and cities throughout NL started to convert to heating with NG. Before houses were mostly heated with coals or city gas. This means that houses which were built before 1960, there is often not a designated location that was designed as a meter box.
With the transition from NG to hydrogen, new norms will have to be formulated. The utilization of hydrogen heating will predominantly be done in old houses which are badly insulated. Therefore hydrogen meters will be replacing NG meters which will not always be located in a meter box. The proposed new norms should guarantee safety for residents to an equal or higher extent than currently with NG.

8.2.1. Gas Meter

In NL a typical household or small business has a gas meter of the class G4 or G6. Table 8.1 shows the different classes of gas meters that are used by small consumers. Meters G10 - G25 can more typically be found in buildings for businesses. If the gas meter is required to be larger than G25, a consumer is considered a large consumer and other regulations apply.
The gas meters currently installed are diaphragm gas meters (figure 8.3). This is the most common type of gas meter. Within the meter there are two chambers formed by a movable diaphragm. The gas flow is directed by internal valves. As the diaphragm expands and contracts a crank turns the linear motion of the diaphragm to a rotary motion that cranks a counter.
A gas meter is required to work at a certain pressure, so that the device calculates the accurate amount of gas. To make sure the pressure of the gas is at the correct level, a valve is placed before the meter to reduce the pressure to the correct level. Figure 8.1 shows a schematic setup with all relevant pressures for a 100 mbar and 30 mbar connection.

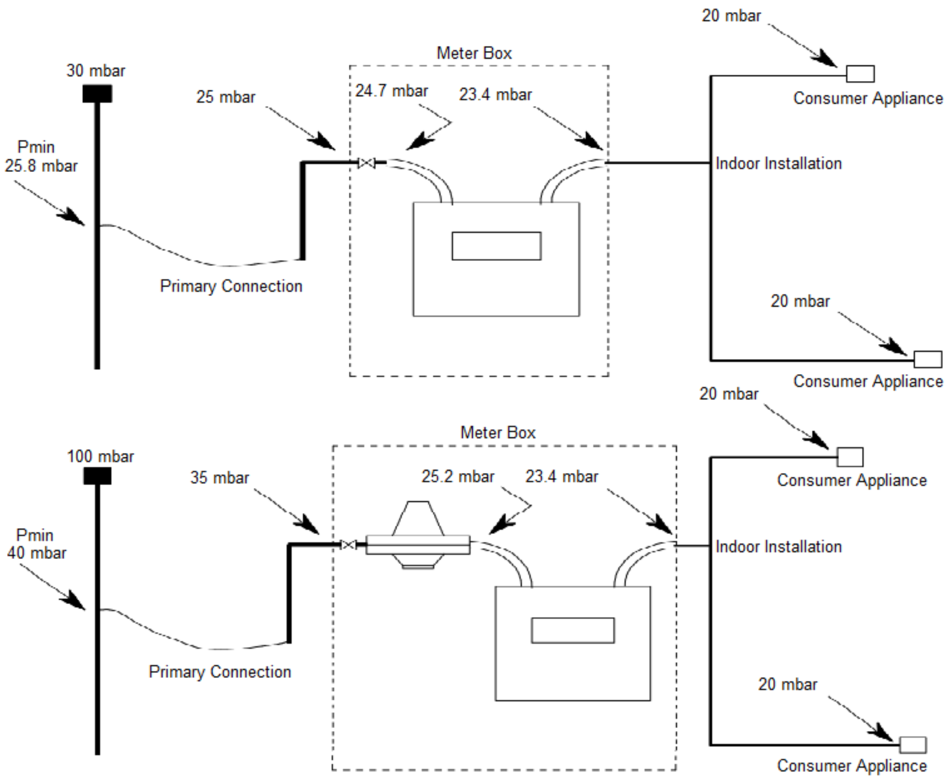


Figure 8.1: Schematic setup of gas components in meter box with corresponding pressures

The newest type of gas meter being installed is the smart gas meter (figure 8.4). The smart gas meter is a gas meter that automatically sends the meter values to the energy supplier. The smart meter can be a diaphragm meter or an ultrasonic flow meter. Ultrasonic gas meters measure the flow velocity of a fluid by using ultrasound. The ultrasound transducer measures the frequency shift from the Doppler effect in the fluid. The ultrasonic meter is often the preferred choice because it has no moving parts like a mechanical meter and is inexpensive. The flow velocity is calculated with equation 8.1, where f_r and f_t are the received and transmitted frequency respectively, v is the fluid flow velocity, ϕ is the relative angle between the ultrasonic beam and the fluid flow and c is the velocity of sound in the fluid.

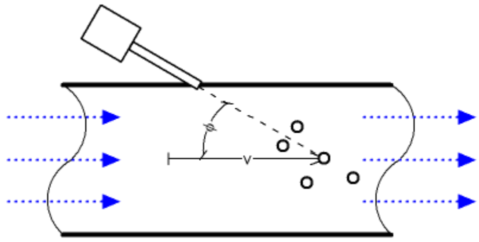


Figure 8.2: Schematic setup of hydrogen passing through an ultrasonic flow meter [72]

$$v = c(f_r - f_t)/(2f_t cos\phi) \tag{8.1}$$

Currently DSO's throughout NL are switching from the mechanical diaphragm gas meters to the smart diaphragm or ultrasonic gas meters. What should be noted is that the smart ultrasonic gas meters are not tuned for hydrogen metering. The ultrasonic gas meters are designed to operate on gases with speeds of sound between 300 m/s and 475 m/s [73], hydrogen has a speed of sound of 1290 m/s. The software of the ultrasonic meter is embedded in the device and can therefore not be updated. A new hydrogen ultrasonic meter would use the same technology and is therefore assumed to eventually have the same price as the current ultrasonic gas meters. Smart diaphragm meters can only continue to be used if they are currently never required to perform over 1/3 of their maximum capacity. Table 8.2 indicates the average peak demand corresponding for several annual NG demands. The hydrogen volumetric flow rate will be approximately 3 times higher than the current NG demand so for a G4 meter a house with a current annual demand under 2300 Nm^3 and a G6 meter with a current annual demand under 3500 Nm^3 it could still be possible to meter hydrogen within volumetric flow limits. However, it should still be researched if the diaphragm meters can accurately meter hydrogen instead of NG. In cases that a G4 meter would not be able to meter a higher flow rate the meter could be changed to a G6 meter; however, it would have to be checked if there is sufficient space for a new larger meter.

Table 8.1: Flow rate of different classes of ultrasonic and diaphragm gas meters [74] [73]

	Diaphragm	**Ultrasonic**	**Capacity [m^3/h]**
G1.6		✓	0.016-2.5
G2.5		✓	0.025-4
G4	✓	✓	0.04-6
G6	✓	✓	0.06-10
G10	✓		0.1-16
G16	✓		0.16-25
G25	✓		0.25-40

Table 8.2: Annual NG demands with corresponding peak demands [75]

Annual demand [Nm^3/year]	**Peak demand [Nm^3/hr]**
0 - 400	0.2
400 - 1000	0.7
1000 - 1600	1.2
1600 - 2300	1.3
2300 - 3500	2.5
3500 - 5000	3.6

Figure 8.3: Standard Issue G4 diaphragm gas meter

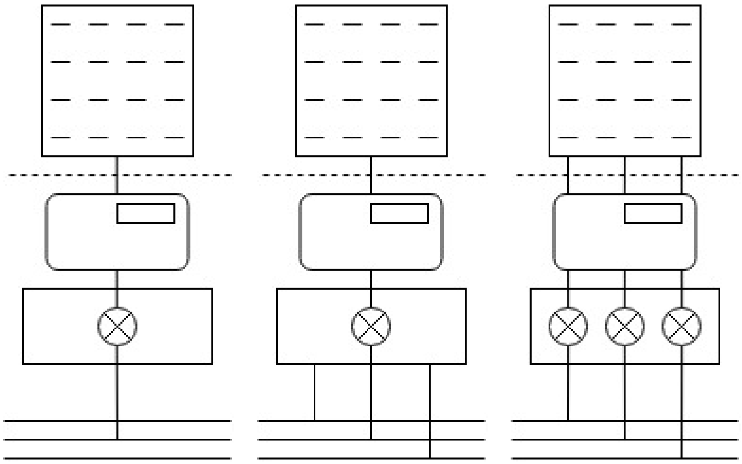
Figure 8.4: Smart G4 ultrasonic gas meter

8.2.2. Electrical Components

Figure 8.5 gives three schematic representations of the main electric components. Stedin is owner of all of the components except the fuse box (everything under dotted line).

The low voltage network can have a single or three phase cable connecting it to a house. Houses built before 1970 typically have a single phase cable. The house, in turn, can have a single or a three phase connection. A three phase connection is not possible without a three phase cable. After the connection of the house comes the (smart)meter.

The electric meter meters the total amount of electricity that is consumed by a household (in kWh). Some meters can distinguish between the amount of electricity that has been produced (e.g. solar panels) and the amount that has been consumed, others can not. Currently DSO's are replacing existing meters with new smart meters. This process started in 2015 and should be completed somewhere in 2020 [76]. These smart meters (figure 8.6) are capable of distinguishing between electricity production and consumption.
The only electric component in the meter box owned by the home owner is the fuse box. The fuse box is an electrical safety device that prevents the electric circuits in the home from over current. The exact workings of the fusebox remain outside the scope of this research. What remains inside the scope is the necessary changes to the meter and fusebox if a transition to hydrogen is carried out. The main alterations would be the change in electric power usage due to appliances changing from NG to electricity. Subsections 8.4.2 and 8.4.3 will go into more detail on expected changes in electricity consumption.
The most common electric connection in homes in NL are the 3x25A, 1x25A and the 1x35A. The 1x35A and 1x25A connections are not a 3 phase power connection. If the consumer wants to increase the connection capacity of the house, there will be costs for the consumer.



(a) 1 phase connection and 1 phase cable (b) 1 phase connection and 3 phase cable (c) 3 phase connection and 3 phase cable

Figure 8.5: Schematic representation of main electrical components

Figure 8.6: Electric smart meter

8.3. Indoor Gas Piping

In NL, the DSOs are responsible for the gas distribution network up to and including the gas meter. After the meter, the owner of the property is responsible for the gas network within the property. By law an owner is not required to have a licensed professional install the home gas network. If the homeowner wants, he/she can install the network themselves. Having the home network installed by a non-professional increases the risk of hazardous situations, this is why several other countries do not allow this.

In NL, there already is a Dutch norm of practical guidelines (NEN 3378) for the installation of in-home gas networks but these guidelines are not safeguarded by law. The introduction of hydrogen into homes instead of NG could prove to be a strategic moment in time for introducing some restrictions regarding work on gas piping within homes.

Research done by Kiwa implicates that there is no increase in risks surrounding hydrogen despite its broad flammability limits. This is presumed to be due to hydrogen's high diffusivity [14]. In more recent research done by Kiwa, caution regarding this previous conclusion is advised [18], because of the lack of accurate living conditions within the experiment's house. It should be noted that definitive answers regarding in-home safety with hydrogen can not be drawn from experiments but only from closely monitoring the introduction of hydrogen into actual homes. If an observable increase in number of incidents is determined, additional safety measures can be taken.

8.4. Appliances

8.4.1. Boiler

Most houses in NL depend on a NG boiler for heating. The boiler is also used for warm water. Boilers that run on NG would have to be replaced by a hydrogen boiler.

Hydrogen boilers currently do not exist but are being developed. The company Bekaert is working on developing a burner, heat exchanger and sensors that can be sold to boiler manufacturers. Also, the company Remeha (part of BDR Thermea Group) is working on developing a hydrogen boiler. This boiler is not capable of burning NG which means that the boiler would have to be completely replaced to be able to burn hydrogen. Replacing a boiler typically takes about three hours for two mechanics (6 work hours) [77]. Two mechanics are necessary because the boiler is to heavy to be carried by one person. There are goals to develop a hydrogen 'ready' boiler further in time. These boilers would be able to burn NG and hydrogen, separately. This means that as soon as boiler would be fed hydrogen, only a switch would have to be flipped making the boiler hydrogen compatible.

The location of a boiler inside a home is not designated like the location of the meter box. Often the boiler is situated at a high point in a house so that it can also remove air from the radiators while running.

Consumers would not come in contact with hydrogen if no problems occurred. If problems do occur however, similar safety measures would have to be put in place as has been done with NG. Section 3.3 discusses safety concerns regarding hydrogen. One of the current safety mechanism of a boiler is the flame ionization detector. This form of flame detection would not work with hydrogen gas and would have to be replaced by some other form of detection to prevent hydrogen gas from flowing after the flame has gone out. Hydrogen flames emit a ultra violet light rather than infra red light with NG flames. The detection of UV is thought to be the way the boiler manufacturers will detect the presence of the hydrogen flame. Because the combustion of hydrogen does not produce any poisonous gases, no poisoning such as carbon monoxide poisoning is possible.

It is also possible that house owners have a separate boiler for warm tap water and central heating. In this case it also might be possible that the warm water boiler is already electric. The boiler setup in homes should be looked at before transitioning to hydrogen. It might be able to change to a more ideal setup in the future depending on the current setup.

8.4.2. Oven and Stove

The oven and stove are generally the only 2 appliances that are connected to NG in a typical Dutch kitchen. More and more consumers are starting to switch to cooking with electricity, already 22% of the Dutch stoves is electric [78]. Electric stoves can be found in several forms, the most common are the induction stove and the ceramic/halogen hub which use 175 kWh and 225 kWh annually, respectively [79]. Electric stoves will use anywhere between 19 kWh and 42 kWh annually, depending on size [78].

If a an average household would transit from cooking with NG to cooking with electric appliances, its electric consumption would increase with roughly 6-9%, depending on chosen technologies and dimensions.

The local DSO should check if the low voltage and medium voltage network are capable of having such an increase in load if a whole area would transit to electric cooking.
Cooking on electricity is preferably done with 3 phase power. This is because cooking with electricity requires a large amount of power. It is possible to cook on single phase power; however, the risks of blowing a fuse are higher. When switching to electric cooking, homeowners should be well informed about the pro's and cons of a single and three phase power connection.
An option that is still in its early stages is cooking with hydrogen. The company Atag is currently looking into the options of developing a stove that works with hydrogen [80]. They are not working on developing an oven that works on hydrogen. Atag is not interested in cooking with hydrogen under glass, to get around the issues of smell or visibility. This is due to previous experiences with cooking under glass with NG. Further research is necessary to determine if cooking with hydrogen is probable in the future.

8.4.3. Other Appliances

NG is used for many other appliances than just central heating and cooking in homes. If a transition from NG to hydrogen is executed it is important to keep these appliances in mind; however, small consumers such as home owners will probably not be the cause for any unsurmountable difficulties. Some examples of unconventional NG appliances that might be encountered during transitioning are gas powered sauna's, gas powered hearths or gas heated swimming pools. In the case of the mentioned examples there are already alternatives that do not run on NG.
The more significant issue which requires more attention is the NG consumption of large consumers such businesses. These businesses could have larger gas heated stoves or other industrial scale appliances which have been significant investments. Additionally, these appliances might not yet be able to be converted to hydrogen at the time of a transition. Large gas consumers must be taken into consideration when identifying if an area is suitable to convert to hydrogen. In some cases it might be able to preserve the connection to the NG grid for large consumers; however, this is totally dependent on the case and the structure of the gas network.

IV

Transition to Hydrogen

9

Transition from Natural Gas to Hydrogen

This chapter will discuss the practical steps that have to be made to realize a transition from NG to hydrogen. A successful transition will consist of several consecutive steps that will have to planned carefully to prevent residents from being left in the cold.

9.1. Transition History

Before NG, town gas was the main supply of energy for heating in NL, as mentioned in subsection 3.1.1. Because of the sudden abundance of NG, the transition from town gas went in a rapid pace. The transition from town gas to NG is very comparable to the transition from NG to hydrogen. This section will lay out the transition as it was organized in the 1960's in NL.

The first step in transitioning to NG was sectioning a town into many little sections, typically the size of several streets. In a specified order the houses in each section handed in their stoves. These stoves were taken to a warehouse where engineers replaced the burners and taps with burners and taps designed for NG at an other pressure. The adjustments to the furnaces were free of charge; however, if the furnace was too old, it was destroyed. The owner of the old furnace would be able to buy a new furnace at a heavily discounted price.

It was not necessary to hand in the boilers. For the boiler only the burners had to be replaced and mechanics were able to this in the homes without moving the boilers.

Eventually when all homes and small businesses were converted to NG, the coal gasification factory would often be demolished.

9.2. Sectioning Transition

Sectioning is an important process when making significant changes to a gas network. As already mentioned in section 9.1, sectioning was a vital process when making the transition to NG from town gas. Nowadays, NG networks are still sectioned when transitioning to a higher network pressure. Old low pressure networks were often only 30 mbar. To improve the efficiency of the network it was decided to increase the low pressure network to 100 mbar where possible.

The process of sectioning is done to divide a project area into several smaller isolated areas. This is done so that the DSO is always in control when carrying out activities. For example, if the pressure is increased throughout an entire neighborhood at once, a large amount of complications may arise at the same time, overwhelming the mechanics. To prevent this from happening, the area is divided into sections. The pressure is increased in one section at a time so that maintenance people will more likely be capable of tackling any issues that arise.

Sectioning with hydrogen is done so that the NG and hydrogen gas network can remain isolated from each other. When transiting to hydrogen gas, several adjustments will need to be done inside of homes. This makes it impossible to transit a large area in just one execution. Also, laws and regulations will have to be amended to enable the introduction of hydrogen for domestic heating.

Figure 9.1 will function as an example to explain how sectioning is done. In this example the network is connected to a hydrogen source and a NG source at two different locations. The first step that would have to be made is connecting street **I** to the hydrogen network while not disconnecting other streets.

This would be done by placing two bladders in the network at the location of the red markings and then inflating them, dividing the network into two sections. Thereafter, street **II** will be added to the hydrogen network.

This would be done by placing two new bladders in the location of the blue markings. The bladder at the top red marking will subsequently be removed, creating a new hydrogen section including street **I** and **II**. Streets **III**, **IV** and **V** are added to the hydrogen network by placing bladders in between the streets as was done between street **II** and **III**. Street **VI** would be the last street added the hydrogen network, this would be done by removing the final bladders.

The NG source feeding the NG part of the network during a transition will have to be able to provide sufficient NG. The load has now significantly increased because the NG part of the network can initially be only a little bit smaller than the total network, whilst the NG part of the network is now only fed from one side.

DSOs in NL are required to provide a security of gas supply. One of the requirements is that all customers have to be guaranteed sufficient gas at temperatures of -12 °C. This is also the case for the areas that are in the transition from NG to hydrogen. The program IRENE PRO can calculate if the capacity of the temporary network is sufficient. If not, there could be several different causes, each with its own solution.

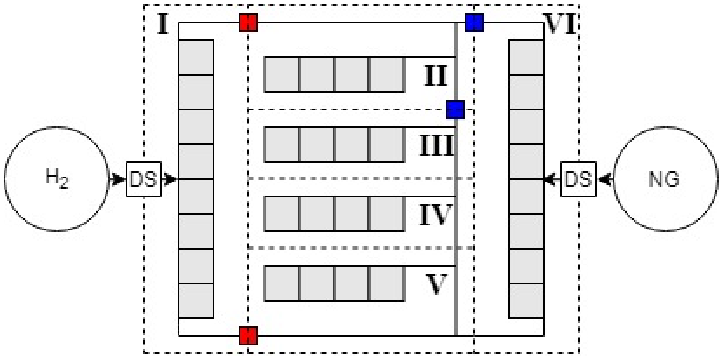


Figure 9.1: Low pressure network fed by hydrogen and NG

9.2.1. Bladders

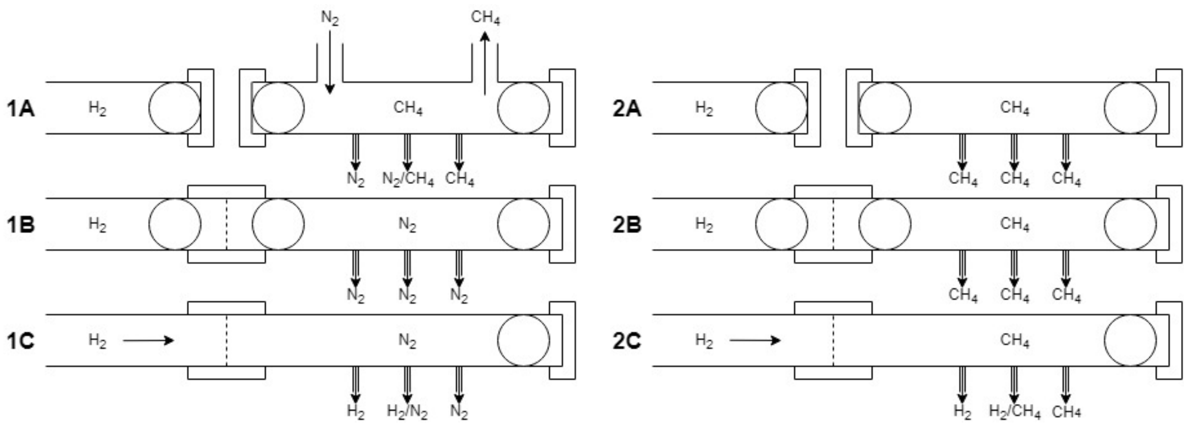
Pipes can be split into two separated sections by placing a bladder (figure 9.2c). The first step in placing the bladder (figure 9.2a) is placing a saddle around the section of pipe one wants to section. This saddle (figure 9.2b) is permanent and will remain around this part of pipe after the bladder is removed. A hole is hand drilled through a designated part of the saddle and the underlying piece of pipe. Because the holes are drilled by hand and most often through plastic, no sparks will arise within the pipe. Through the hole of the saddle and underlying pipe, the bladder is inserted and inflated. During maintenance a mechanic is always required to keep an eye on the saddle and bladder, in case any leaks arise. After the sectioning is done the bladder is removed and the saddle is sealed off. Sectioning of this part of pipe is now complete, but the saddle will remain in place. It is important to remember that a saddle, just like many other parts, are a weak spot of the gas network and must be kept to a minimum. Smaller metal pipes, which are found in apartment buildings are sectioned in the same manner as larger pipes. It is advised to also keep these to a minimum due to vulnerabilities that these saddles add to the network.

(a) Bladder (b) Saddle (c) Bladder inserted into pipe through a saddle

Figure 9.2: Overview of components for the placement of bladders

9.2.2. Flushing Pipes

There are occasions when an existing pipe is no longer needed. Because the pipe might be needed again in the future, the pipe is not always removed. If the pipe is no longer used it can be capped off. This is done by placing two bladders close to each other. The pipe in between the bladders is cut and two caps are placed on both sides of the cut. The pressure is removed from the pipe that is no longer used, but there is still gas in it.
If a pipe has to be removed or maintenance with chance of sparks is required, the gas conditions inside the pipe have to be below 10% of the lower flammability limit. Explosive conditions are significantly larger for hydrogen gas than for NG, as can be found in table 3.1. To remove hydrogen or NG from a pipe, air movers are used. The air movers flush the pipe from one end with air or with an inert gas such as nitrogen. The gas that was previously inside the pipe is vented into the air. Mechanics decide if they want to burn the gas or simply let it rise into the air.
The flammability limits of hydrogen are much larger, which means that there is a much large chance of a flammable mixture when mixing hydrogen with air. Therefore, it is advised to, at first, introduce nitrogen into pipe prevent any flammable/explosive mixtures. The equipment used for measuring the concentration of NG is also suitable for measuring hydrogen concentrations [81].



(a) Option 1 (b) Option 2

Figure 9.3: Two options for introducing hydrogen into a sectioned piece of network

Generally, when sectioning takes place, on either side of a bladder is NG. In the case of sectioning to a hydrogen grid, one side would by hydrogen gas and the other side would be NG. It is still unclear what the consequences would be if the bladder would fail in a hydrogen scenario. Therefore, further research on this subject is advised. As noted, a pipe can be securely sectioned by cutting a pipe between two bladders and placing caps on both side of the cut.

The following part will discuss two options of introducing hydrogen into a sectioned part of a NG network. Figure 9.3a shows the option 1, the safer option of the two approaches. In step A of this approach the NG in the sectioned part is flushed out and replaced with inert nitrogen gas. The houses connected to this part of pipe flush the remaining NG through until nitrogen gas comes out into the boiler and the flame is put out. In step B the sectioned pipe and hydrogen pipe are connected through a saddle and the bladders are removed. In step C the hydrogen is introduced in the new part of pipe and flows into the houses connected to the pipe. The hydrogen boiler of the houses will not ignite as long as nitrogen is fed into the boiler. As soon as hydrogen comes into the boiler the boiler a hydrogen flame will ignite and the boiler will start.
Option 2 (figure 9.3b) would be to not flush the sectioned pipe with nitrogen in step A and the connected houses would still receive hydrogen until there is no more pressure in the pipe. In step B a saddle connects the hydrogen and sectioned pipe and the bladders are removed. Step C will introduce hydrogen to the new part of the network and ideally the NG would be flushed out at the boilers inside the houses. It is still unclear how hydrogen and NG will mix with each other within the pipes. Also, it is not clear if the hydrogen boilers will be able to shortly burn the NG that is flushed out the system or if the gas should be vented out. Both issues will still have to be regarded before considering option 2.

9.3. Timing Transition

It is important to note the timing of a planned transition. Obviously, if the transition were made in December, heating of homes would be a big issue. This is why it is important to keep the transition period as short as possible and within the warmer summer months. The summer months are ideal for a transition because the NG use is already near its minimal use in this period due to no heating. Further consideration would be needed to determine if solutions with temporary heating systems will suffice if the transition takes place in colder months. Gas will still be needed for warm water throughout the year so there is still enough reason to keep the transition as swift as possible.
Because it is necessary that people are home during the boiler switch it is also important that the transition is not planned during the national or local holidays.

9.4. DSO Costs Transition

The first thing that must be mentioned is that DSO profit from a future with hydrogen as an energy carrier. Before the hydrogen scenario was identified as a possible future scenario, DSO's had no future use for their NG assets accept for biogas. Transitioning to hydrogen however will not be without its expenses for the DSO. The costs a DSO will have to make to convert a certain area's network into a hydrogen network will vary per location. The costs will depend on the materials of which the local distribution network is made. As mentioned in section 7.4, not all materials are ideal for transporting hydrogen. For example, cast iron can fracture due to the setting/sinking of the surrounding earth. This is why certain materials should first be replaced before transporting hydrogen.
There is already a program being carried out by DSO's in NL to remove the remaining CI pipes. Because of this program it is disputable if the costs of replacing theses pipes can actually be contributed to the transition to hydrogen. Nevertheless, costs for removing piping can be estimated with the following numbers; removing and replacing low and high pressure lines costs 235 €/m and 300 €/m respectively [59].
Installing new gas meters will also sometimes be necessary for the implementation of hydrogen. This can be due to a higher necessary diaphragm meter or a new ultrasonic gas meter. The cost of a new ultrasonic gas meter is estimated at the same price of current ultrasonic gas meters of €54, due to the same technology. The installation of such a meter takes roughly half an hour including paperwork and internal (after the meter) leak detection.
A second possible cost for a DSO can be the necessary enforcements to the electricity grid of the intended area. The necessary enforcements in turn depend on the hydrogen scenario. For instance; if people in the area would not switch to electric cooking but rather transit to a form of cooking with hydrogen, there would be little to need to reinforce the network. In the electric cooking scenario it is a whole different case.
The electric grid in NL is changing in a rapid speed. One of the pushes behind this shift is the decentralized production of renewable energy, such as with solar panels on homes. Also, electric mobility requires a more resilient grid. To be able to withstand the peak demand of electric mobility and peak supply of solar panels, the electric network will have to be reinforced. So, it would be unfair to say that grid adaptations are solely done to accommodate the hydrogen scenario in combination with electric cooking.

The costs of an electric network being reinforced to be able to handle the future electrical demands of a town that can handle electric mobility, solar panels and electric cooking are hard to generalize. The costs are simply to dependent on the current state of the intended area's grid. The costs that would have to be covered by the DSO would be the following actions: placing new distribution stations and the renewal or reinforcement of the LV and HV grid. In some cases the one phase connection between homes and the grid will have to be replaced by a three phase connection. The cost of these activities are however not for the DSO but for the consumer.

9.5. Appliances After Transition

9.5.1. Oven and Stove: Electric Cooking

Just as with the transition to NG, the gas fired kitchen appliances are an important part of the transition to hydrogen. The first step in the transition to hydrogen is making sure all the residents in the area are not cooking with NG anymore. Switching to electric cooking however, does ask for some requirements.
Electric induction stoves and ovens will require significant power and therefore require a special wall plug and separate fuse in the meter box. The homeowner will have to check if he or she has a suitable wall outlet in the kitchen. If not, such an outlet will have to be placed and connected to the fusebox in the meter box. A professional will have to be hired to install a separate fuse for the new electric stove and oven. A three phase power connection is not necessarily required for electric cooking; however, in some cases it is necessary and the home owner will have to get a three phase connection.
If a heavier connection is required, the DSO will have to come to install it. The costs of installing a heavier connection is dependent on the adjustments required to the connection. In the most expensive case the connection to the grid will have to be reinforced with a maximum cost of €1627,68 for the household [82].
Other costs of switching to electric cooking are the costs of new pots and pans which are compatible to induction cooking. The costs of these pots can vary greatly, depending on the quality and brand one needs.

9.5.2. Boilers

After all preparation for the transition to hydrogen has been made, the final step to converting the boiler can be made. As mentioned in section 8.4.1, the first hydrogen boilers will not be hydrogen 'ready' boilers but rather hydrogen only boilers. This means that every NG boiler will have to be switched with a hydrogen boiler.
Changing a boiler is a labor intensive task. This partly due to the fact that boilers are located in homes which are often hard to reach such as attics. Boilers also don't all have the same connections, these differ in between brands. Then there are the connections; water supply, gas supply, central heating supply, central heating return, warm water, exhaust and drain (figure 9.4). Connecting the boiler in the correct manner is therefore a task that about 6 hours. In practice two people three hours. Two people are needed because they have to carry up the new boiler and take the old boiler down [77].

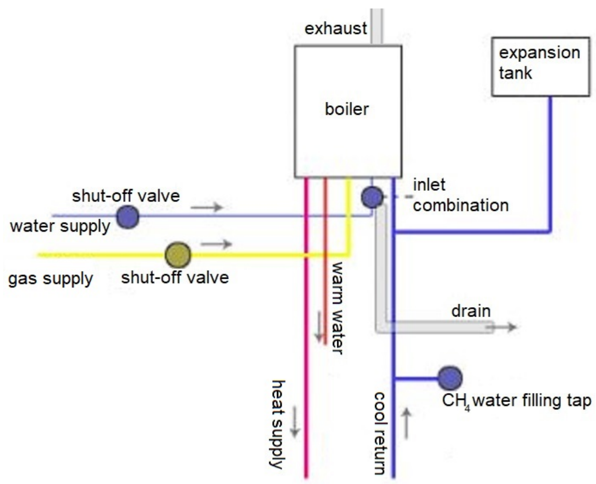


Figure 9.4: Schematic of all boiler connections

9.5.3. Gas Meter

Replacing a gas meter with a new one typically takes half an hour, including paperwork. One of the final steps of installing a gas meter is verifying if there are not leaks behind (in the house) the meter. This is done by closing all the gas taps of the devices that use gas in the house and switching of the main gas tap. If after a few minutes the pressure drops there is a leak within the house's network and a professional should be hired to identify the leak. To check if any of the devices is leaking the the main tap is closed and the taps to the devices are opened one by one. If the pressure drops when one tap is open it means that that device is leaking gas and a solution should be found.

9.5.4. Consumer Costs

There are several actions that consumers will have to take to be ready for a hydrogen scenario. What is important to realize is that the investments made by the consumers often outweigh the investments made by a DSO. This is because the costs are multiplied times the amount of houses in the intended area. Below the steps are identified for switching to hydrogen and electric cooking.

- Scenario cooking with electricity
  - changes to fuse box
  - line between kitchen and fuse box
  - new electric oven/stove
  - new cooking equipment suitable for electric cooking
  - new hydrogen boiler

If necessary, the costs of changing a one phase connection cable to a three phase power connection cable are also for the consumer. For example; a consumer may have a 35A connection to the grid. To have a three phase connection he or she will have to change to a 3 x 25A connection. The costs for this are estimated at roughly €285 [82]. The price can however be considerably larger if the connection cable to the grid is not triple phased. In this case, the power line connecting the house to the grid will have to be replaced with a new triple phase line. The costs for this will be added to the initial €285 to a maximum total price of €1600 [82] if a new connection line is needed as well.
The annual distribution and transport (D&T) costs for a 3x25A or 1x35A connection is €237 [83]. The (D&T) costs for a gas connection is €181 [83].
Behind the connection and the meter is the fuse box. The fusebox will have to be adjusted to make a separate electric cooking group for the electric oven/stove [84]. This is necessary because an electric stove and oven can account for a very large load. Also, the stove often needs 3 phase power or a perilex socket and fuse connection. The installation of a wall socket, connection between socket and meter box and the installation of the new fuse typically costs around €200. [85]
New cooking equipment is only necessary if the consumer chooses to cook with induction. It is also possible to cook with electricity by using ceramic electric cooking, this does not require new equipment. New equipment for induction cooking varies greatly in price but it is possible buy a set of pans and pots for prices as low as €50.
To identify the price of an average electric stove and electric oven the prices were compared of different ovens and stoves. For the stove, the median price of 254 induction stoves was determined, for a price range between €220 and €2820. For an electric oven the median price of 374 electric ovens was determined, for a price range between €150 and €3000. The median price for an induction stove and oven are €650 [86] and €531 [87] respectively.
The final purchase a consumer must make is the hydrogen boiler. The hydrogen boiler will replace the current NG boiler. There is no such boiler on the market yet, but it is being developed. The manufacturer indicate that they expect the costs to be around the same price as current NG boilers, roughly €1500.

9.6. Challenging Transition

9.6.1. Housing

Switching most houses to hydrogen can be relatively straightforward (as soon as law and regulations have been amended) as soon as sectioning has been carried out correctly. Residents have to be home to transit to a new hydrogen boiler. If they are not in, their gas tap will be closed and they will have to make a new appointment for the technician to come by at a later time or date to complete the switch. Depending on the type of neighborhood, willing neighbors might be able to let in technicians if the residents are not home. This willingness will vary largely from area to area. Small towns where the bond between neighbors is stronger this can be expected more often. In cities however, where people often don't even know their neighbors' names, this will be less likely.

Challenging housing to transit from NG to hydrogen are apartment buildings and flats. The most common configuration of a flat's NG network is shown in figure 9.5. The flat has a main pipeline that is ideally connected to the larger grid at both sides of the building. The pipe enters the building at ground floor and crosses underneath the building just under the roof of the ground floor, often the parking garage. The main pipeline has branches (a, b, c or d in figure 9.5) that are directed straight up toward the top floor of the flat.

Every resident from a single branch will have to let in maintenance to prepare the house for hydrogen instead of NG. If a single homeowner is not home, a whole branch cannot be switched to the new gas. This is because the gas branch goes through the homes and a mechanic can not switch of a single connection from outside a residence. The chance of such an issue obviously increases with the number of floors of a flat. It is important homeowners in flats are sufficiently informed on the importance of being present for maintenance so that hindrance is kept to a minimum.

It is possible to transit one branch at a time by placing bladders between the branches (red block in figure 9.5); however, every bladder placed is a potential weakness in the remaining network and the amount of these should therefore be kept to a minimum.

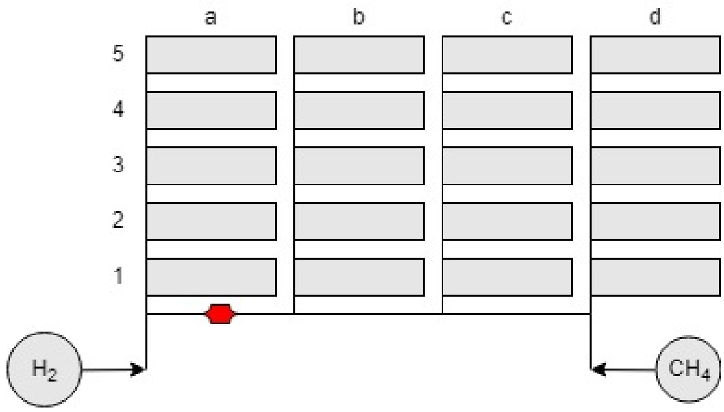


Figure 9.5: Representation of an apartment building connected to the NG network

9.6.2. Businesses

There are many different areas in NL that might convert to a hydrogen network. Most of the areas will be residential and have mainly old housing. Within these areas there will inevitably also be small businesses that are also dependent on NG. Most businesses might not have a large NG consumption because their business does not require it; However, there are also many different businesses which do use a very large amount of NG. The nature of these businesses can vary largely of course and so can their reason for NG demand.

The issue with businesses that have large NG demand is that the demand for NG is not due to excessive heating or large usage of warm water but rather the use of large ovens or heavy equipment fired on NG. These machines might not be able to be converted to hydrogen because the manufacturer of the machines has no other clients that require the same conversion. Large NG users in the area should be identified early on in the conversion design stage to see if there is a viable option for them to switch to hydrogen instead of NG. If this is not the case, the businesses might still need to be connected to the NG network making it very difficult for other properties to make the switch to hydrogen, due to being connected to the same part of the NG network.

V

Case Study: Stad aan 't Haringvliet

10

Introduction Case Study

10.1. Goeree-Overflakkee & Stad aan 't Haringvliet

The island of Goeree-Overflakkee (GO) is situated at the coast, in the south west of NL. The island is the bottom part of the province of South-Holland (SH). The island has a total population of roughly 49.000 people [88] on a total land area of 261 km^2 [89]. This gives a population density of 188 People/km^{-2}, well below the nation's average of 505 People/km^2 [90].

The population is concentrated in 14 towns evenly spread over the island. The sparsely populated areas create the opportunity to realize decentralized renewable energy production on land, which is often not possible in NL due to its high population density.

The port of Rotterdam is situated just across the water (Haringvliet) and Voorne-Putten, to the north of GO. This port is the largest in Europe and is interwoven with large refineries and chemical industry. To GO's east is the industrial site of Moerdijk. To the south of GO are the industrial sites of Vlissingen, Bergen op Zoom and the port of Antwerp. The port of Antwerp is also one of the largest ports in Europe. These industrial sites and ports and their industries require a staggering amount of power and raw materials to function and GO hopes to be able to supply a part of this demand in the future.

(a) Goeree-Overflakkee (Stad aan 't Haringvliet highlighted)

(b) Industrial areas and Ports near Goeree-Overflakkee

Figure 10.1: Geographic location of Goeree-Overflakkee as part of the province South-Holland

The infrastructure of housing on GO does not differ much and nearly every town has housing that dates back to roughly the same period (early 1900's), making no single town stand out as prime candidate for hydrogen pilot; however, there were two main reasons why SatH ended up being the most ideal location for a NG to hydrogen conversion. First, was the fact that the town was small enough that the town center would be included in the conversion, rather than a district of a larger municipality. Second, was the social cohesion between the people in SatH. Organized meetings with Stedin, the municipality and residents of SatH showed that the residents were open to the possibility of taking part of a hydrogen conversion project.

10.2. Current Infrastructure

Gasunie Transport Services (GTS) has a 40 bar natural gas (NG) pipeline that goes straight through GO towards the province Zeeland (figure 10.2). This pipeline is connected to a CGS near Middelharnis which feeds the island's distribution network.

Figure 10.2: GTS 40 bar pipeline on GO (indicated in black)

An interesting case is the hydrogen pipeline network of *Air Liquide*, which is located just above GO in the port of Rotterdam area. This network is one of the few existing hydrogen networks and it connects the port of Rotterdam with the port of Antwerp. Figure 10.3 shows the network of *Air Liquide* (GO indicated with black arrow).

In 2007 Stedin started an investment program for the electricity network of GO. The aim was to optimize the electricity network for renewable energy production. To realize this, several innovations were carried out. The first project was installing a high voltage connection of 18 km from Middelharnis to Voorne-Putten. This was done by placing a cable that goes 50 m under the Haringvliet. After the new cable, an expansion and modernization of the substations at Middelharnis and Ooltgensplaat was realized and a new substation was built at Stellendam [91]. The 2007-2016 project for making GO capable of producing large amounts of renewable electricity, was concluded with the completion of the substation of Ooltgensplaat. With all the new improvements the electricity network on GO is capable of transporting renewable power from, to and over the island.

The island of GO currently has an electric transport demand of up to roughly 100 MW due to the existing renewable energy infrastructure. Stedin has already developed another 7 year plan to make sure that the infrastructure is capable of transporting the large amount of renewable energy in the future. Ambitious plans to produce 225 MW of wind on land, 95 MW photovoltaics and possibly 25 MW of tidal energy in the future ask for continuous significant investment. Depending on the actual realization of these projects Stedin plans to install 2 or 3 150/50 kV transformers in Middelharnis. Figure 10.4 shows the necessary installment of transformers depending on the realization of scheduled projects.

Figure 10.3: North European Network of *Air Liquide* [92]

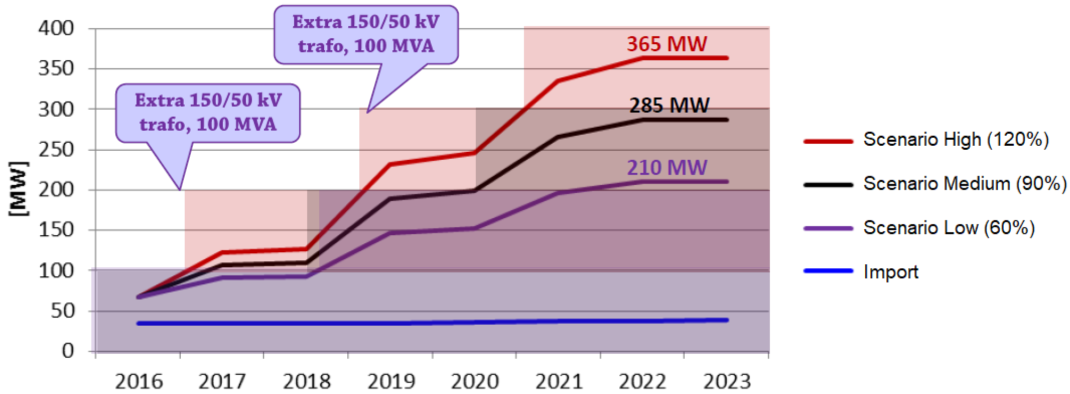


Figure 10.4: Prognosis of electric transport demand on GO [93]

10.3. Renewable Energy Ambitions

GO has the ambitious goal to be energy neutral in 2020 and start exporting power subsequently [94]. It plans to do this by investing in energy saving and in several forms of renewable energy, such as wind, solar and tidal power. In 2016 the island was already producing 34% of its total power use (5060 TJ) from a renewable source [94]. It is projected that the island will produce 5723.2 TJ of renewable power in 2020, this is 112 % of the islands projected consumption in 2020.

10.3.1. Agreement

On the 8th of December, 2017, an agreement was signed between the municipality GO, research institutes and national and international commercial companies. This agreement confirms the ambition of GO to become energy neutral by 2020. The agreement is divided into 6 different projects; Production & Conversion, Mobility, Green Ammonia, Heating in Present Buildings, Regional Hydrogen Roundabout and Regional Power Buffer / Electrical Storage. There is no order of importance between these projects. However, the projects are sometimes interdependent, resulting in a desired logical order of development (e.g. The development of hydrogen electrolysers should be in tune with the expected demand). This report will focus its attention on the heating in present buildings, referred to as 'Project 4' in the agreement.

11
Gas Network

11.1. Why Hydrogen in Stad aan 't Haringvliet?

In NL, two technologies were believed to have large potential as an alternative to heating with NG; heat networks and all-electric heating. Currently, hydrogen is being considered as a new promising alternative. For SatH, a promising alternative to heating with NG seems to be a hydrogen heating scenario. One can think of several different reasons why hydrogen is a risky decision; after all, there are no existing hydrogen fueled towns in NL at this time and the production costs of green hydrogen are still high (table 6.1). The decision to seriously look at the hydrogen option is twofold; First, the unfavorable conditions for the alternatives all-electric and a heat network make case for researching an out of the box alternative. Second, as mentioned in section 10.1, there was a large support from within the community and municipality to search for a progressive renewable solution such as hydrogen.

One of the most important conditions for a heat network is accessibility to a credible heat source. In the case of SatH there unfortunately is no source nearby. Figure 11.1 shows a map of SH and all the credible heat sources and networks. The red blocks and lines indicate the CHP plant and their corresponding heat network respectively. The orange blocks and lines show a mixture of industry waste heat and heat from CHP plants. The purple circles indicate locations of waste heat from industry. The solid purple lines show the existing heat network utilizing industry waste heat, the dotted purple lines indicated planned heat network for industry waste heat. The green blocks indicate sources of geothermal heat. Figure 11.1 indicates that their are no credible heat sources in the area of SatH. Therefore, utilizing heat from a nearby heat network is not an option for SatH. Even if there was sufficient waste heat in the area of SatH, it would still have to be a viable business case for a company to realize such a network. This is generally only the case in high populated area, such as cities with apartment buildings and high rise infrastructure. SatH is a very small town and has a far to low population density to be viable for a commercial heat network.

The heating of homes in an all-electric scenario is most commonly done with heat pumps. Heat pumps are typically installed at a capacity of 5 kW; however, in houses typical to SatH a higher capacity is most likely required. If whole SatH switches to heat pumps the electric network would have be adjusted. Chapter 13 will identify all other necessary adaptations and costs for an all-electric SatH, this chapter will function as a comparison to the hydrogen scenario.

Insulating houses is a good idea in the long run, regardless of the source of heating. However, residents should able to spread out such an investment over time in a more natural and manageable time frame. Introducing hydrogen as a heating solution makes it possible to spread out the insulation works and costs and still be able to heat their homes in a sustainable manner.

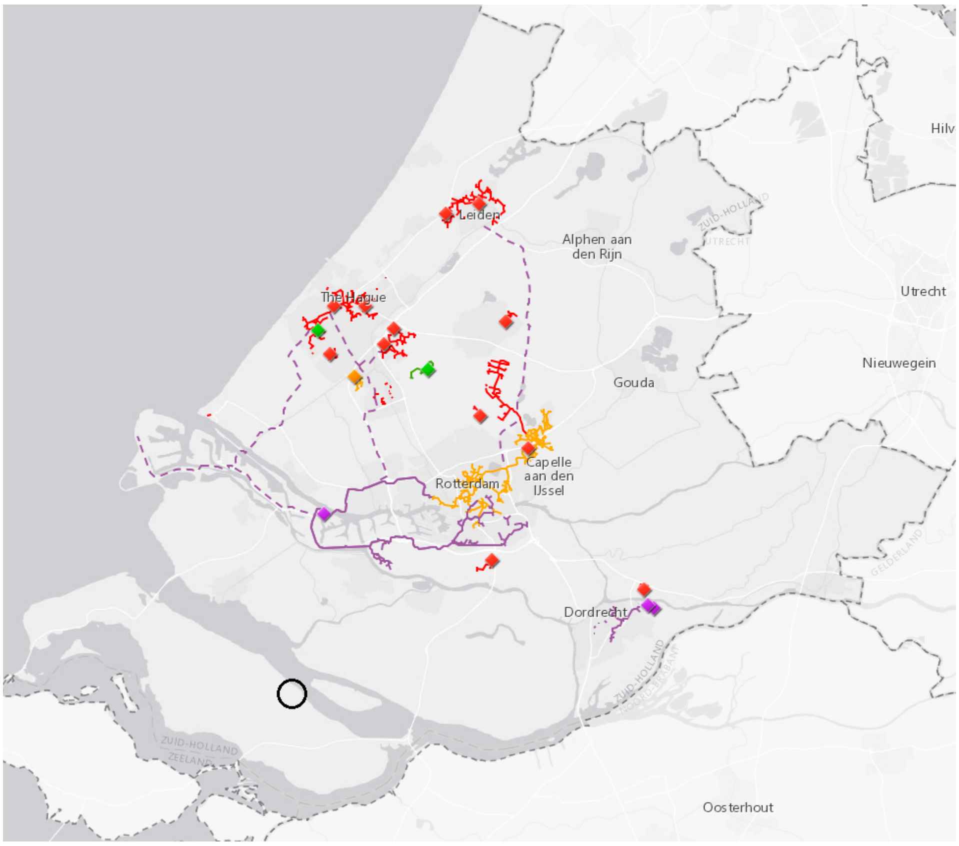


Figure 11.1: 'Warmte Transitie Atlas' Heat map of SH [95]

11.2. Hydrogen Source: Electrolyser and Storage

This section will introduce the potential source of hydrogen for the case study and its location. The initial idea for the case study of SatH would be to identify if SatH could be fed with 'green' hydrogen from an electrolyser outside SatH. This section identifies the constraints determining the location of a potential electrolyser. Appendix A will introduce the demand profile of SatH (without insulation) and how it was determined. During the process of calculating costs and capacity for two different scenarios in appendix B, it became evident that such a stand-alone scenario would become very expensive and would not be an ideal approach for introducing hydrogen to the domestic heating environment. In addition, the scenarios discussed in appendix B used electricity from the grid, which is not 'green'. Chapter 13 explains in more detail which scenario is more realistic and why this scenarios should be considered. For the network calculations it was assumed that the distribution network of SatH would fed from the location of the electrolyser in the following subsection.

11.2.1. Electrolyser Location

Subsection 4.4.2 discusses the necessary conditions for an electrolyser. The location should have a credible water source, power source and connection to the gas network. Just outside of SatH, there is a location which satisfies these three conditions. The final condition is that there is sufficient room to place a complete electrolysis unit. The typical footprint for a MW scale alkaline electrolysis system would be around 200 m^2 [36]. This area has sufficient room to place such a unit; however, the owner of the land and municipality would have to give permission. Figures 11.2a, 11.2b and 11.2c indicate the current water, electric and gas infrastructure at this proposed location, respectively. Figure 11.2d is a satellite image of the location to the north west of SatH (ideal electrolyser location indicated in red).

(a) Water network north west of SatH

(b) Electricity network north west of SatH

(c) Gas network north west of SatH

(d) Satellite image of the location north west of SatH

Figure 11.2: An overview of all relevant networks for production north west of SatH

11.2.2. Storage and Location

In scenario 2 of appendix B storage of hydrogen in SatH was necessary because the demand and production of hydrogen are not aligned. As discussed in chapter 5, there are several different storage technologies. SatH is not near to any salt caverns and storage in an empty cavern is therefore not an option. The best option for storage in SatH would be compressed storage due to its TRL, relatively low costs and dynamic load and unload characteristics. The hydrogen storage requirement for SatH is 447,000 Nm^3.

The gas network of SatH only has a relatively small volume, this means that no significant storage can take place in its isolated network. The storage capacity of the distribution network of SatH was calculated as follows. Together with the diameter and length the so called water volume of the network can be found. The water volume of a network is the actual volume within the pipes regardless of the pressure. The 8 bar, 2 bar and 100 mbar network have a water volume of 82.62 m^3, 22.21 m^3 and 155.75 m^3 respectively with a total of 260.58 m^3. The total amount of hydrogen that could be stored in the network would subsequently be 661 m^3, 44.4 m^3 and 171.3 m^3 for the 8 bar, 2 bar and 100 mbar network respectively. The total hydrogen storage in the network of SatH would therefore only amount to 577.47 Nm^3.

The ideal location for compressed hydrogen storage would be near to the production location. The production of hydrogen from the AEL electrolyser would be at pressures around 15 bar [33]. The required footprint for compressed hydrogen storage will be a rough estimation. Compressed hydrogen tanks (figure 5.1) are often installed horizontally but they can also be installed vertically. In the case of SatH it is assumed that the tanks will be placed horizontally to keep the visual disturbance to a minimum.

The dimension of a typical compressed hydrogen storage unit are roughly between 14m and 18m in length by 3m in height and 2m in width [96]. At what pressure a unit can hold hydrogen has a large influence on price. From the two examples that were found, volumes of 2500 Nm^3 (50 bar) and 4300 Nm^3 (90 bar) were found. Dividing the total storage needed by the volume of 1 unit (4300 Nm^3) results in 104 units! This already shows that placing the units close to each other would already need an area of 2912 m^2.

11.3. Lay-out

The island of GO is covered with a 2 bar and 8 bar high pressure distribution network as can be seen in figure 11.3. The town SatH is fed by an 8 bar pipeline to its north-west, which is fed by a CGS to the west of Middelharnis (indicated with downward pointing black arrow). If the town were to be fed by an electrolyser in the future the ideal location would remain to the north-west of SatH, as noted in subsection 11.2.1. The town is also fed by a 2 bar network to its south. The 2 bar network to the south of SatH is also responsible for the NG distribution to the south-east of SatH.

The low pressure network of SatH is connected to the high pressure network at four different locations, indicated in figure 11.4 by four numbered black rings. Location 1 and 3 both have a DS and a HPDS, location 2 and 4 only have a DS. Figures 11.5a, 11.5b, 11.5c and 11.5d show how the low and high pressure network are connected via the stations.

At location 1, the 8 bar pipe that is fed into the HPDS and DS is split before it does so. This way the pipe continues as an 8 bar pipe and a 2 bar pipe out of the HPDS and as a 100 mbar pipe out of the DS. All three pipes lay in the same direction towards the town center, where they later continue in different directions.

Location 2 is a DS stat connects the 100 mbar network to its northwest with the 2 bar network to the east of the station. The 2 bar connected to DS 2 also connects the 2 bar network to HPDS 1 and DS 4.

Location 3 is connected to the 8 bar pipe that comes from location 1. The 8 bar pipe is fed into a HPDS which feeds a 2 bar pipeline that is fed toward location 4 by connecting to a 2 bar pipeline that runs south of SatH. The 8 bar pipe is also connected to a DS which feeds a 100 mbar pipe that also goes in the direction of location 4 and continues upwards on the west side of the road above location 4.

Location 4 is where the 2 bar pipeline from location 3 and location 2 come together in the southwest corner of SatH. The 2 bar pipeline is connected to a DS which feeds a 100 mbar pipeline. The 100 mbar pipeline feeds the eastern part of the road going up from the DS.

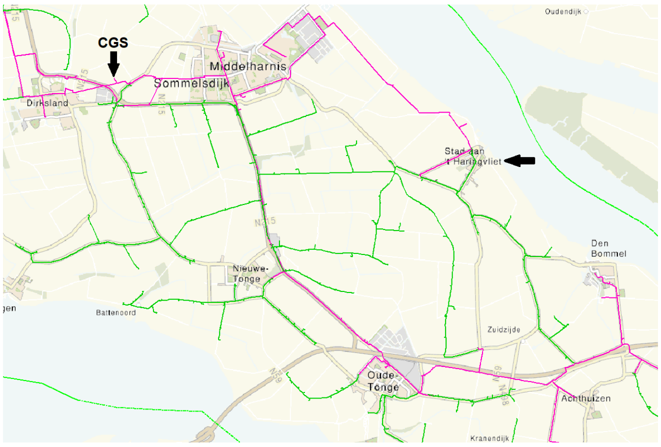


Figure 11.3: High pressure distribution network around SatH (indicated with horizontal black arrow). The 8 bar and 2 bar network are indicated by pink and green lines respectively.

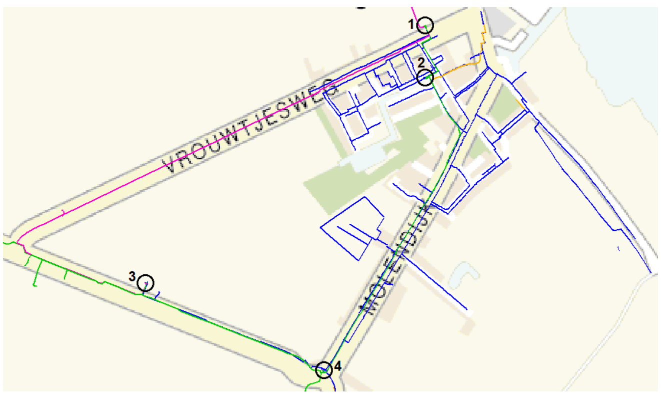


Figure 11.4: Location of HPDSs and DSs of SatH

(a) DS and HPDS at location 1

(b) DS at location 2

(c) DS and HPDS at location 3

(d) DS at location 4

Figure 11.5: A detailed overview of the HPDS's and DS's connections to the low and high pressure network

11.3.1. Isolation Lines

To successfully isolate the gas network of SatH from the larger network, isolations lines have to be chosen with care. This section will explain how the final hydrogen network will be isolated from the larger NG grid. There are several steps needed to transit the NG network of SatH to hydrogen, but these steps will be discussed later in section 12.3.

The northern part of SatH's network is fed NG by an 8 bar network to the northwest of the town at location 1. After the transition this 8 bar network will no longer be feeding SatH with NG but with hydrogen from a hydrogen source. The hydrogen source will be discussed in section 11.2.

The DS at location 2 will be fed with hydrogen from the 2 bar network. This 2 bar network is currently fed from the north and east. The eastern connection to the 2 bar network will be disconnected. When SatH has been isolated from the NG this connection will no longer be necessary.

At location 3 the HPDS will be shut of, this means that the 8 bar pipe feeding the HPDS will only be connected to the DS. The 2 bar network will continue to transport NG. The DS will feed the 100 mbar network with hydrogen.

At location 4 the 2 bar network will continue to feed the 100 mbar network with NG. The 100 mbar network passing through the top of figure 11.5d is transporting hydrogen from the DS at location 3. The 2 bar network to the east in figure 11.5d will be disconnected. The remaining 2 bar network between DSs at location 2 and 4 will be disconnected and put out of use.

With the current connections SatH will still receive NG from the DS at location 4. This is necessary to feed two large NG consumers in the southern part of the town. To successfully isolate SatH's hydrogen network from NG, one more pipe must be cut and disconnected. Figure 11.6 shows how the southern part of SatH with the two large consumers is isolated from the hydrogen network.

The two large consumers are indicated with 2 black arrows. The red arrow indicates where the 100 mbar NG network is cut. The northern part of the cut will be the hydrogen network.
Figure 11.7 shows the final hydrogen grid lay-out. The surrounding NG network and its connections have been removed from the figure to make the hydrogen network more clear. Orange pipes are pipes which are no longer in use. In this case a large part of the 2 bar network in the south of SatH has been taken out of use and in turn has been colored orange.

Figure 11.6: Isolated part of SatH which will stay connected to the NG grid

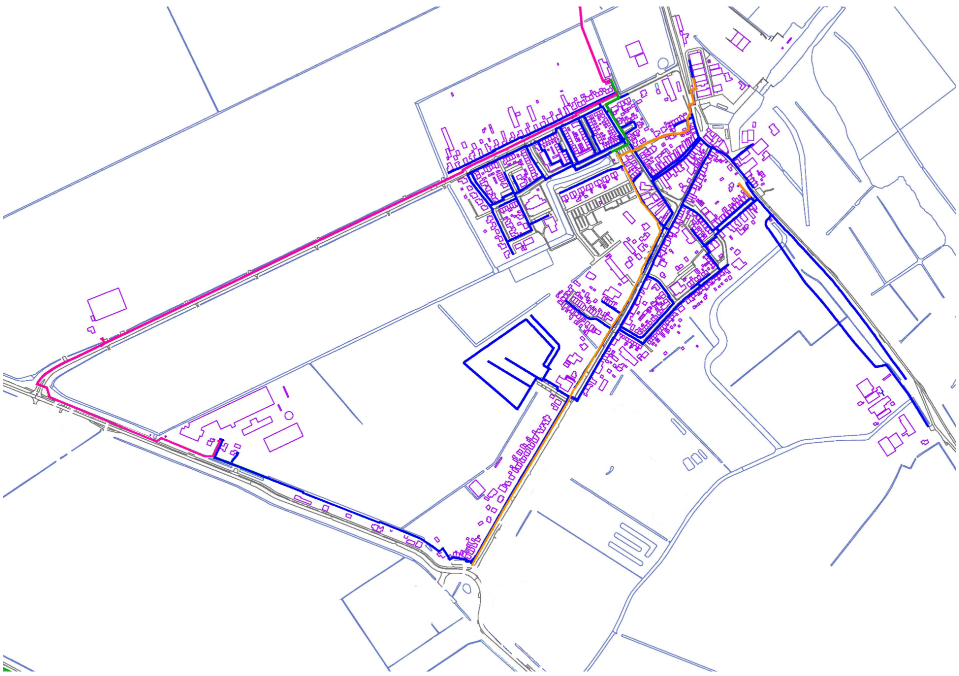


Figure 11.7: Hydrogen grid of SatH after transition is complete

11.4. Components and Materials

The 8 bar, 2 bar and 100 mbar network of SatH have a variety of different materials in them. The 8 bar network only has steel pipes of different diameters. The 2 bar network has steel and PE in its network. The 100 mbar has a far larger variety of materials. Table 11.1 gives an overview of which materials are present in the different networks of SatH, their diameter in mm and the length in which they are present.
As mentioned in subsection 7.4.2, the steel that is found in the network of SatH is capable of transporting hydrogen. Also copper is stated to form no issues with the use of hydrogen. The plastics and polymers PVC, PVC/CPE, PE80 and PE100 are all capable of transporting hydrogen as well as mentioned in subsection 7.4.1. For SatH nearly no network has to be replaced. There is only 1 m of Asbestos Cement in the network which will have to be replaced. MDPE is an old type of PE which stands for medium density PE. Later in time PE types were named according to their strength. MDPE would correspond to PE 80 nowadays. Because hydrogen has no effect on PE it is acceptable to classify MDPE as fit for hydrogen.
If one looks at the composition of Stedin's complete low pressure network, one sees that roughly 10% of the network consists of CI or AC. SatH's network does not have any CI because the town was connected to the network after NG was discovered, so there was no existing CI network from a period with town gas. In an early transition scenario the presence of CI is undesirable due to increased risked inherent to CI. SatH's network is ideal in this regard.

Table 11.1: Network materials with diameters [mm] and lengths [m] of the 100 mbar, 2 bar and 8 bar network of SatH

100 mbar					
PVC/CPE [mm]	**[m]**	**PVC [mm]**	**[m]**	**PE 100 [mm]**	**[m]**
160	6261	110	119	110	18
110	1280	50	51	**Peko [mm]**	
63	1189	40	19	22	3
50	390	32	253	**Copper [mm]**	
40	329	**PE 80 [mm]**		35	1
32	220	110	1090	**MDPE [mm]**	
25	55	63	1	32	11
Steel [mm]		50	44	**Asbestos-cement [mm]**	
114	5	40	86	124	1
51	2	32	313		
32	6	25	149		
25	32				
2 bar				**8 bar**	
Steel [mm]	**[m]**	**PE 80 [mm]**	**[m]**	**Steel [mm]**	**[m]**
168	5	160	973	168	2862
114	237	110	12	114	1813
				60	230
				34	12

12 Transition

This chapter discuss the steps required to convert a the NG network into a hydrogen network. Special focus will go into the activities required by the DSO and consumers. The whole transition is divided into three different stages. The first stage is making certain that no consumers are still dependent on NG for other necessities than hot water and heating. The second stage is inspecting if houses and buildings are ready for the transition to hydrogen. The third and final stage will be the actual transition to hydrogen, carried out by the DSO.

12.1. Switch to electric cooking

There are two scenarios that are taken into account when switching to hydrogen in this case study. The scenarios are cooking with hydrogen and cooking with electricity.
Cooking with hydrogen is an option that still has to be worked out significantly, as noted in section 8.4.2. The most significant advantage to cooking with hydrogen is that it does not require the electric network to be reinforced.
Cooking with electricity generally does not require a three phase connection. This means that a 35A connection is capable of electric cooking. There are however a few side notes one has to consider. There are 2 types of single phase connections cables, a primary connection cable and a non-primary (secondary, tertiary etc.) connection cable. Figure 12.1 schematically indicates a primary and a non-primary connection cable. Primary connections cables are capable of delivering enough power for electric cooking. A non-primary connection cable is not capable of providing several houses with enough power for electric cooking. SatH has non-primary connections cables, which means that all single phase connections cables in SatH will have to be replaced with three phase connection cables. In SatH 60% of the houses has a single phase connection cable. Of the 40% of the houses that does have a three phase connection cable, only half has an actual three phase connection. Table 12.1 gives a clear overview of the electric connection situation in SatH

Table 12.1: Overview of electric connections in Stad aan 't Haringvliet

1 phase cable 1 phase connection	60%
3 phase cable 1 phase connection	20%
3 phase cable 3 phase connection	20%

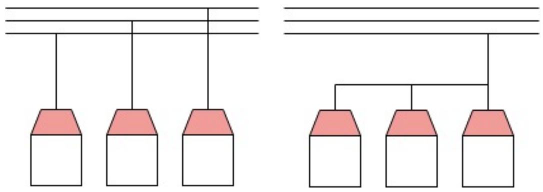
To complete the first phase, all houses in SatH will have to switch to cooking with electricity. The necessary steps for the consumers will be:

- get a three phase home connection cable installed
- get a three phase connection installed
- install separate fuse for kitchen

- buy and install electric stove and oven
- if necessary, buy compatible pots and pans

For Stedin to complete the first phase in SatH, the following step is required:

- replace all one phase home connection cables with three phase cables
- replace all one phase connections to three phase connections
- place a new electric DS (incl. minor adjustments)
- placement of 500 m of low voltage cable



(a) Primary single phase connections

(b) Non-primary single phase connection (present in SatH)

Figure 12.1: Two different types of a single phase connection

12.2. Inspection

In the second phase of the transition, mechanics of Stedin will have to go past all the houses in SatH to check how and where the boiler is installed. This visit will give them the opportunity to foresee any troubles that might be relevant for switching the boiler to a hydrogen boiler and switching the NG meter to a hydrogen compatible meter. Issues such as reachability, or if there is sufficient space for a new meter are typical assessments that should be made. The second phase should not be carried out too far in advance of the third phase, this way the chance is kept to a minimum that there are any major changes between the inspection and installment of the new boiler and meter. Also, as noted in section 8.3, it is advisable to utilize this moment to inspect the state of the building's inner gas network for any leaks.

12.3. Sectioning

The Town of SatH has 522 homes. If NG were to be instantly switched to hydrogen these homes would still need two adjustments. The first adjustment is a new hydrogen compatible meter and the second adjustment is the hydrogen boiler, for warm water and heat. The replacement of these two components would take roughly three and a half hour per house. The replacing the meter takes half an hour including paperwork and replacing the boiler takes three hours for two persons (6 work hours).
Figure 12.2 shows the current NG network of SatH divided into three parts by two red lines. Part to the south east of the bottom red line will be excluded from the hydrogen network due to large consumers. The other two sections will be converted to hydrogen, but not at the same time. The north west section will transit to hydrogen first and will be regarded as part 1 from now on. The other part of SatH that will still have to transit will be regarded as part 2. Part 1 and 2 will be done in two separate phases due to the large a amount of work and time all works will cost.

12.3.1. Part 1

Figure 12.3 shows part 1 of SatH, which consists of 180 houses. During the transition phase, part 1 of SatH will be fed with hydrogen from the 8 bar network to its north. DS 2 (figure 11.5b) will feed the area from the south with NG. The NG and hydrogen are not allowed to mix, so the hydrogen will be introduced street by street.
By cutting off part 1 from part 2 of SatH, the 100 mbar network from part 2 loses the feed of NG from the north side. Figure 12.4 shows the 100 mbar NG pressure of part 1 and 2 of SatH after they have been separated from each other. The pressure has been calculated for temperatures of -12 °C. The minimum pressure of this network is not allowed to drop below 40 mbar. As you can see, part 2 stays above this threshold. Part 2 retains 100 mbar due to the fact that is fed directly with the 2 bar network from DS 2.

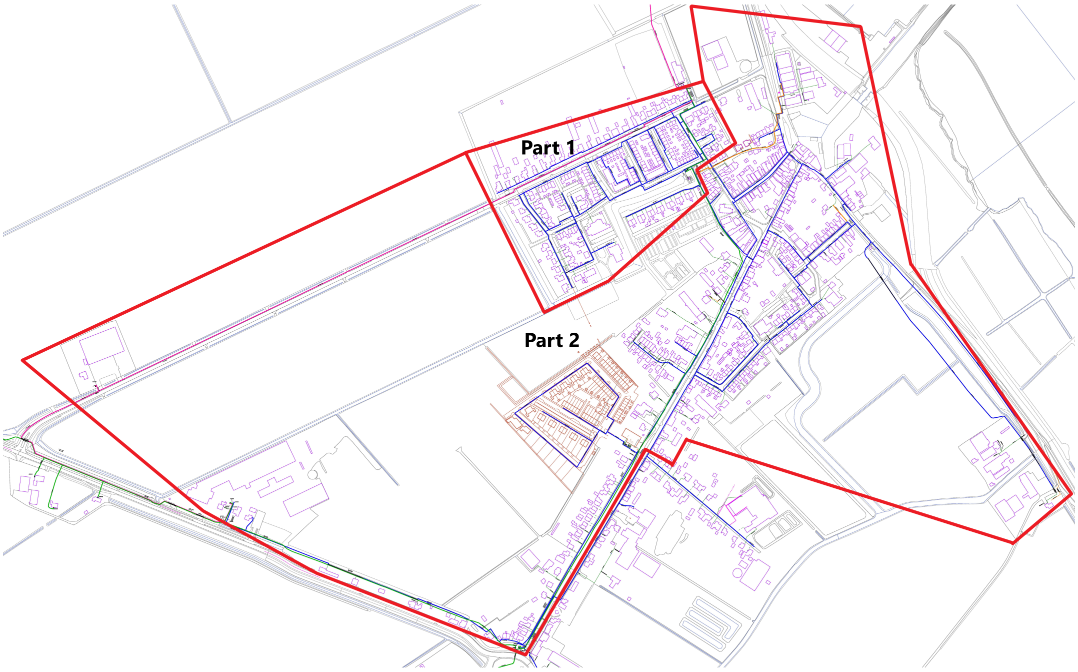


Figure 12.2: Current NG network of SatH

Figure 12.5 is used as an example to help explain the process of switching to hydrogen, street by street. For this figure, the purple 8 bar network and the green two bar network can be neglected. All one has to remember is that the 100 mbar blue network is fed by DS 1 in the top right corner of the figure.
The first street that will be converted to hydrogen will be the top blue horizontal street. The street will be fed by hydrogen from the right, and NG from the left. The first part of the street will be isolated from the NG network by two bladders, indicated by the two horizontal red lines. The street is so long that it can probably not be transited in one day. The vertical red lines are subsequent bladders that are placed between the hydrogen introduced to the right and NG to the left. The NG is fed in by a temporary line at the left end side of the street, indicated by an orange line.
The amount of houses that can be converted in a day is dependent on the size of the work force carrying out the installment of the hydrogen boilers and meters. One couple of mechanics will be able to convert two houses a day. And 10 mechanics could do 10 houses a day, 20 mechanics do 20 houses a day, and so forth. Other necessary works such as the temporary orange line have to be carried out in advance or parallel to installations and are not included in the time estimation.
As soon as the first street is done, connected streets can be added to the expanding hydrogen network. It is advisable to transit the town in as few steps as possible, due to the fact that every bladder placed is a new weak spot in the new gas network.

12.3.2. Part 2

The second part of SatH is nearly twice as large as part 1 and consists of 342 houses. Figure 12.6 shows the gas network of part 2. All other houses have been removed from the figure. Part 2 will be fed hydrogen from the 100 mbar network of part 1 to its north west. The 100 mbar network in part 2 is set up in such a way that it is relatively easy to introduce hydrogen street by street, without having to place temporary or new pipes.
Figure 12.4 shows how part 2 of the town can be fed with NG by DS 4 and DS 3. The hydrogen network will increase in size by gradually adding streets in the north of part 2 and working it’s way to the south east.
At a certain point the hydrogen network will have reached the street that is home to the large consumers of SatH, Boomgaarddreef. The Molendijk street adjacent to the Boomgaarddreef wil be cut of just to the north of Boomgaardreef on the eastern side of the road. Subsection 11.3.1 indicates how this part of SatH network is isolated from the hydrogen network.

Figure 12.3: Part 1 of SatH

12.4. Boiler and Meter

For the home owner the final steps of the transition will be the switch from a NG meter and boiler to the hydrogen meter and hydrogen boiler. As noted in subsection 8.2.1, it is still unclear if diaphragm meters are able of accurately metering hydrogen. If so, and if the hydrogen peak volumetric flow rate is within limits of the meter, the meter would not have to be replaced. Based on standard year demands of houses in SatH it is expected that about 84% of the G4 meters and 91% of G6 meters within the scope of SatH would be able to operate within maximum capacity if hydrogen were introduced. Engineers expect that converting a house from NG to hydrogen will take two technicians 3.5 hours (2x3 hours for boiler and 0.5 hour for a new meter if necessary). This means that it will take a couple of technicians one day to do two houses.

12.5. Work force

The part of SatH that will transit to hydrogen will consists of 522 houses, including new construction on the west side of the Molendijk. The amount of men employed in transiting homes to hydrogen will have a large influence on the time required for the transition. Not only time is greatly impacted by the size of the workforce. The amount of bladders and sections that have to be introduced to the network, which increase the vulnerability, will be reduced if the amount of houses that can be transited in a day is increased. Other technicians will have to be deployed to section the network and lay new piping. The works these technicians will have to do is not significantly different from work that they have already been trained for.

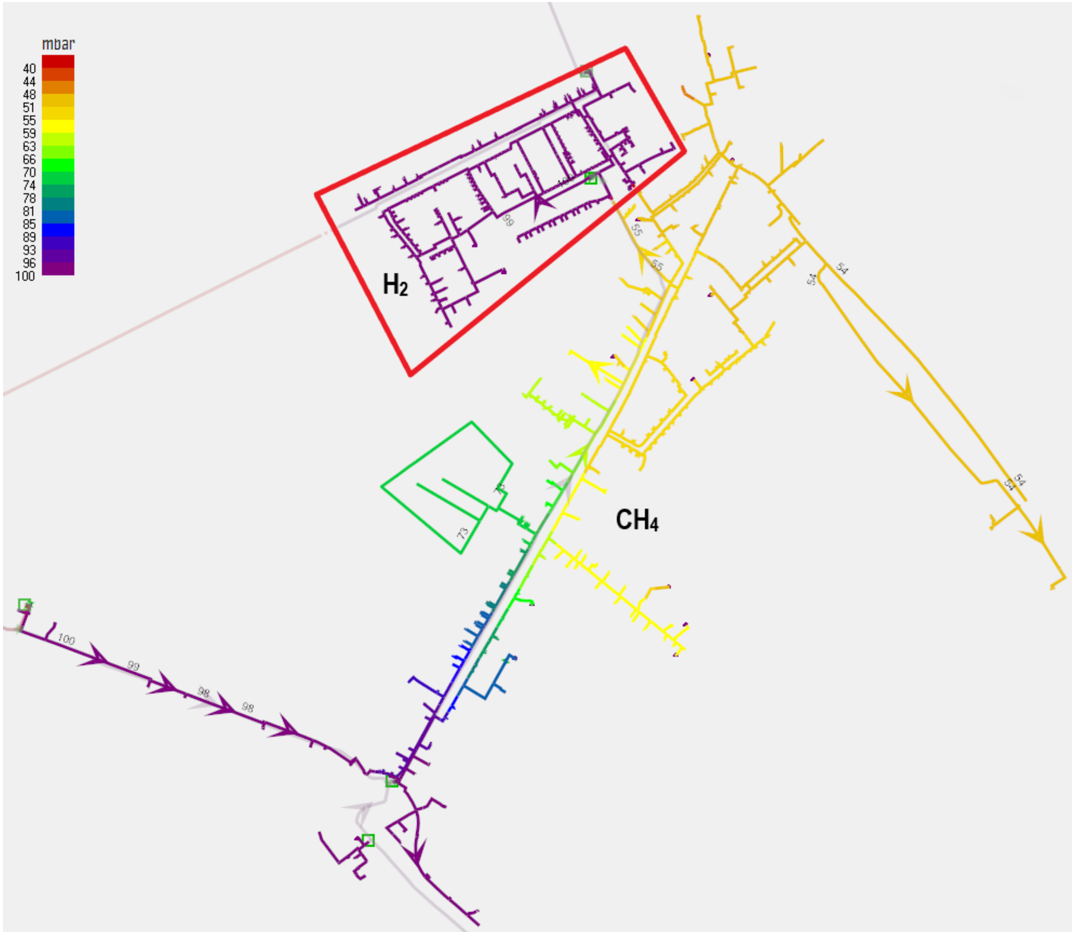


Figure 12.4: Pressure in 100 mbar network of part 1 and 2, when separated from each other (-12 °C)

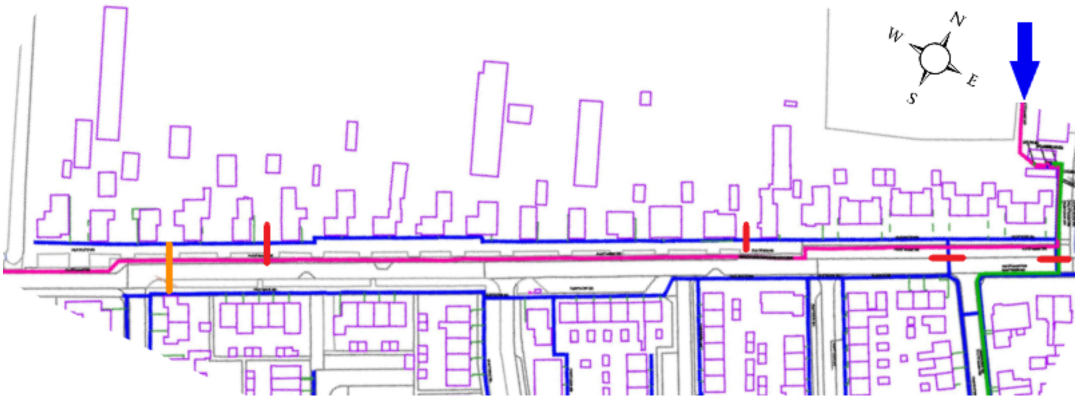


Figure 12.5: First street to transit to hydrogen in part 1

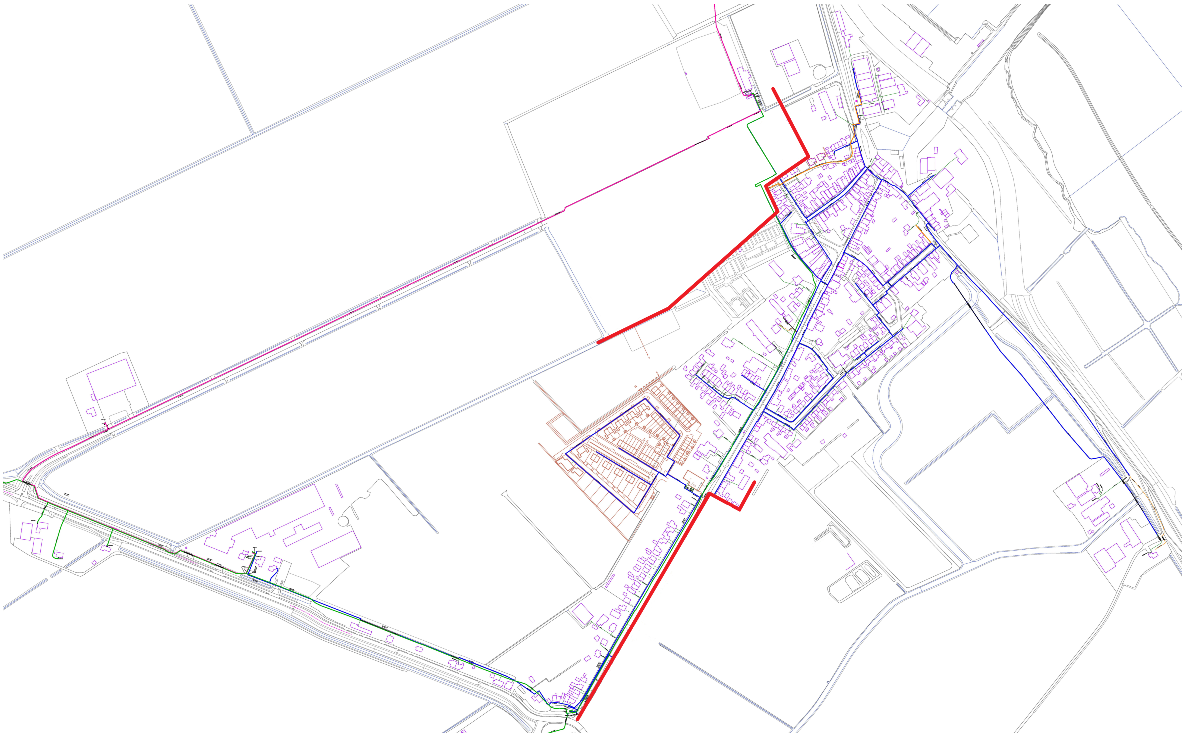


Figure 12.6: Part 2 of SatH

13 System Comparison

13.1. General Introduction

Before deciding if SatH should be switched from heating with NG to heating with hydrogen, a comparison with alternative technologies should first be made. Currently, in NL there are two alternatives that have promising potential; all-electric heating and heating with heat networks. In the case of SatH, a heat network is not a viable option due to the lack of a significant heat source in the area and the low housing density of the town. The primary alternative to heating with hydrogen would therefore be all-electric heating.
This chapter will give three different system comparisons between an all-electric and hydrogen scenario in SatH. All three comparisons will be discussed qualitatively and one of the three scenarios will be worked out quantitatively. A thorough system comparison can help identify the advantages and disadvantages of different technologies and identify where, when and how a technology can best be implemented. When setting up a system comparison it is important that the different technologies are compared fairly. To safeguard a fair comparison between different technologies clear system boundaries must be set. Subsection 13.1.1 will discuss the set system boundaries for the system comparisons in this chapter.

This chapter will discuss the following three system comparisons. Every system will be at a specific moment in time and have a specific grid connection:

System 1 SatH at present day which functions as a stand alone system. All power or energy required for warm water and heating will be produced by the wind turbines just outside of SatH. Power required for other needs such as lighting will be provided by the gray electricity from the national electric grid.

System 2 SatH at present day which is connected to a larger grid. Present day grid hydrogen and electricity can be considered gray.

System 3 SatH in the future which is connected to a larger grid. This future system comparison will be carbon neutral and use predominantly green energy and small amounts of blue energy.

Every system will be discussed for two different scenarios:

Scenario A Hydrogen

Scenario B All-electric

Table 13.1: Overview of Systems with Corresponding Scenarios

	System 1 **Present day** **Stand-alone**	**System 2** **Present day** **Grid-connected**	**System 3** **Future** **Grid-connected**
Scenario A **Hydrogen**	• Green H_2 produced from local wind power • Gray power from electric grid • Compressed H_2 storage • small reinforcements to the local e-grid • minor changes to local g-network • Minor house insulation	• Gray SMR H_2 recieved from Air Liquide pipeline • Gray power from electric grid • No storage • small reinforcements to the local e-grid • minor changes to local g-network and large connection line to Air Liquide • Minor house insulation	• Green H_2 from wind at sea and import. Blue H_2 from ATR with CCS • Green power from renewable sources. Blue power from fossil fuel powerplants with CCS • Salt cavern storage • small reinforcements to the local e-grid • minor changes to local g-network • Minor house insulation
Scenario B **All-electric**	• Green power from local wind turbine • Gray power for lighting and other loads • Battery storage • heavy reinforcements to local e-grid • removal of local g-network • Heavy house insulation	• Gray power from national electric grid • No storage • heavy reinforcements to local e-grid • removal of local g-network • Heavy house insulation	• Green power from wind at sea. Blue power from fossil fuel power plants with CCS • H_2 conversion salt cavern storage • heavy reinforcements to local e-grid • removal of local g-network • Heavy house insulation

13.1.1. System Boundaries

The goal of this chapter is to make a fair system comparison between different scenarios. This section will indicate the system boundaries and why they were chosen. The system comparison will focus on three parties between the production and end-users of SatH. These are producers (of power or hydrogen), the DSO and end-users in SatH.

Specific prices of future hydrogen or power are not discussed due to the uncertainty of how these prices will develop in the future. The production price of gray hydrogen for example is greatly dependent on the NG price. The same goes for green hydrogen prices, these are mainly dependent on the electricity price. The future NG and electricity price are unknown and so no assumptions of there price will be made. In addition, it is unclear how taxes and subsidies of different energy carriers will develop in the future. Therefore, taxes and subsidies will not be included in energy prices and only production costs will be used.

Calculations concerning converting houses to all-electric in SatH were done by an architect hired by the municipality of SatH. The calculations indicate the expected future demand for power for warm water and heating and the expected costs of converting the homes. The estimated power consumption of the homes was calculated by the architect and later aligned with the demand that was calculated with the IRENE PRO model. Choosing to combine the calculations of the architect and the model rather than using data from standard housing type energy labels was done because the calculations included the costs of converting housing specifically found in SatH. And the costs of converting this specific kind of housing is a very important part of identifying why all-electric heating is not suitable for all types of housing.

13.1.2. Gas vs. Electric Demand

It is important to realize how much power is actually consumed for heating and warm water so that one can better understand the implications of switching to a new energy carrier. Figure 13.1 shows the current demand of SatH in gas form and electric form. With this figure it becomes clear how much more energy housing actually consumes aside from the electric demand. The gas demand is produced by combining KNMI local temperature data with IRENE PRO demand data.

Appendix A will go into further detail about how this data was created. The electric demand has been plotted by combining a standard electric profile with the average standard electric demand multiplied by the number of houses in the scope of the transition. The electric demand is typically not temperature dependent but rather sun-hours dependent, as one can see that the peaks coincide with the shortest and longest days of the year.
Switching to an all-electric scenario would require the total demand to come down significantly, otherwise it would simply be impossible to distribute and supply enough power through the electric grid. The predominant way to bring down this total demand is the insulation of houses. Appendix C shows details regarding costs and demand that can be realized for the houses in SatH.
Switching to hydrogen would not require the demand to decrease; however, bringing down the demand by insulation is always a good idea due to the reduction in costs and improved energy efficiency. Therefore the houses in the hydrogen scenarios will have some initial insulation.

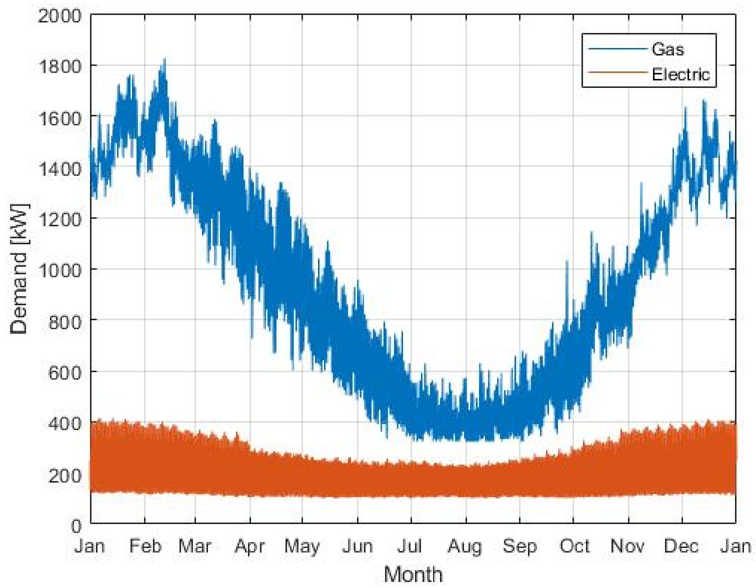


Figure 13.1: Electric demand vs. gas demand for the scope of SatH

13.1.3. Housing Modifications

The required modifications to make old houses capable of heating with hydrogen are far less extensive compared to the required modifications for heating all-electric. The large amount of modifications required for all-electric heating translate into high costs for the home owner. This section will discuss the steps required for a house to convert to heating with hydrogen vs. converting to all-electric. The total costs of such a conversion is dependent on the type of house that is being modified. In appendix C the costs of a typical house in SatH will be worked out to emphasize this fact. Note that large home owner costs are often the largest contributer to the total investment costs due to the fact that these costs are multiplied by a large number of houses.

Hydrogen
For present day and the near future, the first step required to transit a house to hydrogen heating and warm water would be to switch from cooking with NG to electric cooking. Switching to electric cooking requires an electric stove and electric oven. For this an electrician has to come by to make an extra fuse group for the new electric kitchen appliances. Home owners will sometimes also be required to switch from a single phase connection to a three phase connection, depending on the lay-out of the connection lines in the area. After the switch to electric cooking a hydrogen boiler and meter (if necessary) will have to be installed at the moment of the actual transition. Because hydrogen costs are expected to be higher than NG costs, several effective investments can be made into insulating the house. These insulation costs will not be the most cost-effective options, to bring down the energy demand. Typical options are insulation of the roof, insulation of wall cavities and floor insulation.

All-electric
Just like in the hydrogen scenario, the kitchen appliances will have to be switched from using NG to using electricity. In addition to this switch more intensive modifications are required. An all-electric house will be heated with a heat pump. Such a heat pump provides low-temperature heat which requires a corresponding low-temperature heat distribution system. This means that regular radiators will have to be replaced by heating sources such as floor heating. Last but not least, the house will have to be very well insulated. This is necessary because otherwise the heat pump and low temperature distribution system would not be able to provide sufficient heat to keep the house warm throughout the year. For all-electric houses the following insulation is typically required; roof, side, frond and back facade, all windows, floor and roof. The costs of insulating houses sufficiently varies largely and proves to be one of the largest obstacles for converting certain houses to heating all-electric.

13.1.4. Network modifications

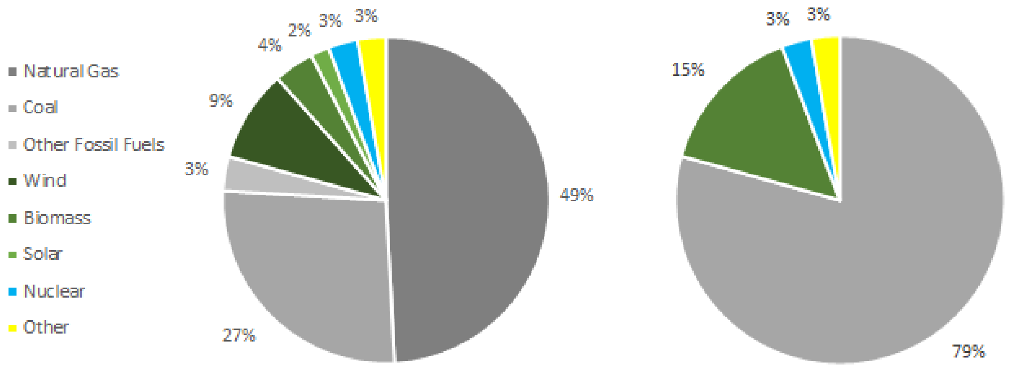
A hydrogen scenario would require several reinforcements to the electric grid due to cooking with electricity. The estimate cost of these reinforcements is €140,000 (€100,000 for a new electric DS and €40,000 for 500m of new low voltage cable ca. €80/m. Only a very small part of the gas network will have to be replaced with suitable materials as is discussed in section 11.4.
An all-electric reinforcement will be much higher. This is because the average required heat pump in SatH will require a capacity of 7kW. The current average demand of a house in SatH is roughly 400 W with a peak demand of 800 W. If every house were to install such a new heat pump it is obvious that the electric grid will have to be reinforced rigorously to facilitate such an increase in electric demand. Determining these costs is difficult without expansive calculations. They have been estimated to be about 5-10 times as expensive as the reinforcements necessary to the e-grid in the hydrogen scenario (€700,000-€1,400,000). In addition to reinforcements, an all-electric scenario will also require to remove the low pressure gas network if no other party is interested in buying the network (which is most likely the case). The cost of removing a low pressure network can be estimated to a price of €130/m. The low pressure network of SatH is 14,586 m. Removing this network will result in a cost of €1,896,180.

13.1.5. Electricity from National Grid

The general understanding within the population is currently that electricity is a clean choice compared to fossil fuels. To a certain degree this may be correct; however, electricity is still predominantly produced by fossil fuels. Figure 13.2 shows the production mix of electricity in NL in 2017. The figure shows that roughly 15% of the electricity produced in 2017 was produced from renewable sources such as wind, solar and biomass. The share of renewable sources for electric may increase over time; however, production through NG will still be needed to help align the power generation to demand to prevent frequency fluctuations in the electric grid. Because fossil fuels are such a large part of power generation and because the conversion efficiency from fossil fuels to electricity is so low the electricity in NL has a significant emission factor. The most recent emission factor of electricity in NL is from 2016 and it is 0.49 kg CO_2/kWh [97].

13.1.6. Carbon Capture and Storage

An important step to reaching climate goals is the deployment of CCS. Unfortunately, capturing CO_2 from flue gases is not a simple process in most cases. An important aspect in determining how much CO_2 can be captured is the composition of the exhaust stream.
SMR plants are currently capable of 90% carbon removal [99]. This subsequently means that hydrogen production through SMR can not be considered blue hydrogen due to fact that there will always be a CO_2 exhaust which is relatively uneconomic to capture due to the low partial pressure in the furnace exhaust.
In ATR steam and oxygen are injected into the reformer. The exothermic reaction between oxygen and the feedstock provides heat to the endothermic SMR reaction. Which in turn makes higher CO_2 recovery possible compared to SMR. The initial investment of ATR is roughly 15-25% less expensive than tubular SMRs; however, the required oxygen feedstock makes it less attractive [100]. One of the production streams of electrolysis is a pure oxygen stream, therefore there is a potential symbiosis between these two technologies which can increase the potential for ATR.
Post-combustion capture challenges are most relevant for coal-, oil-, or gas-fired power plants. For example; "the U.S. DOE/NETL estimates that the deployment of a current 1st-Generation post-combustion CO2 capture technology on a new pulverized coal power plant would increase the cost of electricity by roughly 80 percent and derate the plant's net generating capacity by as much as 30 percent (90 percent carbon capture).



(a) Specific sources with their corresponding share to power generation in NL

(b) Share of fossil fuels, renewables and other sources to power generation in NL

Figure 13.2: Shares of different sources for power generation in NL [98]

Other major challenges include energy integration, flue gas contaminants, water use, CO2 compression, and oxygen supply for pre-combustion systems" [101]. These numbers and issues clearly indicate how expensive and challenging it will be to truly produce blue electricity from fossil fuel fired power plants. Therefor it is expected that truly blue electricity from fossil fuel fired power plants will be extremely expensive and have a far smaller generating capacity than current fossil fuel fired power plants.

13.2. System 1 - Present day, Stand-alone

13.2.1. Scenario A - Hydrogen

Because SatH would most likely be the first town in NL to transit to hydrogen it might be interesting to see if SatH could produce sufficient hydrogen close to the town and function as a stand alone network. Figure 13.3a schematically shows how such a network would look.

The town would produce hydrogen through electrolysis with power provided from wind turbines just outside SatH. Besides the hydrogen demand, the town would still require an electric network. Electricity would be taken from the electric grid, already present in SatH. Currently, electric power in NL is predominantly produced by fossil-fuel powered power stations.

Seasonal storage of hydrogen would be necessary due to the large difference in demand for heating between colder and warmer seasons and the intermittent nature of the wind power, powering the electrolyser. Because the hydrogen network of SatH would be stand-alone, seasonal storage of hydrogen in salt caverns would not be possible. The cheapest alternative for seasonal storage would be compressed storage.

Due to cooking with electricity the power demand of SatH will increase, requiring small reinforcements to the electric grid. All houses would also need to have a three phase connection.

The local gas network of SatH has the capacity for hydrogen instead of NG. Very little pipe will have to be removed but the network will have to be sectioned during the transition.

The energy demand for heating will be reduced by implementing several effective insulation solutions, as discussed in subsection 13.1.3.

13.2.2. Scenario B - All-electric

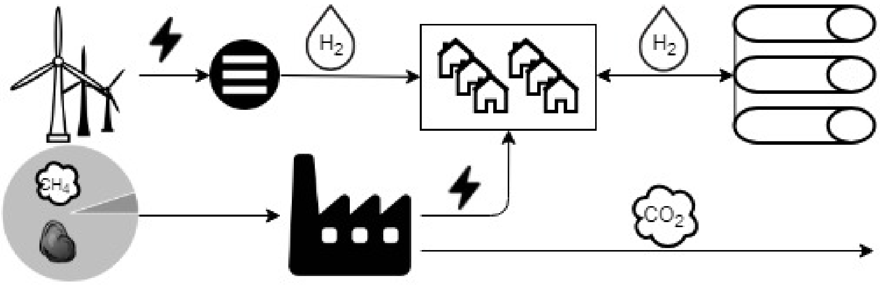
In an all-electric scenario (figure 13.3b)the wind power would be used for warm water and the heating of houses. Gray power from the grid would be used for other electric loads such as lighting, washing clothes etc. This setup is illogical but is necessary for a fair comparison with Scenario A.

Green wind power for heating and warm water will be stored in very large batteries or alternative electric storage solutions for seasonal storage.

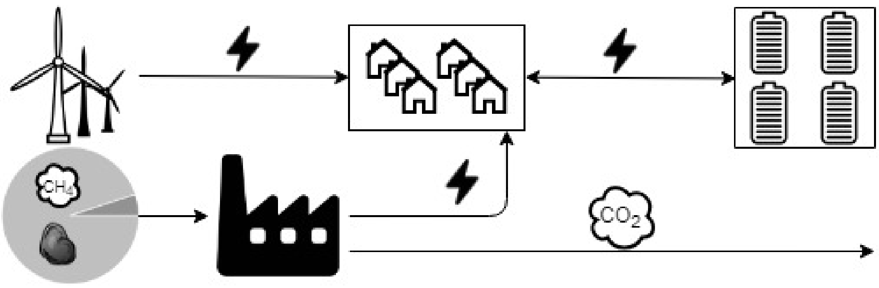
The local electric grid would have to be heavily reinforced due to the large increase in electric demand by heat pumps, electric boilers and electric cooking. The gas network will have to be removed due to becoming obsolete.

The houses of SatH will have to be heavily insulated to be able to heat electrically. The required insulation and other adaptations have been discussed in subsection 13.1.3.

Both Scenario A and B of system 1 are very impractical to realize. Stand alone systems of this scale will cause very high levelised costs of hydrogen and electricity. The national gas and electric grid in NL is very expansive and mature. It would be advised to use this fact to the advantage of a system, rather than neglecting the fact. In addition, Scenario A and B would still not be completely carbon neutral due to gray electric power needed for cooking and lighting.



(a) System 1, Scenario A



(b) System 1, Scenario B

Figure 13.3: Schematic overview of System 1

13.3. System 2 - Present day, Grid-connected

13.3.1. Scenario A - Hydrogen

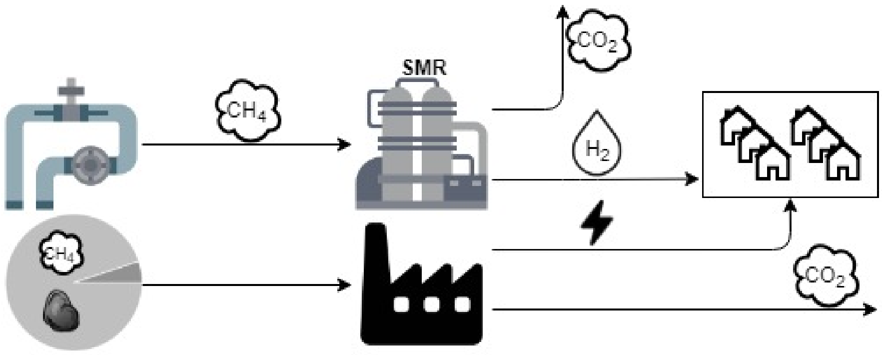
In this scenario SatH would receive its hydrogen from the Air Liquide pipeline to the east of GO. The hydrogen in the pipeline is gray and is produced in the port of Rotterdam by SMR. The pipeline is roughly 23 km away from SatH and a pipe connecting the Air Liquide pipeline and SatH would have to be realized. The costs of such a pipeline are estimated at €6.9 million. It is assumed that such a pipeline has the capacity for the required demand over such a distance. The electric power SatH would need will be taken from the national electric grid, to which SatH is already connected.
Hydrogen storage is not required in this scenario due to the large capacity of the Air Liquide pipeline (40,000 Nm^3/hr). Electric storage is also not required. This is because the current electric production capacity can be varied according to demand.
Due to cooking with electricity the power demand of SatH will increase, requiring small reinforcements to the electric grid. All houses would also need to have a three phase connection.
The local gas network of SatH has the capacity for hydrogen instead of NG. Very little pipe will have to be removed but the network will have to be sectioned during the transition. The energy demand for heating will be reduced by implementing several effective insulation solutions, as discussed in subsection 13.1.3.

13.3.2. Scenario B - All-electric

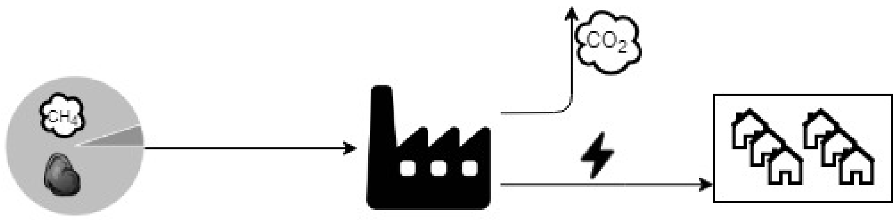
In this scenario SatH only receives gray electricity from the national grid. There is no need for storage because the the grid can vary its production according to the current demand.
The local electric grid would have to be heavily reinforced due to the large increase in electric demand by heat pumps, electric boilers and electric cooking. The gas network will have to be removed due to becoming obsolete.

The houses of SatH will have to be heavily insulated to be able to heat electrically. The required insulation and other adaptations have been discussed in subsection 13.1.3.

Scenario A of system 2 requires relatively few changes to the electric and gas network of SatH. There will be a significant investment needed for the connection to the Air Liquide pipeline. Both scenario A and B require no storage and can be implemented to the larger networks without expected technical difficulties. Both scenarios are however still gray, but they could function as an important step towards realizing a green or blue future system.



(a) System 2, Scenario A



(b) System 2, Scenario B

Figure 13.4: Schematic overview of System 2

13.4. System 3 - Future, Grid-connected

13.4.1. Scenario A - Hydrogen

A carbon neutral future system is interesting to consider because this is the system we will hopefully eventually achieve. In this scenario green hydrogen is produced from wind turbines at sea. Additionally, green hydrogen is imported from areas where it can be produced at cheaper rates. Besides green hydrogen, blue hydrogen could still be produced by ATR with CCS.

Besides green hydrogen, electricity is still needed in this scenario as well. Green power will also be produced from renewable resources such as wind turbines at sea. Blue power would also still be generated at lower capacity due to the high costs and lower power efficiency associated with future CCS of burning fossil fuels in power plants.

A larger future hydrogen network will be able to store hydrogen far cheaper by storing it in converted empty salt caverns. Excess power produced from renewable sources could also be converted to hydrogen and stored in the same caverns for longer periods of time. Later when power is required, hydrogen can be converted back into electricity by large fuel cells.

Due to cooking with electricity the power demand of SatH will increase, requiring small reinforcements to the electric grid. All houses would also need to have a three phase connection.

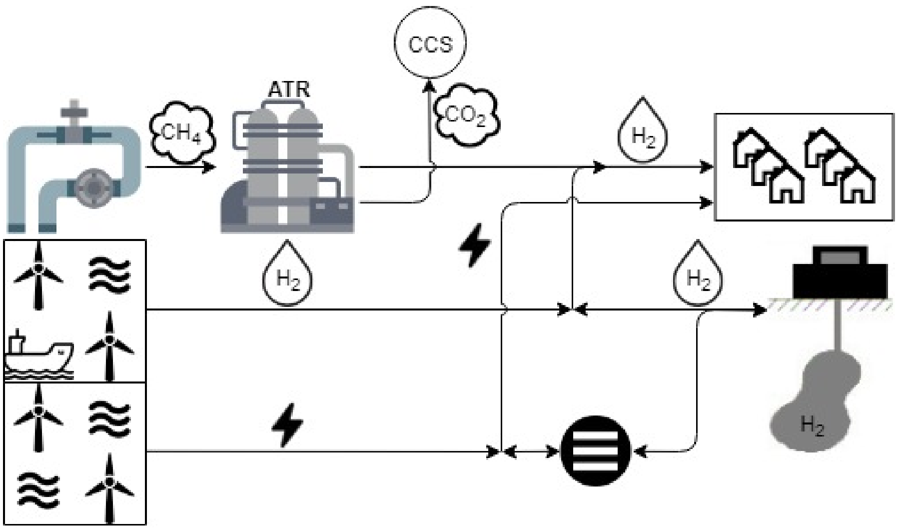
The local gas network of SatH has the capacity for hydrogen instead of NG. Very little pipe will have to be removed but the network will have to be sectioned during the transition.

The energy demand for heating will be reduced by implementing several effective insulation solutions, as discussed in subsection 13.1.3.

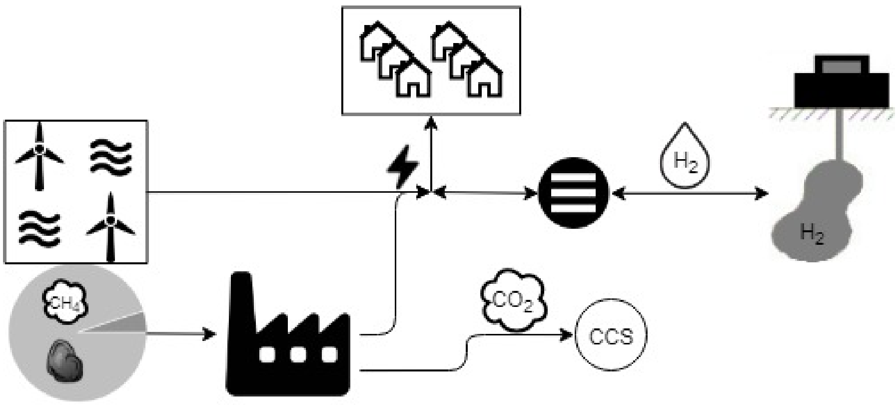
13.4.2. Scenario B - All-electric

Green power in this scenario will be produced from renewable sources such as wind at sea. There will also be a small amount of blue power produced by power plants with CCS. Seasonal storage of power will be done by converting it to hydrogen and storing it underground in converted empty salt caverns. The hydrogen can be converted back into power by large scale fuel cells. The whole grid including that of SatH will have to be reinforced to be able to withstand the larger electric demand due to heat pumps, electric boilers and electric cooking. The gas network will have to be sold to interested parties where possible. Everywhere else the network would have to be removed due to becoming obsolete.
The houses of SatH will have to be heavily insulated to be able to heat electrically. The required insulation and other adaptations have been discussed in subsection 13.1.3.

Even though scenario A and B are ideal solutions to reducing the carbon footprint of NL, both scenarios are still very far away. Large scale green power production will still have to increase dramatically over years to come to realize these scenarios. Large scale storage of hydrogen and conversion to and from electricity are all still technologies that have to be realized at such large scales in NL. Additionally, truly blue hydrogen and power by implementation of CCS is also still far from being a reality and much additional research and progress is required.



(a) System 3, Scenario A



(b) System 3, Scenario B

Figure 13.5: Schematic overview of System 3

13.5. Discussion

The system comparison of system 1 neglects the fact that NL is a small and densely built country which has an expansive and mature electric and gas network. Building a stand-alone network will therefore always be a more expensive and unpractical option compared to connecting to a larger grid and sharing costs and realizing more flexibility. Regarding the design of the all-electric and hydrogen scenarios of system 1 clearly shows unattractiveness and low doability of such systems due to large local storage and production capacity requirements.

One of the aspects that makes a quantitative comparison for system 2 attractive is the fact that is takes place in the present. Therefore there are fewer assumption for costs and carbon footprint of both energy carriers. The systems also don't require any storage in any the scenarios due to being connected to the larger power grid of NL and the Air Liquide pipeline to the east of GO, decreasing system design costs significantly. System 2 can function as an important first step in creating a new hydrogen market and offering a realistic alternative to an all-electric scenario if it proves to be feasible. Scenarios A of system 2 can be part of a road-map in which the CO_2 production by domestic heating is decreased due to the implementation of CCS of SMR. As mentioned, CCS is more attractive for SMR than for power plants due to the fact that the majority of SMR CO_2 production is pre-combustion.

System 3 is interesting to work-out qualitatively because it shows the green/blue scenarios which we eventually want to achieve in the future; however, due to the scenarios being in the future it is not possible to calculate future costs of such systems with sufficient confidence.

Taking all aspects into consideration mentioned in this section, it was decided to quantitatively work out the system comparison of system 2.

13.6. System 2 End-User Costs Comparison

13.6.1. Initial Investment

One of the largest differences in between switching to hydrogen versus switching to all-electric is the initial investment, especially with old buildings such as in SatH. Appendix C gives an overview of the investment required for switching to all-electric or hydrogen in SatH. Both scenarios implement insulation; however, the hydrogen scenario insulates significantly less and tries not to investment more than €10,000 in insulation. Insulation for the hydrogen scenario typically included ground insulation, inner-wall insulation, roof insulation or window insulation.

Currently a house within the scope of SatH has an average demand of 16,000 kWh and 3,350 kWh in gas and electricity respectively. A weighted average all-electric house in SatH will costs €50,000 to convert to and consume 8,298 kWh/year in electricity. A weighted average hydrogen house with minor insulation in SatH will costs €10,996 to convert to (of which €6,927 is for the insulation) and consume 10,089 kWh/year in the form of hydrogen and 3,525 kWh/year in electricity.

13.6.2. Demand

In 2017 the average NG wholesale price was €0.0175/kWh [102]. Retailers sold the NG to small consumers for €0.0292/kWh [103] (including fixed delivery costs). The margin of the suppliers for NG was therefore 66% for small consumers such as home owners. The margin of suppliers for very large industrial consumers was far lower, at 14.2% [103]. To calculate an estimate retail price for hydrogen, the following calculations and assumptions were made. The current cost price of hydrogen through SMR is €1.5/kg [48]. It is assumed that Air Liquide retains approximately the same margin as a large scale commercial supplier of NG (14.2%). Also, it is assumed that the suppliers will retain the same margins for selling to small consumers as they currently do with NG. Therefore, it is estimated that the supplier cost of hydrogen will be approximately €1.5/kg$*1.142*1.66$ =€2.84/kg (€0.072/kWh, excluding D&T costs).

The weighted average supplier price of electricity for small consumers in NL is €0.062/kWh [103]. In addition to supplier prices, a consumer has to pay annual D&T costs which are €181 and €237 for gas and electricity respectively[1].

[1]The hydrogen D&T prices are assumed to be equal to NG due to the use of the same infrastructure. It is expected that the D&T price for gas could rise in the future due to new investments required for converting the NG to hydrogen in some areas; however the price increase for D&T costs is most likely to be due to the decrease in number of connections to the gas grid in the future. In addition, not removing a large amount of network due to a 'second life' could also cause the D&T price to go down in the short term, depending on how the D&T price is determined.

The demand of an average hydrogen house in SatH would require 10,089 kWh of hydrogen a year and 3,525 kWh of electricity a year. Using the prices determined above, an average hydrogen consumer in SatH would have an annual cost of €1363, including D&T costs. An average all-electric consumer with a demand of 8,298kWh would have an annual cost of €751, including D&T costs.

13.6.3. Depreciation

Both the all-electric and hydrogen scenario require specific devices for heating and warm water. Over time these devices depreciate and eventually have to be replaced. The depreciation lifetime of boilers, stove/ovens and heat pumps were found to be 15 years [104] [105] [106]. Other investments such as insulation do not depreciate over time as the devices do. To better compare the costs of both scenarios the depreciation costs of the required devices should be included. Table 13.2 indicates the annual depreciation costs of both scenarios. The annual costs of the hydrogen and all-electric scenario are €179 and €712 respectively.

Table 13.2: Reoccurring costs for hydrogen and All-electric scenario

	Hydrogen	**All-electric**	**Lifetime [years]**	**Cost [€/year]**
Hydrogen boiler	✓		15	100
Electric boiler		✓	15	22
Heat pump		✓	15	611
Oven and stove	✓	✓	15	79

13.6.4. Carbon Footprint

Both scenarios of system 2 are gray and thus both scenarios have a carbon footprint. Nowadays consumers and governments are not only interested in prices but also increasingly more in this carbon footprint. This section will compare both scenarios to identify in which scenario an average house in SatH will produce more CO_2.

As mentioned in subsection 13.1.5, the emission factor of electricity in NL is 0.49 kg CO_2/kWh. Using molar weights and equations 4.1 and 4.2, a theoretical CO_2 to hydrogen production ratio can be calculated (5.5 kg CO_2 : 1 kg H_2). The actual average ratio however is slightly higher with 8.9:1 [107], resulting in an emission coefficient of 0.23 kg CO_2/kWh for hydrogen.

An average house in SatH in a hydrogen scenario would produce 4047 kg CO_2/year whilst an all-electric house would produce 4066 kg CO_2/year.

13.7. Concluding Remarks

Looking at the end-user cost comparison, several things stand out. The annual costs in SatH for the all-electric scenario (712+751=€1463) are only slightly cheaper than the hydrogen scenario (1363+179=€1542) with an initial insulation investment. The initial investment required for a house in SatH to become all-electric is very high. The investment for conversion and insulation for hydrogen is high as well; however, the investment is significantly lower and the insulation investment is not a necessity to heating with hydrogen. If no insulation were implemented annual costs for the hydrogen scenario would obviously be higher. Considering the initial investments and the small difference in annual costs shows that implementing hydrogen as an energy carrier in areas such as SatH is a cheaper option than an all-electric solution.

Another interesting fact is that the carbon footprint of both scenarios is practically the same. This highlights the prospect of implementing gray hydrogen as an energy carrier even more because it does not have a significantly larger carbon footprint than a current all-electric scenario with gray power but it does enable hydrogen to enter a new market and create new opportunities for blue and green hydrogen in the future.

Finally, reinforcements and alterations to the electric grid will be significantly smaller in a hydrogen scenario compared to an all-electric scenario and a second life of the NG grid could prevent the early depreciation of investments made into the current NG network.

VI

Research Results

14
Discussion

14.1. Limitations of Scope

Large consumers only account for 0.6% of all the NG connections in Stedin's area. However, these consumers are responsible for half of the total gas demand [108]. Leaving out large consumers of the scope leaves a significant part of the gas demand unregarded. Also fuel cells (domestic CHP and mobility) were not included in the scope. The effects and opportunities this technology might bring to DSO's should not be underestimated. However, including this technology into the scope would have been to much.

14.2. Limitations of Data

When modeling the demand profile of SatH data was combined from IRENE PRO and KNMI temperature data. The program makes several assumptions which distances its result from reality. Large consumer demand profiles are assumed to be constant and independent of temperature or consumer behavior. In reality the large consumers in SatH are farmers which most likely have alternating demand depending on the season. In part, this is why large consumers were excluded from SatH's scope. The demand of consumers which were included in the scope was only based on the meter capacity, which is not the same as the actual consumption of the houses. Finally, the IRENE PRO data was based on temperature data from outside of SatH. Actual temperature data from SatH would have been more accurate.

14.3. Future Assumption Limitations

The case study of SatH mostly looked at the option of introducing hydrogen in the year 2025. This is because a lot of literature expects to be more mature and at a more cost-effective efficiency by then. Prices for hydrogen production have shown to decrease rapidly the current years and the expected decrease in price has gone faster than predicted. This rapid decrease in price increases the uncertainty of the actual future price; however, the expectations have changed for the better. In addition, it has to be noted that other costs such as NG and electricity are also not certain. For example, it is not clear if the price of electricity will go down towards the year 2025 and this assumption has a great effect on the expected hydrogen production price.

15

Conclusion

The objective of this research was to improve the existing approach for identifying the ideal future energy carrier for different locations within Stedin's operating area. By answering the four main research questions stated in chapter 2, this report has determined additional characteristics for identifying areas suitable for hydrogen as an energy carrier. These additional characteristics have been tested and confirmed with the case study of SatH for validity.

1. **Which characteristics are relevant for assessing if hydrogen is suitable as an energy carrier?**

Hydrogen is a gas which can safely be distributed through the distribution network. The gas does have several characteristics that differ from NG which have to taken into account. Hydrogen has a greater flammability and explosive range than NG which increases the chance accidental combustion. Just like NG, hydrogen gas is odorless and hardly visible when it burns. A fitting solution still has to be found to address these characteristics.
Hydrogen gas has characteristics which make it a promising replacement to NG. The same amount of energy can be transported with hydrogen as with NG whilst retaining the same pressure drop, the most important parameter for the distribution of energy through pipe networks. The lower energy density of hydrogen and it's density make it necessary to adjust burners and flow meters which are currently designed for NG.
Hydrogen gas can be produces through the steam methane reforming, biomass/waste gasification and electrolysis. The dynamic characteristics differ greatly between these production options. Electrolysis with a PEM electrolyser is the most dynamic producer and can even be implemented for e-grid frequency control but it is still more expensive compared to the AEL. The AEL is a mature technology but has a lower the dynamic characteristic compared to a PEM electrolyser; however, together with power electronics AEL dynamic characteristics are capable of following the dynamic behavior inherent to power from renewable energies. Hydrogen through SMR is currently the cheapest form of hydrogen production and is widely used in industry. All three options are feasible production methods for hydrogen production for the distribution network. Hydrogen production through biomass/waste was not extensively regarded but is also feasible as a future hydrogen source for the distribution network.
There is a large variety of different forms of hydrogen storage technologies. The technologies still differ greatly in TRL, energetic efficiency, gravimetric energy density, volumetric energy density and cost-efficiency. Compressed hydrogen in cylinders is a mature storage technique, however it is paired with high costs which make it unattractive at larger volumes. Compressed hydrogen in salt caverns has existed for a long time and is a proven technology. It is also the cheapest form of hydrogen storage and is viable for the distribution network. There is however little experience with this technology in NL currently and more research is required for its implementation.
Hydrogen can be consumed by end-users through combustion or by reacting in a fuel cell. This report focuses on the combustion of hydrogen.

2. **What are the relevant stages to converting a natural gas distribution network to hydrogen?**

For the transition from natural gas three parties are required. The first party is the DSO which is responsible for reinforcing the electric network for electric cooking in SatH, and sectioning the gas network from NG to hydrogen during the transition. A second party will be responsible for switching current NG boilers to hydrogen boilers for the houses in SatH.
The transition to hydrogen could consist of the following three stages. The first stage is the transition from cooking with NG to electric cooking throughout SatH. The second stage is the inspection by the DSO to check if there are any apparent issues in the homes to be solved before the actual transition. The final step will be the transition itself, including sectioning and the installation of a new hydrogen boiler in the homes.
One of the identified constraints on the duration of the transition was the size of the workforce and collaboration between the second party reponsible for the boilers and Stedin. Other factors such as there being no prior experience will obviously contribute to the duration.

3. **Is Stad aan 't Haringvliet capable of successfully implementing hydrogen as an energy carrier?**

Local production of hydrogen through electrolysis at SatH has been identified to be an unfavorable scenario due to the scale of the proposed production and the resulting corresponding costs of production; however, calculations for capacity and costs were made for two scenarios with an AEL electrolyser.
Local seasonal storage is not a realistic option due to there being no possible hydrogen storage in salt caverns. In addition, current alternative hydrogen storage technologies are not suitable due to high costs.
A residential consumer is required to switch to cooking with electricity. Also, the boiler will have to be replaced with a new hydrogen boiler. Further testing will have to determine if current diaphragm meters are suitable for hydrogen. For a system comparison with all-electric heating, additional cost-effective insulation was included in the hydrogen scenario.
The hydrogen demand profile of SatH is predominantly determined by the temperature. A minimal demand of more than zero is due to hydrogen that would be used for warm water. The electric demand profile will have increased due to electric cooking.
A system comparison was with an all-electric scenario. The system comparison showed that converting a house to hydrogen would cost about €11,000 including cost effective insulation with annual costs of €1,540. This proves to be a more interesting option than the compared all-electric scenario with an initial investment of €50,000 with annual costs of €1,460. If the diaphragm meters prove to be hydrogen compatible, most meters will not have to be replaced. As a result, the costs will mostly have to be made in to the electric grid. The costs for these adjustments are estimated at roughly €140,000. Sectioning costs of the gas network are excluded.

4. **What can be said about the criteria that must be met by Stedin vs. the criteria that must be met by other parties to succesfully implement hydrogen as an energy carrier?**

A number of technical issues still have to be resolved, such as odorization, flame and leakage detection and meter compatability; however, no show-stoppers have been identified. The most important technical step to be realized is the realization of a hydrogen boiler. A hydrogen boiler is currently under development and the first demonstration of the boiler is expected beginning next year.
The main costs in a hydrogen scenario is the cost of hydrogen itself. Production prices vary greatly with production technology. In suitable areas, costs for consumers and a DSO can be significantly lower than for alternatives such as all-electric heating.
Ideal areas for the implementation of hydrogen are areas with houses that are very expensive to insulate and have no potential for a local heat network. The network of a potential area should also be able to be isolated from the surrounding NG network without creating any capacity issues in the hydrogen and NG network. This means that areas on the periphery of the existing NG network are more suitable. Networks that have very little or no CI or AC in the network have the preference to networks which do, due to the inherent risks of CI and AC. Also areas which are close to a potential hydrogen source have better chances to converting to hydrogen due to the fact that the network would not need realize any hydrogen production or storage of its own. Finally, businesses with large NG consumption might not be able to convert to hydrogen; therefore, areas with no large consumers or with consumers which could stay connected to a surrounding NG grid are preferred.

16 Recommendations

At this moment in time no show-stoppers have been identified for the distribution of hydrogen in the Dutch NG distribution network. There are however still several issues to be resolved and several subjects that require future testing or research. This chapter lists the recommendations for actions and future research.

16.1. Hydrogen Safety

A suitable odorant for hydrogen still has to be determined so that the gas can be detected by people without specialized equipment, increasing safety. Odorants are being developed which show no poisoning to fuel cells and these developments could be followed closely. Also, it is still unclear how long traces of sulfur or other fuel cell poisoning substances will remain in an existing distribution network. Stedin could research how long fuel cell poisoning substances will remain in old networks before they drop below acceptable levels for future fuel cell application.
The lack of visibility of a hydrogen flame still creates safety concerns for maintenance. Risk in these situations could however be reduced by implementing hydrogen flame detection equipment. MSIR detection currently seems the most promising technology in regard to the tasks maintenance crews complete (e.g. welding) but Stedin could investigate if this is indeed the case. Current leak detection methods sensors might be able to detect a hydrogen leak; however, these sensors can most likely not measure a hydrogen concentration accurately enough. Therefore, the supplier of the leakage detection equipment could be approached to check if the current equipment is qualified.

16.2. Converting Network

Sectioning a gas network and converting it to hydrogen requires several steps. First,all equipment currently used for sectioning (bladders, saddels, etc.) should be checked if they also function for hydrogen gas. In early transitions it is advised to first remove NG from the network with nitrogen and later remove the nitrogen with hydrogen gas. Ideally the nitrogen gas would not be required and the NG would be removed from the pipe by hydrogen gas directly. It should however first be tested if the hydrogen and NG mix sufficiently for the NG to be vented out. In addition, when removing the NG from the home networks it should be tested if hydrogen boilers can withstand small amounts of NG until the hydrogen reaches the boiler.
Stedin is currently installing smart ultrasonic meters throughout its operating area. Ultrasonic technology is capable of measuring hydrogen flow precisely; however, the current ultrasonic meters being installed are not calibrated for the higher speed of sound characteristics of hydrogen. Manufacturers of the product could be approached to see if the product could be altered in such a way that it could be considered 'hydrogen ready'.
In most cases the capacity of a diaphragm meter is capable of metering new flow rate of hydrogen gas accurately; however, it is not yet clear if current diaphragm meters are hydrogen compatible. Stedin could look into the compatibility of existing diaphragm meters for hydrogen.

Implementing hydrogen instead of NG would mean that a nearly three times as high volumetric flow rates would be needed to ensure an equal energy flow through the network. There are guidelines that indicate the the flow velocity through the network should not surpass determined levels throughout the network. These flow rates will be surpassed if hydrogen is implemented and Stedin could research if there are any noise issues as a result of a faster hydrogen velocity.

16.3. Collaboration with Other Parties

In NL there are currently only guidelines for indoor gas piping. The transition to hydrogen seems to be a strategic moment and Stedin could request to change these guidelines into regulations. These regulations could help reduce any risks inherent to hydrogen due to the lower ignition energy.
Large consumers only comprise a small fraction of Stedin's gas connections but they are also responsible for a significant part of the gas consumption. This is why Stedin could look into the gas consumption of its large consumers. Understanding their use and demand characteristics could create a better understanding if hydrogen could also be a viable energy carrier for a significant part of the energy demand.
The recent ambition of the Dutch government is to reduce the G-gas demand by finding an alternative for the 100 largest NG consumers. Stedin could research if connecting some of these consumers to a hydrogen network is viable and more cost effective than installing a special H-gas network, which is not a permanent solution.
A close collaboration between TSO and DSO seems advisable regarding the future prospects of large scale hydrogen storage. Implementing hydrogen storage will greatly improve the 'green potential' of hydrogen by enabling seasonal storage and higher production capacity of electrolyser technologies would bring down the LCOH considerably. In addition, the large scale production of hydrogen should most likely be introduced into the transport level of a gas grid rather than distribution level. The transportation of hydrogen over a future hydrogen 'roundabout' will require large scale production and also the expertise of the TSO further favoring a close collaboration.

16.4. Errata

A promising technology which could have large implications for the electric and gas grid is fuel cells. The implementation of residential combined heat and power plants (at house level of street level) could be researched to more completely understand the future potential of hydrogen gas.

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A

Hydrogen Demand Data

The demand of SatH has been approached as an approximation, based on the historical temperature data and the size of the gas meters connected to the specific grid. It is unfortunately not possible to determine actual smart meter data. The reason for this is twofold; first, the stored data does not go back far enough to be of any value for this research. second, the data is not easily accessed due to strict privacy regulations. The average Demand profile of SatH was determined using a program called IRENE PRO in combination with KNMI temperature data.

A.1. Irene and KNMI data

Figure A.1 gives the hydrogen 'Stoke curve' of SatH for the determined isolated area. The figure shows the approximated amount of hydrogen the town consumes if hydrogen would be used in all the same manners as NG is (heating and cooking). One can note that the consumption does not decrease further when the temperature is 18 °C or higher, this is due to the consumption of gas for functions such as warm water or cooking. This method of approximating consumption is only relevant on a larger time scale such as years or months. This is because the method only considers temperature and not the consumption behavior of consumers. Furthermore, large consumers such as certain businesses may use a lot of gas, but their gas consumption is not dependent on ambient temperature. Irene determines the gas meter size of large consumers in the selected area and estimates their usage on a constant 70% of the meters maximum capacity, regardless of temperature. The consumption of homes is also based on meter size but these values are temperature dependent, unlike large consumers.
When determining the demand of SatH, Irene and KNMI data was brought together and used to determine demand of the town. An other method would have been to determine the consumption of the primary and secondary gas connections, this data is also available within Stedin. This data gives a more accurate view of what the typical consumption is of SatH in a year but it does not indicate how the consumption varies throughout the year. When designing a gas network, the consumption of the primary and secondary gas connections should be kept in mind; however, Irene is the designated program when designing a network for a certain capacity.

Figure A.3 shows the hydrogen usage pattern of SatH based on temperature and Irene. The temperature data has been used from the KNMI website [109].

The temperature data used for SatH was from the weather station situated in Hoek van Holland, 28 km away from SatH (figure A.2). This station was chosen for 2 reasons. First, the weather station was the station nearest to SatH together with the station in Rotterdam. Second, just as SatH, the station of Hoek van Holland was close to the coast and inland waters, which have a considerable influence on air temperatures. The weather station in Geulhaven and Wilhelminadorp did not collect temperature data. Otherwise it would have been interesting to take the temperature of Geulhaven or the mean of Geulhaven and Hoek van Holland. Wilhelminadorp also has a comparable location on the map to SatH, due to it also being surrounded by inland waters and being close to the coast but unfortunately this station did not collect sufficient temperature data.
Figure A.3 has 8760 data points which all indicate the consumption of hydrogen on an hourly basis. The figure shows an average consumption of hydrogen gas from 2007 to 2017 (2,581,000 Nm^3 H_2/year). The hydrogen consumption is hypothetical and approximated by Irene and is in essence equal to three times the

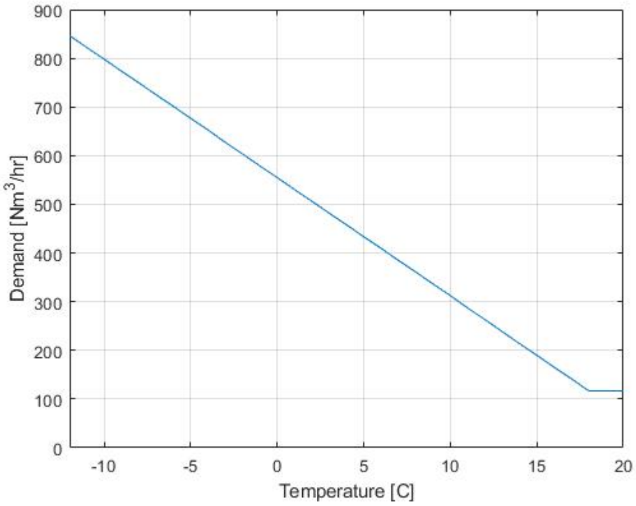

Figure A.1: Hydrogen stoke curve of SatH produced by Irene

consumption of NG. This is due to the HHV of hydrogen being three times lower than that of NG as mentioned in subsection 3.2.4. Figure A.4 gives the same daily usage determined by Irene but for the year 2010. The graph shows more clearly that there is a minimum base demand for warm water and it shows the highest peak demand since 2007 (763 Nm^3/hr).

Figure A.5 shows the cumulative usage of SatH since 2007. Figure A.5 is based on 8760 data points, just as in figure A.3. Figure A.5 shows that the year 2010 was a considerably ’cold’ year. 2010 was also the year with the lowest ’etmaal’ temperature since 2007 with a temperature of -6 °C. This means that -6 °C was the maximum temperature in a period of 24 hours. As mentioned, the location of an area has a large influence on the air temperature. Area’s near the coast or large bodies of water have more moderated temperatures whilst area’s inlands have more extreme summers and winters. Area’s at the coast will therefore have higher minimal ’etmaal’ temperatures requiring a smaller peak demand than area’s situated more land inwards.

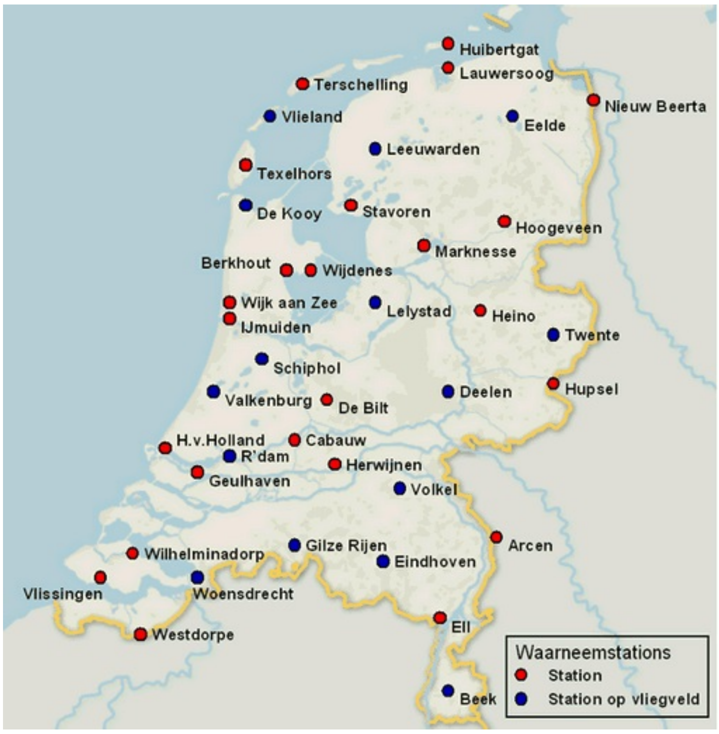

Figure A.2: Map of all KNMI weather stations in NL

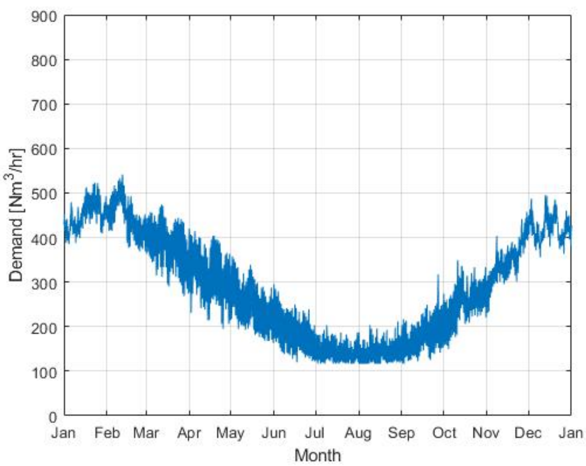

Figure A.3: Average usage on hourly basis since 2007

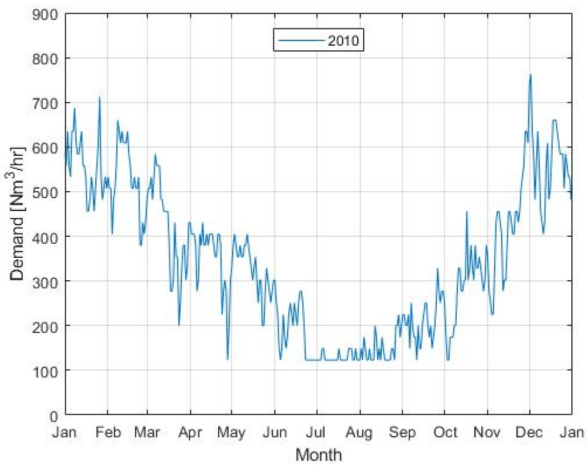

Figure A.4: Demand on daily median basis for several different years

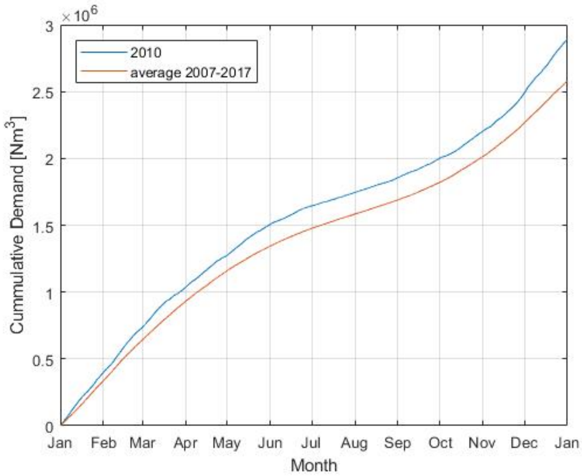

Figure A.5: Average cumulative usage since 2007 vs. 2010's cumulative usage, on hourly basis

B

Electrolyser and Storage Calculations

B.1. Electrolyser

The first necessary decision when choosing an electrolyser technology is determining the task. In the situation of this case study, the electrolyser would not be required to vary production to realize frequency containment in the electric grid. An AEL can be implemented instead of a PEM electrolyser due to the fact that together with power electronics, AELs are capable of following the variation of renewable sources such as wind. If frequency control of the electric grid is desired, AEL will not be able to vary demand fast enough. The efficiency chosen for the AEL was the expected efficiency in 2025 of 79% [33].

B.2. LCoH

The LCoH is used to calculate what hydrogen would cost if the town of SatH were to be isolated from a national grid and produce hydrogen from the electric grid. Two scenarios will be worked out in this section; a scenario with only an electrolyser and a scenario with an electrolyser with seasonal storage.
In the scenario with only an electrolyser (scenario 1), the electrolyser is capable of producing the peak demand of SatH of -12 °C (847Nm^3/hr). Because an AEL electrolyser is capable of varying its production fast enough for renewable sources, no storage is needed. The electrolyser will be switched on year round, but will vary its production according to demand. To be able to produce the peak demand a rated capacity of 3.9 MW is necessary.
The scenario with storage (scenario 2) has a lower production capacity because the system can deliver hydrogen from the electrolyser and storage. For this scenario the electrolyser produces at a base load of 1.6 MW throughout the year. With this production profile a seasonal storage of 447,000 Nm^3 is required. What can be seen in table B.3 is that compressed storage is extremely expensive if utilized on this scale.
Table B.1 shows the values used to calculate the LCoH for the two scenarios. Tables B.2 and B.3 indicate the capex and opex of scenario 1 and 2 respectively. Equation B.1 was used to calculate the CRF and equation B.2 was used to calculate the LCoH.
The chosen lifetime of the loan for the system was 20 years. O&M costs of the system were chosen as 3% [33] of the capital costs of the elctrolyser. Accurate O&M of compressed storage proved to be difficult to find. The LCoH for scenario 1 and 2 were 4.75 €/kg H_2 and 8.66 €/kg H_2 respectively. Both the LOCH of scenario 1 and 2 are considerably higher than the expected commodity price of hydrogen in 2025.

$$CRF = \frac{(1+r)^n r}{(1+r)^n - 1} \cdot n \tag{B.1}$$

$$€/kg\,H_2 = \frac{Capex_{CRF} + n \cdot (C_{M\&O} + C_{Feed\,water} + C_{Replacement} + C_{Electricity})}{n \cdot Produced\,Hydrogen} \tag{B.2}$$

Table B.1: Values used for calculating the LCoH

Lifetime [33]	20	[Yr]
Efficiency [33] [110]	79	[%]
Process water : Hydrogen [33]	15	[kg : kg]
Process water cost [111]	3	[€/ ton]
Interest rate [112]	3	[%]
CRF 20 year	1.34	[-]
Electricity price [8]	0.07	[€/ kWh]
Produced hydrogen	233,291	[kg / Yr]

Table B.2: Costs regarding 'electrolyser only' scenario

Electrolyser	2,340,000	[€]
$\text{Electrolyser}_{CRF}$	3,135,600	[€]
O&M costs	70,200	[€/yr]
Feed water costs	10,498	[€/yr]
Replacement costs [33]	55,380	[€/yr]
Electricity costs	816,518	[€/yr]
Max.capacity	860	[Nm^3/hr]

Table B.3: Costs regarding 'electrolyser and seasonal storage' scenario

Electrolyser	960,000	[€]
Storage	16,080,000	[€]
$(\text{Electrolyser \& Storage})_{CRF}$	22,832,443	[€]
M&O costs	28,800	[€/yr]
Feed water costs	10,498	[€/yr]
Replacement costs [33]	22,720	[€/yr]
Electricity costs	816,518	[€/yr]
Capacity	345	[Nm^3/hr]

C
All-electric and Hydrogen Costs

All-electric

housing type	# of houses in SatH	new constructions	Boomgaarddreef and part of molendijk	scope # of houses	insulation costs	costs low temp. Heating system	costs heat pump	costs electric boiler	costs oven and stove	new kitchen fuse + line to kitchen	connection adjustment weighted average	3 fase cable weighted average	consumer investment costs	Consumer investment * # of houses	new kWh/year	(kWh/year) * # of houses
1	49		5	44	€ 85.244,50	€ 3.000,00	€ 17.908,00	€ 326,00	€ 1.181,00	€ 200,00	€ 228,45	€ 960,00	€ 109.047,95	€ 4.798.109,71	5.102	224.495
2	141		14	127	€ 44.686,51	€ 2.000,00	€ 10.445,93	€ 326,00	€ 1.181,00	€ 200,00	€ 228,45	€ 960,00	€ 60.027,89	€ 7.623.541,78	3.092	392.711
3	22		4	18	€ 53.860,73	€ 3.000,00	€ 14.922,93	€ 326,00	€ 1.181,00	€ 200,00	€ 228,45	€ 960,00	€ 74.679,11	€ 1.344.223,94	4.793	86.273
4	17		8	9	€ 42.455,27	€ 2.500,00	€ 13.431,00	€ 326,00	€ 1.181,00	€ 200,00	€ 228,45	€ 960,00	€ 61.281,72	€ 551.535,46	4.051	36.457
5	20		3	17	€ 32.702,67	€ 2.000,00	€ 10.445,93	€ 326,00	€ 1.181,00	€ 200,00	€ 228,45	€ 960,00	€ 48.044,05	€ 816.748,82	3.092	52.568
6	118			118	€ 21.332,30	€ 1.500,00	€ 10.445,93	€ 326,00	€ 1.181,00	€ 200,00	€ 228,45	€ 960,00	€ 36.173,68	€ 4.268.494,00	6.226	734.703
7	60			60	€ 23.960,42	€ 1.500,00	€ 10.445,93	€ 326,00	€ 1.181,00	€ 200,00	€ 228,45	€ 960,00	€ 38.801,80	€ 2.328.107,88	4.732	283.935
8	10		1	9	€ 57.257,20	€ 3.000,00	€ 14.922,93	€ 326,00	€ 1.181,00	€ 200,00	€ 228,45	€ 960,00	€ 78.075,58	€ 702.680,20	4.430	39.866
9	9		1	8	€ 32.702,67	€ 2.000,00	€ 10.445,93	€ 326,00	€ 1.181,00	€ 200,00	€ 228,45	€ 960,00	€ 48.044,05	€ 384.352,38	3.092	24.738
10	16	18		34	€ 19.946,85	€ 1.500,00	€ 8.954,00	€ 326,00	€ 1.181,00	€ 200,00	€ 228,45	€ 960,00	€ 33.296,30	€ 1.132.074,13	6.442	219.022
11	6	25		31	€ 18.658,20	€ 1.500,00	€ 8.954,00	€ 326,00	€ 1.181,00	€ 200,00	€ 228,45	€ 960,00	€ 32.007,65	€ 992.237,09	6.210	192.516
12	11	1	4	8	€ 6.655,00	€ 3.000,00	€ 13.431,00	€ 326,00	€ 1.181,00	€ 200,00	€ 228,45	€ 960,00	€ 25.981,45	€ 207.851,58	4.422	35.375
13	20			20	€ 18.857,85	€ 1.000,00	€ 8.954,00	€ 326,00	€ 1.181,00	€ 200,00	€ 228,45	€ 960,00	€ 31.707,30	€ 634.145,96	3.754	75.076
14	11	8		19	€ 3.327,50	€ 1.500,00	€ 8.954,00	€ 326,00	€ 1.181,00	€ 200,00	€ 228,45	€ 960,00	€ 16.676,95	€ 316.862,01	4.935	93.771
				522							0,8*€285,00	0,6*€1600	Total	€ 26.100.965	Total	2.491.506
													WA	**€ 50.002**	WA	**4.773** kWh/year elec.
															+	3.525 kWh/year elec.
																8.298 kWh/year total.

Hydrogen

Housing Type	costs oven and stove	new kitchen fuse + line to kitchen	hydrogen boiler	connection adjustment weighted average	3 fase cable weighted average	Insulation costs	Insulation investment * # of houses	new kWh/year	(kWh/year) * # of houses
1	€ 1.181,00	€ 200,00	€ 1.500,00	€ 228,45	€ 960,00	€ 3.630,00	€ 159.720,00	18.501	814.047
2	€ 1.181,00	€ 200,00	€ 1.500,00	€ 228,45	€ 960,00	€ 11.236,00	€ 1.426.972,00	13.382	1.699.536
3	€ 1.181,00	€ 200,00	€ 1.500,00	€ 228,45	€ 960,00	€ 8.856,00	€ 159.408,00	19.571	352.283
4	€ 1.181,00	€ 200,00	€ 1.500,00	€ 228,45	€ 960,00	€ 6.606,00	€ 59.454,00	14.338	129.042
5	€ 1.181,00	€ 200,00	€ 1.500,00	€ 228,45	€ 960,00	€ 5.553,00	€ 94.401,00	12.490	212.330
6	€ 1.181,00	€ 200,00	€ 1.500,00	€ 228,45	€ 960,00	€ 5.683,00	€ 670.594,00	6.543	772.127
7	€ 1.181,00	€ 200,00	€ 1.500,00	€ 228,45	€ 960,00	€ 6.073,00	€ 364.380,00	5.681	340.831
8	€ 1.181,00	€ 200,00	€ 1.500,00	€ 228,45	€ 960,00	€ 7.404,00	€ 66.636,00	17.436	156.920
9	€ 1.181,00	€ 200,00	€ 1.500,00	€ 228,45	€ 960,00	€ 5.553,00	€ 44.424,00	12.490	99.920
10	€ 1.181,00	€ 200,00	€ 1.500,00	€ 228,45	€ 960,00	€ 7.471,00	€ 254.014,00	7.449	253.255
11	€ 1.181,00	€ 200,00	€ 1.500,00	€ 228,45	€ 960,00	€ 6.182,00	€ 191.642,00	6.476	200.751
12	€ 1.181,00	€ 200,00	€ 1.500,00	€ 228,45	€ 960,00	€ 0,00	€ 0,00	4.422	35.376
13	€ 1.181,00	€ 200,00	€ 1.500,00	€ 228,45	€ 960,00	€ 6.212,00	€ 124.240,00	5.305	106.093
14	€ 1.181,00	€ 200,00	€ 1.500,00	€ 228,45	€ 960,00	€ 0,00	€ 0,00	4.935	93.765
						Total	€ 3.615.885,00	Total	5.266.275
						WA	€ 6.926,98	WA	10.089 kWh/year H2
						+	€ 4.069,45	+	3.525 kWh/year elec.
							€ 10.996,43		**13.614** kWh/year total

D
Conversion Table

H_2 **Conversion Table**	
1 kg = 11.12 Nm^3	1 kg = 39.41 kWh
1 Nm^3 = 3.54 kWh	1 Nm^3 = 0.09 kg
1 kWh = 0.28 Nm^3	1 kWh = 0.03 kg