university of groningen

faculty of economics and business

Outlook for a Dutch hydrogen market

economic conditions and scenarios

Machiel Mulder, Peter Perey and José L. Moraga

Centre for Energy Economics Research (CEER)

Policy Papers | No. 5 | March 2019

Outlook for a Dutch hydrogen market

economic conditions and scenarios

Machiel Mulder, Peter Perey and José L. Moraga

CEER - Policy Papers | no. 5 | March 2019

Mulder, M., P.L. Perey and J.L. Moraga
Outlook for a Dutch hydrogen market: economic conditions and scenarios, Centre for Energy Economics Research, CEER Policy Papers 5 – University of Groningen, The Netherlands – March 2019

Keywords:
hydrogen, climate policy, scenarios, market design

The research for this policy paper has been conducted on request by and with financial support from GasTerra, a Dutch wholesaler in natural gas and green gas. The full responsibility of the content of this policy paper lies solely with the authors. The report does not necessarily reflect the opinion of GasTerra.

@Mulder, Perey & Moraga
ISBN: 978-94-034-1567-3 (print)
ISBN: 978-94-034-1566-6 (pdf)

Centre for Energy Economics Research; http://www.rug.nl/ceer/ Department of Economics and Business, University of Groningen; http://www.rug.nl/feb/ Nettelbosje 2, 9747 AE Groningen

Contents

1. Introduction

1.1 Background

In comparison to the energy market, the market for hydrogen in Europe is still small.[1] Up to now, hydrogen is mainly used as feedstock in the chemical industry, for the production of ammonia and methanol in the refining industry, where it is used to crack heavier crudes and produce lighter crudes, and in the metal industry for the production of iron and steel. In the future, however, the market for hydrogen may grow strongly. In fact, hydrogen is increasingly seen as a potential energy carrier to provide high-temperature process heat, to heat buildings and produce electricity while it is also expected that it can become a major fuel in transport (Certifhy, 2016; CE Delft, 2018; Hydrogen Council, 2017; IEA, 2017; Waterstof Coalitie, 2018; Irena, 2018; WEC, 2018). In addition, hydrogen may play a role to help the electricity sector to deal with the increasing shares of renewable power by offering flexibility regarding the timing and location of production (Van Leeuwen & Mulder, 2018).

Hydrogen does not exist in a pure form in nature and has, therefore, to be produced. Currently, the most common method to produce hydrogen is the so-called Steam Methane Reforming (SMR), a process by which hydrogen is produced from natural gas (CH_4). Hydrogen can also be produced through electrolysis of water (H_2O). Hydrogen produced through electrolysis can act as a bridge between the electricity system and the gas system, for instance by acting as a source of demand flexibility in the electricity market.

[1] The total consumption of hydrogen is equal to about 1.3% of the total consumption of energy (see Appendix A).

The potential of hydrogen as a key energy carrier has been analysed extensively from a technical-economic perspective (see e.g. Götz, et al., 2016; Cardella et al., 2017). Most of that research focusses on the technical feasibility and the production costs at the plant level.[2] Less attention has been paid, however, to the design of markets for hydrogen.[3] It is not evident that a well-functioning market of hydrogen will develop automatically, even if the production is technically feasible and the overall societal benefits exceed the overall societal costs.

The development of the hydrogen market may be hampered by so-called market failures. Market failures are fundamental shortcomings in a market design which prevent that the market results in optimal outcomes. Examples of such shortcomings are the existence of significant economies of scale, network externalities, information asymmetry and market power. For each type of market failure, solutions can be put forward. Such solutions can be implemented by the market parties themselves and/or a regulator. Therefore, an analysis of the existence of such shortcomings is required in order to determine to what extent the market for hydrogen is able to develop automatically or to what extent regulatory intervention is required.

1.2 Research questions and method of research

The questions addressed in this report are: Which economic factors drive the outlook for a hydrogen market in the Netherlands? To what extent will the market for hydrogen move in the direction of a liquid market if there is sufficient potential demand and supply? Is there any need for specific intervention by market parties or public authorities?

---

[2] For an overview, see for instance: TKI Nieuw Gas, Contouren van een Routekaart Waterstof, March 2018.

[3] A research report discussing technical, economic as well as policy aspects of hydrogen is IRENA (2018).

We start answering these questions by exploring the economic conditions behind the production, transportation and storage of hydrogen. Based on information on the economics of hydrogen in literature, we calculate the required hydrogen prices for various types of production to be profitable. In addition, we determine the investment costs for various types of transportation as well as storage.

Using the results from this explorative analysis, we formulate a number of scenarios regarding the outlook of the hydrogen market. This scenario development is based on the primary economic drivers behind the competitiveness of hydrogen, which are the tightness of the international natural-gas market and the stringency of the international climate policy. These factors strongly affect the electricity price and, hence, the competitive position of hydrogen produced through electrolysis vis-à-vis hydrogen produced through SMR.

Having explored the potential outlook of hydrogen consumption and supply, we analyse the extent to which the market for hydrogen will develop automatically and if sector-specific regulation is required. Using the micro-economic framework, we analyse for each component of the hydrogen supply chain whether there are specific market failures hindering its development and if so, which regulatory solutions can be put forward to address these market failures.

1.3 Outline of paper

The structure of this report is as follows. In Section 2, we explore the economic conditions behind the production, transportation and storage of hydrogen. In Section 3, we develop the scenarios for the hydrogen market in the Netherlands, while in Section 4 we analyse the need for sector-specific regulation. In Section 5 we present our conclusions.

2. Supply of hydrogen

2.1 Introduction

The potential supply of hydrogen depends on the economic conditions for the various stages of making, transporting and storing hydrogen. In Section 2.2, we explore the economic factors that drive the outlook of various ways of producing hydrogen, in Section 2.3 the various manners of transporting hydrogen and in Section 2.4 the various ways of storing hydrogen. In Section 2.5 we explore the consequences of an alternative design of the supply of hydrogen.

2.2 Economics of production

2.2.1 Types of production

Hydrogen does not exist in pure form in nature and has, therefore, to be produced.[4] Currently, the most commonly used method to make hydrogen is Steam Methane Reforming (SMR). By letting steam (H_2O) under high temperature react with methane coming from natural gas (CH_4), hydrogen (H_2) can be produced next to carbon monoxide (CO) or carbon dioxide (CO_2).[5] An alternative method is electrolysis in which electricity is used to split water (H_2O) into hydrogen (H_2) and oxygen (O_2).[6]

Both production techniques use different types of energy (i.e. gas in case of SMR and electricity in case of electrolysis). SMR typically uses natural gas but, technically speaking, one could also use bio-methane, which is gas (CH_4) produced either from the anaerobic digestion of wet

[4] Hence, hydrogen is a secondary energy carrier just as electricity.
[5] Hence, the chemical process is: CH4 + H2O -> CO + 3 H2. Carbon dioxide (CO_2) is produced when the carbon monoxide (CO) reacts in an additional water-gas shift reaction: $CO + H_2O \rightarrow CO_2 + H_2$.
[6] The chemical process: 2H2O -> 2H2 + O2.

organic residual materials or from the thermal gasification of dry organic residues. Electrolysis uses power, which can be generated in various ways. When the electricity is generated through renewable sources, like wind turbines or solar panels, the hydrogen is made in a pure renewable way and it is therefore called 'green'. Because often users cannot distinguish electricity generated by a renewable source from electricity generated by other (non-renewable) sources as all sources are generally connected to the same grid, a system of guarantees-of-origin (or certificates) has been implemented in Europe as a tracking-and-tracing system. Users of electricity (including electrolysis plants) generally need these certificates in order to be able to prove that electricity from renewable sources is used.

In addition, the carbon emissions associated to the production of hydrogen can be treated in different ways. If the carbon emitted in the SMR process is not captured and stored, the hydrogen is called 'grey'. Grey hydrogen has been produced for many years in the Netherlands and is currently the only type of hydrogen being produced in large quantities. If the carbon is removed and stored, the hydrogen is called 'blue'. This technique is increasingly considered as an option to produce hydrogen without carbon emissions. If bio-methane is used as input in SMR, then there would be no net carbon emissions while with carbon capture even negative emissions would occur.

Hydrogen made through electrolysis does not have direct carbon emissions but the electricity which is used may be generated by fossil-fuel power plants which indirectly results in carbon emissions. Note, though, that both SMR plants and electricity plants do participate in the European Emissions Trading Scheme (ETS) by law, which means that a change in the level of emissions by one of these plants is fully offset by the responses of other participating firms. These responses are triggered by changes in the price of carbon resulting from changes in emissions by one firm or industry. Because the overall level of carbon emissions with the ETS industries is completely determined by the emissions cap of the ETS, it does not matter for the carbon emissions which type of electricity is used for making hydrogen. Based on the above, we define 3 types of SMR as well as 3 types of electrolysis (see Table 2.1).

Table 2.1 Types of hydrogen

Name	**Production technique**	**Type of energy used**	**Treatment of CO2**
SMR-grey	Steam Methane Reforming	natural gas	emitted
SMR-blue	Steam Methane Reforming	natural gas	captured and stored (CCS)
SMR-green	Steam Methane Reforming	green gas	(no net emissions)
electrolysis-grey	electrolysis	electricity	(outside of scope of electrolyser)
electrolysis-green	electrolysis	electricity from renewable sources	(outside of scope of electrolyser)
electrolysis-orange	electrolysis	electricity from renewable sources in the Netherlands	(outside of scope of electrolyser)

2.2.2 Method, data and assumptions

In order to assess the economic outlook for the various ways of producing hydrogen, we calculate the minimum price of hydrogen necessary for the various technologies to be profitable. This required price is the financial compensation needed to cover both fixed and variable costs over the lifetime of the hydrogen plants. The fixed costs can be related to the required hydrogen price by making assumptions on the investment costs per unit of capacity, the number of hydrogen units produced with one unit of capacity and the lifespan of a plant. The data and assumptions used for both SMR plants and electrolysis plants are given in Tables 2.2 and 2.3. Note that for the electrolysers, we assume almost continuous production (8000 operating hours per year), which is only possible if the plants are just connected to the electricity grid and not operated based on available power generated by for instance a wind turbine. In the latter case, the number of operating hours would be much lower, and correspondingly the efficiency. In Section 2.5 we will reflect on another type of use of hydrogen plants that results in a lower utilisation and therefore efficiency.

Table 2.2 Assumptions on the costs of producing hydrogen through SMR, per type

	Assumption per type of SMR			
Variable	**Grey**	**Blue**	**Green**	**Source**
investment costs in SMR of 323 MW (mln. €)	307	307	307	Collodi et al. (2017)
total production during lifetime (mln. kg.)	1850	1850	1850	Collodi et al. (2017)
investment costs in CCS (mln. €)	0	54	0	CBS
gas needed per kg H_2 (MWh)	0.04	0.05	0.04	Collodi et al.. (2017)
gas price (€/MWh)	20	20	20	CBS
CO2 emission per kg H2 (kg)	9.01	4.12	0.00	Collodi et al. (2017)
CO2 captured (kg)	0.00	5.18*	0.00	Collodi et al.. (2017)
CO2 allowance costs (€/ton CO2)	15	15	15	EEX
cost of CO2 transport and storage per kg (€)	0.00	0.05	0.00	Collodi et al. (2017)
premium green gas (€/MWh)	0.00	0.00	8.19	Gasunie

Note: * For SMR-blue, we assume an efficiency of the capturing the CO2 of 55% (total emissions are 9.3 kg and 5.18 is captured and stored). Higher efficiencies are possible, but this would result in higher costs as well. At a 55% capturing rate, the costs are minimized according to Collodi et al. (2017).

Table 2.3 Assumptions on the costs of producing hydrogen through electrolysis, per type

Assumptions	Value	Source
input capacity (MW)	20	Chardonnet et al. (2017)
operating hours/year	8000	idem
discount rate	5%	
production (mln. kg/y)	43	
CAPEX (mln. €)	15	idem
annual operation and maintenance costs (mln. €)	0.3	idem
stack replacement after 10 years (mln. €)	4.15	idem
fixed costs electrolyser (€/kg)	0.54	idem
efficiency electrolyser	72%	
water costs (€/kg)	0.01	Waterbedrijf Groningen
electricity use (MWh/kg)	0.05	Chardonnet et al. (2017)
electricity price (€/MWh)	47	CBS
premium Dutch green electricity (€/MWh)	5	Hulshof et al. (2019)
premium green electricity (€/MWh)	2	idem

2.2.3 Results

Figure 2.1 shows how the required hydrogen price for the various types of hydrogen production through SMR depends on the natural-gas price, while Figure 2.2 shows how the required hydrogen price for the various types of electrolysis relates to the price of electricity.

If the natural-gas price is 20 euro/MWh, which is about the average price over the past years, SMR-grey needs at least a hydrogen price of about 1.50 euro/kg to be profitable.[7] If the carbon emissions are captured and stored (SMR-blue), the required price increases to about 1.60

[7] This is a bit lower than what was found by Dillich et al. (2012), who estimated the cost of hydrogen production between 1.74$/kg and 2.03$/kg.

euro/kg, while for SMR-green the required price would be about 1.80 euro/kg. Note that the required price for SMR-blue increases more when the natural-gas price increases than SMR-grey (i.e. the line is a bit steeper), because of the additional gas demand resulting from carbon capture.

The required hydrogen price for electrolysis plants is a linearly increasing function of the electricity price. If the (average annual) electricity price is 40 euro/MWh, electrolysis plants need the hydrogen price to be at least 2.50 euro/kg. If the hydrogen must be produced with electricity generated with renewable sources, the required hydrogen price increases with 0.10 euro/kg, as green certificates have to be bought. If, in addition, the renewable sources must be located in the Netherlands, the required hydrogen price is 0.25 euro/kg higher, as green certificates related to Dutch renewable power generation are more expensive (because of the tight market conditions) than general green certificates (Hulshof et al., 2019).

Figure 2.1 Required hydrogen price for SMR in relation to natural gas price, per type

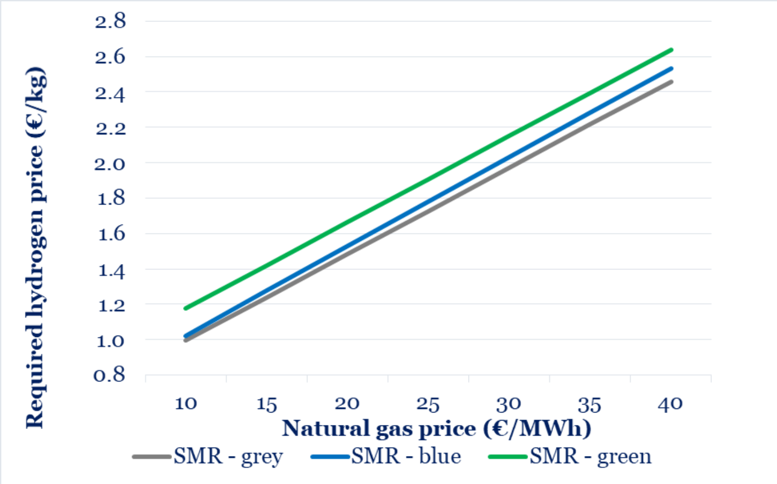
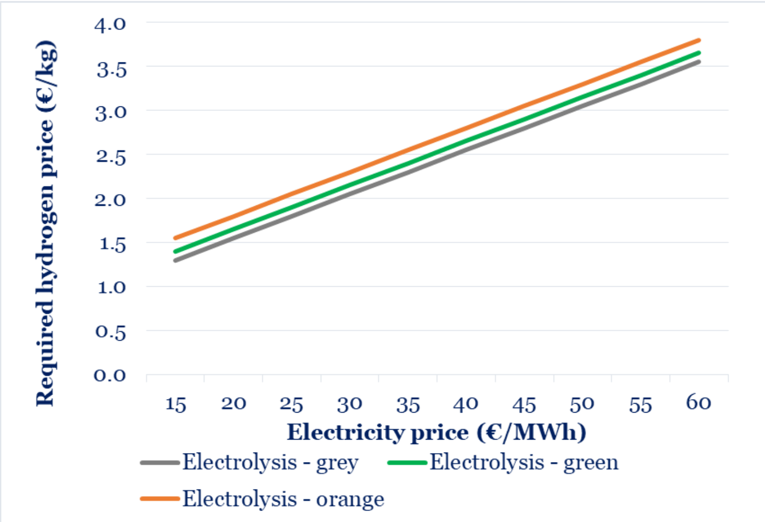


Figure 2.2 Required hydrogen price for electrolysis in relation to electricity price, per type

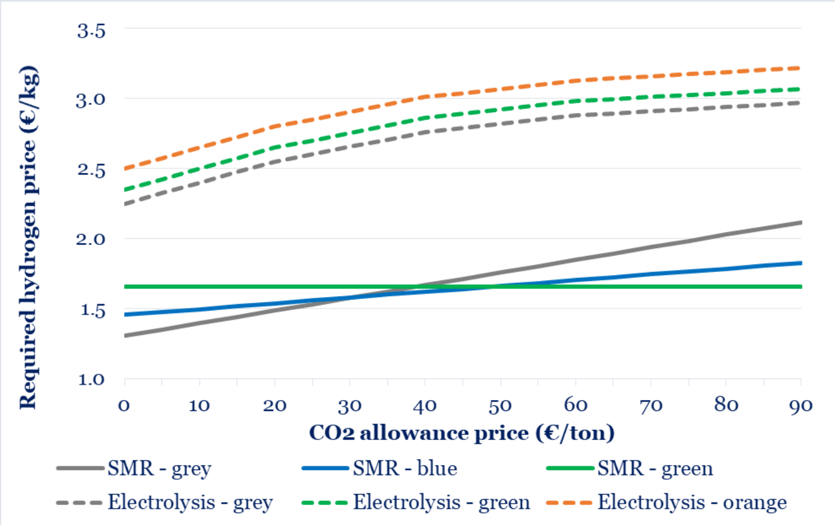


In the above calculations we have assumed a CO_2 price of 15 euro/ton, which is about the average price over the past year. Recently, this price has risen sharply, so it makes sense to analyse the sensitivity of the above results to the price of CO_2. Figure 2.3 depicts the impact of the price of CO_2 on the required hydrogen price per type of technology. In particular, SMR-grey is affected by the price of CO_2, as in this technique all carbon is emitted. Although the carbon is captured and stored in SMR-blue, there are still some emissions during the process of storing, which means that the price of CO_2 also affects the required hydrogen price of this technique, albeit to a smaller extent.[8] The break-even price of CO_2 is about 30 euro/ton. At higher carbon prices, SMR-blue is more competitive than SMR-grey.

The CO_2 price also affects the required hydrogen price for electrolysis, even if the electricity is produced through renewable sources. After all, the electricity price is set by the marginal power plant, which is most of the time, at least in the Dutch power market, a gas-fired power plant. One may, however, assume that a higher CO_2 price coincides with higher shares of renewables and, as a result, less hours in which these plants are the price-setting plants. Hence, when the CO_2 price increases, the impact on the electricity price reduces, as is shown by Figure 2.3. Nevertheless, we find that the CO_2 price has an upward effect on the required hydrogen price of electrolysis.

[8] Note that the amount of remaining emissions in case of SMR-blue strongly depends on the technology used. In our calculations, we assumed a capture rate of 55%. Higher rates are possible, but that would require more expensive technologies.

Figure 2.3 Required hydrogen price in relation to price of CO_2 allowances, per type of technique



Note: for the assumptions on the price of natural gas and electricity, see Tables 2.1 and 2.2.

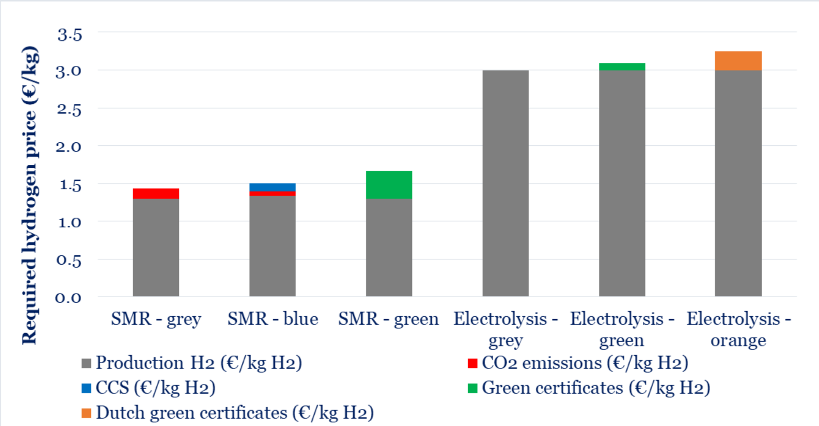
From Figure 2.3, it follows that electrolysis requires a much higher hydrogen price than SMR. This is mainly due to the high production costs as is shown in Figure 2.4.[9] Taking all costs into account and given the assumptions made (see Tables 2.1 and 2.2), we find that SMR-grey can operate with the lowest hydrogen price. The required price of electrolysis plants is about twice as high.

As the competitive position of SMR versus electrolysis is mainly determined by the relative prices of natural gas and electricity, we also calculate the break-even price ratios (see Figure 2.5). If the CO_2 price were 10 euro/ton and the natural-gas price were at the average level of the past

[9] The production costs mainly consist of the variable input costs (electricity and natural gas, respectively) and to a lesser extent capital costs.

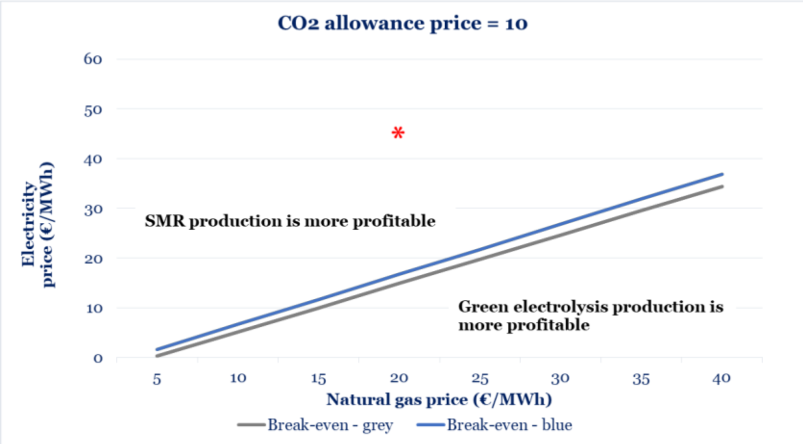
decade (20 euro/MWh), the price of electricity should be below 17 euro/MWh in order to make electrolysis based on green electricity more competitive than SMR-blue. If the CO_2 price were 40 euro/ton, electrolysis would still be profitable for a slightly higher electricity price (20 euro/MWh). This price is, however, much lower than the past and current electricity prices as we will see in Section 3.

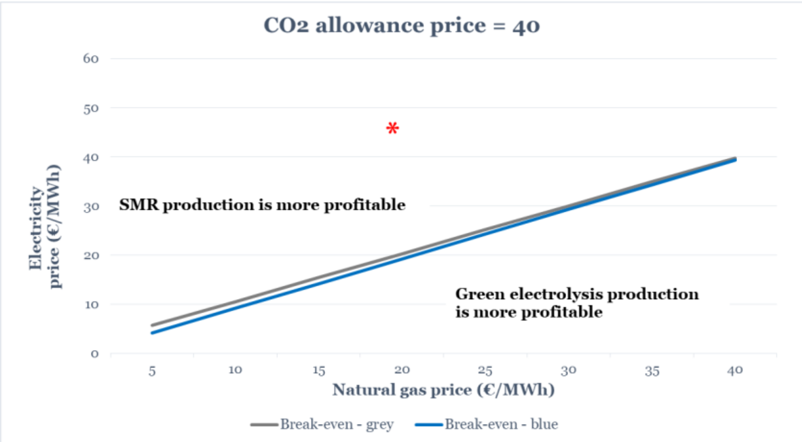
Figure 2.4 Cost components of the required hydrogen price per type of technique



Note: for the underlying assumptions, see Table 2.1 and 2.2.

Figure 2.5 Break-even prices of natural gas and electricity for SMR and electrolysis, for different prices of CO2

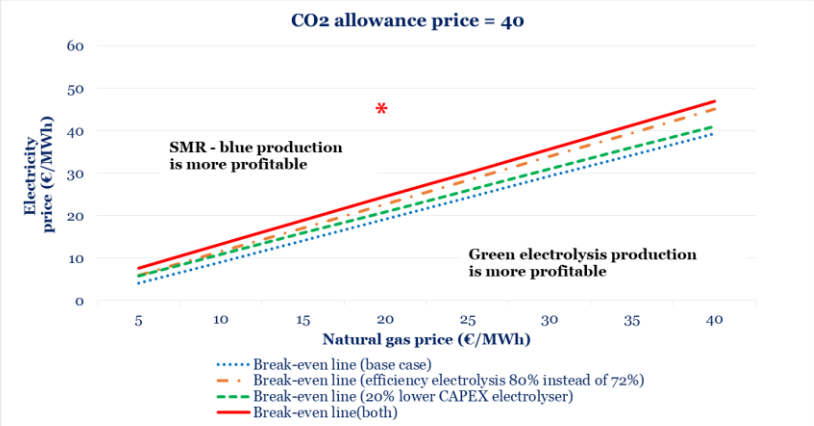




Note: * indicates the average year-ahead forward price of electricity and natural gas over the period 2010-2018

The above analysis is based on static assumptions on the level of costs for the various hydrogen production techniques. In the future, the costs may change as a result of technological developments, learning-by-doing effects and changing market circumstances. In particular, the costs of electrolysis may decrease in the future, which may change the above the conclusions. In order to check this, we have calculated the break-even electricity and gas prices for electrolysis versus SMR-blue using more favourable assumptions on the productivity of electrolysis (Figure 2.6).

Figure 2.6 Sensitivity analysis: break-even prices electrolysis/SMR in case of lower investments costs and higher efficiency of electrolysis plants



Note: * indicates the average year-ahead forward price of electricity and natural gas over the period 2010-2018

If the efficiency of electrolysis plants increases from the previously assumed 72% to 80%, the maximum electricity price an electrolysis plant can afford would increase with a few euros per MWh. The same holds if the investment costs per unit of capacity of electrolysis plants decreased by 25%. If both changes did occur (i.e. higher efficiency and lower investment costs), the maximum electricity price affordable for an electrolysis plant would increase with about 5 euro/MWh. If the natural-gas price were 20 euro/MWh (which is the average price over the past decade) and the CO_2 price 40 euro/ton, then an electrolysis plant would be more competitive than a SMR plant with CCS provided that the average annual electricity price is less than 25 euro/MWh. In the next Section, we will see that this price is much lower than the past and current electricity prices.

2.3 Economics of transportation

2.3.1 Types of transportation

Transportation of hydrogen can be done in various ways. Currently, transportation is mostly carried out by dedicated pipelines. The current pipeline infrastructure for hydrogen connects production and consumption facilities in Rotterdam, Bergen op Zoom, Terneuzen, Antwerpen and several places in Belgium and France.[10]

An alternative option for transportation is by road or rail. In both cases, transport can be done in two ways. One option is transportation of gaseous hydrogen in tube trailers, that can carry up to 1000 kg hydrogen per truck. Another possibility is transportation of liquefied hydrogen in double-walled insulation tanks, which can carry up to 4300 kg of hydrogen per truck and up to 9100 kg per railcar.

Compared to gaseous hydrogen, the transport of liquefied hydrogen has extra costs. First of all, the trucks and railcars require specially designed tanks. Besides that, the hydrogen has to be liquefied and often, due to users' demand, be converted into gas again. In this process, boil-

[10] One of the key players in transport of hydrogen is Air Liquide, who owns over 1100 km of hydrogen pipelines in the Netherlands, Belgium, western Germany and the north of France (TKI Nieuw gas, 2018). Next to owning a network of pipelines, Air Liquide is also active in supply and storage of hydrogen. Thus, Air Liquide can be seen as a vertically integrated firm when it comes to hydrogen.

off by transfers between tanks is around 10-20% with an additional boil-off of 0.3% per day during transport (Amos, 1998).

2.3.2 Method, data and assumptions

The costs per unit of hydrogen of a hydrogen gas pipeline depends on the costs per meter of pipeline, the quantity of the hydrogen transported per meter of pipeline and, finally, additional costs for maintaining the pressure within the system through compressor stations. Table 2.4 presents the assumptions we use to calculate the costs of transport via pipelines.

Table 2.4 Assumptions on costs of transportation by pipelines

Assumptions	Value	Source
β1	0.0008	Krieg (2012)
β2	0.92	Krieg (2012)
β3	250	Krieg (2012)
hydrogen density (kg/m3)	8.51	
velocity (m/s)	15	GTS
pressure pipelines (kpa)	10000	Tebodin (2015)
distance compressor stations (km)	80	GTS
capex compressor stations (€)	4980000	GTS

Note: Krieg (2012) estimates the costs of a hydrogen pipeline per meter (C) as a function of the diameter of the pipeline (D) using the following equation: $C = \beta 3 + \beta 2 * D + \beta 1 * D^2$. Hence the costs per meter consist of a fixed component independent of the diameter of the pipeline, a component linearly related to the diameter and a component that increases with the square of the diameter.

For transport by trucks, the costs depend on the capacity of a truck and trailer, the investments required, and the variable costs related to the use of energy and labor. Table 2.5 summarizes the assumptions we use to calculate the costs of transport by trucks.

Table 2.5 Assumptions on costs of transportation by trucks

Assumptions	Value	Source
quantity (kg/truck)	1000	Reuss et al. (2017); Linde Group
lifespan (years)	12	Reuss et al. (2017); Amos (1998)
CAPEX Truck (€)	160000	Reuss et al. (2017)
CAPEX Trailer (€)	550000	Reuss et al. (2017)
fuel costs (€/km)	0.47	Amos (1998); Reuss et al. (2017); CBS
total wage costs (€/km)	0.38	Amos (1998); Reuss et al. (2017); CBS

2.3.3 Results

The investments required for building a hydrogen pipeline infrastructure are a slightly increasing function of the diameter of the pipeline (Figure 2.7). The capacity of the pipeline increases more strongly if the diameter increases and this effect is stronger the higher the pressure in the system (Figure 2.8). As a result, the cost of transporting hydrogen via pipelines has economies of scale. The higher the diameter the lower the average investment costs. In other words: a pipeline of 600 mm has the same capacity as 4 pipelines each of 300 mm, while the total investments required are about 50% (Figure 2.9). Hence, hydrogen transportation via pipelines can be regarded as a natural monopoly, which has consequences for the optimal design of the market.

The costs of hydrogen transport by truck strongly increase with distance, which implies that the variable costs related to the use of fuel and labour are much more important than the fixed costs related to the investment in trucks and trailers (see Figure 2.10). The low share of fixed costs in the total costs imply that this type of transportation is not characterised by economies of scale.

Figure 2.7 Installation costs of a hydrogen gas pipeline in relation to the diameter of the pipeline

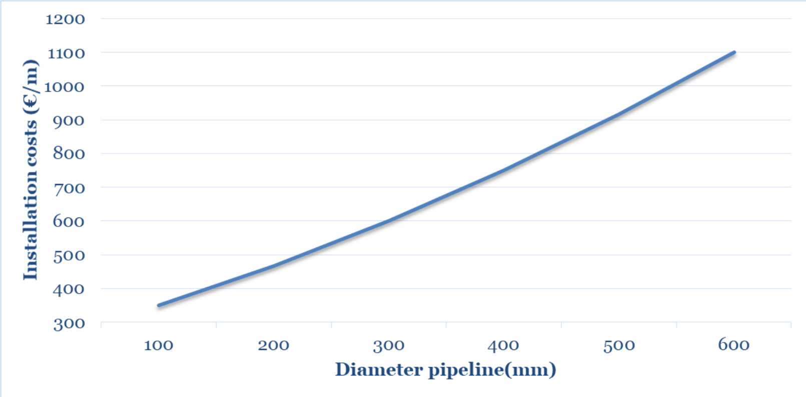


Figure 2.8 Capacity of hydrogen gas pipeline in relation to diameter of pipeline and the velocity of gas flow (meter/second)

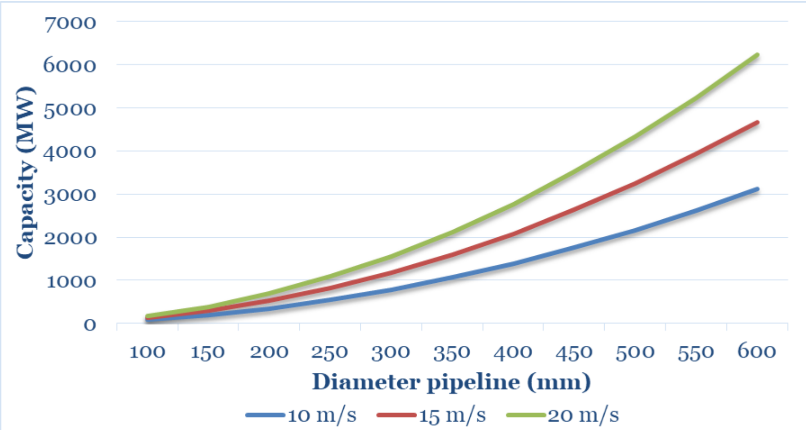


Figure 2.9 Capital expenditure (CAPEX) of investments in a hydrogen gas pipeline in relation to distance and

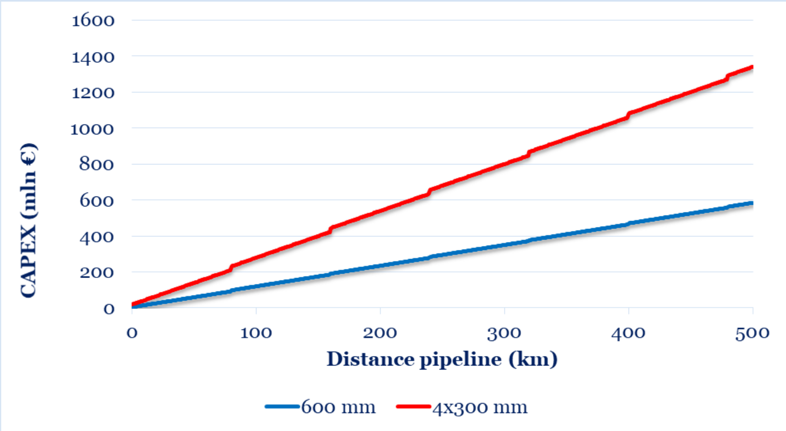
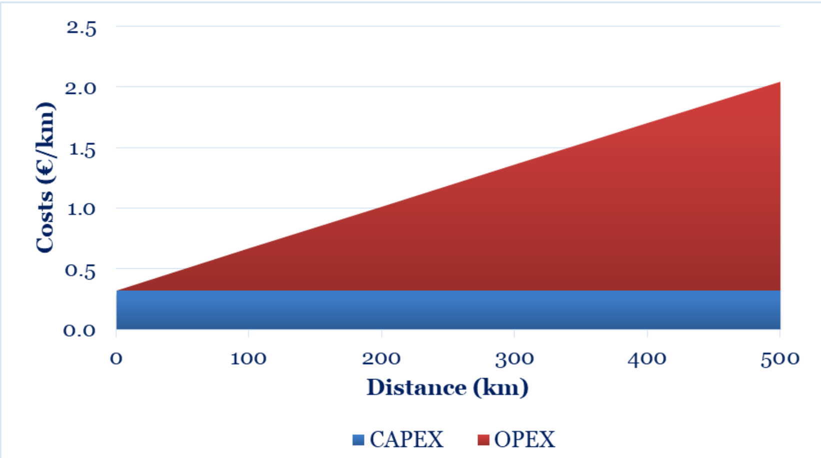


Figure 2.10 Costs (CAPEX and OPEX) of hydrogen transport by truck in relation to distance



2.4 Economics of storage

2.4.1 Types of storage

Over the years, various types of hydrogen storage have been investigated, but until now, only two storage methods are proven and in actual use. These methods are high-pressure tanks for small-scale storage at for instance refueling stations, and empty salt caverns for larger scale storage. The capacity of tanks is about 45 MWh, which is equal to the annual gas consumption of 3 Dutch households, while the capacity of salt caverns can be 150 GWh, which is equal to the annual gas consumption of 10,000 Dutch households.

A third potential option for storing hydrogen is using depleted gas fields which can possibly be used for large-scale storage. However, there is no experience with this storage method yet.

2.4.2 Method, data and assumptions

The costs of the various methods mainly depend on the capacity and the required investments expenditures. The capacity of storage is related to the working volume, which is the volume of hydrogen that can be stored, and the amount of hydrogen that can be injected and withdrawn in a specific period of time. A specific type of investment is related to cushion gas, which is the volume of hydrogen needed to be permanently within the storage facility in order to have sufficient pressure. Table 2.6 presents the assumptions we have used to calculate the costs of storage of hydrogen in a salt cavern and a depleted gas field.

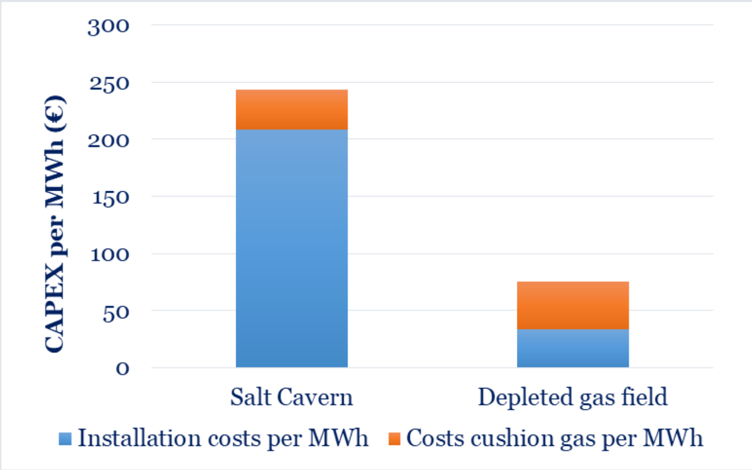
Table 2.6 Assumptions on costs of storage

Assumptions	Value	Source
installation costs salt cavern (mln. €)	30	Kruck et al. (2013)
costs cushion gas salt cavern (mln. €)	4.98	idem
working gas salt cavern (TWh)	0.14	idem
installation costs depleted gas field (mln. €)	375	idem
costs cushion gas depleted gas field (mln. €)	469	idem
working gas depleted gas field (TWh)	7.8	idem

2.4.3 Results

The required investment in a salt cavern per unit of MWh is about four times as high as the investment required for a depleted gas field (Figure 2.11). However, gas storage is typically characterised not only by its volume, but also by its capacity, and more specifically, its send-out (production) capacity and send-in (storing) capacity. When these capacity are important for the service that the storage provides, the economic picture may be different. For this study, we assume that seasonal storage is the most relevant service of hydrogen storages.

Figure 2.11 Investment costs per MWh for two types of storage



2.5 Alternative design of hydrogen production through electrolysis

In the previous analysis we assumed that the business case of electrolysis plants is strongly related to the price of electricity. We also assumed that the plants are connected to the electricity grid which implies that they have continuous access to electricity. As a consequence, the operator needs to buy green certificates if she wants to make green hydrogen.

An alternative design of the hydrogen supply is that the electrolysis plants operate in close connection to wind turbines. A benefit of such a design is that the electricity generated by these wind turbines need not to be transported through an electricity grid; instead, the hydrogen itself has to be transported. If the infrastructure for transporting hydrogen is already present, such as in the form of an existing natural-gas network, then there might be significant savings on network costs. A plan with these features has recently been presented by the TSOs of the Dutch high-voltage network and the Dutch high-pressure gas network

(Gasunie/TenneT, 2019). Here, we briefly evaluate the business case of this plan.

The costs of connecting offshore wind parks to the electricity grid have been estimated by several studies. Based on these studies, we assume that the network costs of connecting offshore wind parks are 20 euro/MWh.[11] Producing hydrogen offshore spare these costs. We assume that there neither adapting the natural-gas network to the requirements of hydrogen transport nor building the offshore hydrolysis plants involves additional costs, which is of course too optimistic and results in an underestimation of the costs of this project.

Another benefit of producing the hydrogen offshore in direct connection to the electricity production by wind turbines is that there is no need to buy green certificates, as there is already full transparency on the (green) origin of the electricity.

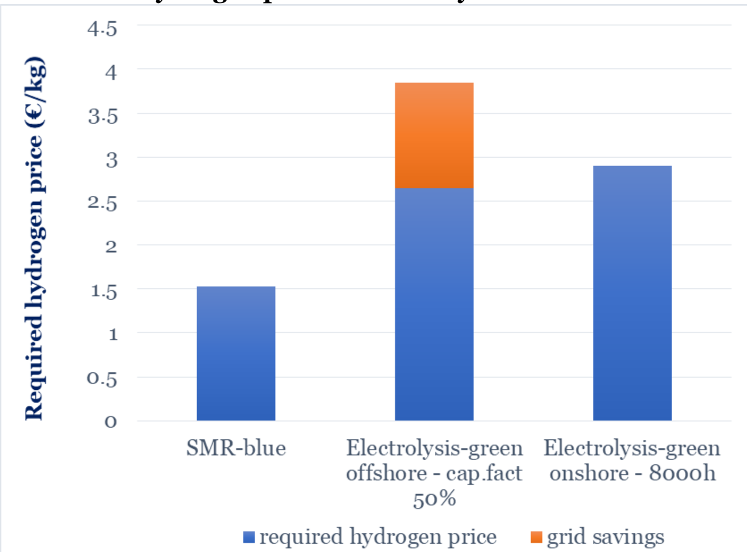
The close connection between an electrolysis plant and a wind park also implies that the cost of using electricity is not related to the market price, but to the electricity price the investors in the wind turbines require to recoup their investments and operational costs. The price of the electricity can be estimated on the basis of the price in the recent tenders

[11] Algemene Rekenkamer (2018), referring to the study ECN, mentions a cost of 25 euro/MWh. They also state that these costs should reduce to 15 euro/MWh because of the agreement made between the State and the network operator. They also refer to a statement by TenneT that the current costs are about 15 euro/MWh, but that in the future the costs will be higher because the offshore wind parks will be located further away from the shore. Another source of information is the cost-benefit analysis made by Decisio (2018). They conclude that for 7500 MW offshore wind park the total investment in networks is about 8 billion euro's; meanwhile about 7 billion euro is needed for operating and maintenance costs during the lifetime of 30 years of the project. Using these data and assuming a capacity factor of 50% and a discount rate of 3%, we find that the (present value of the) total network costs are about 20 euro/MWh.

for offshore wind parks. Based on Algemene Rekenkamer (2018), we set this price at 45 euro/MWh.[12]

Producing the hydrogen when the wind turbines generate electricity implies that the utilisation rate of the electrolysis plant is determined by the capacity factor of the wind turbines. We assume that the capacity factor of the offshore wind turbines is 50%. In the previous sections we have seen that a lower utilisation of electrolysis plants decreases the efficiency, while also a higher return per operating hour is required in order to recoup the investment costs.

Figure 2.12 Impact of potential grid savings on required hydrogen price of electrolysis



Note: the grid savings can be seen as social benefits for which the investor in the offshore electrolysis plant is remunerated in one way or the other.

[12] The price in the latest tender was 43 euro/MWh, but on top of that the investor in the wind turbines receives revenues from selling green certificates which have a value of about 2 euro/MWh.

Based on these assumptions, we are able to calculate the required hydrogen price of an electrolysis plant which is directly connected to an offshore wind farm (Figure 2.12). Because of the lower utilisation and efficiency, the total costs per unit of hydrogen are significantly higher than when the hydrogen is produced on an almost continuous basis (3.9 euro/MWh versus 2.9 euro/MWh). The savings of this project in terms of the unneeded extensions of the offshore electricity grid are estimated at 1.2 euro/kg. These benefits reduce the required hydrogen price to make this project profitable to 2.65 euro/MWh, which is below the price of a hydrogen plant which produces continuously, but also significantly above the price required by SMR-blue production.

3. Scenarios: outlook for hydrogen demand and supply

3.1 Introduction

Using the insights on the economics behind the supply of hydrogen, we formulate a number of scenarios regarding the future outlook of supply and demand in the Netherlands. We assume that the demand for hydrogen is mainly driven by the relative end-user prices, as in the long run transaction costs to move from one commodity to the other are less relevant. We also assume that in the long run, the infrastructure costs for energy users are similar as they are likely largely socialized. Hence, the scenarios are based on different future end-user prices, which depend on the commodity prices plus additional taxes imposed by the government.

It is important to realise that scenarios should not be seen as forecasts, but as conceivable and internally consistent stories about the future market development. The purpose of making scenarios is to think systematically on what might or should happen. The latter types of scenarios are called normative and start from objectives regarding the situation at the end of a period and then analyse via which alternative routes these objectives can be realised. Example of this type of scenarios are EC (2011) and WEC (2018). In this paper we use the former type of scenarios, generally referred to as explorative, which depart from the current situation and make story lines regarding the driving factors which affect the decisions of governments, firms and consumers. Below we first discuss the driving factors, the story lines and the method of quantification (Section 3.2), before presenting the results, i.e. the quantitative outlook per scenario (Section 3.3).

3.2 Method

3.2.1 Driving factors

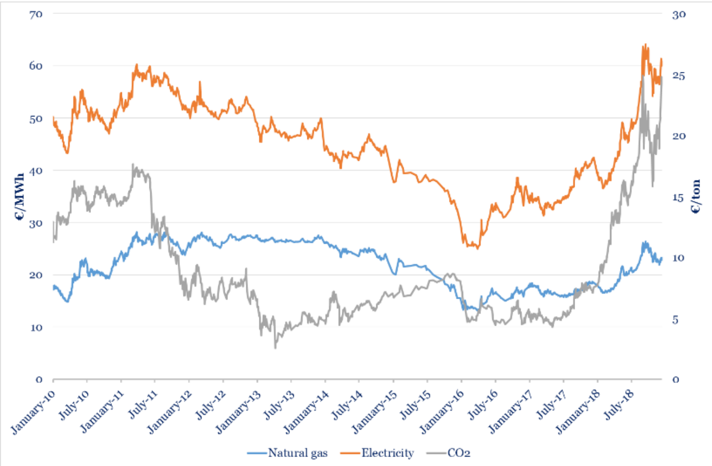
From the analysis in Section 2, it follows that three economic factors are the key drivers behind the future development of hydrogen, namely, the tightness of international natural-gas markets, the stringency of (inter)national climate policy and the electricity price. The tightness of the gas market depends on global developments in supply and demand, such as discoveries of new resources, technological developments in exploration and production and energy policies around the globe, such as regarding the generation of electricity. The tightness of the market is reflected in the price of natural gas. The stringency of climate policy also depends on international developments, in particular on the extent to which countries agree on policy targets. This stringency translates into the price of CO_2.[13] These factors determine the extent to which hydrogen can compete with natural gas as a feedstock and/or as fuel for heating in industry and residential sectors and with gasoline in transport. In addition, these factors also determine which technique for making hydrogen is most competitive.

The prices of natural gas, electricity and CO_2 are mutually related. The price of natural gas results from a global market and can be treated as exogenous from the perspective of the Netherlands (Hulshof et al., 2016). The relevant electricity price, however, results from the Northwest-European market in which gas-fired power plants are still often the price setting plants. This means that the marginal costs of these plants are a major factor behind the electricity price. These marginal costs mainly

[13] By the price of CO_2, we not only mean the price of CO2 allowances for firms which operate within the European Emission Trading Scheme, but also other types of (implicit) prices on the emissions of CO_2, such as through a tax imposed on the use of fossil energy, a tax on gas consumption, or regulatory constraints on the use of fossil energy.

depend on the price of natural gas and the price of CO_2 allowances in the European ETS. As a result, the higher the price of natural gas or the higher the price of these allowances, the higher the electricity price will be, as can be seen in Figure 3.1.[14] In this figure we observe that even the year-ahead forward prices are fairly volatile. During the period 2010-2018, the price of natural gas fluctuated between 10 to 30 euro/MWh (average price was about 20 euro/MWh), the CO_2 price between less than 5 and 25 euro/ton recently (average price was about 10 euro/ton), and the price of electricity between 25 and 60 euro/MWh (average price was about 45 euro/MWh).

Figure 3.1 Daily year-ahead forward prices of natural gas, CO_2 and electricity (baseload), 2010-2018



Source: Bloomberg

[14] Using the data on the daily year-ahead forward prices for gas, CO_2 and electricity over the period 2010-2018, we find the following relation based on OLS regression: *Electricity price = 6.74 + 1.34 Gas price + 1.02 CO2 price + error term*, where all coefficients are highly significant and with a R^2 of 91%.

This relationship between these prices is an important factor for the analysis of the competition between the two types of hydrogen production: SMR and electrolysis. A higher price of natural gas or CO_2 not only raises the required hydrogen price of SMR, but indirectly also the required hydrogen price for electrolysis plants. This impact of the natural gas price on the electricity price will, however, be weaker when the share of renewables in the electricity system increases. A higher share of renewables implies, after all, a higher likelihood that renewable plants (like wind turbines, solar parks) are the price setting plants. For the hours in which this is the case, the electricity price and the gas and CO_2 prices are fully decoupled, while the electricity price may go to almost zero as the marginal cost of renewable power is close to zero.

In many hydrogen studies such situations are welcomed as these 'oversupply situations' make electricity cheap, which gives electrolysis a competitive position compared to SMR. However, economic intuition suggests that hours of oversupply in which the almost-zero marginal costs determine the electricity price will not happen very frequently for otherwise the investors in renewable energy projects would choose to place their funds in other investment opportunities. In order to realise a reasonable return in the long term, investors in renewable electricity generation will invest an amount that results in a sufficient number of hours with high prices. Hence, it is expected that there will always be a number of hours in which other plants, in particular gas-fired power plants, remain determining the electricity price. However, the higher the marginal costs of these power plants (resulting from higher prices of natural gas or CO_2), the less hours of positive prices the investors of renewables need in order to recoup their investments.

The costs of using electricity not only depend on the electricity price, but also on the price of green certificates if the hydrogen is supposed to be produced by renewable energy. The market of green certificates is not very liquid and transparent, but from Hulshof et al. (2019) we can infer that the price of unspecified green certificates is about 1 euro/MWh. If the hydrogen must be produced by using Dutch renewable energy, then the producer needs to buy green certificates originating from Dutch renewable electricity production (wind mills, solar parks). It appears that the price is significantly higher (in the range of 5 to 10 euro/MWh), as this market is tight due to the limited supply compared to the demand. This implies that a product like 'Orange Hydrogen' (which is fully produced in the Netherlands) requires a much higher hydrogen price than 'Electrolysis-green hydrogen' and 'Electrolysis-grey hydrogen'.

3.2.2 Story lines

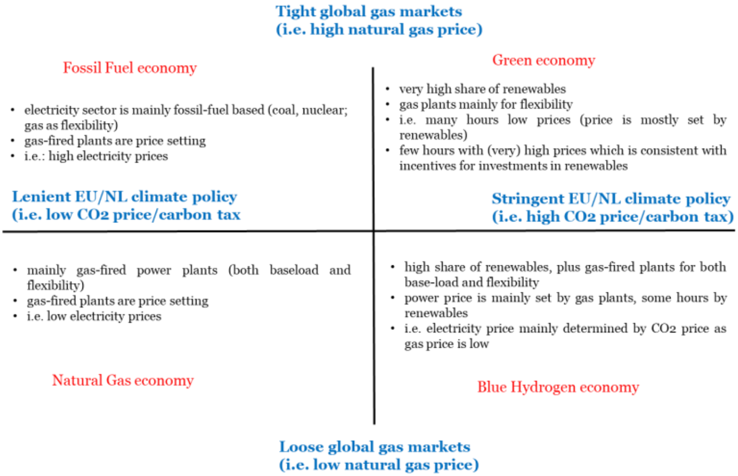
Because the electricity price strongly depends on the prices of natural gas and CO_2, the latter two factors are the key exogenous factors affecting the economic outlook of hydrogen. Therefore, we develop our scenarios on the basis of two dimensions: the tightness of international markets for natural gas and the stringency of (inter)national climate policy (see Figure 3.2). This results in four possible storylines: high gas prices and a lenient climate policy (*Fossil-fuel economy*), low gas prices and a lenient climate policy (*Natural Gas economy*), low gas prices and a stringent climate policy (*Blue hydrogen economy*) and high gas prices and a stringent climate policy (*Green economy*).[15] The next step in the scenario development is determining the consequences for the price of electricity in each storyline.

In *Fossil Fuel economy*, the baseload electricity is generated by coal-fired power plants. Because these plants have relatively high fixed costs,

[15] The names for these scenarios will be clear when we have presented the outcomes regarding the composition of energy production and use.

it is more efficient to have plants with lower fixed costs like gas-fired plants to take care of flexibility as that means that the annual number of running hours is lower. With the electricity price set by the latter plants for a substantial number of hours, the result is a high average annual electricity price.

Figure 3.2 Electricity prices in four scenarios based on tightness global gas markets and stringency of climate policy



In *Natural Gas economy*, gas-fired power plants are responsible for the majority of electricity generation, both for baseload and flexibility, as they outcompete coal-fired power plants because of the low gas price. As a result, also here the electricity price is set by these plants, which results in a low electricity price.

In *Blue Hydrogen economy*, the stringent (inter)national climate policy is translated into a high carbon price as well as high taxes on the use of natural gas by industry and households in order to give incentives to energy users to become more energy efficient. The high carbon price raises the electricity price, which fosters the business case of investments in renewable electricity capacity. As a result, in a number of hours this capacity will be price setting, resulting in zero electricity price because of the zero marginal costs of the renewable techniques. In the remaining of the time, the electricity price is set by gas-fired power plants.

In *Green economy*, a stringent climate policy is implemented in a tight international gas market environment. The tight gas market may be due to energy policies all over the globe which promote the use of gas instead of for instance coal. Consequently, the variable costs of gas-fired power plants are raised by both a high natural-gas price and high carbon prices. As a consequence, the electricity price is high when these plants are price setting. High prices during these hours strongly foster investments in renewable electricity capacity, resulting in many hours in which this capacity is price setting and, hence, the electricity price is zero. Note that in the long run, this number of hours cannot be too large as investors in renewable capacity need a sufficiently high number of hours in which they can realise revenues to recoup their investments.

Using data on actual prices and taxes in the recent past, we translate these storylines into estimates of the commodity prices in each scenario (see Table 3.1). As the average gas price (year-ahead forward) over the past 10 years was about 20 euro/MWh, while fluctuating between 15 and 25 euro/MWh (see Figure 3.1), we set the gas price at 25 euro/MWh when the gas market is assumed to be tight and at 15 euro/MWh when the market is loose. For the CO_2 price, we set the price at 10 euro/ton in case of a lenient climate policy (which is about half of the current price) and at 50 euro/ton in the stringent climate policy (which is more than twice the current price).

For the scenarios with a lenient climate policy, we state that renewable plants are never price setting. In the *Blue-hydrogen* scenario we set the percentage of hours these plants set the electricity price at 30% of all annual hours and in the *Green scenario* at 70%.[16]

Table 3.1 Assumptions on gas prices and climate policy and consequences for electricity price, per scenario

Commodity price / tax	Scenario			
	Fossil fuel	Natural gas	Blue hydrogen	Green
gas price (€/MWh)	25	15	15	25
CO2 price (€/ton)	10	10	50	50
price electricity if gas plant is price setter (€/MWh) *	51	37	78	91
price electricity if gas plant is not price setter (€/MWh)	0	0	0	0
percentage of hours renewable plants are price setter	0%	0%	30%	70%
average electricity price (€/MWh)	51	37	55	27
tax on natural gas - households (€/MWh)	10	10	35	35
- industry (€/MWh)	1	1	30	30
tax on electricity households (€/MWh)	12	12	25	25

Note: * price of electricity is calculated using the results of OLS estimation on daily data on year-ahead forward prices over period 2010-2018: Electricity price = 6.73 + 1.34 * Gas price + 1.02 CO2 price.

Besides the (international) CO_2 price resulting from the European emissions trading scheme, there are national taxes on the use of natural gas (and other fossil fuels). Currently, households in the Netherlands pay about 30 euro/MWh and the industry (large users) about 1 euro/MWh (as

[16]These percentage are based on the economic principle that in equilibrium investors in renewable energy capacity will receive sufficient revenues to recoup their investments, but not more than that. Assuming a CAPEX of a wind turbine of 750,000 euro/MW, a capacity factor of wind turbines during the hours that gas-fired plants are price setting of 20% (as in many of these hours there will be no wind), a discount factor of 5% and lifetime of the wind turbine of 15 years, the present value of the flow of revenues generated by the investment is about equal to the investment costs.

marginal tariff).[17] We assume in the scenarios with a lenient climate policy that the tax for households is reduced to 10 euro/MWh, while the industry tax remains the same. In the stringent climate policy, we assume that the tax for households increases to 35 euro/MWh, and for industry strongly increases to 30 euro/MWh.

3.2.3 Quantification

Having set the various commodity prices and taxes for each scenario, we are able to make a quantitative outlook for the use and supply of energy per type of carrier. The basic assumption behind this outlook is that energy users make their decisions regarding the type of energy on the basis of the relative end-user prices, which are a function of the commodity prices and the taxes. This implies that we ignore transaction costs to move from one commodity to the other and that we also assume that the infrastructure costs for energy users are similar.[18]

In the *Fossil Fuel* and the *Natural Gas* scenario, hydrogen produced through SMR without the use of CCS has the lowest required price (Table 3.2). In the *Blue Hydrogen* scenario, hydrogen produced with SMR plus the use of CCS has the lowest required hydrogen price, while in the *Green* scenario, hydrogen through electrolysis on the bases of renewable sources and hydrogen based on SMR-blue have both the lowest required price.

[17] Source: www.belastingdienst.nl

[18] In the long run, transactions costs are not that relevant. Moreover, it is not unrealistic to assume that the infrastructure costs will be socialized, reducing the impact on decisions on micro level.

Table 3.2 Required hydrogen prices per type of technology, per scenario (€/kg)

Type of hydrogen	Scenario Fossil fuel	Natural gas	Blue hydrogen	Green
SMR-grey	1.64	1.15	1.51	2.00
SMR-blue	1.74	1.23	1.40	1.90
Electrolysis-green	3.08	2.40	3.28	1.92

Note: red numbers indicated the lowest price(s) per scenario.

Although SMR-grey results in the lowest required hydrogen price in both the *Fossil Fuel* and the *Natural Gas* scenario, in both scenarios the end-user price (including taxes) of natural gas is lower for industry as well as households (Table 3.3). In the *Blue Hydrogen* scenario, however, the price of hydrogen is lower than the end-user price of natural gas for industry and households, while the end-user price of electricity is also higher than the price of hydrogen. In the *Green* scenario, the end-user price of natural gas is higher than the price of hydrogen and electricity

Table 3.3 End-user prices per type of energy and user, per scenario (€/MWh)

Type of energy and user	Scenario Fossil fuel	Natural gas	Blue hydrogen	Green
hydrogen	45	32	39	53
natural gas for households	35	25	50	60
natural gas for industry	26	16	45	55
electricity for households	63	49	80	52

Note: red numbers indicated the lowest prices per scenario.

In order to translate the end-user prices of the various energy carriers into volumes of consumption per type of energy per sector per scenario, we have to make a number of assumptions on the current volumes of use and efficiencies and how they may develop. Table 3.4 provides our assumptions on the current efficiencies of engines in various modes of road transport, while Table 3.5 presents the assumptions regarding the current efficiencies in electricity generation.

Table 3.4 Assumptions on efficiency of engines in transport

Variable	Value
Fuel efficiency (l/100km)	
passenger cars	6.7
vans	10
trucks	22
special vehicles	25
buses	29
Hydrogen fuel cells efficiency (kg/km)	
passenger cars	0.01
delivery vans	0.02
trucks, trailers, buses	0.04
Efficiency electric cars (kWh/km)	
passenger cars	0.2
vans	0.35
trucks	0.7
buses	1

Source: see Moraga & Mulder (2018)

Table 3.6 presents our assumptions regarding the changes in volumes and efficiencies in industry, households and mobility for each of the four scenarios. Here, the general idea is that the growth in volume is negatively related to the level of end-user prices, while the efficiency improvement is positively related to these prices.[19] In the *Natural Gas* scenario, where energy prices are low, the annual growth of the industry and the mobility sector is set at 1.5% and 1.25% respectively, while in the *Green* scenario, with much higher energy prices, this growth is set at 0.5%. At the same time, the annual change in efficiency in the *Green* scenario is the highest of all scenarios, while in the *Natural Gas* scenario, the annual efficiency improvement is assumed to be only 0.75%.

Table 3.5 Assumptions on efficiency of power plants in 2018

Variable	Value
Efficiency power plants	
gas-fired power plants	42%
coal-fired power plants	40%
other fossil-fuel plants	40%
Capacity factor	
wind turbines	40%
solar panels	10%

Source: see Moraga & Mulder (2018)

The annual growth in market shares of hydrogen, heat pumps and district heating are based on the relative prices on these energy systems (see Table 3.2). In the *Green* scenario, for instance, electricity for households is the least expensive energy carrier, strongly stimulating the use of heat pumps and electric cars. In the *Blue Hydrogen* scenario, the industry will change to blue hydrogen instead of natural gas because this is more profitable.

[19] Higher energy prices result in higher product prices which reduce demand and, hence, production. In addition, higher energy prices incentivize activities to reduce energy consumption per unit of output resulting in higher energy efficiencies.

Table 3.6 Assumptions on development per sector per scenario, annual change in 2018-2050

Variable	Scenario: Fossil Fuel	Natural Gas	Blue Hydrogen	Green
Industry				
annual production growth	1.0%	1.5%	1.0%	0.5%
annual efficiency change	1.0%	0.75%	1.0%	1.25%
annual growth use of hydrogen	0%	0%	3%	3%
Households				
annual growth number of households	0.5%	0.5%	0.5%	0.5%
annual efficiency change heating	1.0%	0.8%	1.0%	1.3%
annual growth in market share of:				
hydrogen	0.0%	0.0%	2.5%	0.3%
heat pumps	0.0%	0.0%	0.0%	2.2%
district heating	0.0%	-0.2%	0.5%	0.5%
initial efficiency heat pumps (COP)	3	3	3	3
annual efficiency change heat pumps	0.0%	0.0%	1.0%	1.25%
Mobility				
annual growth road traffic	1.0%	1.25%	1.0%	0.5%
annual efficiency change engines	1.0%	0.75%	1.0%	1.25%
annual growth in market share of:				
hydrogen passenger cars/delivery vans	0%	0%	2%	0%
electric passenger cars/delivery vans	0%	0%	1%	3%
hydrogen trucks, trailers and buses	0%	0%	2%	3%

Note: the growth rate for the market shares of hydrogen, electricity and heating systems are based on assumed markets shares for 2050 based on the relative energy prices per scenario.

The hydrogen supply side strongly grows in the *Blue Hydrogen* scenario. In this scenario, blue hydrogen has a lower end-user cost than grey hydrogen and natural gas, strongly stimulating the market share of this energy carrier (Table 3.7). In the *Green* scenario, both blue hydrogen and green hydrogen from electrolysis see increasing market shares, while grey hydrogen fully disappears. In the other two scenarios, the hydrogen supply remains small and only based on SMR-grey.

The electricity sector also develops very differently across the scenarios. In the *Fossil Fuel* scenario, new investments are made in coal-fired power plants because of the low carbon price and high natural-gas price. In all other scenarios, in particular the scenarios with a stringent climate policy, no now coal-fired plants are built while the existing plants are closed.

In the *Fossil Fuel* and the *Natural Gas* scenarios, there are no incentives anymore to invest in renewable energy capacity. Hence, we assume that in these scenarios the installed capacity reduces gradually over time. In the other two scenarios, and in particular in the *Green* scenario, there are strong incentives to invest in renewables. In addition, in these two scenarios with a stringent climate policy, we assume that there are more improvements in renewable technology, resulting in a strong annual increase of the capacity factors.

Note that the gas-fired power plants are treated as residual suppliers, which means that they adapt to what is needed to fulfil demand, just as in Moraga and Mulder (2018). In the scenarios with high natural-gas prices, we assume that the efficiency of gas-fired power plants increases more than in the other scenarios, while in the scenario with the lowest prices (*Natural Gas* scenario), the annual efficiency improvement is low.

Table 3.7 Assumptions on development in hydrogen and electricity sector, per scenario, annual changes in 2018-2050

	Scenario			
Variable	**Fossil Fuel**	**Natural Gas**	**Blue Hydrogen**	**Green**
Hydrogen production, *annual change market share*				
electrolysis	0%	0%	0%	2%
SMR - grey	0%	0%	-3%	-3%
SMR - blue	0%	0%	3%	2%
Electricity production				
annual change in production per type				
coal-fired plants (%)	3%	-1%	-8%	-8%
other fossil fuel plants (%)	3%	-3%	-14%	-14%
nuclear plants (%)	3%	-8%	-8%	-8%
wind turbines until 2030 *	-0.6	-0.6	1.5	4.4
wind turbines after 2030 *	0.0	0.0	1.4	2.8
solar panels until 2030 *	-0.1	-0.1	0.3	1.1
solar panels after 2030 *	0.0	0.0	0.4	0.7
biomass (%)	1%	1%	3%	6%
net import (if negative, this refers to export) (%)	3%	0%	0%	3%
annual efficiency change per type of plant (%)				
gas-fired power plants	1.25%	0.75%	1.0%	1.5%
coal-fired power plants	1.0%	1.0%	1.0%	1.25%
other fossil fuel plants	1.0%	1.0%	1.0%	1.25%
annual improvement in capacity factor (%)				
wind turbines	0.5%	0.5%	1.0%	1.3%
solar panels	0.5%	0.5%	1.0%	1.3%
Electricity consumption				
autonomous annual change (%)	0.5%	1.0%	0.5%	0.25%

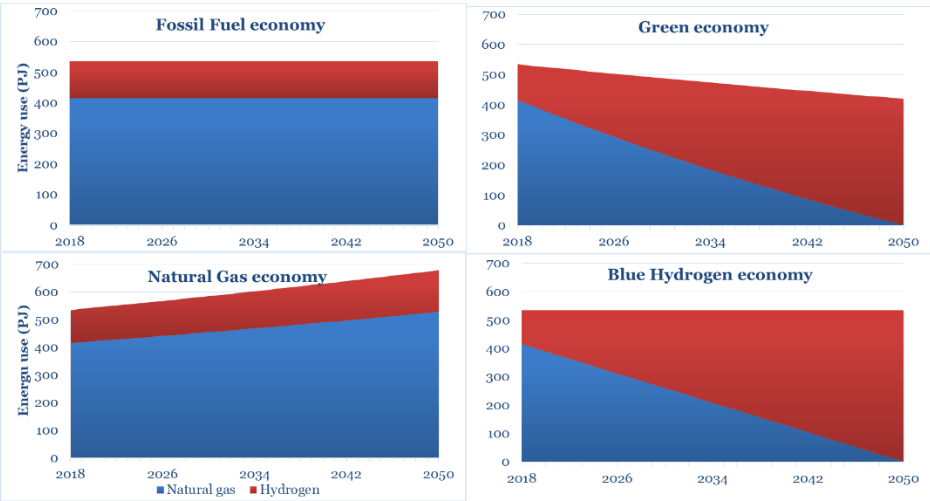
Note: The growth rate for the market shares of hydrogen, electricity and heating systems are based on assumed markets shares for 2050 based on the relative energy prices per scenario (* is in TWh).

3.3 Results

3.3.1 Energy use per sector

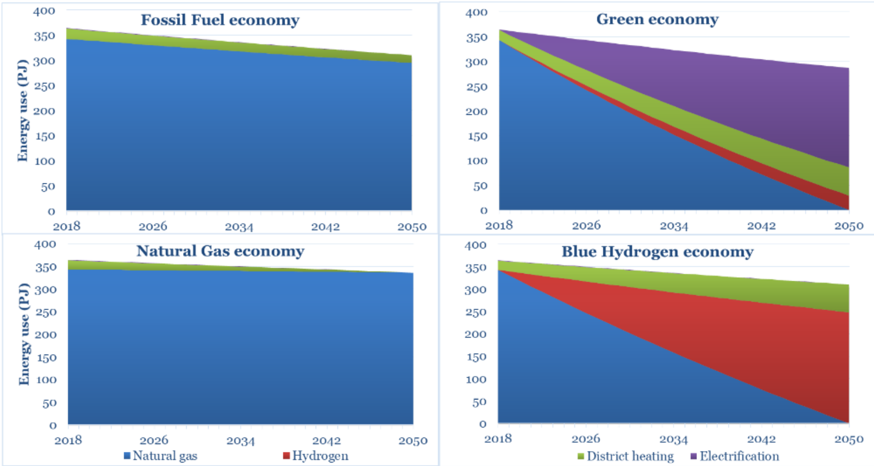
Departing from data on the current type of energy use and using the above assumptions, we get a quantitative outlook of the use of energy per type of carrier per sector per scenario. In the *Fossil Fuel* and the *Natural Gas* scenario, the use of natural gas by the industry increases, while in the other two scenarios, this use gradually declines and completely vanishes by 2050 (see Figure 3.3). In the *Green* scenario, also the total energy use reduces over time because of the improved efficiency which is induced by the high end-user prices.

Figure 3.3 Use of natural gas and hydrogen in the industry, per scenario, 2018-2050



In the *Blue Hydrogen* and the *Green* scenario, also the households stop consuming natural gas (Figure 3.4). In the former scenario, it is mainly replaced by hydrogen, while in the *Green* scenario many households use heat pumps to heat their houses, while also a group of houses becomes connected to a district heating system. A similar story holds for the mobility sector: in the *Green* scenario all cars become fully electric, while in the *Blue Hydrogen* scenario, hydrogen and full-electric cars coexists (Figure 3.5).

Figure 3.4 Energy use for heating by households per type of energy carrier, per scenario, 2018-2050



3.3.2 Hydrogen consumption and supply

The scenarios not only differ in the amount of hydrogen consumption, but also in how the hydrogen is produced. In the *Fossil Fuel* and the *Natural Gas* scenarios, hydrogen demand remains small and this demand is met through SMR-grey (Figure 3.6). In the *Blue Hydrogen* scenario, hydrogen demand increases strongly from the current 120 PJ to about 1000 PJ in 2050. This hydrogen is completely produced through SMR in combination with CCS at that time. In the *Green* scenario, the hydrogen supply increases to about 500 PJ, which is produced both through SMR-blue and electrolysis. The reason for the latter is that the required prices of both types of hydrogen are fairly similar.

Figure 3.5 Energy use in road transport, measured in distance covered by various types of cars, per scenario, 2018-2050

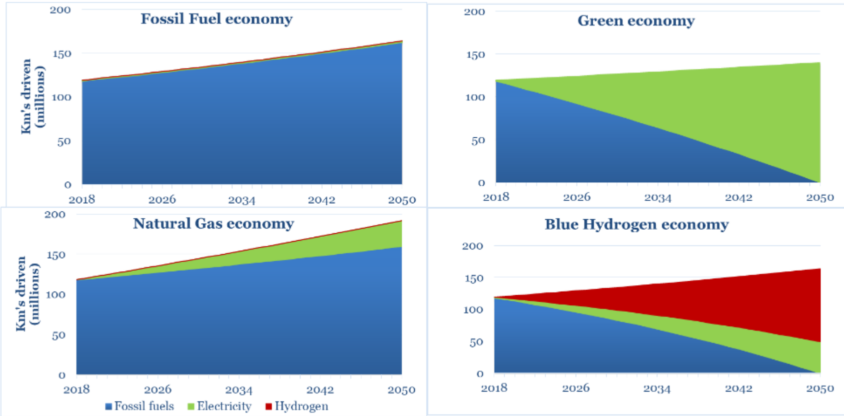
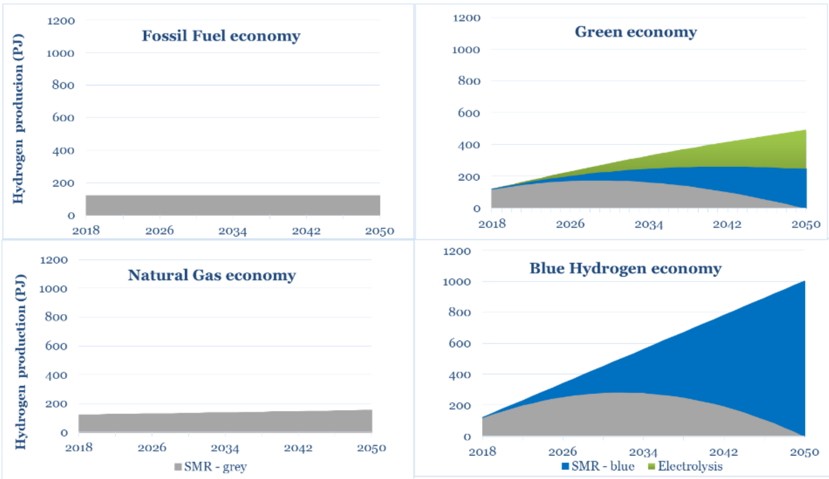


Figure 3.6 Origin of hydrogen supply, per scenario, 2018-2050



3.3.3 Electricity consumption and supply

In all scenario's the total annual electricity consumption increases from the current 120 TWh to about 140 TWh in 2050, except in the *Green* scenario where the electricity consumption more than doubles, reaching about 250 TWh (Figure 3.7). This strong increase is due to the relatively high end-user price of natural gas and the relatively low price of electricity, which stimulates electrification in heating, road transport as well as hydrogen production.

In the *Fossil Fuel* scenario, the electricity is mainly produced by coal and gas-fired power plants and in the *Natural Gas* scenario mainly by gas-fired plants only (Figure 3.8). In the other scenarios, the share of renewable sources (wind, solar and biomass) is much higher which holds in particular for the *Green* scenario. As higher shares are not possible because of the economics of investments in renewable energy (see Section 3.2.2), natural-gas fired plants are required to fill the gap between demand and supply by other sources.

Figure 3.7 Total electricity demand, per scenario, 2018-2050

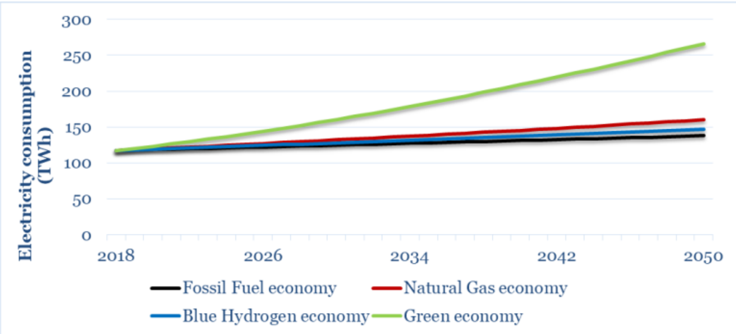
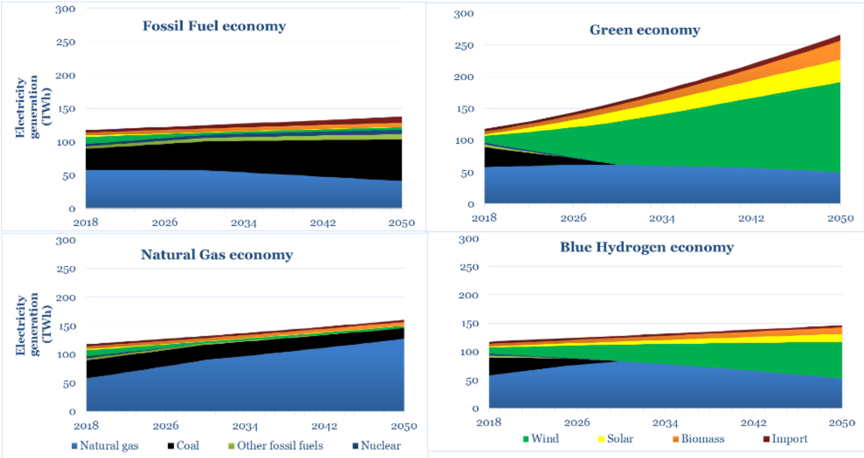
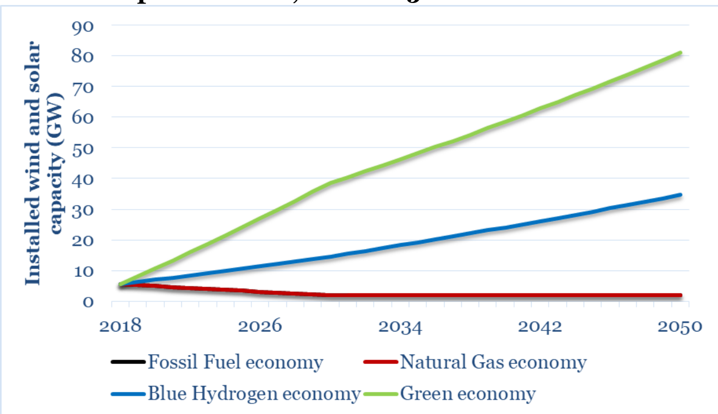


Figure 3.8 Origin of electricity supply, per scenario, 2018-2050



The high shares of renewable generation in the *Green* scenario require huge investments in wind turbines and solar panels (Figure 3.9). In 2050 the total installed capacity should be about 80 GW, while the current level is about 6 GW.

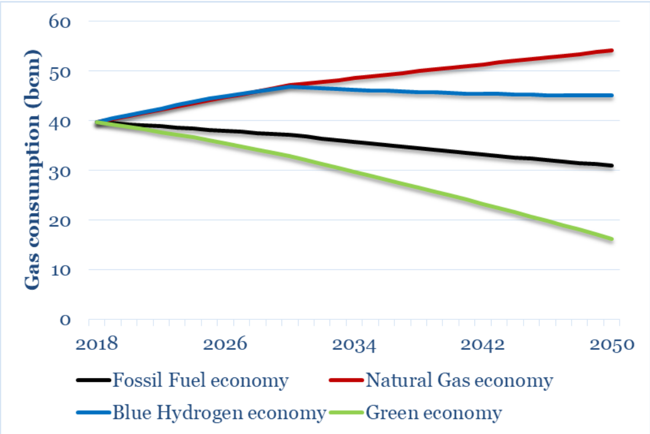
Figure 3.9 Installed capacity wind turbines and solar panels, per scenario, 2018-2050



3.3.4 Natural gas demand

In the *Green* scenario, the total consumption of natural gas reduces strongly, from the current 40 bcm to about 15 bcm in 2050 (Figure 3.10). The remaining gas consumption in this scenario is related to the production of hydrogen through SMR as well as electricity generation by gas-fired power plants (see Figure 3.6). Also, in the *Fossil Fuel* scenario the consumption of natural gas declines, because of the high gas prices. In the other two scenarios, the consumption of natural gas increases. In the *Natural Gas* scenario, this results from the low gas prices and the leniency of climate policy, while in the *Blue Hydrogen* scenario the production of hydrogen through SMR requires significant amounts of gas.

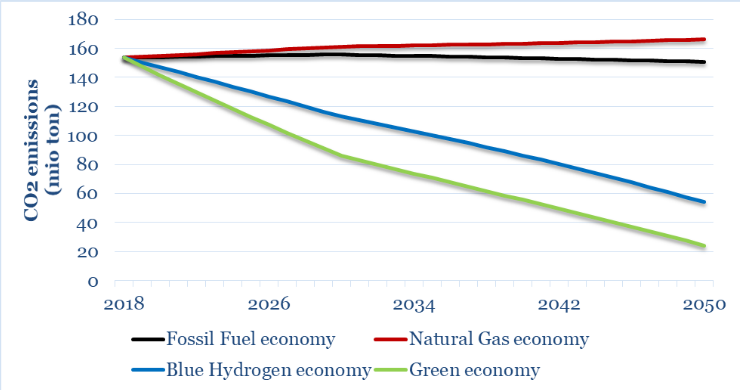
Figure 3.10 Total natural-gas demand, per scenario, 2018-2050



3.3.5 Carbon emissions

In both the *Blue Hydrogen* and the *Green* scenario, the total emissions of carbon reduce strongly, from the current level of about 150 Mton to 60 and 20 Mton in 2050, respectively (Figure 3.11). Only in the *Natural Gas* scenario, the carbon emissions increase because of the relatively strong growth in production volumes and low improvements in efficiency. In the *Fossil Fuel* scenario, coal-fired power plants obtain higher market shares in electricity generation, resulting in higher carbon emissions, but this effect is compensated by the lower growth in production volume and higher efficiency improvements compared to the *Natural Gas* scenario.[20]

Figure 3.11 Total carbon emissions per scenario, 2018-2050



[20] Note that the kinks that appear in the curves corresponding to the *Blue Hydrogen* and *Green* scenarios in the year 2030 results from the closure of the coal-fired power plants which is completed in that year.

4. Creating a market for hydrogen

4.1 Introduction

In the previous sections we have explored the economic conditions under which a market for hydrogen may evolve. The next question to address is to what extent such a market may develop automatically or whether some regulatory help is required. The framework for analysing this issue can be derived from microeconomic theory, which is described in Section 4.2. In this section, we also briefly describe the lessons which can be learned from the development of markets for natural gas and electricity. In Section 4.2, we go to the hydrogen market and analyse the occurrence of market failures and the need for regulation.

4.2 Analytical framework

4.2.1 Perfect markets and market failures

In economics, a market is defined as any structure that allows buyers and sellers to exchange any type of goods, services and information. All buyers and sellers that influence the price of a specific good, service or information are called market participants. In theory, in a well-functioning market the goods are produced and allocated to users in the most efficient way. This means that the right mix of goods are produced by producers having the lowest costs and which are consumed by the consumers having the highest willingness-to-pay for these goods.

In case of a perfectly functioning market, a number of conditions have to be fulfilled. One of these conditions is that no market player is able to strategically influence the market outcome, which means that the market price is fully exogenous to the suppliers and consumers. As a result, in a perfectly competitive market the only option firms have to make higher profits is to either reduce their costs or to improve the quality of their products and to sell the products to consumers having a higher willingness to pay for such products. Generally, one can say that the higher the number of producers in a market, the less firms are able to act strategically, but the relation between market structure (i.e. degree of concentration) and intensity of competition is not that straightforward. Moreover, no firm may have a strategic advantage over others because it is better able to access the market, for instance by using a specific infrastructure which cannot be used by others. In other words, all firms should operate in a level playing field. Another key condition that has to be realized in order to get perfect competition is the presence of full transparency. Producers and consumers need to know the relevant product characteristics and what the price and other conditions are for a market transaction.

This theoretical notion of perfect competition is useful to have in mind as this can act as a benchmark when assessing actual markets. In practice, many markets suffer from fundamental shortcomings which prevent that the market results in an efficient allocation of goods. These fundamental shortcomings are called market failures. In theory, the following market failures can be distinguished:

- *negative externalities*, which occur when economic agents do not take into account all costs of their activities. This may result in a too high level of activities from a social point of view. An example of this market failure is carbon emissions resulting from the use of fossil energy.
- *positive externalities*, which may result in a too low level of activities as firms cannot capture all benefits of their activities. This may, for instance, occur if the benefits of innovation cannot be protected by the innovative firms. In that case, firms will not innovate enough.
- *network externalities*, which may result in a limited number of suppliers capturing the full market and, as a result, other firms being

unable to enter the market. If network externalities exist in the market, market parties should coordinate how they want to organize the market, or a regulator should impose regulations on market design.

- *economies of scale and scope*, which may result in structural positions of dominance (market power) and as a consequence, a too low level of activity. This may occur in case of activities with large fixed costs, such as investments in networks, which have as effect that one firm can conduct these activities more efficiently than several firms.
- *information asymmetry*, which may result in so-called adverse selection. As an example, consumers are not prepared to pay their maximum price if they are uncertain about the true characteristics (quality) of a product. This may occur if consumers cannot fully assess the quality of a commodity and, as a result, they may not be inclined to pay the full price. If this market failure occurs, coordination or regulation is required, for instance by organizing a trustworthy certification scheme.
- *hold up*, which may result in a too low level of investments because firms are uncertain about the ex post revenues once they have made an investment. This may occur in the case of long-term investments without long-term contracts with customers or without the existence of liquid markets. If this market failure exists, coordination or regulation is needed to give investors more certainty about the future revenues.

4.2.2 Lessons from other energy markets

If there are no fundamental shortcomings, markets just develop if individual supplies and consumers see opportunities to start exchanging goods and money. Energy markets, however, have some peculiarities hindering that these markets fully develop automatically without any help. The markets for electricity and natural gas have been liberalised over the past decades. In this process a number of themes can be distinguished:

regulation, restructuring, competition, the integration of domestic markets and the establishment of a liquid market place.

With the liberalisation of a market, a main goal is to develop effective competition. However, sometimes, not every aspect of a market is well suitable for competitive behaviour. One factor which makes that parts of the market are not suitable for competition is the presence of natural monopolies. In electricity and gas markets, the networks are characterised by economies of scale, which makes them infeasible to create parallel networks. As a result, it is crucial for all potential network users to get access to the network which is called third party access (TPA). Another component of regulation is taking care of the network tariffs and to stimulate the network operators to be efficient and to maintain the quality of the network.

Although energy markets have monopolistic elements that cannot be eliminated by increasing competition, there are other elements that are well suitable for competition. To foster the entry of players in those segments of the market, authorities can choose to restructure the market in such a way that the monopolistic and competitive activities are not done by the same firm. This is called vertical unbundling of activities and is a well-known way to prevent conflict of interest. Another restructuring measure is the horizontal splitting of large incumbent firms in the competitive segments. Without this, incumbent firms may have excessive market power, which enables them to behave strategically, i.e. to raise the market price to the monopoly level. A final form of restructuring is the privatisation of ownership of incumbent firms. Privatising the commercial elements of a sector gives those firms stronger incentives to be efficient.

With the vertical unbundling of monopolistic segments and TPA, there is not automatically a competitive market. Effective market competition can only be achieved when the number of firms active in the market is sufficiently high while consumers are able to make a choice for the supplier and product they prefer. The benefits of such effective competition are that the market price is more related to the marginal costs.

A regulatory measure that may further enhance competition is market integration. When regional markets become more integrated with each other, domestic firms are able to operate in other markets as well. This (potentially) increases the number of players in all the markets which will foster competition and, therefore, the final price will be a better reflection of costs. Next to improving competition, market integration may also result in higher productive efficiency: firms with lower costs will replace those with higher costs. Second, and especially important in energy markets, there will be more flexibility to deal with demand or supply shocks.

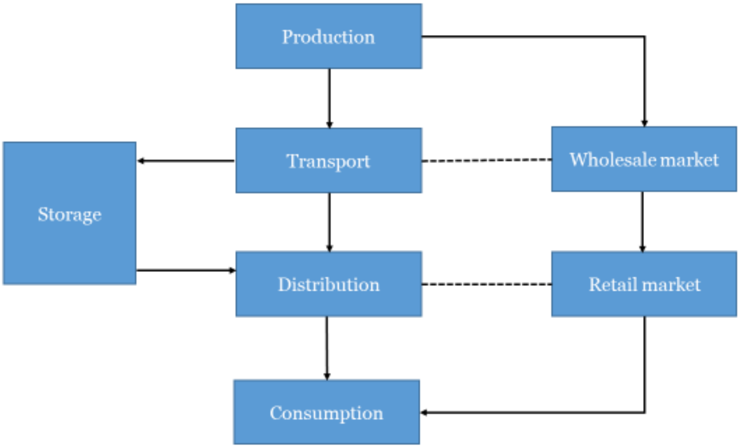
A market is called liquid when the price of a good traded is not noticeably affected by an individual's action. The liquidity depends on the transaction costs market parties have to make and the confidence they have in the market system. The latter depends on transparency of the operation of the market, When these conditions are met, the market will attract more parties, increasing its volume and further improving its liquidity.

4.3 Market failures in hydrogen market

4.3.1 Supply chain

In order to determine whether the development of a market for hydrogen may be hindered by fundamental shortcomings, we analyse for each component of the supply chain (see Figure 4.1) whether there are potential market failures like economics of scale, externalities, structural lack of competition, information asymmetry or hold up situation, and how these could be overcome. If such failures are found, we explore potential regulatory solutions to address them.

Figure 4.1 Supply chain of hydrogen

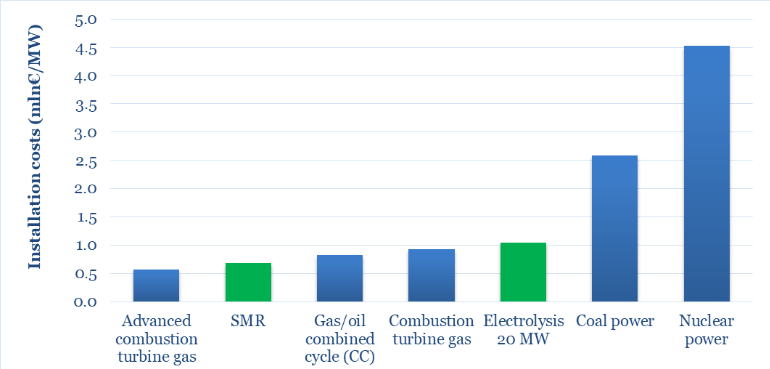


4.3.2 Production

To determine to what extent the production of hydrogen is characterised by economies of scale, we look at the required investments per MW of capacity (Figure 4.2). It appears that production of hydrogen can be compared to the production of electricity. Both commodities are secondary energy carriers, which means that they have to be produced by converting a primary energy carrier. The installations required to do this conversion require similar amounts of investment. An advanced combustion turbine gas plant requires about 0.5 million euro/MW, which is a bit less than the investment size of a SMR plant, while the investment in an electrolysis plant is equal to about 1 million euro/MW (Figure 4.1).

Coal-fired and in particular nuclear power plants are, however, way more capital intensive.

Figure 4.2 Investment costs for hydrogen production through SMR and electrolysis in comparison with electricity production



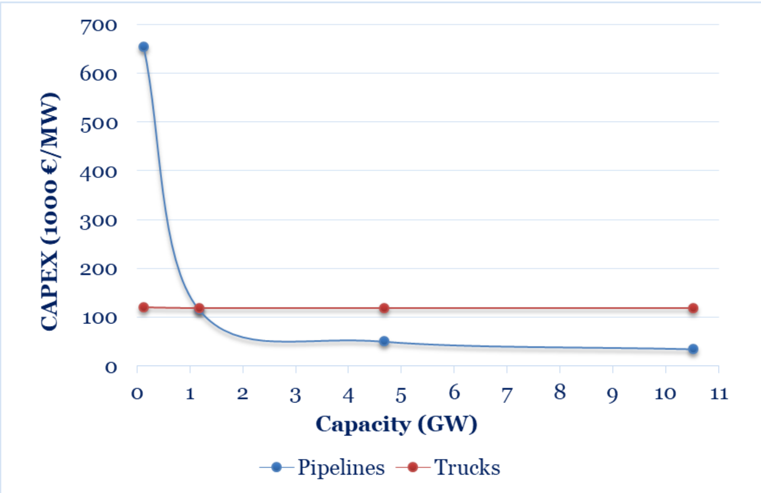
In addition, it appears that neither types of hydrogen production require specific locational circumstances. SMR plants need access to the gas network and electrolysis plants need access to the electricity grid and water network, but access to these networks is in principle everywhere available in the Netherlands. In case of SMR-blue also proximity to a transport-and-storage system for CO_2 is required, and here they may be some locational constraints.

The above implies that the supply side of hydrogen production needs no particular economic regulation as the relatively small scale of the production facilities and the absence of strong locational advantages prevent the occurrence of a natural monopoly. Hence, it will be sufficient to have the existing regulation of TPA to electricity and gas networks besides the general competition policy oversight to realise competition in the production of hydrogen.

4.3.3 Transportation

The transport of hydrogen by pipeline, however, is characterised by scale economies and is therefore regarded as a natural monopoly. With large quantities of hydrogen, transport via pipelines is the most suitable and cost-efficient option (Figure 4.3). Although the capital costs of pipelines are high, the large quantities that can be transported (up to 9000 kg/h) and the relatively low operation costs make the costs per kg hydrogen small. For smaller quantities, however, the construction costs of a pipeline per unit hydrogen are simply too high, which means that in such a situation transport by trucks is more efficient.

Figure 4.3 Investments in pipelines and trucks in relation to total transport capacity (in 1000 €/MW)



When the hydrogen market evolves, like in the *Blue Hydrogen* or the *Green* scenario, transport will be done through pipelines. In such scenarios, it is not efficient to have more than a single network for the transport of hydrogen, which means that competition cannot evolve in the transport business. The transport of hydrogen, therefore, needs to be subject to economic regulation, just as the transport of natural gas and electricity.

4.3.4 Storage

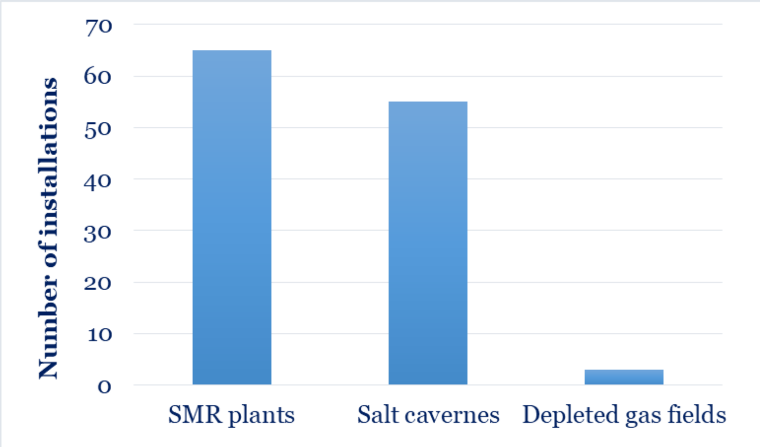
If hydrogen is used for producing heat in households and offices, the demand will be strongly related to the outside temperature. If the temperature drops, the supply side should be able to increase its production in order to meet the demand. For competition to be effective under such circumstances, it is crucial to know how many facilities would be required and available to realise this increase in supply. In order to get an impression of the competitive situation in case of a cold winter period, we estimate the number of facilities required for various types of techniques. (Table 4.1) shows our assumptions we make this calculation.

If there were no storage facilities available, the increase in supply should be realised by extra production by hydrogen plants. If there was a period of 14 cold winter days, then there would be a need of 60 extra SMR plants to realise the required extra supply of hydrogen to heat all houses (Figure 4.4). If storage were available in the form of salt caverns, then about 50 of them would be needed. However, if depleted gas fields could be used, then only 3 fields would be required. In the latter case a monopoly may easily occur if these fields were all operated by a single firm. In such case, regulation would be required in order to prevent that the flexibility to supply extra hydrogen during cold winter days is available to the market against reasonable prices. This regulation is comparable to the current regulation of storages in the natural-gas market.

Table 4.1 Assumptions to determine market situation in case of a period of 14 days cold weather

Assumptions:	value	source
average gas consumption household normal day (m^3)	3.4	CBS
average gas consumption household cold day (m^3)	10.00	
number of households (millions)	7.9	CBS
capacity SMR plant (GWh/h)	0.33	Collodi et al. (2017)
capacity withdrawal salt cavern (GWh/h)	0.39	Kruck et al. (2013)
capacity withdrawal depleted gas field (GWh/h)	7.8	Kruck et al. (2013)

Figure 4.4 Number of installations needed to meet the heat demand during a period of 14 days cold weather



4.3.5 Wholesale market

A liquid wholesale market requires standardisation of products, low level of transaction costs, transparency on prices and market conditions, and a high volume of trade. The hydrogen market may learn from how the market for natural gas has developed over the past decade

Despite the differences in qualities of various sources of gas, the trade in natural gas is done in uniform units (in MW) which strongly facilitates trade.[21] To sell the commodity as a homogenous product, each type of gas is valued in terms of the energy content it carries. This means that not the volume (like m^3) of the gas is sold, but the amount of energy it carries since heating is the main purpose of gas.

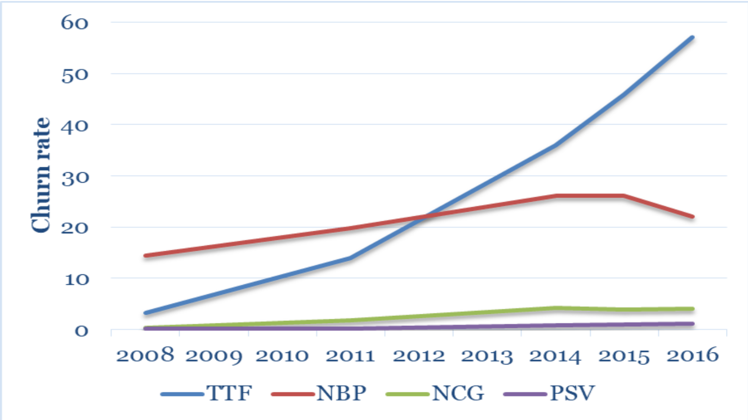
In order to reduce the transaction costs and increase the transparency of trade, a market hub called Title Transfer Facility (TTF) has been created. The TTF is a virtual hub based on an entry-exit system in which market parties can transfer gas already injected into the national grid to other parties.[22] As long as the gas is within the system, it can change owner. It is common that gas ownership changes numerous times between entry and exit. This is the so-called churn rate which has increased strongly over the past years, thereby indicating a highly liquid market (Figure 4.5).

One factor behind the liquidity of the TTF is the high quantities supplied relative to the quantities demanded (Figure 4.6). The total supply to the Dutch natural-gas market has been about twice as high as the total Dutch gas consumption, while in most other countries this ratio is much lower.

---

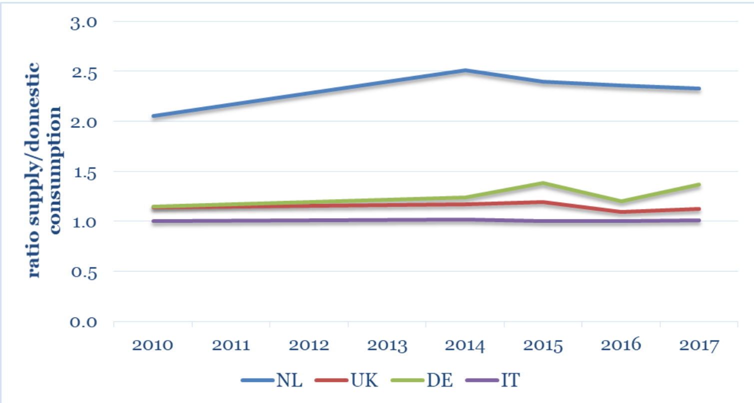
[21] Natural gas is a heterogeneous product as, the precise characteristics of the gas differ from field to field. These characteristics are measured through the so-called Wobbe-index, which indicates the thermic value of the gas. Broadly speaking, the product natural gas can be separated into two categories: low- and high-calorific gas. Low-calorific gas contains a higher percentage nitrogen than high-calorific gas resulting in a lower Wobbe-index. Hence, the thermal energy stored in a unit of low-calorific gas is lower than in the same unit of high-calorific gas.
[22] Actually, the TTF also facilitates trade in ownership rights of gas that is not yet injected into the grid.

Figure 4.5 Churn rates of a number of natural-gas hubs, 2008- 2016 (average per year)



Source: Heather & Petrovich (2017)

Figure 4.6 Ratio Supply/Domestic consumption of natural gas in a number of European countries, 2010/2017



Source: IEA (2018)

Hence, in order for a liquid hydrogen market to emerge in the Netherlands, there should be more supply coming to this market, which can be traded and re-exported. What could be international sources of supply of hydrogen to the Dutch market? It is often said that hydrogen could be produced through electrolysis in North-Africa and then transported to the Netherlands. The question is, however, what the required hydrogen price should be in the Netherlands (say, the Maasvlakte) to make such import profitable. In order to get an impression of this price, we have made a calculation based on a number of assumptions derived from the literature (Table 4.2).

Table 4.2 Assumptions on supply of hydrogen from North-Africa

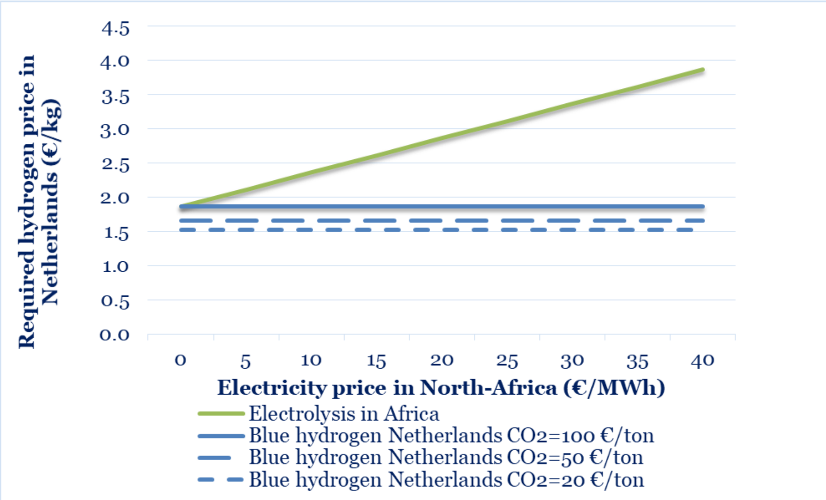
Assumptions	Value	Source
distance Netherlands - North-Africa	3300	
CAPEX onshore pipelines (€/kg)	0,48	Krieg (2012)
ratio CAPEX offshore/onshore	2,00	Cornot-Gandolphe (2003); figure 6
variable transportation costs (€/kg)	0,31	Krieg (2012)
fixed production costs hydrogen (€/kg)	0,54	
gas price Netherlands (€/MWh)	20	
water costs (€/kg)	0,05	5 times as high as in NL
electricity use (MWh/kg)	0,05	

Note: Total transport costs per kg are € 1.27, which is almost similar to what Amos (1998) found (€ 1.42)

Figure 4.7 depicts the required price in the Netherlands of hydrogen produced in North-Africa through electrolysis. A crucial assumption in this calculation is the price of electricity in this region. If we assume that this electricity price is 5 euro/MWh, which is about 25% of the current price in that region now, then the required hydrogen price would be about 2 euro/kg. upon arrival in the Netherlands. This required price would be higher than that required for SMR-blue, even if the price of CO_2 would be 100 euro/ton. Hence, we conclude that hydrogen produced in North-

Africa is not a competitive alternative and cannot be part of extra supply to a Dutch hydrogen market.

Figure 4.7 Required hydrogen price for hydrogen produced in North-Africa and transported to the Netherlands and for blue hydrogen produced in the Netherlands (for different carbon prices)



4.3.6 Retail market

Consumers may have different preferences for the type of hydrogen, just as they have different preferences for various types of electricity and gas. The economics of the transport of hydrogen, however, make it that it is not efficient to have alternative transport infrastructures. All hydrogen coming from different sources (SMR-grey, SMR-blue, SMR-green, Electrolysis-grey, Electrolysis-blue or Electrolysis-orange) will have a standardized physical quality and transported through the same infrastructure.

Users who prefer a specific physical quality (i.e. pureness) of hydrogen, may need to convert the hydrogen to a different quality level upon arrival of the hydrogen at their location. This will likely only hold for chemical industries who use the hydrogen for feedstock. Most users, however, will use the hydrogen for heating and they only have to adapt their appliances to the hydrogen quality transported through the network.

A more important distinction in quality is related to the way the hydrogen is produced, as consumers may have a preference of green or even orange hydrogen. This quality is not related to the physical characteristics of hydrogen, but to how 'sustainably' it is produced. In order to facilitate these consumers a certificate system is required, just as it currently exists for electricity and gas based on the European system of Guarantees-of-Origin.

5. Concluding remarks

5.1 Introduction

Hydrogen is increasingly seen as an energy carrier that can help to decarbonize energy systems. It may offer flexibility to the electricity system by converting electricity into hydrogen at times when the generation of electricity by renewable sources exceeds the demand for electricity. This hydrogen can be used to produce electricity again at other times when renewable sources are not able to generate sufficient electricity to meet demand. Hydrogen production on offshore locations where also the renewable electricity is generated may result in lower system costs because transporting gases is less expensive than transporting electricity. This hydrogen may be used for heating in buildings and for chemical processes in the industry. In these applications of hydrogen, it may help these sectors to decarbonize without the need to make major investments themselves.

In this paper, we have analysed the economic factors that affect the outlook for a hydrogen market in the Netherlands. This analysis was directed at three aspects: a) the factors that determine the business case of alternative options to make hydrogen, b) the factors that determine the quantitative outlook of hydrogen markets and c) the need for specific regulatory measures to foster the hydrogen market.

5.2 Business case of hydrogen

The business cases of alternative options to produce hydrogen are strongly determined by the (expected) prices of the inputs used in the production process. For SMR, the gas price is crucial and for electrolysis the electricity price is the major factor. Based on our analysis in this report, we formulate the following conclusions:

- At the market prices of natural gas and electricity which we have seen in the past decade, SMR hydrogen is much more attractive than electrolysis hydrogen. At the current gas price of about 20 euro/MWh, the electricity price should be less than half of the current electricity price (which is about 45 euro/MWh) to make electrolysis more favourable than SMR. This conclusion is robust against more optimistic assumptions on higher efficiencies and lower investment costs of electrolysis plants.
- This conclusion hardly changes when we compare electrolysis hydrogen with SMR hydrogen where the carbon is captured and stored (CCS) which results in so-called blue hydrogen. At current market prices, blue hydrogen is way more favourable than electrolysis hydrogen. It also appears that blue hydrogen becomes even more favourable than SMR hydrogen without CCS (so-called grey hydrogen) when the price of CO_2 is above 30 euro/ton.
- Hydrogen produced through electrolysis is not only more expensive than hydrogen produced through SMR, it also faces several difficulties as a tool for climate policy. One of these difficulties is that an efficient climate policy requires a relatively high carbon price, but a higher carbon price raises the electricity price which makes electrolysis more expensive. This effect occurs because gas-fired power plants set the electricity price during many hours in a year. This effect will remain also when the share of renewables is much higher, as investors in renewable electricity need these hours of high prices in order to recoup their investments. The higher the share of renewables, the smaller this effect will become though.
- Another factor why electrolysis creates challenges for climate policy is that low electricity prices, which are necessary for electrolysis to be profitable, are an incentive for all energy users to consume more

electricity, while climate policy just needs a reduction of energy demand. In addition, when the electricity price is low, then it is reasonable to expect that other sectors will tend to switch to using electricity for their energy-related activities, such as households switching to heat pumps and full-electric cars. Hence, in a situation of low electricity prices, the demand for electricity likely surges. In our quantitative exploration, we find that the total Dutch electricity consumption may more than double. This would require a tremendous increase in installed capacity of renewable generation as otherwise the electrification would raise the carbon emissions. Such an increase may not be realistic given all kind of restrictions which may pop up when the scale of renewable generation increases.

- This is not the only way by which electrolysis competes with other sectors that want to decarbonize. Hydrogen produced through electrolysis is often referred to as green hydrogen when the electricity is produced by renewable sources. There are, however, many firms in other sectors (but also households) that also want to claim that they use green electricity. In order to be able to make such claims these firms buy green certificates (guarantees of origin). In the recent years, the prices of these certificates have risen, in particular for the certificates that refer to renewable electricity production in the Netherlands. Hence, green hydrogen production raises the costs for other firms that want to buy green electricity which implies that a number of these firms (and households) will not be able to use green electricity because of the extra demand by electrolysis plants.
- If an electrolysis plant is directly connected to a wind turbine or solar panel, then there is no need to buy green certificates as the origin of the electricity is clear. However, in such a setup, there is another disadvantage. When an electrolysis plant can only use electricity which

is generated by a specific wind turbine, for instance, the production becomes related to weather circumstances and, hence, way more volatile. This strongly reduces the efficiency as well as the number of operating hours, which raises the required revenues per unit of hydrogen in order to be able to recoup the investments. This disadvantage of this setup exceeds the potential benefits of not having to make costs for electricity grid extensions and green certificates.

- Importing green hydrogen from countries, like North-Africa, where the conditions for solar power are way more favourable, does not seem to be profitable as well. The costs of transporting this hydrogen to the Netherlands make that the required hydrogen price of this imported hydrogen is likely higher than the price of alternatives.
- Despite these challenges for electrolysis, a future in which hydrogen is produced in this way is conceivable. When the international gas markets become tight, with high natural-gas prices as result, and when massive investments in renewable electricity generation are made, with many hours of low electricity prices as result, electrolysis may become the most efficient way of making hydrogen. When also the industrial use of natural gas is taxed like it is now done for households in the Netherlands, the industry will have a strong incentive to substitute away from natural gas to hydrogen.
- When these conditions are not met, blue hydrogen may be an efficient alternative to decarbonize a significant part of the Dutch economy. Key economic conditions for blue hydrogen to become profitable are a low price of natural gas and a price of CO_2 which is at least 30 euro/ton.

5.3 Future outlook

The future outlook for hydrogen depends, of course, strongly on the storylines regarding the future driving factors. We have defined two key driving factors: the tightness of the global natural-gas market and the stringency of (inter)national climate policy. In a scenario with a tight global gas market and stringent climate policy, green hydrogen will be the most favourable type of hydrogen, while in a scenario with a loose global gas market with a stringent climate policy, blue hydrogen is more likely. In the other circumstances (scenarios), the hydrogen market remains dominated by grey hydrogen. For these scenarios, we have the following outlook:

- In the scenarios with favourable conditions for green hydrogen or blue hydrogen, the total production of hydrogen increases strongly. This holds in particular for a scenario in which blue hydrogen is most favourable. In this scenario, total consumption could increase from the current 120 PJ to about 1000 PJ in 2050. In the scenario where green hydrogen is favourable, the total consumption is estimated at a much lower level: 500 PJ in 2050. This is due to the fact that in a scenario in which electrolysis is attractive because of low electricity prices, electrification is also attractive. Hence, green hydrogen has to compete with heat pumps in buildings and with full-electric cars in transport.
- In both scenarios, the total carbon emissions may reduce dramatically, which shows that hydrogen can indeed be an effective energy carrier to decarbonize the economy. Decarbonisation does not imply a strong reduction of the use of fossil energy, as is shown by a scenario where the use of blue hydrogen strongly increases. In this scenario, the total consumption of natural gas increases as well.

5.4 Creating markets

The need for specific regulatory measures to create a Dutch hydrogen market depends on the existence of structural shortcomings (market failures). It appears that the market for hydrogen is quite similar to the electricity market with regard to the production side, while for the transportation side and the wholesale trade, the hydrogen market can be well compared to the natural-gas market. For the market failures and need for regulation we conclude the following:

- In the production of hydrogen there is a clear market failure when the carbon emissions are not priced correctly. Introducing a (implicit) carbon price that is related to the social marginal costs of climate change would solve this market failure.
- The transport of hydrogen shows clear economies of scale resulting a natural monopoly for a pipeline infrastructure. This monopoly should be regulated in the same way the current natural-gas network is regulated.
- The storage of hydrogen may also show the risk of a natural monopoly when it is possible to store hydrogen in depleted gas fields. When the hydrogen is stored in salt caverns, however, then there will likely be many facilities and active firms which may result in sufficient and effective competition.
- A wholesale market for hydrogen will not develop automatically, as a number of conditions have to be satisfied, just as we have seen in the natural-gas market. The products need to be standardized, transport capacity should be available for traders, while there should also be sufficient volumes in order to get a liquid market. As we have seen above, it is not likely that this volume will come from hydrogen produced in for instance Africa or the Middle-East because of the high costs of transportation.
- In the retail market, regulation is required to enable consumers to buy hydrogen produced by different sources. Such a regulation can be similar to the system of guarantees-of-origin in the natural-gas and electricity markets.

References

Algemene Rekenkamer (2018). Focus op kosten windenergie op zee. Den Haag.

Amos, W. A. (1998). Costs of storing and transporting hydrogen, *National Renewable Energy Laboratory*. NREL/TP-570-25106. November.

Cardella, U., L. Decker and H. Klein (2017). Economically viable large-scale hydrogen liquefaction. *IOP Conference Series: Materials Science and Engineering*, 171 012013.

CE Delft. (2018). Waterstofroutes Nederland; Blauw, groen en import. Delft, June 2018.

Certifhy. (2015). Overview of the market segmentation for hydrogen across potential customer groups, based on key application areas. Deliverable No. 1.2.

Certifhy. (2016). Generic estimation scenarios of market penetration and demand forecast for "premium" green hydrogen in short, mid and long term. Deliverable No. D1.3.

Chardonnet, C., Giordano, V., De Vos, L., Bart, F., & De Lacroix, T. (2017). Study on early business cases for H2 in energy storage and more broadly power to H2 applications. FCH-JU: Brussels, Belgium, 228.

Cornot-Gandolphe, S., Appert, O., Dickel, R., Chabrelie, M. F., & Rojey, A. (2003, June). The challenges of further cost reductions for new supply options (pipeline, LNG, GTL). *In 22nd World Gas Conference* (Vol. 5, pp. 1-17).

Collodi, G., Azzaro, G., Ferrari, N., & Santos, S. (2017). Techno-economic Evaluation of Deploying CCS in SMR Based Merchant H2 Production with NG as Feedstock and Fuel. *Energy Procedia*, 114, 2690-2712.

Decisio – Witteveen+Bos (2018). Integrale kosten-batenstudie vervolgroutekaart windenergie op zee. Amsterdam, maart.

Dillich, S., Ramsden, T., & Melaina, M. (2012). Hydrogen production cost using low-cost natural gas. DOE Hydrogen and Fuel Cells Program Record, 12024.

Gasunie & Tennet. (2019). Infrastructure Outlook 2050; A joint study by Gasunie and TenneT on integrated energy infrastructure in the Netherlands and Germany.

Götz, M., J. Lefebvre, F. Mörs, et al. (2016). Renewable Power-to-Gas: A technological and economic review. *Renewable Energy* 85 (2016) 1371-1390.

Heather, P., & Petrovich, B. (2017). European traded gas hubs: an updated analysis on liquidity, maturity and barriers to market integration. *Oxford Institute for Energy Studies*.

Hulshof, D., van der Maat, J. P., & Mulder, M. (2016). Market fundamentals, competition and natural-gas prices. *Energy Policy*, 94, 480-491.

Hulshof, D., Jepma, C., & Mulder, M. (2019). Performance of markets for European renewable energy certificates. *Energy Policy*, 128, 697-710.

Hydrogen Council. (2017). How hydrogen empowers the energy transition. January 2017.

International Energy Agency (IEA) (2017). Global trends and outlook for hydrogen. Paris, December.

International Energy Agency (IEA) (2018). Natural gas information. Paris.

IRENA (2018). Hydrogen from renewable power; technology outlook for the energy transition. September.

Krieg, D. (2012). Konzept und Kosten eines Pipelinesystems zur Versorgung des deutschen Straßenverkehrs mit Wasserstoff (Vol. 144). *Forschungszentrum Jülich*.

Kruck, O., Crotogino, F., Prelicz, R., & Rudolph, T. (2013). Assessment of the potential, the actors and relevant business cases for large scale and seasonal storage of renewable electricity by hydrogen underground storage in Europe. HyUnder Deliverable No. 3.1.

Leeuwen, C. van, & Mulder, M. (2018). Power-to-Gas in Electricity Markets dominated by Renewables. *Applied Energy*, 232, 258-272.

Moraga-González, J. L., & Mulder, M. (2018). Electrification of Heating and Transport; a Scenario Analysis for the Netherlands Up to 2050. *CEER Policy Paper No.2*.

Reuss, M., Grube, T., Robinius, M., Preuster, P., Wasserscheid, P., & Stolten, D. (2017). Seasonal storage and alternative carriers: A flexible hydrogen supply chain model. *Applied energy*, 200, 290-302.

Tebodin. (2015). QRA leidingen Air Liquide, Alle leidingen. Tebodin Netherlands B.V., Velsen-Noord.

TKI nieuw gas. (2018). Contouren van een Routekaart Waterstof, Amersfoort: TKI nieuw gas.

Waterstof Coalitie (2018). Waterstof essentiële bouwsteen energietransitie. Mei.

World Energy Council (WEC) – The Netherlands (2018). Hydrogen industry as catalyst; accelerating the decarbonisation of our economy until 2030. Tilburg.

Appendix A The current hydrogen market

The total European consumption of hydrogen in 2010 is estimated at 7 Mtons, which is equal to about 1.3% of total European energy consumption (Certifhy, 2015). [23] The current hydrogen consumption almost completely consists of demand from industrial users. The main components of industrial demand are: chemical, refining, metal working and other industrial use. These components have a relative share of 63%, 30%, 6% and 1% of industrial consumption.

The main chemical applications of hydrogen in the chemical segment are in the production of ammonia (84%) and methanol (12%). A representative ammonia plant needs between 57,500 to 115,000 tons of hydrogen per year, where this is around 266,000 tons/ year for a methanol plant (Certifhy, 2015).

In refining, the hydrogen is used to crack the heavier crudes and produce lighter crudes. This feedstock demands a high purity of the hydrogen as it is crucial for the utilization (Certifhy, 2015). A typical plant uses hydrogen in a range of 7,200 – 108,800 tons/tear.

In the metal processing segment hydrogen is used to realise iron reduction. The market share of 6% is an equivalent to 410,000 tons with a single plant using up to 720 tons/year (Air Liquide, 2004). Table A.1 gives an overview of the industrial usage and their main players.

The current consumption in the markets for mobility and power-to-gas is negligable. However, both are expected to play an increasing role in hydrogen demand in the future (Certifhy, 2015; CE Delft, 2018; TKI Nieuw gas, 2018). In the mobility sector, the use of hydrogen is limited to heavily subsidized pilot projects. The slow introduction of technology and

[23] Assuming an energy equivalent of 130MJ/kg H^2, this is 910 PJ. This adds up to roughly 1.3% of total European energy consumption. Total energy consumption in 2015 was 68,119 PJ (Eurostat).

infrastructure can be identified as one of the reason of the low rate of implementation (Certifhy, 2015).

Table A.1 Overview of current hydrogen use in Europe, per segment

Segment	Key applications	Accumulated H2 demand	Key player(s)
Chemical	Ammonia production	4.3 Mtons	Yara (fertilizer supplier)
	Methanol		Methanex and Sabic
	Others		DuPont, BASF, Lanxess, DSM and Bayer Material Science
Refineries	Hydro-cracking & Hydrotreating	2.1 Mtons	BP, Total, Shell and EXXON
Metal working	Iron reduction	0.41 Mtons	Arcelor Mittal

Source: Certifhy (2015)

The current supply of hydrogen consists of two main types: on-site production and as a by-product in chemical processes. On-site production is done by the large consumers in the chemical industry and composes 64% of total European hydrogen production (Certifhy, 2015). Hence, for this type production, the hydrogen is not sold but directly used by the producer. Another 27% of the hydrogen production is produced as residual product in chemical processes. This hydrogen is sold through bilateral contracts. This market is shallow, meaning that the number of transactions and number of players are small.

Because of this, the hydrogen market is not transparent (Certifhy, 2015). There is no database yet of prices and transactions. As a result, the price of hydrogen is likely highly dependent on the local market situations. Hence, a global (regional or national) price of hydrogen does not exist.

Acknowledgements

We are very grateful for the support given by GasTerra to conduct this research. In particular, we thank Gerard Martinus and his colleagues for the valuable input and discussions during the project. We also thank the representatives of a number of stakeholders in the hydrogen and gas industry for sharing their views with us. Finally, we thank the participants of the workshop on hydrogen in Utrecht on 14 February 2018 and the organizer of this event, MSG, for the discussion and feedback on the draft version of this report. As usual, the full responsibility of the content of this policy paper lies solely with the authors.

Hydrogen is increasingly seen as the energy carrier of the future as it has the potential to replace natural gas for heating and electricity production while it can also be used as a fuel in transport and as feedstock in the industry. The potential of hydrogen as a key energy carrier has been analysed extensively from a technical-engineering perspective, but less attention has been paid, however, to the economic conditions behind the supply of hydrogen and the design of markets for hydrogen.
In this paper the authors explore the economic outlook for various types of hydrogen production, its transportation and storage in the Netherlands. They also develop scenarios based on the key economic drivers for hydrogen, which are the tightness of international energy markets and the stringency of (inter) national climate policy. For the scenarios in which hydrogen supply and demand may grow strongly, they finally analyse the design features for a well-functioning hydrogen market.

Machiel Mulder is professor of Regulation of Energy Markets and the Director of the Centre for Energy Economics Research (CEER) at the Faculty of Economics and Business at the University of Groningen.

Peter Perey is MSc in Economics and is researcher at the Centre for Energy Economics Research at the Faculty of Economics and Business of the University of Groningen.

José L. Moraga is professor of Microeconomics at the Department of Economics of the Vrije Universiteit Amsterdam and professor of Industrial Organization and co-director of the Centre for Energy Economics Research at Faculty of Economics and Business of the University of Groningen.

The research for this policy paper has been conducted on request by and with financial support from GasTerra, a Dutch wholesaler in natural gas and green gas.

AACSB ACCREDITED EFMD EQUIS ACCREDITED

www.rug.nl/ceer