HyDelta 2

WP4 – Regional blending in the regional transmission (40 bar) pipelines to overcome congestion in the electricity grid

D4.1 – Introducing hydrogen in decentral end-user areas to deal with e-grid congestion in the Netherlands

Status: final

Dit project is medegefinancierd door TKI Nieuw Gas | Topsector Energie uit de PPS-toeslag onder referentienummer TKI2022-HyDelta.

Document summary

Corresponding author

Corresponding author	Salar Mahfoozi
Affiliation	New Energy Coalition (NEC)
Email address	s.mahfoozi@newenergycoalition.org

Document history

Version	Date	Author	Affiliation	Summary of main changes
1	21 Jul – 2022	SM, RvZ, CJ	NEC	80% Draft
2	09 Sep – 2022	SM, RvZ, CJ	NEC	100% Draft
3	21 Sep – 2022	SM, RvZ, CJ, JL	NEC, GTS	Additions and changes based on feedback from the EAG
4	24 Oct – 2022	SM, RvZ, CJ	NEC	Further feedback changes and editorial changes/proof-reading
5	06 Dec – 2022	SM	NEC	Cosmetic changes

Dissemination level

Dissemination Level		
PU	Public	X
RE	Restricted to • Partners including Expert Assessment Group • External entity with whom a Non-Disclosure Agreement exists	

Document review

Partner	Name
GTS	Jelle Lieffering
Stedin	Iman Pishbin
Liander	Bart Vogelzang
NEC	Catrinus Jepma
NBNL, Gasunie, Kiwa, DNV, TNO, NEC, NDG, OGH2	HyDelta Supervisory Group

Executive summary

In order to move towards a renewable energy system in the Netherlands, an increasing capacity of renewables has to be connected to the electricity grid (e-grid). Reinforcement of this grid costs time also because of the immanent electrotechnical workforce scarcity in the country. Therefore, Dutch electricity DSOs already face and foresee rapidly growing (localised) challenges in providing grid connections (in time) for connecting local renewable energy capacities. In this study it was investigated whether and to what extent local or regional P2G systems may alleviate congestion in the e-grid in some critical areas by introducing green hydrogen produced via P2G – blended or otherwise – in decentral industrial clusters and/or the mobility sector in particular areas.

The focus in the study on decentralized (so-called cluster 6) industry and local mobility as potential green hydrogen consumers (rather than the five main industrial clusters in the country) was chosen because, unlike the main industrial clusters, the more local industry and mobility hydrogen uptake is typically not easily connected to the foreseen national hydrogen backbone. Therefore, the regional transmission gas line (RTL) will have to act as the main potential hydrogen grid connection for these industries. To identify the country's most suited areas for establishing such potential local hydrogen connections (and hydrogen blending), four location criteria have been combined: the severity of supply side driven e-grid congestion; the presence of local industry with a grid connection decoupled from the built environment/public distribution system (because such a connection would complicate blending); the proximity to (future) renewable energy production sites; and the assumed little industries' decarbonization alternatives. Based on these criteria, some dozen potential 'hydrogen blending regions' were identified throughout the Netherlands, each with multiple possible local blending sites (see figure below).

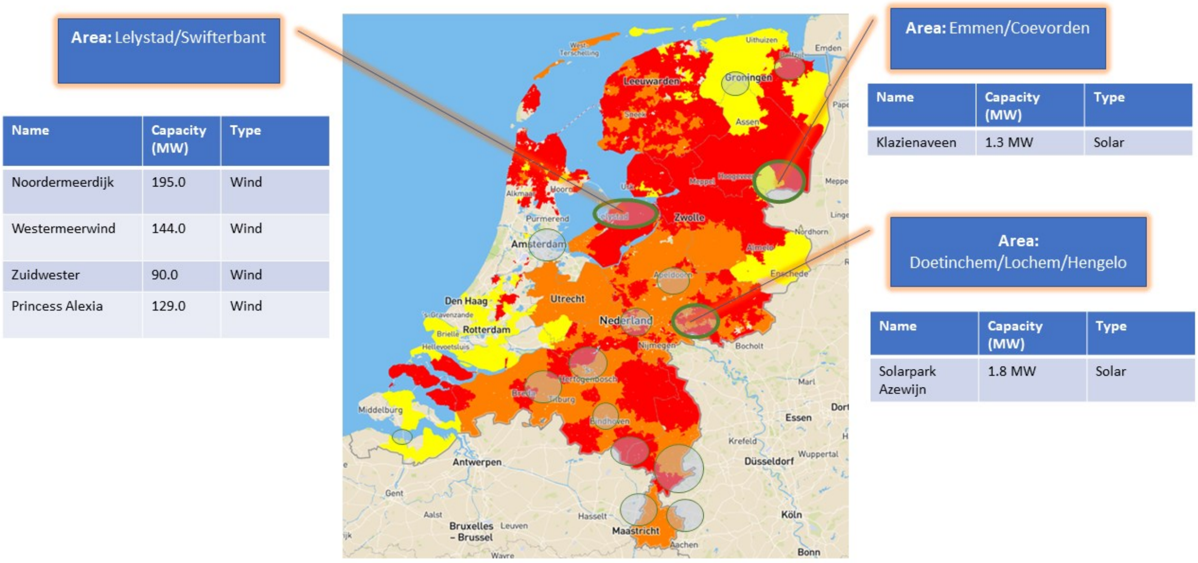


Figure 1: Potential blending sites [1]

Modelling[1] of the supply side economics of P2G congestion solutions for these regions revealed that, although the P2G option may be promising on the longer term, currently its business case is difficult from the perspective of energy suppliers given the combination of current assumed market prices of green hydrogen and local industry demand levels. Under the present conditions on the whole for energy suppliers in the selected regions trying to deal with e-grid congestion, utility-scale batteries turned out to offer a higher utilization rate and to be more cost-effective to deal with the issue. The latter is due to batteries' scalability and currently lower CAPEX-levels (than electrolysers) and to handsome electricity trading margins given current high electricity prices. Obviously the most economic congestion combatting option for the suppliers of energy will not always coincide with what is most economic from the perspective of the demand side, i.e. industries or mobility sector units in the area off-taking energy. The same may apply if cost conditions alter e.g., as P2G technology matures.

Another key finding from modelling the optimal options for energy suppliers to deal with congestion via hydrogen blending in the given regions under current conditions was that deliveries to the mobility sector dominated. This was because hydrogen prices in mobility are assumed to be higher than those for industry. A backdrop of delivery to mobility, however, is that both prices and demand volumes are more uncertain than deliveries to industry.

Interviews with various stakeholders revealed the following main perceived opportunities and barriers of implementing P2G investment and local blending in decentral industries.

The main barriers:

- As long as it is uncertain if local e-grid congestion is a lasting and growing or instead temporary problem in a particular region (e.g., because operators may or may not extend grid-capacities), the profitability of an electrolyser investment by a local energy provider to deal with congestion will be uncertain as well. Given that electrolyser and related equipment CAPEX levels on the whole are quite high, such uncertainty can pose a serious barrier.
- If congestion is mitigated via P2G involving a relatively small hydrogen blend of, say, 10% hydrogen admixed to natural gas (corresponding with ≈3% emission reduction), the decarbonisation impact remains quite small; at the same time the energy content of the blend gets smaller than of natural gas only (when compared at constant volumetric flowrate). Introducing hydrogen blends therefore is only considered to be worthwhile by decentral industries if it offers a serious and ultimately complete step forward towards decarbonising the use of gas.
- P2G investment to deal with congestion remains tricky as long as uncertainty remains about the degree to which energy system operators are legally allowed to facilitate 'pure' hydrogen connections to the gas grid to serve specific local demand and to apply blends of hydrogen in their local grid.

The main opportunities:

- Local P2G investment and subsequent hydrogen blending can be a first step towards local integration of the electricity and gas systems. This way it can help: offering a solution for local

[1] The modelling activities that took place in this study were based on the 2022 state of the art with respect to the cost of batteries and electrolyzers and with respect to the availability of SDE++ subsidies and conditions.

e-grid congestion problems; enhance the profitability of RES investment; and improve local security of supply conditions.

- Local P2G investment designed to deal with e-grid congestion can also: act as a stepping stone to synergistically serve an increasing number of end users besides local industry (e.g. mobility and the built environment); and may act as a dominant enabler of a decisive decarbonisation trend in the entire relevant area.

Market conditions for P2G are generally expected to improve as the technologies are scaling up such that ultimately hydrogen may develop into a dominant energy carrier; given this perspective, first-mover issues may have to be taken for granted for the technology to ultimately pay off. Not following this path carries the risk of missing out in the future.

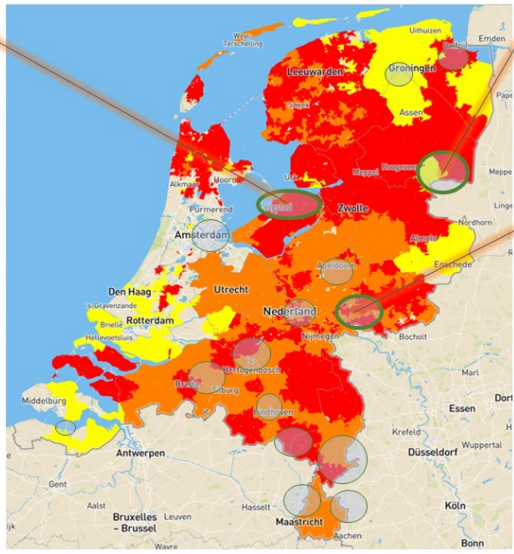
Samenvatting

Om in Nederland een koolstofneutraal energiesysteem te kunnen realiseren, moet een toenemende productiecapaciteit van duurzame energie worden aangesloten op het elektriciteitsnet. Versterking van het elektriciteitsnet kost tijd en de beschikbaarheid van elektrotechnisch personeel wordt een steeds groter probleem. Daarom voorzien de Nederlandse regionale netbeheerders (RNB's) grote uitdagingen om op tijd te voorzien in netaansluitingen voor additionele lokale hernieuwbare energiecapaciteit. Er is in deze studie onderzocht of en in hoeverre lokale P2G-systemen kunnen worden ingezet om in bepaalde gebieden waar aansluiting op de waterstof-backbone lastig is congestie op het elektriciteitsnet te verminderen door gebruik te maken van op basis van groene stroom geproduceerde waterstof in lokale industriële clusters en mobiliteit.

Er is in het onderzoek gekozen voor een focus op lokale decentrale industrieclusters (de zgn. cluster 6 industrie, zulks ter onderscheid van de vijf erkende grotere industrieclusters in ons land) en de mobiliteit in de cluster 6 gebieden, omdat meestal de voorziene grote nationale waterstoftransportleidingen (backbone) niet in de buurt zijn van deze clusters, zodat alleen een regionale transmissiegasleiding (RTL) - waarop dit onderzoek zich typisch richt - kan fungeren als een potentieel leveringssysteem van waterstof. Er werden vier criteria gebruikt om potentiële cluster 6 locaties voor invoeding van waterstof (via bijmenging of anderszins) ter vermindering van congestie in het elektriciteitsnetwerk te identificeren: de ernst van de lokale elektriciteitscongestie aan de aanbodzijde; de beschikbaarheid van decentrale industrie die qua gasnet verbinding is losgekoppeld van de gebouwde omgeving/het openbare distributiesysteem (omdat dit eventuele bijmenging teveel compliceert); de nabijheid van (toekomstige) productielocaties voor hernieuwbare energie; en de naar verwachting geringe beschikbaarheid van andere (meer) koolstofneutrale alternatieven voor de afnemers. Op basis van deze criteria zijn in heel Nederland ruim een dozijn potentiële 'waterstof bijmengregio's' geïdentificeerd, met elk meerdere locaties waar lokale bijmenging 'op papier' mogelijk is (zie onderstaande figuur).

Area: Lelystad/Swifterbant

Name	Capacity (MW)	Type
Noordermeerdijk	195.0	Wind
Westermeerwind	144.0	Wind
Zuidwester	90.0	Wind
Princess Alexia	129.0	Wind



Area: Emmen/Coevorden

Name	Capacity (MW)	Type
Klazienaveen	1.3 MW	Solar

Area: Doetinchem/Lochem/Hengelo

Name	Capacity (MW)	Type
Solarpark Azewijn	1.8 MW	Solar

Figure 2: Potentiële waterstof bijmeng gebieden [1]

Op basis van de modelresultaten[2] is het voor de geselecteerde locaties onder de huidige omstandigheden over het algemeen de vraag of en in hoeverre P2G-oplossingen vanuit potentiële aanbieders gezien nu al economisch interessant zijn als een middel om lokale congestie op het elektriciteitsnet in te dammen. Dit komt vooral door de huidige (nog) hoge kosten van electrolysetechnologie en veronderstelde geringe afnameprijzen van groene waterstof en het volume van de vraag vanuit de lokale industrie en mobiliteit. Modelresultaten suggereerden dat voor de aanbieders van energie die geplaagd worden door congestie op het stroomnet batterijen voor het verminderen van net-congestie een hogere benuttingsgraad bieden in vergelijking met P2G-systemen en thans kosteneffectiever zijn. Dit hangt ook samen met hun aanzienlijk lagere investeringskosten en het feit dat de verhandeling van stroom voor de exploitant van hernieuwbare energie onder de huidige hoge elektriciteitsmarktprijzen relatief winstgevend is. Het spreekt voor zich dat deze uitkomsten niet hoeven te corresponderen met wat vanuit de vraagzijde optimaal is en bovendien door veranderende kostendata bij opschaling van de P2G technologie op den duur en op bepaalde locaties anders kunnen uitpakken.

Nog een van de belangrijke bevindingen van de modelleringsactiviteiten was dat met het oog op een optimaal rendement vanuit de aanbieder bezien de levering aan de lokale industrie een qua omvang tweede prioriteit krijgt als ook aan de mobiliteitssector geleverd kan worden. Dit komt doordat de waterstofprijzen in de mobiliteit verondersteld worden hoger te liggen. Daar staat dan wel weer tegenover dat zowel de prijs als vraagvolumes van waterstof in de mobiliteitssector meer onzeker zijn dan bij afname uit de lokale industrie.

Interviews met lokale partijen leverde het volgende globale beeld op omtrent de percepties van de kansen en belemmeringen van lokale waterstofproductie en -toepassing (al dan niet op basis van bijmenging) ter vermindering van congestie op het stroomnet.

De belangrijkste belemmeringen:

- Zolang onduidelijk is of de congestie of dreigende congestie op het lokale stroomnet tijdelijk is dan wel van blijvende aard en wellicht verergerend, is er dus ook grote onzekerheid over de rentabiliteit van eventuele investeringen in P2G technologie en de daarop gebaseerde levering van waterstof aan de regio. Met weet dan niet of en zo ja, wanneer bijvoorbeeld de lokale congestie opgelost zal worden door netverzwaringen, noch wat het verdienmodel is.
- Indien bij toepassing van P2G met het oog op congestie gekozen wordt voor het bijmengen van de waterstof in de aardgasstroom en het waterstofdeel van het mengsel vrij laag blijft, zeg, 10% (hetgeen correspondeert met ca. 3% emissiereductie), dan blijft het decarbonisatie effect bij de afnemers (zeer) beperkt. Tegelijkertijd neemt de energie-inhoud van het mengsel wat af t.o.v. aardgas. Dit is voor afnemers meestal niet interessant, tenzij er door oplopende waterstofpercentages werkelijk het perspectief kan worden geboden van verdere stappen in de richting van uiteindelijk volledige vergroening van het gasgebruik.
- Investeringen in lokale P2G blijven riskant zolang juridisch onduidelijk blijft of, in hoeverre en wanneer de beheerders van het gasnet wettelijk is toegestaan om ’zuivere’ waterstofaansluitingen op het gasnet te faciliteren dan wel (bepaalde) mengsels van waterstof en aardgas in het net toe te passen.

De belangrijkste kansen:

[2] De modelleringswerkzaamheden die in dit onderzoek hebben plaatsgevonden zijn gebaseerd op de stand van zaken in 2022 met betrekking tot de kosten van batterijen en elektrolyzers en met betrekking tot de beschikbaarheid van SDE++ subsidies en voorwaarden.

- P2G en de lokale levering van waterstof via het gasnet in zuivere vorm of via lokale bijmenging kan een stap zijn naar lokale systeemintegratie van de elektriciteits- en gassystemen. Dit kan niet alleen bijdragen aan het oplossen van lokale congestieproblemen in het stroomnet, maar ook de rentabiliteit van lokale investeringen in hernieuwbare capaciteit verhogen en de lokale leveringszekerheid van energie versterken.

- Lokale waterstoflevering kan bovendien een opstap zijn naar de levering van groene energie aan andere lokale afnemers dan de industrie, zoals de lokale afnemers in de mobiliteit en gebouwde omgeving. Dit kan voor alle betrokken partijen synergievoordelen opleveren die ter plaatse het afname proces verder versterken zodanig dat de vergroening in de gehele betrokken regio wordt versneld.

Door de verwachte opschaling van de waterstofactiviteiten zullen de opties om kosteneffectief in de technologie te investeren naar verwachting steeds verder toenemen, uitmondend in een grote, stabiele rol voor waterstof in het energiesysteem. Eventuele aanloopproblemen zullen in die gedachtegang op den duur wegvallen tegen de voordelen en zouden dus in dit stadium de voortgang niet moeten belemmeren op straffe van het risico uiteindelijk achter te lopen bij de feiten.

Table of contents

1. Introduction

To achieve climate neutrality, all sectors of the economy need to decarbonize. In some sectors, such as buildings or passenger transport, this could entail direct electrification, e.g., through heat pumps and electric vehicles. In others, such as steel, chemical or long-distance air travel, electrification is not an option over the short to mid-term. Here, renewable hydrogen and its derivatives represent the foundation of a long-term solution. This is because renewable H_2 can be used to decarbonize sectors and applications that are resistant to electrification.

Sustainable production of hydrogen can occur through the process of electrolysis which is obtained from renewable electricity sources such as solar and wind. However, the increasing generation of renewable electricity from solar and wind resources is contributing to 1) heightening intermittency issues within national electricity grids and 2) an ever-growing congested electricity grid where the grid capacity cannot cope with the requests from new local solar and wind farms since expansion takes time and is limited by scarce manpower. As an approach, it has been investigated several times whether a link between the local gas and electricity grid can offer a solution, whereby during surplus hours, electricity can be converted to hydrogen and injected into the gas distribution network.

This hydrogen does have blending potential in local areas of the regional transport grid for offtake by local industries but also for mobility applications in hydrogen refuelling stations. These local industries are defined as industrial clusters that are outside of the 5 main industrial clusters of the Netherlands a.k.a. the 6th cluster (het zesde cluster). While blending in the national transmission grid and distribution grids have been researched in the past, blending in local parts of the regional transmission grid for industrial usage has not been explored and does have potential for utilization.

In this way, the aim is to accelerate the roll-out of local-generation (as part of Regional Energy Strategies) and making distributed industry (i.e., cluster 6) more sustainable. At the same time, parts of the grid are prepared for a long-term conversion to sustainable gases, including local links between the local electricity and gas grid for an increased system flexibility. The emphasis of the research in this work package will be on quantifying the accelerated regional generation potential, investigating the effect on the business case and behaviour of wind and solar farms with coupled electrolysers and the gas costs for end users.

The main research questions to be discussed in this report is: What are the likely techno-economic conditions of **introducing clean hydrogen, either pure or blended with natural gas, at specific places in the regional transmission network in cluster 6 areas; and what are the most important perceived barriers and opportunities of such introduction from both the supply and demand side?**

2. Congestion in the electricity distribution grid

2.1 Overview of the problem in the Netherlands

In the spirit of the EU and national climate targets, the Netherlands' still predominantly fossil energy landscape is experiencing a prominent transition shift towards a sustainable and low-carbon energy system. This process involves a rapid increase in the utilization of intermittent renewable energy sources such as wind and solar. In order to deal with intermittency, electricity, heat, and energy (and feedstock) molecules (predominantly gases and liquids) will become increasingly integrated in the energy systems of the future [2]. Such an increasingly integrated energy system is expected to contribute to a greener, more cost-effective and secure energy system amongst others by providing more flexibility and better transport and storage services needed to balance the system that is increasingly dominated by intermittent supply [3]. An integrated energy system is illustrated in Figure 3 involving sources, energy carriers/energy converters, and applications.

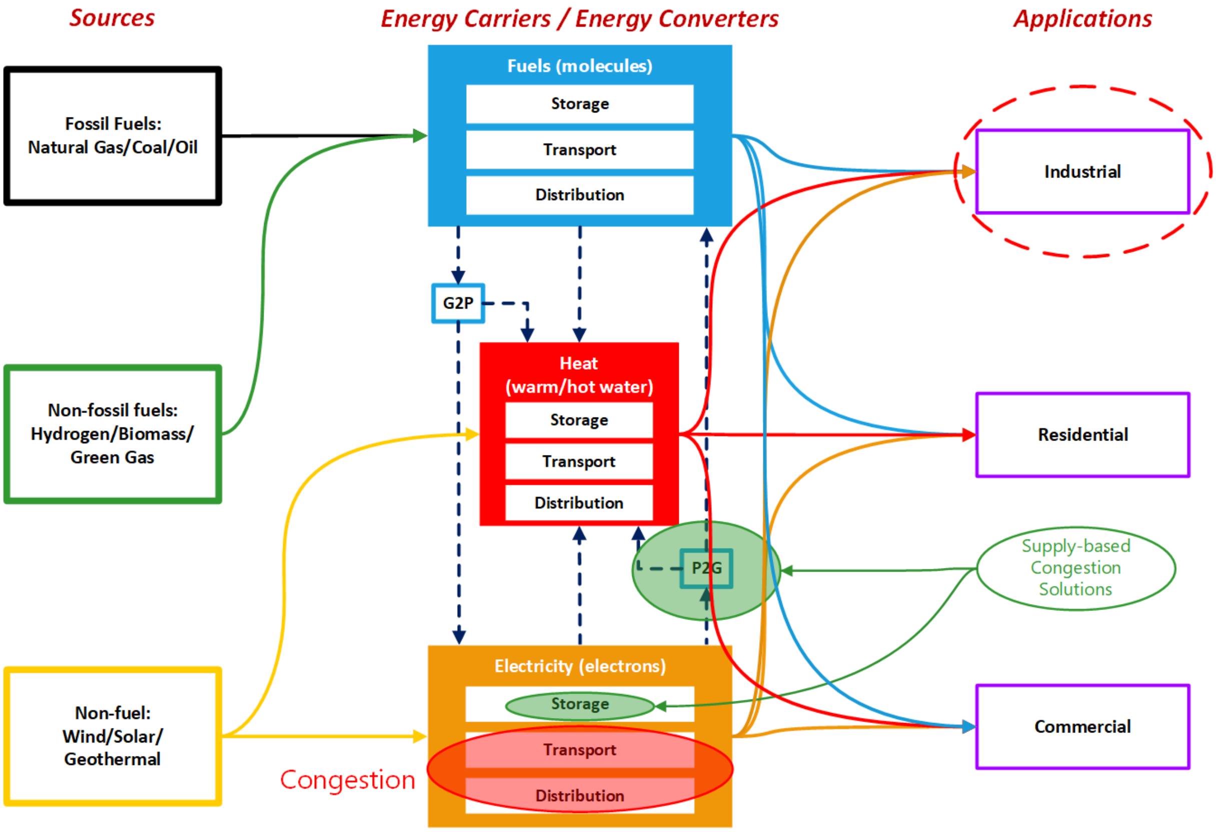


Figure 3: An integrated energy system based on sources, energy carriers/converters, and applications

In the typical conditions of the Netherlands' energy system that traditionally heavily relied on gas from domestic sources, the rapid RES-based electrification makes it difficult for the Transmission Service Operator (TSO) and Distribution System Operators (DSOs) to keep up with servicing all additional supply of electricity and keeping balance of the e-grid. Meanwhile a situation has been reached that the e-grid is facing serious congestion problems up to the point that some supply or some demand can simply not be serviced. Such congestion occurs when either the supply of electricity, or its demand and the associated capacity needed surpasses capacity in (part of the) transmission system [4].

E-grid congestion in the country is expected to further increase in the upcoming years. Figure 4 provides an overview for both the supply (L) and demand side (R) in the current situation. As far as demand side congestion is concerned, many locations, such as the Northern part of the Netherlands, Zuid-Holland, Zeeland, West-Brabant, etc., are demarcated red, orange and yellow, indicating 'fully congested', 'pre-announcement of structural congestion' and 'looming transport scarcity', respectively. Also, in terms of supply side congestion, a large expanse of the country's transmission grids is now already dealing with congested e-grid lines.

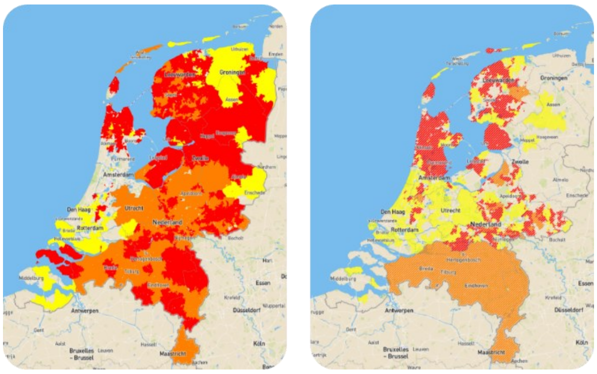


Figure 4: Demand side (L) and Supply side (R) e-grid congestion in the Netherlands *[1]* (From 09/06/2022).

Several studies are ongoing to assess whether a link between the use of the local/national gas grid and of the e-grid via P2G-activity can help mitigating supply-side congestion in regional e-grids. For a schematic overview, see Figure 5.

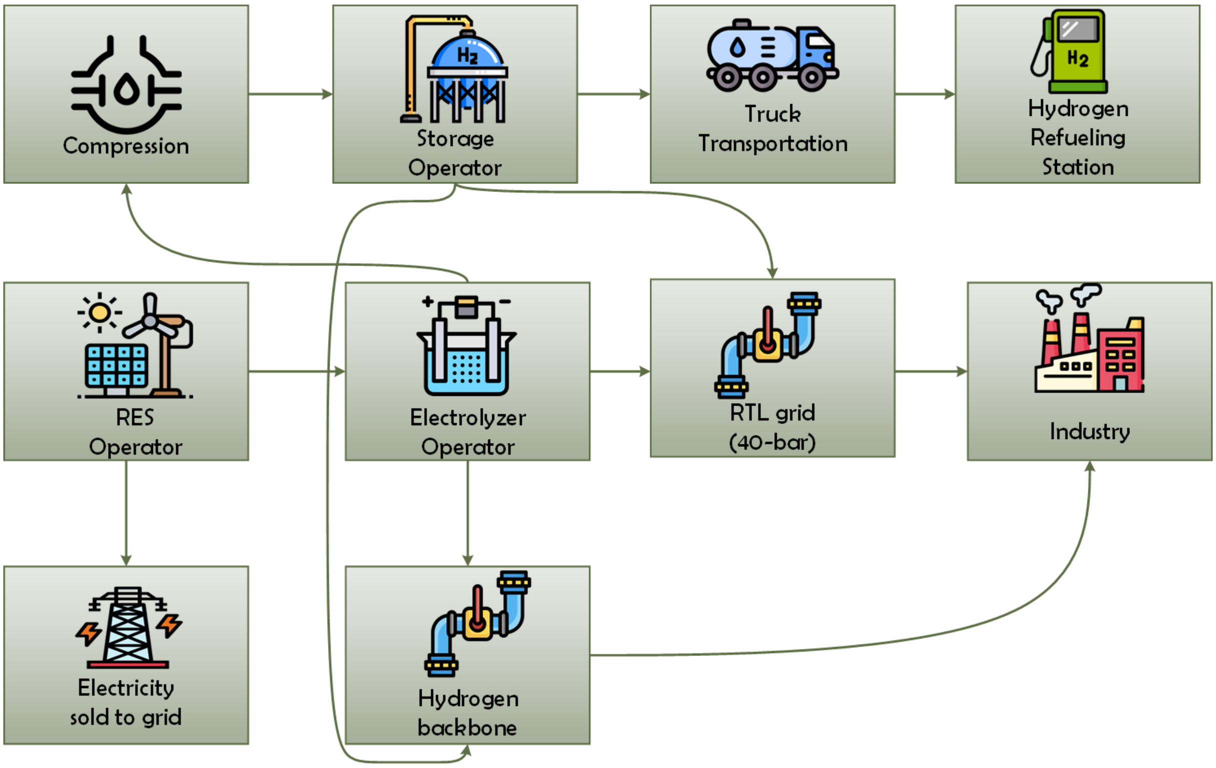


Figure 5: Potential elements of a hydrogen value chain

In this study we will also analyse how P2G can provide not only important input for industry, but also energy market flexibility. We will do so by specifically focusing on decentralized industrial clusters, the so-called cluster 6 industries, in the Netherlands. These industries' energy issues are generally little researched, while the same industries are typically not connected to the hydrogen backbone and often located in e-grid congestion areas while having RES-activity going on given available space. All this makes these industries logical candidates for decentralised P2G initiatives. Because their processes often require heat, which is still typically generated by the combustion of natural gas [5], they often are looking for energy-molecules-based greener options. Although electricity-driven heating systems can be promising for generating low-temperature heat, for producing high-temperature heat (> 250°C) one typically needs ultimately green energy molecules, which makes 'decentral' clean hydrogen potentially attractive as one of the very few alternatives [5].

2.2 Decentralised industries, the gas transmission network and criteria for P2G

Gas Transport Services (GTS), part of Gasunie, operates the Dutch onshore gas transport network. It consists of: 12,000 kilometres of transport pipelines, connection points, compressors, and mixing stations. The transportation network consists of two parts, the main transport system (HTL), and the regional transport system (RTL). The HTL is linked to: gas producers, import points, significant end users (such as power plants and industries), international transmission operators, storage facilities, and, of course, the RTL, into which it feeds [6]. The RTL is linked to the grid of regional distribution system operators (DSOs), smaller power plants, and industrial facilities. Similarly, the network is subdivided into two sections: the high-pressure distribution grid (HDD) and the low-pressure distribution grid (LDD) [6] (Figure 6).

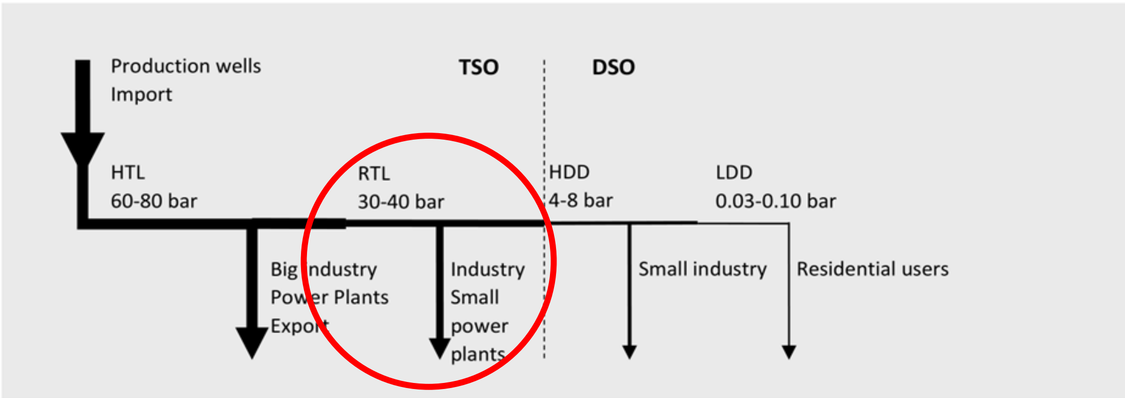


Figure 6: Overview of the Dutch onshore gas grid [6]

The 40 bar GTS pipelines are linked to gas receiving stations (GRS) of both the gas distribution networks and industrial (large) consumers. Many experts suggest that industries are the prime first candidates for introducing hydrogen-based technologies and to act as catalysts for deploying a hydrogen economy [7]. Especially pipelines only linked to industrial consumers are considered promising transport modes to start using them for flexible amounts of physical blending in the regional transmission grid, because:

- They cover a small number/single industrial user(s) with usually substantial volume offtake, keeping costs of replacement of gas meters (gas chromatograph) limited.
- They absorb a rather constant gas flow and can often deal with different mixes, so that relatively large flows of hydrogen can be admixed anytime when electricity surpluses occur.
- Specific users at specific parts of the grid can be selected which are able with no or minor adjustments to handle, say, up to 20% of hydrogen blends (or higher percentages for modified installations).

Figure 7 may serve as an illustration of the spatial distribution of potential hydrogen injection points for industrial endpoints in a highly industrialised non-cluster 6 region in the Netherlands.

Figure 7: Potential blending endpoints in a heavily industrialized region [8]

As was already mentioned, this report focuses on the industrial cluster 6 areas. The cluster 6 industry is currently emitting 16.5 MtC/a, of which 4.3 MtC/a has to be cut by 2030 [9]. Its industrial activities' locations differ from those of the five major industrial clusters in the Netherlands (Figure 8) (Northern Netherlands, Noordzeekanaal, Rotterdam/Moerdijk, Zeeland, Chemelot) and are scattered over the country area [9]. The latter generally adds to the complexity for these industries to gain access to the energy infrastructure and therefore to decarbonisation options.

Figure 8: The five main industrial clusters of the Netherlands [10]

For a successful energy transition, industries typically need facilities such as: upgrades of the electricity grid, infrastructure for hydrogen, or networks for geothermal energy, heat supply and CCUS [9]. The scale of potential cluster 6 area demand for such facilities (as well as for clean hydrogen) is, however, on the whole small compared to similar demands from the five major industrial clusters, so that the economies of scale for a good business case are sometimes lacking [11]. Yet, the option to introduce clean hydrogen is increasingly becoming important for a number of these regional industrial clusters given their mitigation targets. That is why the feasibility of the local development of P2G activity to service cluster 6 areas' potential needs for clean hydrogen has to be thoroughly inventoried.

3. Decarbonizing the decentralized industries

3.1 Overview of decentral industries

The cluster 6 industries cover a wide range of activities, such as: metallurgical, chemical, food, paper and cardboard, glass, ceramic, waste and recycling, ICT, and oil and gas exploration (Figure 9).

Figure 9: Industries associated with the sixth cluster and their relevant industrial associations

Many of the companies involved are still almost completely dependent on natural gas for their processes. However, this source will have to be replaced by CO_2-neutral energy carriers such as hydrogen or other clean gases, sustainable electricity, or geothermal energy; for most options other than hydrogen or other clean gases, it is a challenge to provide the high temperatures required (e.g. >500 °C) [5]. The traditional use of natural gas often determines the design and configuration of process installations and sometimes also qualities and properties of the products. So, natural gas mostly cannot be replaced overnight and just-like-that by another energy carrier. A great deal of individual research, development, testing, calculation and design therefore is needed before final implementation decisions can be made.

Energetic and feedstock use of hydrogen is generally seen as potentially highly relevant for metallurgical, chemical, food, paper & cardboard, glass and ceramic industries. In this study also the textile/leather, wood, cement, asphalt and concrete industries have been considered as industries potentially using hydrogen. Table 1 below provides a general overview of some the main energy consumption characteristics of the cluster 6 industrial activities. For more details, see [9] [12] [13].

Table 1: General characteristics of cluster 6 industries

Industry	General characteristics	Products
Ceramic [9]	• Homogenous industry, has similar type of processes (clay preparation, shaping, drying and firing) • Core processes are drying and baking of products • Collective annual energy consumption is 8821 TJ equivalent to 200 million m^3 of natural gas and 400 million kWh of electricity	• Ceramic tiles • Masonry and paving bricks • Roof bricks • Wall and floor tiles
Food [9]	• 70% of total energy consumption in the food industry is based on natural gas • 23% of the total energy consumption is based on electricity	• Dairy, sugar, potato and grain processing, beer, etc. • Diverse processes
Metallurgy [9]	• Consists of secondary metal producers • Remelting and reprocessing of recycled materials for reuse via cupola and induction furnaces (>1000°C) • Also includes companies engaged in the primary production of pure metals but for the production of steel pipes, iron and steel rolling mills, non-ferrous smelters, extrusion companies and hot-dip galvanizing plants • Responsible for some 23% of CO_2-emissions of the entire industry[3].	• Secondary metals • (most) Products from metals
Decentralized Chemical [9]	• Mainly consisting of smaller chemical companies and innovative start-ups • Innovations are well suited to facilitate the circular economy • Hydrocarbons will remain the main building blocks for many chemical products	• Chemicals • Very diverse processes
Paper and Carton [9]	• Thermal drying of paper is responsible for the main part of steam demand	• Packaging (76%) • Graphic paper (21%) • Hygienic (3%)
Glass [9]	• CO_2-emissions can be reduced by 80 kton/a by 2030 • Most energy is used to convert raw metals into a hot glass melt at temperatures of some 1500 °C	• Table glass • Optical fibres • Glass wool • Quartz glass • Specialty glass
Cement [12]	• Cement industry in the Netherlands extensively uses blast furnace slag from the steel industry • Clinker is mostly imported from Belgium and Germany • Production capacity of 2000 kt/a	• Cement
Asphalt [13, 14]	• Total energy consumption of the sector in 2015 was 2.5 PJ • Total use of sustainable energy in the sector in 2015 was 257.3 TJ due to green electricity usage	• Asphalt

[3] Important to emphasize that this value represents the whole metallurgical industry which 1) includes Primary steel production companies (e.g., Tata Steel), 2) Secondary Steel production, 3) Non-ferrous base metals and 4) (Iron) foundries

Textiles & Leather [13]	• Total fossil fuel consumption is around 2.6 PJ/a	• Clothes • Textile • Leather
Wood [13]	• Total fossil fuel consumption is 0.5 PJ/a • Majority of activities involves the drying of wood	• Drying of Wood

Table 2 below provides an overview per industry of the: number of locations, CO_2-emissions, natural gas usage profiles, and the equivalent hydrogen volumes needed. The data lacks uniformity since values differ from one year to another. The total natural gas use of decentralised industries amounts to roughly 8.8 bcm/a. This broadly corresponds with 89,857 GWh/a of H_2.

Table 2: Some indicators and natural gas use and its hydrogen eq. for Netherlands' decentralized industries [15, 13, 9, 12, 14]

Industry	Number of Locations	CO_2 emissions ($MtCO_2$/y)	Natural gas (Mm3/y) (year)		Hydrogen eq. (kT/y)	
			Total Demand	Average Demand	Total Demand	Average Demand
Ceramic [9]	40	0.42	200 *(2020)*	5	61.3	1.5
Metallurgic[4] [15, 9]	400	3.31	324.14 *(2021)*	0.81	99.3	0.2
Food [15, 9]	>500 (50 ETS[5] locations)	17.4	1706 *(2021)*	34.12	522.6	10.5
Chemical[6] [15, 9]	390	61.98	6076.2 *(2021)*	103.87	1861.2	31.8
Paper/Carton [13]	21	2.14	210 *(2017)*	10	64.3	3.1
Glass industry [15]	6	1.94	190.5 *(2021)*	31.75	58.4	9.7
Cement [12, 15]	2	4.26	417.7 *(2021)*	208.85	127.9	64.0
Asphalt [14]	37	0.61	60 *(2015)*	1.62	18.4	0.5
Textile & Leather industry [15]	Unknown	0.67	65.4 *(2021)*	Unknown	20.0	Unknown
Wood industry [15, 16]	9	0.17	17.06 *(2021)*	1.896	5.2	0.6

[4] The values for the metallurgic industry represent industry as a whole (e.g., primary steel industry etc.)
[5] Number of companies involved in the European Trading Scheme (ETS)
[6] The values for the chemical industry represent industry as a whole and do not reflect decentralized chemical industries

3.2 Industrial temperature ranges, industrial appliances, and hydrogen blends

Table 3 provides decentral industry information on the temperature ranges used and whether direct/indirect processes are used.

Table 3: Processes, temperature ranges and direct/indirect applications of processes

Industry	Potential hydrogen in process		
	Process	**Temperature Ranges (°C)**	**Direct/Indirect**
Ceramic [9] [13]	Baking bricks	1000 - 1200	Direct
	Drying bricks	<100	Indirect: waste heat of baking process is used
Metallurgic [9] [13]	Primary/Secondary metals	1000 - 2000	Direct
	Non-ferrous metal	500 - 1500	Direct
	Foundries	200 - 900	Direct
Food [9] [13]	Drying	100 - 200	Indirect
	Hot water	0 - 100	Indirect
Decentral Chemical [9] [13]	Feedstock	Mostly pure hydrogen required, but depends on the process	Direct/Indirect
	Distillation	380	Indirect
	Chemical Conversion	100 - 600	Indirect
Paper/Carton [9] [13]	Drying (90 – 100%)	100 – 600 (probably between 100 – 200)	Indirect
	Hot Water	0 - 100	Indirect
Glass [9] [13]	Glass melting	1200 - 2000	Direct
Cement and Asphalt [12] [13] [14]	Cement	1800 - 2200	Direct
	Asphalt	100 – 600	Direct
Textile & Leather [13]	Drying (70%)	100 – 600 (probably between 100 – 200)	Indirect
	Hot water	0 - 100	Indirect
Wood [13] [16]	Drying	100 – 600 (probably between 100 – 200)	Indirect

Burning hydrogen or hydrogen mixtures to obtain high temperatures for most of the processes mentioned in the table seems a technically feasible option, whereas its economics is primarily determined by the costs of the hydrogen (mixtures) and the CAPEX of refurbishment or replacing of the appliances required (see [17] and [13] for a detailed analysis). Changing the gas mixture can significantly impact processes in which the gas flame is in direct contact with the product ('direct processes') and thus product quality. This is, for example, typically the case in the ceramic industry where certain product qualities (e.g. roof tiles) are affected by the composition of the gas flame. It is therefore extremely important for these industries to precisely understand the impact of new gas mixes and flame interaction on the product quality, and therefore to specifically test before integrating hydrogen blends in their processes. Generally speaking, it holds true that the higher the temperature a process requires, the more difficult it becomes to find sustainable alternatives for natural gas which are at the same time technically and economically feasible [13].

For processes involving no direct contact between the flame and the product ('indirect processes'), a change of flame characteristics obviously generally involves less technical complications. An example of an indirect green heating process is via steam production (and the application of hydrogen through retrofit techniques). However, mostly 'indirect processes' require less high temperatures so that a broader mix of technically and economically sustainable options than clean hydrogen, including electrification, may be available.

Table 4 lists a prevalent range of manufacturing processes involving heat in the aforementioned industries. For each process the suitability of indirect/direct heating has been specified. Indirect heating is widely applied in: drying, distillation, chemical conversion, and the provision of hot water, while it has proven to be reliable in burners for admixtures of <30%. A complication is, however, that the addition of hydrogen causes the release of NOx flue gases, which may require abatement.

Table 4: Overview of Indirect/Direct heat applications for various industrial appliances in different industrial clusters

Process	Process specific burner	Used in industry								
		Ceramic	Food	Chemical	Metallurgic	Paper	Glass	Cement etc.	Textile	Wood
Hot water	No		I			I			I	
Drying (Convection & conduction)	No	I	I			I			I	I
Drying (Radiation)	Radiation burner	I	I			I			I	I
Distillation	No			I						
Chemical conversion	No		I	I						
Melting & glowing	Sometimes FLOX burners				D					
Glass melting	No						D			

Calcination	No							D		
Baking of bricks	Often customized burners	D								

Table 5 provides an overview of the extent to which hydrogen blends are possible within industrial processes and equipment. There is a considerable variation in tolerance for assorted appliances and components in the gas value chain. New technology developments can increase tolerance levels significantly.

Table 5: Mixing allowance for gas burners and various grid components, according to both source 1 [18] and source 2 [19]. Dark green: possible without adjustments; green: modifications may be needed; light green: only under certain circumstances and/or modifications may be needed; yellow: replacement or large modifications may be required; orange: contradicting references were found and further R&D is required for clarification.

Appliance	S	0 - 5%	5 - 10%	10 - 15%	15 - 20%	20 - 30%	30 - 50%	50 - 98%
Gas burners	1				*Controlled processes			
	2							
Pipeline (steel, >16 bar)	1							
	2							
Compressors*	1							
	2							
Dryer*	1							
	2							
Cathodic protection	1							
Valves, gas meters, converters, filters, repeater	1							
	2							
Process gas chromatograph	1							
	2							

Gas burners are proven to be virtually reliable for hydrogen admixtures of up to 5-10% (depending on the source of the study) and not requiring retrofitting. The feasibility of introducing hydrogen for indirect processes (e.g., steam production) is technically possible up to gas blends involving 15-20%;

higher blends are also possible (up to 50% blends) but under controlled processes only. More research is done for blends in the 50-98% range. Fluctuations in hydrogen fractions in blends also affect their combustion properties and the efficiency of end-use appliances (see [20]). A constant composition of the gas mixture may therefore be vital to maintain a robust operation of appliances.

Pipelines are shown to offer a great level of flexibility in accommodating hydrogen-natural gas blends. For steel, stainless steel and cast iron, which are commonly used in gas distribution, it can be concluded from the literature that a potentially critical failure mechanism, namely hydrogen embrittlement will not pose an issue in practice. The deterioration of some mechanical properties is small and can be considered unimportant [21]. Copper, brass and aluminium do not seem to be affected by hydrogen. For the existing gas distribution networks, it can therefore be stated that they are on the whole suitable for transporting hydrogen [21]. For non-metallic materials, such as medium density polyethylene (PE80), hydrogen absorption does not affect subsequent squeeze-off or electrofusion joining of pipework [22].

The literature on compressors mentions the risk of embrittlement with respect to compressor and flange components, because of the use of metals, such as titanium and nickel. Valves, gas meters, converters, filters and repeaters provide solid flexibility up to 10%, while flexibility can virtually be achieved for blends up to 45%.

Industrial Dryers are used for reducing the moisture content of the material by exposing the contents to a hot gas stream. This stream is heated with coal, oil or gas. If the hot gas stream is made up of a mixture of air and combustion gases from a burner, the dryer is known as ‘directly heated’. Alternatively, the gas stream may consist of air or another (sometimes inert) gas that has been preheated. When burner combustion gases do not enter the dryer, the dryer is known as ‘indirectly-heated’ [23]. Utilization of hydrogen for ’direct’ drying processes is highly feasible and has great potential, whereas for indirect processes this depends on to what extent contamination is an issue.

The bottom-line with regard to the implementation of hydrogen for industrial equipment is that user acceptability differs per industrial sector. Indirect fired equipment, such as boilers, may only require cross-sectoral trials and an OEM (Original Equipment Manufacturer) guarantee that equipment conversion not adversely affects operations, as these equipment types are more general across sectors and applications [17]. Direct fired equipment, such as kilns and furnaces, will generally require a greater level of demonstration to reach TRL 9 and secure user acceptability, due to potential impacts of flames on product quality [17].

3.3 Local blending in the (40 bar) regional transmission pipelines

Converting renewable energy into hydrogen at locations close to the renewable production facilities will generally relieve bottlenecks in the electricity infrastructure without causing problems for the gas infrastructure [2]. Such infrastructure could be the regional transmission pipeline, the hydrogen backbone, or infrastructure related to production and storage in hydrogen filling stations. So, the location of P2G installations is crucial for how and where green energy flows through the system and what amount of renewable energy will be available for the market using hydrogen as a carrier [2].

There are several locational hot-spots in the Netherlands that theoretically fulfill the selected requirements for potentially successful introduction of hydrogen in decentralized industries while at the same time contributing to dealing with e-grid congestion problems.

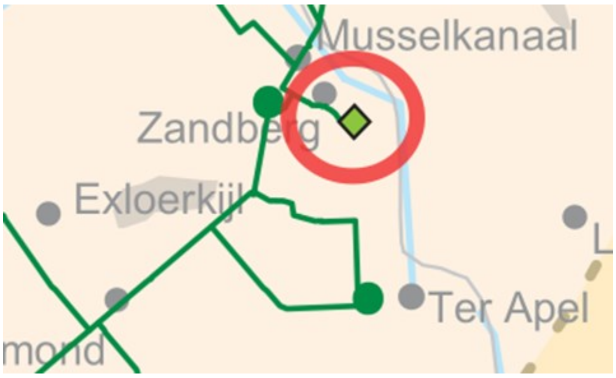


Figure 10: Example of an industrial endpoint potentially suitable for decentralized utilization of hydrogen

1. Supply- and/or demand side e-grid congestion is or is likely to be a serious issue in the area

2. The gas grid connection of industrial energy end-users in the area is decoupled from the built environment/public distribution system (typically demanding other blends) and ideally constitute an RTL end-point (Figure 10).

3. The area contains a cluster of industries with similar appropriateness for hydrogen so that locally produced hydrogen can be adopted for a wider group of industries and generate economies of scale

4. The area is in close proximity (in terms of transport distance) to sufficient local renewable electricity production capacities (e.g. 1MW solar or 60 MW wind) generating enough power to justify the investment in local electrolyser capacity

5. No other (more) attractive alternatives for local production of green energy molecules are available in the area

Figure 11 provides an overview of where the majority of wind and solar farms are located throughout the Netherlands in 2021. Naturally, onshore wind-turbines clearly located near the coastline, due to higher windspeeds. Solar PV sites are distributed more throughout the country, although the major clusters can be found in less populated areas. This gives already a first impression of where potential blending sites could be located close to.

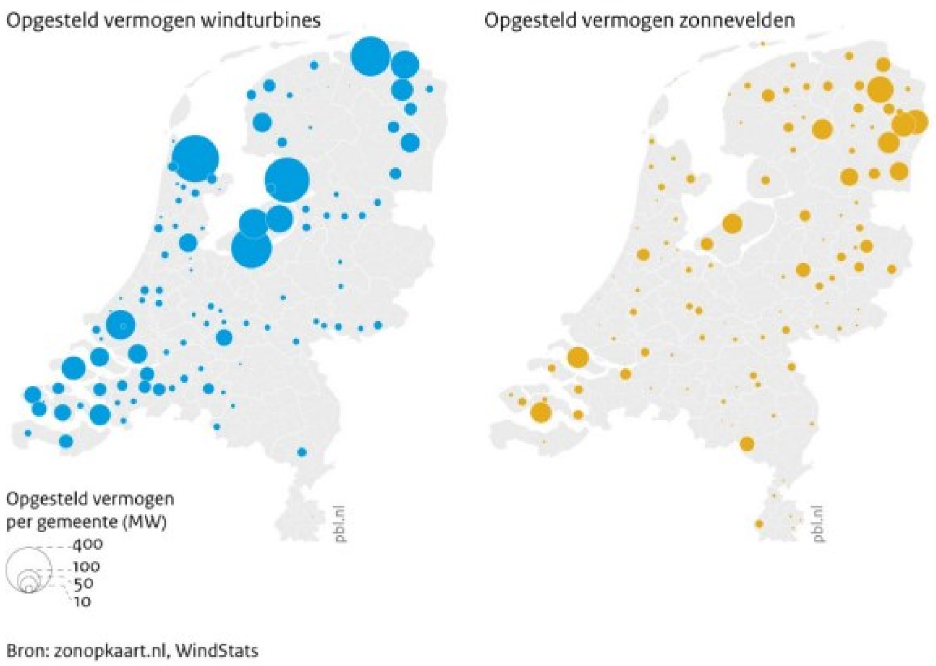


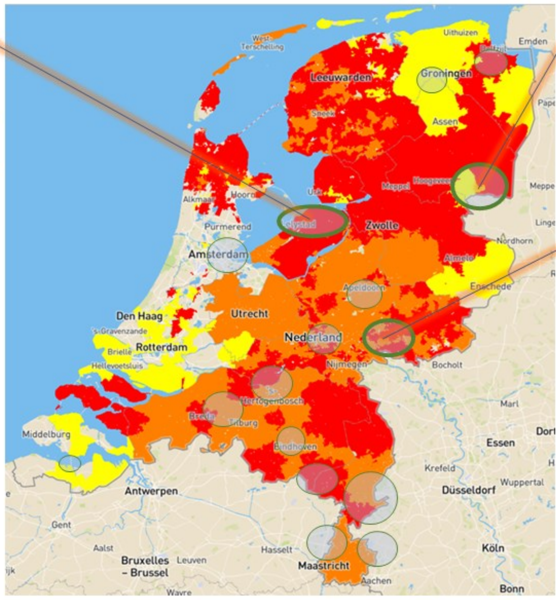
Figure 11: Locations of wind energy (left) and solar energy generation sites (left)

Figure 12 takes a next step by showing areas where cluster 6 industrial activity satisfies the panopticon of the aforementioned criteria for possibly relatively good conditions for the introduction of decentral hydrogen production and use initiatives. Some of the most prominent locations (identified by ovals with a thick border) for decentral hydrogen development seem to be the:

- Lelystad/Swifterbant area
- Emmen/Coevorden area
- Doetinchem/Lochem area

Area: Lelystad/Swifterbant

Name	Capacity (MW)	Type
Noordermeerdijk	195.0	Wind
Westermeerwind	144.0	Wind
Zuidwester	90.0	Wind
Princess Alexia	129.0	Wind



Area: Emmen/Coevorden

Name	Capacity (MW)	Type
Klazienaveen	1.3 MW	Solar

Area: Doetinchem/Lochem/Hengelo

Name	Capacity (MW)	Type
Solarpark Azewijn	1.8 MW	Solar

Figure 12: Potential P2G sites that are in congested areas and close to prominent renewable energy productions sites (Congestion map from 09/06/2022)

It is important to point out that there are about a dozen other locations (identified by ovals with a thin border) that also satisfy the criteria mentioned above and that are also indicated on the map in Figure 12. So, apart from the five recognized main industrial areas in the country (see section 2.2.), some 15 areas in the country can be considered potential sites for local P2G activities for decentralized industries and industry clusters (and possibly other end users).

3.4 Alternative utilization of hydrogen: hydrogen refuelling stations and injection into the backbone

The commercialization of FCEVs and the related refuelling infrastructure is expected to grow further thereby supporting the utilization and efficiency of existing e-grids and the development of renewable energy capacities [24]. At the time of writing (Autumn 2022) there are 15 hydrogen refueling stations in the Netherlands, which number most likely will grow much further [25]. Hence, for a complete picture of areas suitable for decentral distribution and sales of hydrogen, the mobility sector needs to be included. Transport of hydrogen to decentral distribution points for mobility currently typically takes place via tube trailers. Such transport is therefore explicitly considered in the modelling activities of this study. In doing so, for the sake of convenience tube trailers were chosen as the only relevant means of transporting hydrogen to refuelling stations (so, not the 40 bar RTL grid): because few refuelling stations are actually connected to the RTL grid (such as CNG stations) and it is unrealistic to assume that soon more will be; because most vehicles cannot handle natural gas-hydrogen blends that may be provided by the RTLs, so that blends need first to be separated which drives up costs to unacceptable levels, and because overall hydrogen demand is still relatively modest.

In the modeling activities the notion has been included that the regional natural gas transmission and distribution networks may be repurposed for hydrogen transmission either in its pure form or blended. Producers of hydrogen may want to use those grids to sell it to a larger market beyond their own region (possibly via certificates). Apart from that even for decentral hydrogen producers and consumers, the national gas transmission ring or hydrogen backbone, may in the future in specific circumstances also serve as the transport system providing (pure) hydrogen [11] or as delivery points for decentral production. An example is a cluster 6 industrial area that by coincidence is located close or well-connected to the backbone so that tapping pure hydrogen from it or injecting on it may be attractive and possible if sufficient volumes can be guaranteed. For the routing of the Netherlands hydrogen backbone currently in development, see Figure 13. Most of the capacity is based on existing infrastructure, although some parts of the trajectory require new pipeline connections [11].

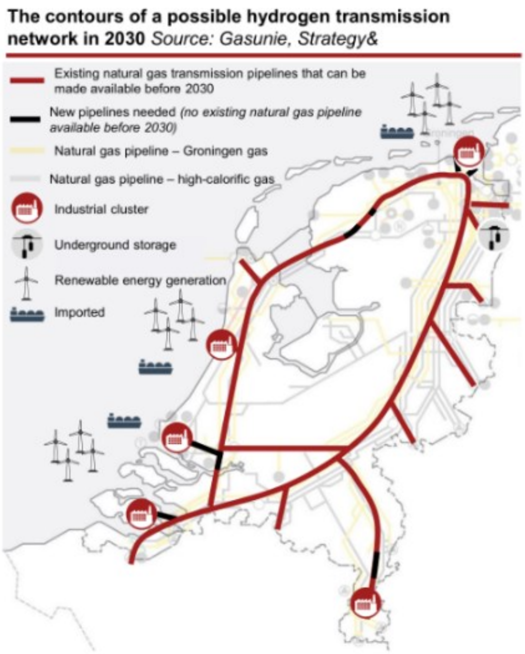


Figure 13: Contours of a possible hydrogen transmission network in 2030 [11]

4. Business case analysis of regional blending

Under what conditions is local, cluster 6 area hydrogen production and delivery in a pure form or blended (into the natural gas flows) to decentral industries and other off-takers in the own area economically feasible? This question is central in this section, and will be analysed with the help of dedicated modelling taking the decentral conditions in the Netherlands' cluster 6 areas into account. Thereby one of the points of focus will be what economic difference it makes if a wider group of local stakeholders than local industry, i.e. local mobility, decides to use local gas blends if policy allows them to do so.

Typical questions investigated were:

- When will it economically be interesting for renewable electricity producers to install their own local electrolyser capacity?
- Would the use of batteries be a better alternative than P2G for the renewable electricity producer to overcome supply-side congestion issues?
- If hydrogen is produced decentrally, what option would be best: to inject it in the regional transmission pipeline system and/or to sell it on the local mobility market? (Note that in the Netherlands the costs of a pipeline connection from the P2G operator to the RTL on average amount to some 1 million euros)
- Does the willingness-to-pay for green hydrogen of decentral industry depend on the expected investment volume, and if so, how?

4.1 Definition of cases

Four main factors have been assessed in the modelling process for each of the scenarios (for scenario details, see next):

- KPIs from the RES operators' perspective (wind or solar farm)
- KPIs of electrolyser utilization and possibly hydrogen storage
- Share of hydrogen utilization for industrial and mobility-based end-users
- Annual profits for the RES and electrolyser/storage operators

A category for batteries is also included involving scenarios where large-scale electricity storage is seen as an alternative to procuring electricity directly from the electricity grid. KPIs are listed in Table 6:

Table 6: Investigated categories in the modelling process and performative KPIs

Investigated category	KPIs
RES operator	• Capacity (MW) • LCOE (€/MWh) • Sold to grid operator (%) • Sold to electrolyser operator (%) • Curtailed electricity (%)
Electrolyser and storage operator	• Capacity (MW) • Utilization (%) • Storage capacity (kg) • LCOH (€/kg) (without considering electricity costs) • H_2 to industry (%)

	• H_2 stored (%) • H_2 to mobility (%)
End-users	• Potential industrial demand utilized (%) • Potential mobility demand utilized (%)
Annual Profits	• Revenues (M€)
Battery	• Capacity (MW) • LCOE of battery storage (€/MWh)

Explanation of investigated cases/scenarios

- Baseline
- Baseline + Subsidy + Mobility
- Baseline + Subsidy + Mobility + Battery (two variations)

Baseline: The baseline scenario (Figure 14) assumes that the RES and P2G activities are operated by one and the same entity. Based on the electricity market conditions, the RES operator can choose to either sell renewable electricity to the grid, or opt for hydrogen production. Whether the latter is preferred or not will depend on whether there is enough profit margin of buying electricity at a low price and selling the hydrogen at a high price. The electricity needed for the production of hydrogen can be either sourced from the grid, or directly from the RES site; the latter is beneficial when the electricity is obtained more cost-effectively than from the market [26].

Baseline + Subsidy + Mobility: This scenario (Figure 14) has the same characteristics as the baseline scenario. However SDE++ subsidies (a policy instrument in the Netherlands to subsidize renewable energy production and carbon emission reduction technologies) are received for renewable hydrogen production; and hydrogen can be sold to mobility applications.

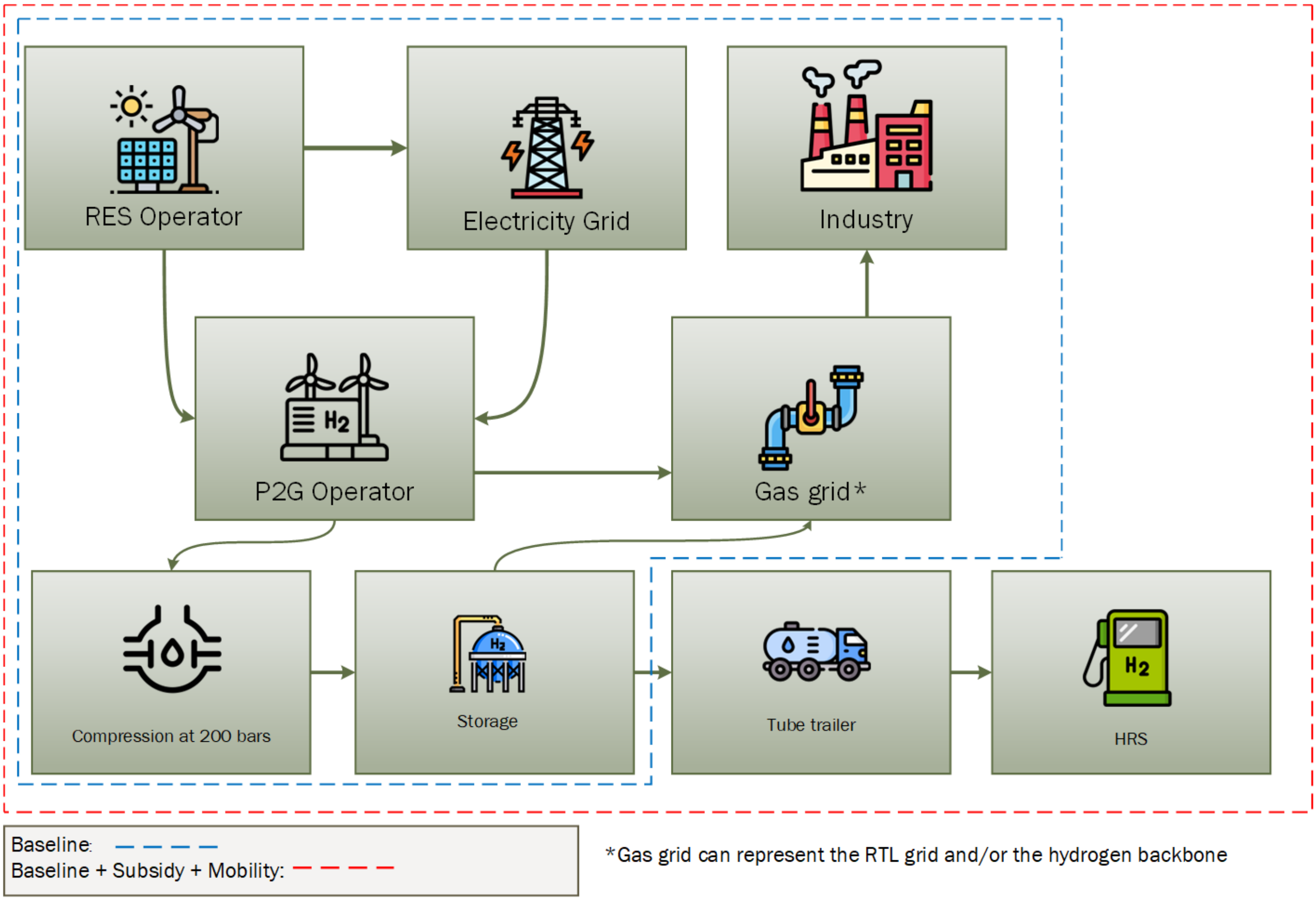


Figure 14: Diagram of the Baseline and Baseline + Subsidy + Mobility scenarios. Gas grid is used to cover both the RTL and backbone.

Baseline + Subsidy + Mobility + Battery (var. 1): In this scenario (Figure 15) a proposed SDE++ subsidy will be provided for the production of hydrogen for use in industry or mobility. The option of installing a battery by the RES operator is also considered where it could store electricity for arbitrage but also to see the effect that it could play in reducing congestion hours.

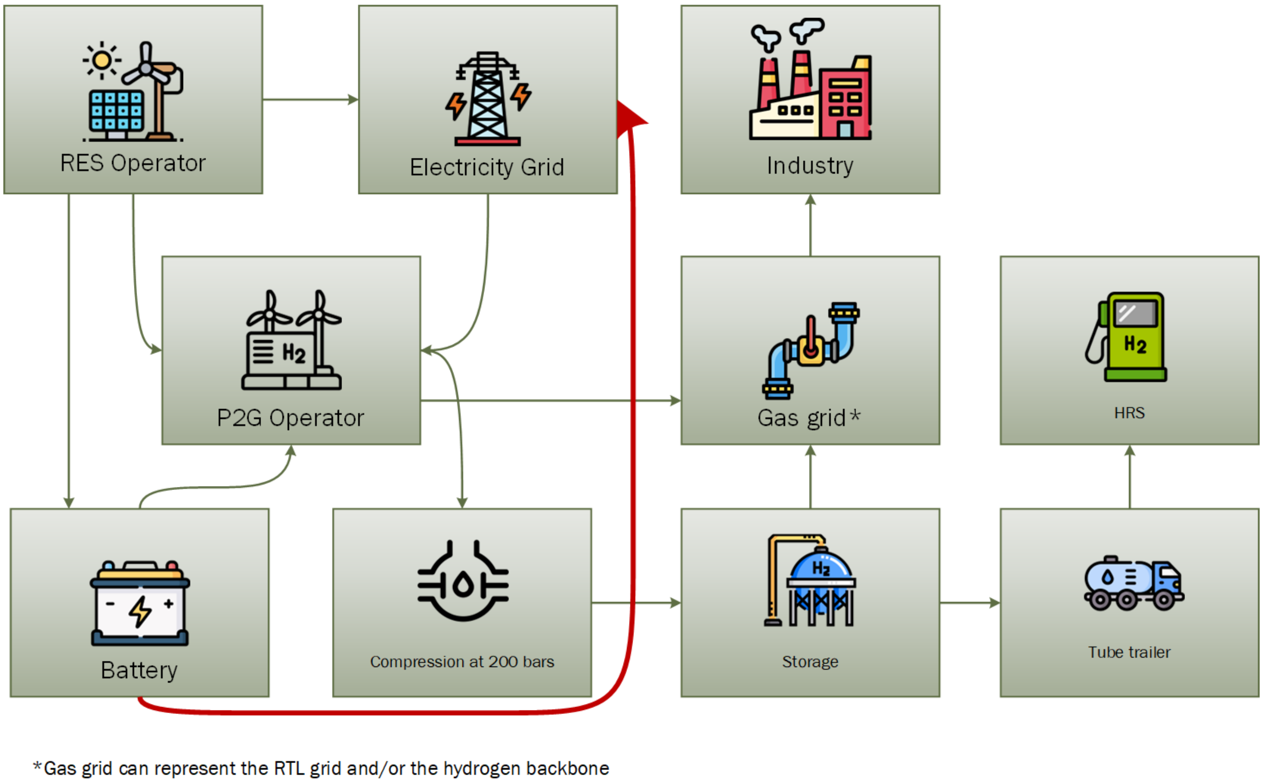


Figure 15: Diagram of the Baseline + Subsidy + Mobility + Battery (var. 1) scenario where the RES operator can also store and sell electricity to the grid

Baseline + Subsidy + Mobility + Battery (var. 2): This scenario (Figure 16) is similar to the previous one, except that batteries are only used for storing electricity for the electrolyser.

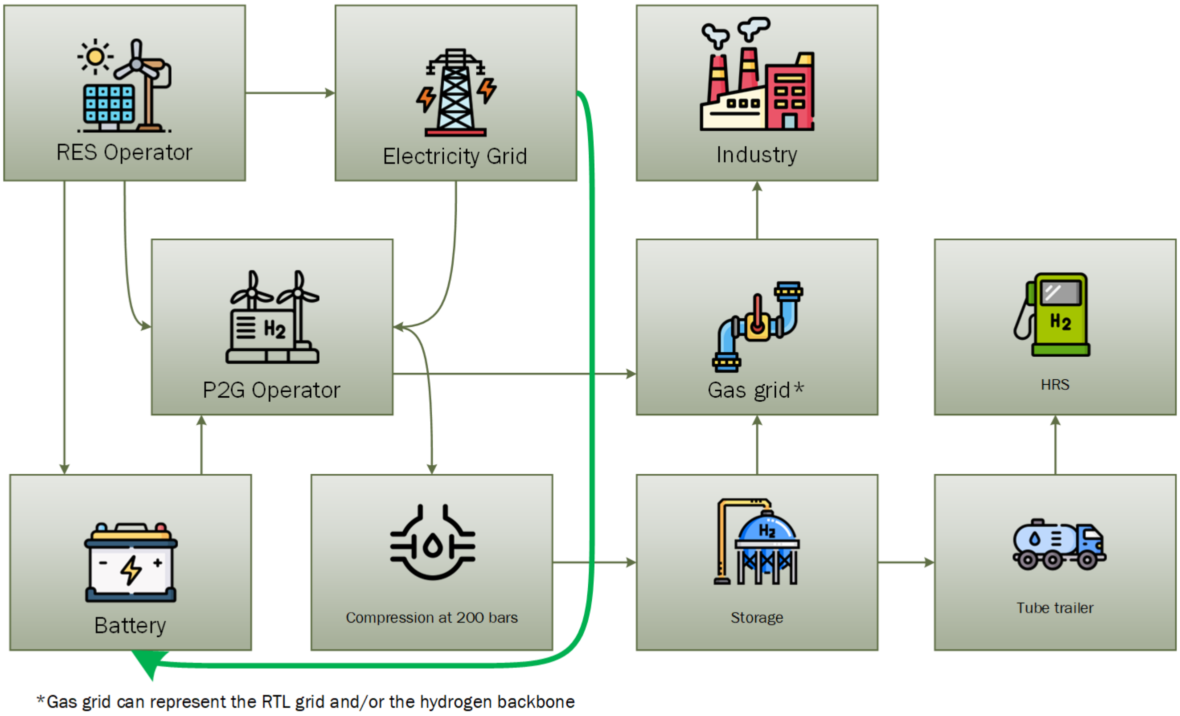


Figure 16: Diagram of the Baseline + Subsidy + Mobility + Battery (var. 2), where the battery stores electricity from the grid and provides it to the P2G operator

Main sensitivities that affect the outcomes of the model are:

- End user demand
- % of blending possible
- Hydrogen/gas/CO_2 price
- Electricity price/amount of congestion
- Electrolyser CAPEX/PtG infrastructure costs

4.2 Model and data used

To investigate the abovementioned cases and stakeholders' decisions, a Mixed-Integer Linear Programming model has been used that optimizes the investment and operational decisions of a combined renewable electricity and hydrogen producer (for a model description, see [26]). The aim of the model is to optimize the annual profitability based on capacity and operational decisions for each asset, or issues such as: how much capacity of wind, solar, electrolyser and hydrogen storage should be installed; at which hours should electricity either be sold to the market, or used for hydrogen production; and at which hours should hydrogen be stored, or rather sold to off-takers? An overview of the model's parameters and decisions is shown in Appendix A. The hourly data (e.g. electricity prices, generation patterns, etc.) are based on historical data over 01/08/21 - 31/07/22; the techno-economic data on the equipment (e.g. wind turbines, electrolyser, etc.) is based as much as possible on similar values as used in the SDE++ subsidy mechanism to calculate expected subsidy rates.

5. Results

5.1 Baseline

The KPI outcomes of the model under baseline conditions have been presented in **Error! Reference source not found.**.

Table 7: KPI results baseline

		Amount of congestion on local electricity grid					
	KPI	**0**	**1000**	**2000**	**3000**	**4000**	**No grid**
Windpark decisions	Capacity (MW)	26.4	26.4	26.4	26.4	26.4	0
	LCOE (€/MWh)	36	45	65	102	168	-
	Directly sold to grid (%)	98%	77%	53%	32%	17%	
	To system (P2G)[7] (%)	0%	0%	0%	2%	3%	-
	Curtailed (%)	2%	23%	47%	66%	80%	-
Battery	Battery capacity (MW)	No battery option included in this case					
	LCOE battery storage (€/MWh) excl. electricity costs						
Electrolyser & storage decisions	Capacity (MW)	0	0	0	0.5	0.6	0
	Utilization (%)	-	-	-	34%	43%	-
	Storage capacity (kg)	-	-	-	-	-	-
	LCOH (€/kg) excl. electricity costs	-	-	-	3.52	2.77	-
	H2 direct to industry (%)	-	-	-	100%	100%	-
	Stored H2 to industry (%)	-	-	-	0%	0%	-
	H2 to mobility (%)	No option to sell hydrogen to mobility in this case					
Annual profits (RES+electrolyser) (M€)		**10.1**	**7.6**	**4.8**	**2.1**	**0.1**	**-**
End-users	Potential industrial demand utilized (%)	-	-	-	29%	45%	-
	Potential mobility demand utilized (%)	No option to sell hydrogen to mobility in this case					

Based on the modelling results, the following highlights are worthwhile mentioning:

- In terms of spatial use, it is more economic to opt for installing wind turbines than solar panels.

[7] This KPI indicates what percent of energy yield from the wind park goes to the P2G system

- It is preferrable to sell electricity over hydrogen, because currently higher marginal revenues can be received for electricity. Figure 17 shows the electricity price and willingness-to-pay for hydrogen (based on the natural gas and CO_2 allowance costs) for every hour. The orange line depicts the tipping points of whether more marginal revenues can be gained by directly selling electricity, or converting and thus selling the electricity to produce hydrogen. The blue dots on the left side of the orange line show the hours in which it is more beneficial to sell hydrogen, while the dots on the right side show the hours in which it is more beneficial to sell the electricity directly. The figure clearly shows that there are more hours in the analysed period in which it was more beneficial to sell the electricity directly.

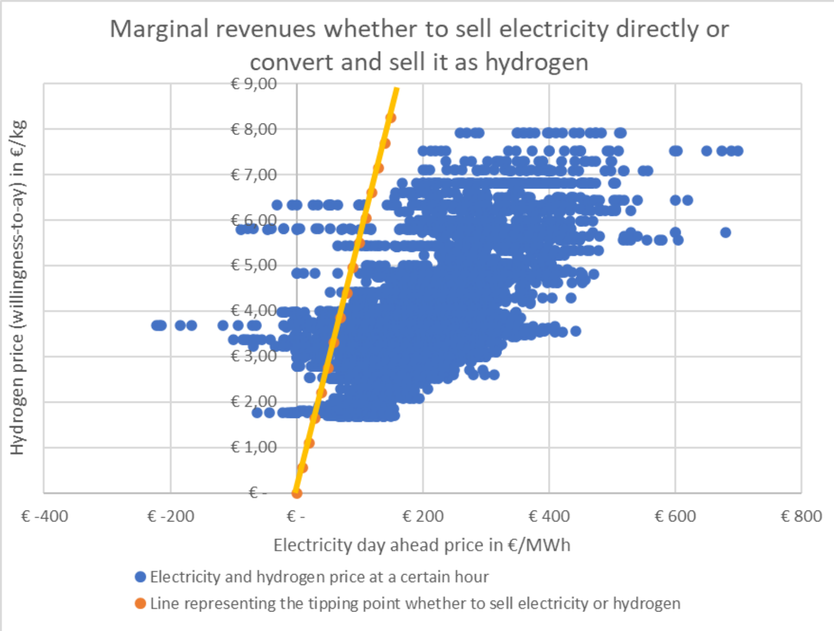


Figure 17: Marginal revenues whether to sell electricity directly or convert and sell it as hydrogen

- The high electricity prices in 2022 resulted in high levels of profitability, even if various shares of the electricity (resp. 2%, 23%, 47%, 66%, 80%) could not be sold due to congestion.
- In order to avoid curtailment due to congestion, it is only profitable to install an electrolyser of a capacity that can be utilized enough. The results show that if there are yearly 3000 congestion hours, renewable hydrogen can be competitively delivered to the industry (compared to deliveries of natural gas), even without any support for renewable electricity or hydrogen. In the baseline case the option to sell the hydrogen to mobility applications has not (yet) been included.
- The optimal size of the electrolyser installed (and so the curtailment that can be overcome) is highly dependent on the size of the renewable energy source and the assumed volume of hydrogen demand. To illustrate: a case involving a wind farm capacity of 6.6 MW under 3000 congestion hours has as a result that 7% of otherwise curtailed electricity is utilized by the P2G system (0.5 MW installed electrolyser capacity, LCOH 3.90 €/kg) in comparison to the 2% utilized by the P2G system (0.5 MW installed electrolyser capacity, LCOH 3.90 €/kg) established under 3000 congestion hours. A condition involving a five times higher industrial demand of hydrogen leads to 10% electricity used by the P2G system (2.9 MW installed capacity, LCOH of 3.58 €/kg) instead of 2% at 3000 congestion hours under the initially assumed demand i.e. a proportional relationship.
- When the CAPEX of the electrolyser decreases, the required utilization of the electrolyser for economic operation is reduced so that the amount of electricity curtailed due to congestion can be reduced further. However, the impact of a CAPEX reduction from 1800 to 1000 €/kW would be minor in the baseline case with 3000 congestion hours: the amount of electricity to the P2G system would increase from 2% to 4% only.

- In any case where P2G is performed, the largest share of electricity is obtained from the installed windfarm itself (36-168 €/MWh), instead of from the grid (+-200 €/MWh).
- It will be decided not to invest in any wind farm or electrolyser to supply hydrogen onto the 40-bar gas grid, if the e-grid operator cannot provide a grid connection in time.

A more extended explanation and discussion of these results is provided in Appendix B.1.

5.2 Case including SDE++ subsidy, mobility market and battery (var. 1)

The KPI outcomes of the model if: a battery could be installed; SDE++ subsidy is received for renewable hydrogen production; and hydrogen is sold to mobility applications, is shown in **Error! Reference s ource not found.**.

Table 8: KPI results case including SDE++ subsidy, mobility market and battery use (var. 1)

		Amount of congestion on local electricity grid					
	KPI	**0**	**1000**	**2000**	**3000**	**4000**	**No grid**
Windpark decisions	Capacity (MW)	26.4	26.4	26.4	26.4	17+17*	3.3+2.7**
	LCOE (€/MWh)	37	38	42	46	47	46
	Directly sold to grid (%)	35%	29%	21%	12%	6%	
	To system (P2G&battery) (%)	64%	70%	72%	75%	79%	74%
	Curtailed (%)	2%	1%	7%	13%	14%	26%
Battery	Battery capacity (MW)	80.8	97.2	123	157.4	132.4	1.5
	LCOE battery storage (€/MWh) excl. electricity costs	43	48	59	72	69	39
Electrolyser & storage decisions	Capacity (MW)	0	0	0	0	0	1.6
	Utilization (%)	-	-	-	-	-	63%
	Storage capacity (kg)	-	-	-	-	-	1250
	LCOH (€/kg) excl. electricity costs	-	-	-	-	-	2.61
	H2 direct to industry (%)	-	-	-	-	-	39%
	Stored H2 to industry (%)	-	-	-	-	-	1%
	H2 to mobility (%)	-	-	-	-	-	60%
Annual profits (RES+electrolyser) (M€)		**12.6**	**12.3**	**10.8**	**9.1**	**7.6**	**0.1**
End-users	Potential industrial demand utilized (%)	-	-	-	-	-	69%
	Potential mobility demand utilized (%)	-	-	-	-	-	100%

* 16.5 MW wind park and 17.45 MW solar field is installed
** 3.3 MW wind capacity and 2.7 MW of solar panels is installed

Based on the results, the following highlights can be mentioned:

- Under the assumed conditions, the option of installing local battery capacity is economically preferrable over the option of hydrogen production for decentralized industry (incl. SDE++ subsidy) or mobility applications. This is because of the: lower investment costs of batteries (200 €/kW instead of 1800€/kW), higher efficiencies (≈90% instead of ≈60%), and higher prices of electricity compared to hydrogen.
- The decision to install a battery is carried forward even with no congestion at all. This is due to the relatively high market prices of electricity and its relatively large fluctuations compared to the costs of renewable electricity generation and storage in batteries.

- A significantly larger share of curtailment can be avoided by the installation of batteries compared to an electrolyser. This is due to the same factors as mentioned under the first bullet point.
- Significant capacities of batteries are installed for the 26.4 MW wind park, which, however, only represent storage capacity for 6-12 hours (160-320 MWh) of the maximum generation capacity.
- Under 4000 congestion hours the modelling suggests to not only install wind turbines but also solar panels in order to flatten out the production peaks and lower the required battery capacity.
- If there is no timely available e-grid connection for the renewable energy sources, it could still be (slightly) profitable to install an autonomous wind turbine and solar park dedicated for hydrogen production to be used in mobility (60%) and industry (39% directly and 1% via storage). The number of solar panels and wind turbines that can be profitably installed depends on the volume of hydrogen demand.

A more extended explanation and discussion of these results is provided in Appendix B.2.

5.3 Case including SDE++ subsidy and mobility market

Table 9 summarizes KPIs under a scenario in which: batteries are not installed; SDE++ subsidies[8] are received for renewable hydrogen production; and hydrogen can be sold to mobility applications[9].

Table 9: KPI results case including SDE++ subsidy and mobility market

		Amount of congestion on local electricity grid					
	KPI	**0**	**1000**	**2000**	**3000**	**4000**	**No grid**
Windpark decisions	Capacity (MW)	26.4	26.4	26.4	26.4	26.4	3.3+2.3*
	LCOE (€/MWh)	36	45	60	83	120	49
	Directly sold to grid (%)	98%	77%	52%	31%	17%	
	To system (P2G) (%)	0%	0%	6%	10%	11%	70%
	Curtailed (%)	2%	23%	42%	59%	72%	30%
Battery	Battery capacity (MW)	No battery option included in this case					
	LCOE battery storage (€/MWh) excl. electricity costs						
Electrolyser & storage decisions	Capacity (MW)	-	0	2	2.7	2.4	1.7
	Utilization (%)	-	-	28%	33%	42%	57%
	Storage capacity (kg)	-	-	750	1500	1750	1250
	LCOH (€/kg) excl. electricity costs	-	-	5.17	4.45	3.69	2.85
	H2 direct to industry (%)	-	-	17%	19%	25%	34%
	Stored H2 to industry (%)	-	-	7%	16%	15%	3%
	H2 to mobility (%)	-	-	76%	65%	61%	63%
Annual profits (RES+electrolyser) (M€)		**10.1**	**7.6**	**4.9**	**2.3**	**0.5**	**0.1**
End-users	Potential industrial demand utilized (%)	-	-	-	54%	68%	62%
	Potential mobility demand utilized (%)	-	-	-	96%	100%	100%

[8] The SDE++ subsidy is assumed to be up to 4.94 €/kg minus the expected willingness-to-pay by the market [38]

[9] For mobility applications a willingness-to-pay for hydrogen of 7 €/kg is taken, for further information see Appendix A.1

* 3.3 MW wind-turbine and 2.3 MW of solar panels is installed

Based on the results, the following can be concluded:

- Per kg of hydrogen higher revenues are received than in the baseline scenario. Therefore an electrolyser is already installed at 2000 hours of congestion. Hence a lower utilization rate is required to operate the electrolyser profitably (which increases the costs per kg of produced hydrogen).
- There is a preference to sell the hydrogen to the mobility sector because in almost all the hours a higher price is received per kg of hydrogen sold in this market. If there would have been unlimited demand from the mobility sector then all the hydrogen would be sold to the mobility industry.
- There is a synergy in using the hydrogen storage capacity for both industrial and mobility offtake. The result is that more industrial hydrogen demand can be fulfilled if hydrogen is sold to the mobility market as well.
- Also in this case matching supply and demand matters: the current assumed hydrogen demand is relatively low compared to the size of the wind park. If the demand would be 5 times higher, at 3000 congestion hours 21% of electricity would be used for the P2G system (5.7 MW installed capacity, LCOH of 3.83 €/kg) instead of 10%. And if a 6.6 MW wind farm would be installed instead of a 26.4 MW wind farm, 31% of the electricity would be used for P2G (2.1 MW installed capacity, LCOH of 4.35 €/kg) instead of 10%.
- Even without the battery option, it could, again, be (slightly) profitable to autonomously install a wind turbine and solar park for hydrogen production only.
- The other results have comparable explanations as in the baseline case.

5.4 Case including SDE++ subsidy, mobility market and battery for P2G (var. 2)

In this last case, again battery capacity is added, but only for storing electricity used for the electrolyser. The KPI outcomes of this case are shown in **Error! Reference source not found.**.

Table 10: KPI results case including SDE++ subsidy, mobility market and battery for P2G

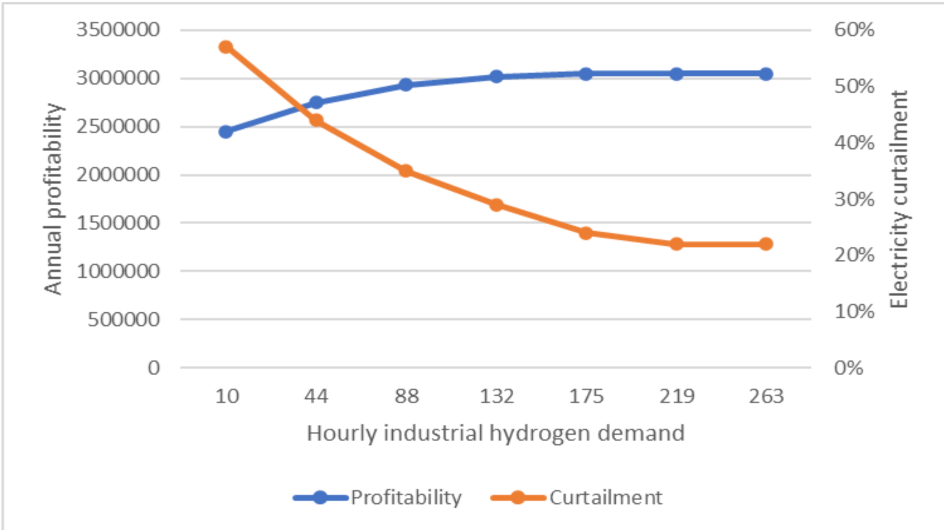
		Amount of congestion on local electricity grid					
	KPI	**0**	**1000**	**2000**	**3000**	**4000**	**No grid**
Windpark decisions	Capacity (MW)	26.4	26.4	26.4	26.4	26.4	3.3+2.7*
	LCOE (€/MWh)	36	42	56	81	116	45
	Directly sold to grid (%)	97%	76%	53%	32%	17%	N.A.
	To system (P2G&battery) (%)	0%	6%	9%	11%	12%	75%
	Curtailed (%)	3%	18%	38%	58%	70%	25%
Battery	Battery capacity (MW)	0	10.1	10.5	8.3	6.8	1.6
	LCOE battery storage (€/MWh) excl. electricity costs	-	52	47	42	41	46
Electrolyser & storage decisions	Capacity (MW)	0	1.1	1.3	1.4	1.5	1.6
	Utilization (%)	-	58%	66%	67%	70%	62%
	Storage capacity (kg)	-	750	1000	1000	1250	1250
	LCOH (€/kg) excl. electricity costs	-	2.86	2.57	2.47	2.40	2.65
	H2 direct to industry (%)	-	28%	34%	38%	41%	38%
	Stored H2 to industry (%)	-	0%	0%	0%	0%	0%
	H2 to mobility (%)	-	72%	65%	62%	58%	61%
Annual profits (RES+electrolyser) (M€)		**10.1**	**7.7**	**5.0**	**2.4**	**0.5**	**0.1**

End-users	Potential industrial demand utilized (%)	-	31%	51%	61%	76%	67%
	Potential mobility demand utilized (%)	-	75%	92%	96%	100%	100%

* 3.3 MW wind-turbine and 2.7 MW of solar panels is installed

Based on the results of this modelling specification, the highlights are:

- Adding the battery to store the electricity in front of the electrolyser turns out to be an effective method to increase the electrolyser utilization and lower local hydrogen production costs, as the CAPEX of batteries (200 €/kW) is significantly lower than adding additional electrolyser capacity (of 1800 €/kW). By adding battery capacity, electricity from the congestion hours could be stored for the short term and be released in a spread fashion over time to the electrolyser. This way the electrolyser can absorb more - otherwise curtailed - electricity with a lower installed capacity and increased utilization rate. The more congestion hours there are, the less a big battery capacity is needed to get an acceptable utilization rate for the electrolyser.
- Installing an electrolyser with a dedicated battery would be typically beneficial if more than 1000 congestion hours apply. Then 25% of the otherwise curtailed electricity could be saved.
- Still, the contribution to lowering the electricity curtailment seems low in the results presented. The electrolyser CAPEX level has little impact on the amount of saved and curtailed electricity; it mainly affects the battery/electrolyser ratio. Again, a five times higher level of hydrogen demand would result in 25% of the electricity being saved from curtailment by P2G (3.9 MW of installed capacity, LCOH of 2.30 €/kg), instead of 11% at the default demand at 3000 congestion hours. Figure 18 shows the relation between hydrogen demand, the profitability, and the electricity curtailment reduction. More electricity curtailment would be reduced if more demand than 10 kg/h would be available. If demand exceeds 219 kg/h, no additional electrolyser capacity would be installed because there are not enough hours to run this additional capacity in a profitable manner. At that demand level also the 26.4 MW wind park would be too small to reach the optimum balance between wind park, electrolyser and demand capacities.



Hydrogen demand (kg/h)	Annual profitability (M€)	Electricity curtailment (%)	Electrolyser capacity (MW)	Electrolyser utilization rate	LCOH (€/kg)	Battery capacity (MW)	Industrial demand utilization (%)
10 (base)	2.45	57%	1.4	0.67	2.47	8.3	62%
44	2.75	44%	3.7	0.60	2.33	17.7	62%
88	2.93	35%	6.3	0.50	2.60	17.8	49%
132	3.02	29%	8.6	0.44	2.85	14.7	42%
175	3.04	24%	10.8	0.41	3.06	13.0	38%
219	3.05	22%	11.7	0.40	3.13	12.3	27%
263	3.05	22%	11.7	0.40	3.13	12.3	27%

Figure 18: Impact of a good match between the industrial hydrogen demand and the renewable energy generation capacity (in this example 26.4MW) on the profitability and curtailment reduction assuming 3000 hours of congestion

Secondly, it can be observed that by profit optimization electricity curtailment would not be applied to its fullest potential (minimum is 22%). For the 219 kg/h demand case it was analysed what the additional costs are of decreasing the electricity curtailment even further. This is presented in Figure 19. It shows that electricity curtailment can be completely overcome by sacrificing 640,000€ of annual profits, or 21% of total annual profits. By accepting 3% less profitability, curtailment could already come down from 22% to 13%.

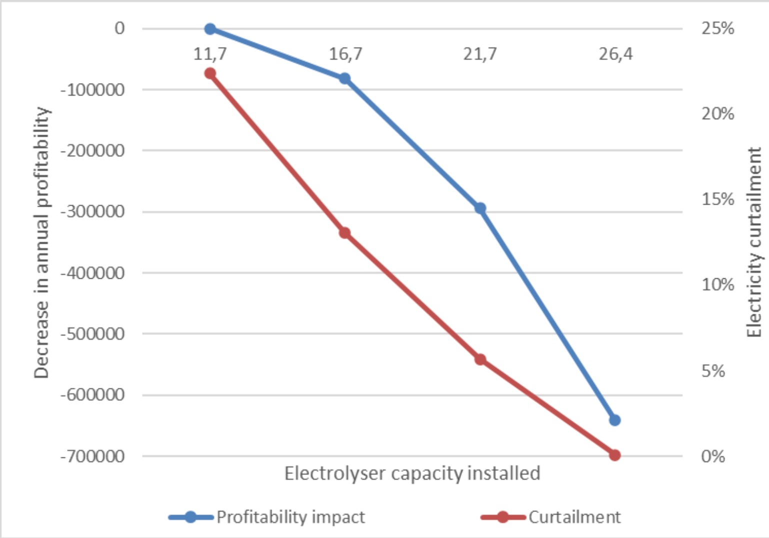


Figure 19: Decrease in annual profitability when an overcapacity of electrolysers is installed to increase the reduction of electricity curtailment

6. Implications of the results and reflections

This chapter returns to the second key question of this report: based on the literature, modelling results and conversations with two stakeholders, the different perspectives have been assessed of the main stakeholder categories with respect to local hydrogen blending for decentralized industries. Such local blending initiatives can probably only come off the ground if all the involved parties acknowledge their potential benefits in terms of enhancing the various business cases, accelerated emission reduction, and the improvements/solutions it can provide for e-grid congestion.

6.1 Perspective of renewable energy producer

Based on the modelling results, it has become clear that commercially it does not always make sense for operators of wind and solar farms to also install an electrolyser. In most cases and under current market conditions generally more revenues can be gained by directly selling electricity (current average price: ≈200 €/MWh) compared to accepting the willingness-to-pay-based price for hydrogen by industry based on the natural gas and CO_2 allowance prices (average of 3.7 €/kg of hydrogen, which corresponds to ≈110 €/MWh excl. energy losses due to the conversion). If electricity cannot be delivered to the electricity grid at any time - which is foreseen to become the norm for new wind and solar farms due to changing regulations of electricity DSOs – the installation of an electrolyser and production of renewable hydrogen for the decentral industry may under the assumption of current market conditions become a commercially feasible option to reduce electricity curtailment.

However, it is expected that alternative options might be more preferable:

1. Installation of a battery under current high electricity prices is evaluated to be more commercially attractive than the installation of an electrolyser. Moreover, the battery is able to reduce more electricity curtailment than the electrolyser, although quite significant battery capacities are required in these scenarios (up to 6-12 hours of storage).
2. By selling hydrogen to the mobility market, potentially more profit is expected to be made than by selling it to decentral industry. However, the price and demand volumes of hydrogen in the mobility sector involve large uncertainty.

Under the assumed willingness-to-pay-based price for hydrogen and electrolyser CAPEX, the investment in an electrolyser becomes attractive when a minimum utilization rate of around 30% can be reached (i.e. 2628 load hours). The higher the willingness-to-pay for hydrogen, the lower the costs of electricity (independent if it is self-generated or purchased electricity from the grid); and the lower the electrolyser CAPEX, the less load hours are required to make the investment in an electrolyser cost-effective. Installing an additional battery for the sole purpose of increasing the utilization of the electrolyser turned out to be an effective measure at a less congestion hours than without installing a battery.

The modelling revealed that the volume of hydrogen demand is an important determinant of the size of the electrolyser installed. Moreover, the larger the hydrogen demand volume at a given renewable energy capacity, the higher the share of electricity that can be saved from curtailment. So, matching the volumes of supply and demand is relevant for making local electrolysis an effective solution for congestion. Without a good match - as in most of the modelling results in which the assumed hydrogen demand was generally low compared to the size of the wind farm - the share of generated electricity saved from curtailment is rather low.

Finally, even if the e-grid connection cannot be procured in time, connecting a wind and solar park to the gas grid only could become (slightly) profitable if a subsidy is received for hydrogen and a share of the hydrogen is sold to mobility applications. If waiting periods for e-grid connections become too long, one may consider to connect local wind and solar parks to the gas grid in the first phase. The optimal size of the combined wind and solar park depends on the amount of hydrogen demand.

Based on both qualitative reflections and modelling results, the following additional aspects can be mentioned for renewable energy producers when considering local production and blending of hydrogen:

- Investment in electrolyser capacity is typically done for a period of at least 10-15 years, while congestion is typically a temporary problem (after some years the grid may be strengthened). So, if congestion is an economic precondition to invest in an electrolyser, one is advised to carefully take the likely duration of that congestion into consideration[10].
- Since selling electricity is the preferred option for renewable energy operators at least under current market conditions, hydrogen producers may, if feasible, opt for a flexible offtake contract with industrial consumer(s).

The conditions of these two points may change in the future, in which the penetration of renewables in the energy system will increase. As intermittent renewable energy becomes more dominant in setting electricity prices, this will also cause more (hourly) price volatility, so that it may become economical to install an electrolyser even without congestion. But then again, future energy market conditions are hard to predict.

6.2 Perspective of electricity DSO

As was already discussed in Section 2, Dutch electricity DSOs increasingly have problems facing the increasing number of new requests from solar and wind farms for e-grid connections: grid reinforcement can be extremely costly and a time consuming endeavour, while also hampered by a limited electro-technical workforce. Moreover, revised regulation will allow DSOs to accept 150% of installed capacity on their e-grids (instead of 100%), which adds to the supply-side congestion problems. All of this forces DSOs to the undesirable situation of adapting the contracts that they are closing with customers, because 100% availability of the grid simply can no longer be guaranteed in many cases. So, due to the rapidly expanding domestic wind and solar capacities (also supported by the vast rise in electricity prices from ≈40 (2019) to ≈200 €/MWh (av. 2022)), solutions have to be found to catch up with the resulting congestion issues.

Our modelling results show that both batteries and electrolysers can help to deliver solutions to nevertheless utilize the electricity when it cannot enter the e-grid. However, both options are only commercially attractive as long as respectively the electricity and hydrogen prices are high and stable enough. If not, other pricing and redispatch mechanisms can be introduced, such as the GOPACS initiative of TenneT, or the Smart Energy Hub initiative (SEH) in the province of Overijssel (strongly relying on hydrogen production, storage and local use without extensions of the national e-grid). Although it still is not quite clear how these initiatives relate to local electrolyser investment business cases – also because prices for redispatch are still heavily fluctuating – it is clear that DSOs will have to play a vital role in introducing such new mechanisms and related regulation and contracting to stimulate flexibility to utilize intermittent energy in smarter ways than in the past.

6.3 Perspective of gas TSO

From the perspective of the gas TSO – operating the high-pressure backbone as well as the 40-bar regional gas grid - it is important to be able to guarantee a certain degree of safe and cost-effective

[10] Admittedly the transportability of electrolysers could possibly circumvent this issue since electrolysers are skid-mounted and could be relocated to other congestion areas

transport of gas when a natural gas/hydrogen blend of hydrogen is offered to dedicated local industries (or other end-users) at specific local parts of the grid. In 3.2 an overview was provided of the technical implications of various blending percentages for different components of the gas grid. This made clear that the modifications on the gas grid required depend on the blending percentage ranges and the gas components in that local part of the grid. For blends up to 10% it is, for instance, foreseen that gas chromatographs have to be replaced (which involves relatively limited costs). If hydrogen is blended in higher percentages than 10%, in addition an assessment is needed of the degree to which for example valves, converters, filters and repeaters need to be replaced in the local grid. Moreover, assessment is then needed if the materials used in the pipeline section are suitable for such hydrogen blends.

Beyond technical grid adjustments also some other cost-specific aspects should be taken into account:

- Hydrogen blending percentages may switch even on an hourly basis due to the intermittent production of hydrogen. It therefore needs to be assessed to what extent fluctuations matter for the grid components and those of the end-users;
- Currently in the Netherlands the gas TSO and hydrogen producers are legally not allowed to add 'pure' hydrogen to the natural gas in the grid (more precisely 'pure' hydrogen injection is not allowed and hydrogen blends in the grid should be less than 0.02 mol% [27]). The Dutch gas law therefore will have to be adjusted before considering a more generic practice of locally blending 'pure' hydrogen into the grid at higher blending rates. Since July 2022 there is legal room for DSOs to gain experience via pilots involving hydrogen distribution, but this exception only applies to pilots in the built environment [28];
- Another point of attention with regard to the costs for grid operators of introducing hydrogen relates to the accepted size of the entry connection of electrolysers. Connecting small units generally involves high societal costs [29], so that one may decide to introduce minimum size requirements for electrolysers to be connected to the RTL grid. This holds a fortiori if direct connections are considered from the future hydrogen backbone; this will only be considered if the uptake volumes are large enough.
- Table 11 gives a rough indication of the meaning of pipeline capacity for local blending volumes and percentages of hydrogen. It shows that for the smallest pipelines in the RTL (6 inch diameter) blending up to 30% would only allow for connecting very small electrolysers (<0.5 MW). In our modelling a hydrogen demand of about 10 kg/h was assumed (based on 350 TJ/y natural gas demand and 10% blending), corresponding with 10% blending in a 12 inch pipeline. The table shows that if flexible blending up to 100% would be possible and accepted in 12-16 inch pipelines, flexibility of 18-37 MW could be delivered by the RTL without having to consider any hydrogen storage at the electrolyser site. The table also shows that if a minimum size connection requirement for electrolysers of about 5 MW would be applied by the TSO, blending below 30% would not be sufficient given the capacities of 6-16 inch pipelines.

Table 11: Broad indication of capacities for typical RTL pipelines (6-16 inch diameter, 40 bars). The values represent a broad indication because values vary depending on pipeline length, pressure drop, and velocity regime. For the data in the table it has been assumed: a pipeline length of 20km and 5km for connecting the electrolyser with the gas grid, a maximum pressure drop of 3 bars, and maximum velocity of 20 m/s.

**Capacity connected without curtailment or intermediate hydrogen storage.*

	6 inch pipeline				12 inch pipeline				16 inch pipeline				Unit
Volume NG capacity	1.5				10.5				21.9				Million m^3/y
Energy NG capacity	49				336				700				TJ/y
Hydrogen blend ratio	**10%**	**20%**	**30%**	**100%**	**10%**	**20%**	**30%**	**100%**	**10%**	**20%**	**30%**	**100%**	Vol%
Transport capacity hydrogen	-	-	-	46.6	10.7	23.1	38	320	22.3	48	79	665	Kg/h
Energy content hydrogen	-	-	-	49	11.3	24.3	39.6	336	23.5	50.7	82.6	700	TJ/y
Diameter connection electrolyser to gas grid	-	-	-	5	3	4	4	10	4	5	6	14	Inch
Max electrolyser capacity connected*	-	-	-	2.6	0.6	1.3	2.1	18	1.3	2.7	4.4	37	MW

- Finally, when 'pure' hydrogen injection is allowed as well as local blending on the RTL grid, still a decision is needed on how grid adaption costs are billed to the users of the grid. Currently such costs are borne by the hydrogen producers and users, but it would be equally possible that these costs are settled via the generic gas transport and connection tariffs and thus socialised.

6.4 Perspective of industrial off-taker

Creating proper conditions for developing hydrogen demand from decentral industries is crucial to get hydrogen production and the rest of the value chain towards such industries off the ground. Some industries have technological challenges to introduce hydrogen, whereas others, such as ceramics, can technologically switch to hydrogen blends (from natural gas) quite easily because most burners are fine with mixtures of up to 20%, while burners utilizing 100% hydrogen have already been tested in kilns [30]. Such tests are often meant to understand what impact oxygen and water vapor have on the heat transfer rate, and what the impact of the oxygen level is on the discoloration of the product and the temperature homogeneity among the kiln carts [30]. In these cases, the technology is, however, on the whole not a limiting factor. Instead, the main challenges are in the stable supply, sufficient availability, and market price of the green hydrogen production and safety regulations regarding the replacement of burners [30]. So, while technical interest in switching to hydrogen is generally high, it is financial aspects that may get in the way [30].

For the paper/cardboard industry drying is among the central industrial processes in which steam boilers are used to produce the steam required for drying. These steam boilers traditionally run on natural gas, but switching to electric or hydrogen boilers is becoming more attractive given decarbonization targets [31]. Under current technology conditions, electrification is often more attractive than introducing hydrogen, because electric boilers are readily available and can be employed out-of-the-box. However, using hydrogen carries a serious potential because it may in the future provide cost-effective energy solutions if hydrogen prices get more attractive (compared to electricity prices) [31]. Moreover, extending electrification of equipment increasingly poses challenges due to demand-side congestion on e-grids. In short, whether hydrogen will be used in this industry depends on energy market conditions, security of supply factors, and the presence of an proper infrastructure [31].

A crucial factor of introducing hydrogen is that rather small blending percentages of some 10 generate relatively little decarbonisation while costs for end-users already increase noticeably. In fact, generic adaptation measures for somewhat higher hydrogen blending levels into the grid may seriously increase costs for end users, namely by up to 43% for industrial end-users and up to 16% for households at a blending level of 20 Vol-% [19]. Still, substituting 20 Vol-% of natural gas by green hydrogen generates 6 to 7% GHG savings only (due to the lower heating value of hydrogen compared to natural gas). For the relationship between blending percentages and resulting end-user price increases in various EU-countries, see also [32] and (Table 12).

Table 12: End-user gas price increase for industrial customers due to blending [19]

Industry	End-user	Blending tax			End-user price increase		
Year 2018	Gas price	5%	10%	20%	5%	10%	20%
Country	ct/kWh	ct/kWh	ct/kWh	ct/kWh	Percent	Percent	Percent
EU	3.135	0.042	0.312	0.746	1.3	9.9	23.8
Germany	3.160	0.026	0.308	0.767	0.8	9.8	24.3
France	3.715	0.043	0.296	0.683	1.2	8.0	18.4
Italy	2.895	0.037	0.328	0.794	1.3	11.3	27.4
Portugal	2.840	0.052	0.555	1.230	1.8	19.6	43.3
Ireland	3.650	0.000	0.231	0.480	0.0	6.3	13.1

One of the challenges of switching from natural gas to hydrogen relates to NOx control and related changes in heat transfer. Proper denoxification units may overcome this challenge; see also [17] and [13].

Another challenge of turning to hydrogen is in actual practices that industries will only do so if transitions to hydrogen burning equipment are considered by them to be no-regret. If natural gas prices are expected to remain relatively low, hydrogen prices rather high and unstable, and adequate hydrogen infrastructure unreliable, many industries remain reluctant to take drastic investment decisions towards hydrogen. Switching to hydrogen-based appliances also typically only occurs in line with maintenance, renovation and/or investment cycles of the plant and therefore often occur either in bursts [9] or, instead, in steps to spread out costs.

Conclusions

In order to move towards a renewable energy system in the Netherlands, an increasing capacity of renewables has to be connected to the electricity grid. This causes very serious e-grid congestion issues. Reinforcement of the e-grid: can be very expensive if technologically and/or legally feasible at all, costs considerable time for various reasons; and requires an electrotechnical workforce that often is not or scarcely available. So, Dutch electricity DSOs are facing growing congestion problems in providing grid connections in time for new renewable energy capacities. It is in fact likely that in the Netherlands e-grid congestion will be a reality and growing concern for at least the coming decade. This results in sometimes long connection waiting times for solar and wind farms (i.e., supply-side congestion) and similar adverse access conditions for the energy end-users (demand-side congestion), and also means that in the near future new solar and wind farms will not be able to deliver electricity to the grid at all times.

At the same time, there are a number of decentral industrial clusters in the Netherlands – the focus of this study or so-called cluster 6 industries (responsible for some 14% of national CO_2 emissions) – that are quite dependent for their decarbonisation on access to green energy (and green molecules in particular) and related energy and feedstock transport infrastructure (e.g. for CO_2, heat, electricity and gases). However, especially for these industries the right transport connections for that, such as the hydrogen backbone or heat- and CO_2-networks, are often not in proximity, not easily accessible, or not within reach at all. Stakeholder information and literature on this suggests that there sometimes is great potential for these decentralised industries and industry clusters to switch to blends of hydrogen sometimes even at relatively short notice, especially if no other efficient decarbonisation alternatives are available. This is especially so if renewable capacity and the willingness to invest in electrolyser capacity is available in the area for industrial use, and if such industries are connected to parts of the RTL (regional transmission gas grid) without other types of end consumers (e.g., built environment) so that gas quality issues are relatively easy to solve.

In this study, several types of industries and processes have been assessed on the issue to what degree they seem to be good candidates for switching to hydrogen blends. The result is quite different for industries with processes with a direct contact between the flame of the burner and the product on the one hand, and where that is not the case on the other hand. In the first category processes generally require quite high temperatures so that except for using green hydrogen there are very few other decarbonization options, even if considerations on the impact of changed flame characteristics on the end product may play a role. For the second category, such implications are immaterial, so that hydrogen mixtures can be implemented without complexity, while at the same time also more other decarbonization alternatives (such as electrification) are available.

In this study, based on the combination of four criteria (supply side e-grid congestion; decentral industry with unique connection to RTL-gas grid; proximity to local (future) renewable energy capacity; and little other decarbonization options), a number of key Netherlands' regions with a theoretical potential for introducing hydrogen blends to industry have been identified.

For a number of these areas our modelling results based on *current*[11] energy and energy technology costs and prices revealed that the business case for energy producers to deal with supply-side e-grid congestion via switching to hydrogen blends is often problematic given the still high costs of hydrogen technology and high and uncertain green hydrogen prices. In fact, modelling results showed that for

[11] The modelling activities that took place in this study were based on the 2022 state of the art with respect to the cost of batteries and electrolyzers and with respect to the availability of SDE++ subsidies and conditions.

energy producers suffering such e-grid congestion utility-scale batteries mostly provided a more cost-effective way to deal with their e-grid congestion problems than introducing P2G. Obviously this result will not automatically always be the same from the perspective of the demand side or end-user perspective facing e-grid congestion, nor for possible future conditions in which P2G technology costs have come down and therewith green hydrogen prices.

Moreover, modelling that included next to decentral industry also other potential green hydrogen demand sectors such as mobility, showed that in the optimum, mostly the volume of green hydrogen demand from local mobility was much higher than from local decentralized industry. This was because mobility is expected to be able to offer much higher green hydrogen prices than industry, even their demand volumes will probably fluctuate more heavily. This finding suggests that it may be interesting to explore if 'smartly' combined future regional offtake of green hydrogen by both industry and mobility can provide feasible P2G options.

Interviews with relevant cluster 6 stakeholders on current practical barriers to already now consider switching to green hydrogen as an energy source revealed that the lack of knowledge whether the congestion problems one is facing is a lasting or rather temporary problem, may paralyse decisions on whether or not to move to green hydrogen. The same applies for potential investors in P2G to deal with e-grid congestion: will the electrolyser still be a feasible investment if after some years the supply side congestion turns out to be resolved?

Another barrier from the end users' perspective was the uncertainty if the green hydrogen first offered in blends can offer a final solution for the need to ultimately decarbonise completely. The decarbonisation potential of a first, say, 10% hydrogen blend is disappointingly low (≈3% emission reduction), while it also reduces the energy content of the natural gas mix (when compared at constant volumetric flowrate). So, it is vital that the investments to go for a hydrogen blend really are a step towards full decarbonisation of natural gas use in decentral industries: one has to be sure that ultimately one will be able to implement pure green hydrogen via increasing blending percentages.

A third and related perceived barrier is the regulatory uncertainty if and when the gas TSO or DSO is legally allowed and/or capable to facilitate a 'pure' hydrogen transport connection to the gas grid, or in the preceding stages to apply blends of hydrogen in the grid.

On the other hand hydrogen also offers opportunities. The interviews also revealed that some stakeholders are well aware that the alternative, electrification, does not offer a universal solution for decarbonization of various decentral industries. Some industries simply physically need energy molecules because of the high temperatures needed; for other industries electrifying their components will have to wait very long to run and operate their equipment, as long as they keep facing e-grid congestion, so that hydrogen may be the better alternative for that reason.

Table 13 shows a summary of all the factors per stakeholder that should be taken into account to consider local blending.

Table 13: Table with summary of the crucial factors per stakeholder to take into account before local blending might become an option

Type of stakeholder	Crucial factors for stakeholders to consider local blending
Renewable energy operator	• Under current market conditions selling electricity is more profitable than producing and selling hydrogen. • Only if a certain amount of congestion hours is in place, it is worth considering to install an electrolyser. • The options of installing a battery or selling hydrogen to the mobility market are assessed to be more preferred than local blending. • A good match between the size of the renewable energy plant and the offtake of hydrogen is required in order to effectively reduce the share of curtailed electricity due to congestion. • As congestion in most cases will be a temporary problem, long-term perspective is required to allow the investment in electrolyser capacity.
Electricity DSO	• Currently DSOs are allowed to connect wind and solar farms up to 100% of their grid capacity. If a grid is congested it means that no additional solar and wind parks can be connected anymore. • In the future it is expected that new solar and wind farms are not able to provide electricity to the grid at any time, as it will be allowed to connect up to 150% of the grid capacity. • Both the battery and P2G are suitable options to reduce the amount of congestion. The higher the electricity and hydrogen prices, the more economically effective these solutions can be implemented.
Gas TSO	• At any case specific assessments are required to identify the costs of allowing specific hydrogen blends at local parts of the RTL. For blends up to 10% it is foreseen that a gas chromatograph has to be replaced which involves relatively limited costs. • It should be assessed to what degree flexible blending percentages could be handled by the grid and for end-users. • The Dutch Gas Law needs to be adapted so that the TSO is legally allowed to facilitate a 'pure' hydrogen connection to the gas grid and apply blends of hydrogen. There may be a minimum required size for an electrolyser to be connected to the RTL grid. • It should be determined how costs for grid adaptions are billed towards hydrogen users and/or users of the gas grid in general.
Industrial off-takers	• Stable and affordable prices of hydrogen, reliability of supply, and a robust infrastructure are key in stimulating industrial applications of hydrogen.

	• Utilization of hydrogen in no-regret applications is the best way to stimulate uptake of hydrogen by industry and create markets and stable demand. • Limited blending percentages of up to 20% lead to relatively little decarbonisation while costs for end-users increase. • Onsite, local blending could provide an alternative and potentially lower cost solution (than via the grid) since the right concentrations can be introduced directly and costly upgrading is avoided.

References

[1] Netbeheer Nederland (NBNL), “Capaciteitskaart afname elekrtriciteitsnet,” Netbeheer Nederland, 09 June 2022. [Online]. Available: https://capaciteitskaart.netbeheernederland.nl/. [Accessed 21 June 2022].

[2] Gasunie/TenneT, “Infrastructure Outlook 2050,” Gasunie/TenneT, 2019.

[3] J. Sijm, G. Janssen, G. Morales-Espana, J. van Stralen, R. Hernandez-Serna and K. Smeken, “The role of large-scale energy storage in the energy system of the Netherlands, 2030 - 2050,” TNO, 202.

[4] R. Hakvoort, D. Harris, J. Meeuwsen and S. Hesmondhalgh, “A system for congestion management in the Netherlands,” D-Cision B.V., The Brattle Group, Zwolle, 2009.

[5] R. J. Detz, F. O. Lenzmann, J. M. Sijm and M. Weeda, “Future Role of Hydrogen in the Netherlands,” TNO, 2019.

[6] R. van Zoelen, C. Jepma and J. Bonetto, “HyDelta - D8.1 - Admixing literature review,” HyDelta , 2020.

[7] World Energy Council Netherlands, “Hydrogen - Industry as Catalyst,” World Energy Council, 2019.

[8] Gasunie, “Gasunie's Dutch Transport System,” Gasunie, 1 August 2015. [Online]. Available: https://www.gasunietransportservices.nl/uploads/fckconnector/6327f456-1aad-401b-b974-1c5933077cdb/2989913628/Gastransportkaart%20GTS%202015%20final.pdf?lang=nl. [Accessed 18 June 2022].

[9] Klimaatakkoord, “Klimaattransitie door de Nederlandse industrie,” Klimaatakkoord, 2020.

[10] N. H. van der Linden, “Inventarisatie van de behoefte van de industrieclusters aan grootschalige infrastructuur voor transport van elektriciteit, waterstof, warmte en CO2 nodig voor het realiseren van klimaatdoelstellingen,” TNO, Amsterdam, 2019.

[11] HyWay27, “HyWay 27: hydrogen transmission using the existing natural gas grid?,” PWC, 2021.

[12] C. Xavier and C. Oliveira, “Decarbonisation Options for the Dutch Cement Industry,” TNO/PBL, The Hague, 2021.

[13] DNV GL, “Verkenning naar mogelijkheden om aardgas te vervangen in industriële verhittingsprocessen,” DNV GL, 2018.

[14] F. van der Pas and L. Hua, “MJA-Sectorrapport 2015,” Rijksdienst voor Ondernemend Nederland, Roermond, 2015.

[15] C. B. o. S. (CBS), “Energy balance sheet; supply and consumption, sector,” CBS, 16 June 2022. [Online]. Available: https://opendata.cbs.nl/#/CBS/en/dataset/83989ENG/table. [Accessed 20 September 2022].

[16] VVNH, “Leden VVNH,” [Online]. Available: https://www.vvnh.nl/vvnh_leden?prov=All&kenmerk=12. [Accessed 26 07 2022].

[17] Element Energy, “Conversion of Industrial Heating Equipment to Hydrogen,” 2019.

[18] Marcogaz, “Overview of available test results and regulatory limits for hydrogen admission into existing natural gas infrastructure and end use,” Marcogaz, 2019.

[19] Frauenhofer, “The limitations of hydrogen blending in the European gas grid,” Frauenhofer, 2022.

[20] H. de Vries, A. V. Mokhov and H. B. Lewinsky, “The impact of natural gas/hydrogen mixtures on the performance of end-use equipment: Interchangeability analysis for domestic appliances,” *Applied Energy,* vol. 208, pp. 1007 - 1019, 2017.

[21] R. Hermkens, S. Jansma, M. van der Laan, H. de Laat, B. Pilzer and K. Pulles, “Future-proof gas distribution networks,” KIWA, Appeldoorn, 2018.

[22] K. Birkitt, M. Loo-Morrey and L. O'Sullivan, “Materials aspects associated with the addition of up to 20 mol% hydrogen into an existing natural gas distribution network,” International Journal of Hydrogen Energy, 2021.

[23] Mitchell Dryers, “Rotary Dryers,” Mitchell Dryers, [Online]. Available: http://mitchelldryers.co.uk/solutions/rotary-dryers/. [Accessed 14 July 2022].

[24] A. Hajimiragha, C. Canizares, M. Fowler, S. Moazeni, A. Elkamel and S. Wong, “Sustainable convergence of electricity and transport sectors in the context of a hydrogen economy,” *Intenrational Journal of Hydrogen Energy,* vol. 36, no. 11, pp. 6357 - 6375, 2011.

[25] glpautogas.info, “Hydrogen Stations in netherlands in August 2022,” glpautogas, 01 August 2022. [Online]. Available: https://www.glpautogas.info/en/hydrogen-stations-netherlands.html. [Accessed 09 AUgust 2022].

[26] R. van Zoelen, “Flexible hydrogen production from the perspective of the electrolyzer and storage operator,” 2020.

[27] Ministerie van Economische Zaken en Klimaat, “Regeling van de Minister van Economische Zaken en Klimaat van 16 april 2021, tot wijziging van de Regeling gaskwaliteit,” 16 4 2021. [Online]. Available: https://zoek.officielebekendmakingen.nl/stcrt-2021-20909.html. [Accessed 5 9 2022].

[28] ACM, “Tijdelijk kader voor waterstofpilots,” 5 7 2022. [Online]. Available: https://www.acm.nl/nl/publicaties/tijdelijk-kader-voor-waterstofpilots. [Accessed 5 9 2022].

[29] Netbeheer Nederland, “Advies: 'Creëren voldoende invoedruimte voor groen gas',” Netbeheer Nederland, 2018.

[30] J. Stam, Interviewee, *Interview with Jelle Stam from Weinerberger regarding the role of hydrogen in their company.* [Interview]. 30 August 2022.

[31] C. Schreurs, Interviewee, *Interview with Claire Schreurs from Smurfitt-Kappa regarding their initiatives toward the adoption of hydrogen.* [Interview]. 22 September 2022.

[32] J. Bard, N. Gerhardt, P. Selzam, M. Beil, M. Wiemer and M. Buddensiek, "The Limitations of Hydrogen Blending in the European Gas Grid," Fraunhofer Institute for Energy Economics and Energy System Technology (IEE), Berlin, 2022.

[33] Investing.com, "Dutch TTF Natural Gas Historische data," 12 8 2022. [Online]. Available: https://nl.investing.com/commodities/dutch-ttf-gas-c1-futures-historical-data. [Accessed 12 8 2022].

[34] EEX, "EU ETS Auctions," 12 8 2022. [Online]. Available: https://www.eex.com/en/markets/environmental-markets/eu-ets-auctions.

[35] M. Reuß, T. Grube, M. Robinus, P. Preuster, P. Wasserscheid and D. Stolten, "Seasonal storage and alternative carriers: A flexible hydrogen supply chian model," *Applied energy,* no. 200, pp. 290-302, 2017.

[36] Windturbinemodels.com, "Nordex N100 Delta," [Online]. Available: https://en.wind-turbine-models.com/turbines/438-nordex-n100-delta. [Accessed 01 08 2022].

[37] Zonnepaneel info, "Methoden om de opbrengst van PV panelen te bepalen," [Online]. Available: https://zonnepaneel-info.nl/nl/opbrengst3.html. [Accessed 1 8 2022].

[38] TNO, DNV, "Eindadvies Basisbedragen SDE++ 2022," Planbureau voor de Leefomgeving, Den Haag, 2022.

[39] v. Z. R., K. J., J. C., v. S. M. and M. S., "D7A.2 - Techno-economic analysis of hydrogen value chains in the Netherlands: value chain design and results," HyDelta, 2022.

[40] Staatscourant, "Staatscourant van het Koninkrijk der Nederlanden," 25 5 2022. [Online]. Available: https://zoek.officielebekendmakingen.nl/stcrt-2022-14201.html. [Accessed 26 8 2022].

[41] Enexis, "Tarieven," [Online]. Available: https://www.enexis.nl/tarieven. [Accessed 01 08 2022].

[42] G. Janssen, "Technology factsheet - Compressed hydrogen storage," TNO, 2020.

[43] N. Rustagi, A. Elgowainy and J. Vickers, "DOE Hydrogen and Fuel Cells Program Record," DOE, 2018.

[44] S. Lamboo, "Technology factsheet - Lithium-ion battery for power applications," TNO, 2019.

[45] NREL, "How to calculate the levelized costs of energy - a simplified approach," 28 4 2009. [Online]. Available: https://energytechnologyexpert.com/cost-of-power-generation/how-to-calculate-the-levelized-cost-of-power-or-energy/. [Accessed 14 11 2022].

[46] NREL, “Simple levelized costs of energy (LCOE) calculator documentation,” [Online]. Available: https://www.nrel.gov/analysis/tech-lcoe-documentation.html#:~:text=Simple%20Levelized%20Cost%20of%20Energy%20Calculation,rate)%20%2B%20variable%20O%26M%20cost.. [Accessed 14 11 2022].

[47] G. Hieminga and N. Tillier, “High gas prices triple the cost of hydrogen production,” ING, 28 October 2021. [Online]. Available: https://think.ing.com/articles/hold-1of4-high-gas-prices-triples-the-cost-of-hydrogen-production. [Accessed 8 September 2022].

Appendix A – Overview input data & decisions variables

This appendix provides 1) an overview of the input data used in the model and 2) an overview of the decisions the model is able to make in order to optimize the annual profitability.

A.1 Description of data

The data used to run the model can be separated into two categories: hourly data strings with values for each hour of the year the model is running for (Table 14), and techno-economic data for the equipment installed (Table 15).

Table 14: Overview input data with hourly interval

Parameter	Unit	Indicative value	Source
Wind generation	Load factor	2900 full load hours	Based on KNMI weather data
Solar generation	Load factor	815 full load hours	Based on KNMI weather data
Electricity day ahead price	€/kWh	Avg. 0.19 €/kWh	ENTSO-E
Water costs	€/m^3	Always 0.728 €/m^3	OASEN
Hydrogen willingness-to-pay industry	€/kg	Avg. 3.69 €/kg	TTF [33] ETS [34]
Hydrogen willingness-to-pay mobility	€/kg	Always 7 €/kg	Calculation
Maximum hydrogen demand industry	kg	Constant 10 kg/h	350 TJ/y gas demand
Maximum hydrogen demand mobility	kg	One tube trailer (670 kg) every three days	Assumption and [35]
Congestion	binary	0, 1000, 2000, 3000, 4000 or 8760 hours	Scenario parameter

All hourly data is provided based on the period between the 1st of August 2021 and the 31st of July 2022. The wind and solar generation data is based on historical weather data from the location of Eelde in Groningen. The load factor of wind is based on the power curve of the Nordex N100 Delta with a power rating of 3.3 MW [36]. For the load factor of the solar panels a performance ratio of 0.85 is assumed [37], as the load factor is multiplied with the capacity installed (which is kWp for solar) to obtain the hourly produced electricity in kWh, the load factor for solar therefore never reaches 1.

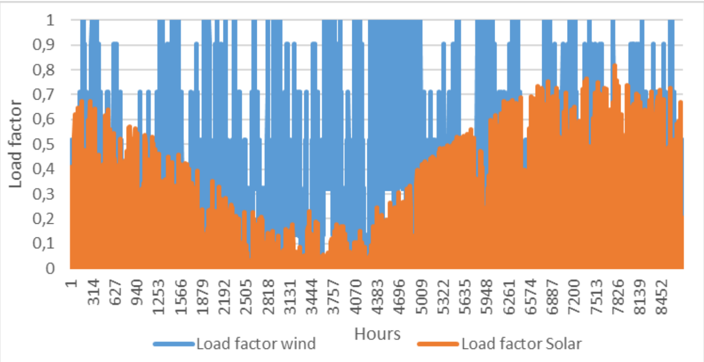


Figure 20: Hourly load factors determining the generation patterns for wind and solar based on historical weather data from Eelde

For the water costs a fixed tariff for large users is assumed. The hourly Dutch day ahead prices are retrieved in kWh from the ENTSO-E data platform. In Figure 21 the smoothed version of the used electricity prices is shown. It is seen that the electricity price has risen during the year due to 1) the end of the COVID-19 pandemic, 2) the Russia-Ukraine war and some specific events within this crisis show some temporal peaks. It is still chosen to use a period based on the more recent market situation compared to the significantly lower prices that were seen before this period, based on a feeling that the global situation between the EU and Russia will not return to stability in the coming years.

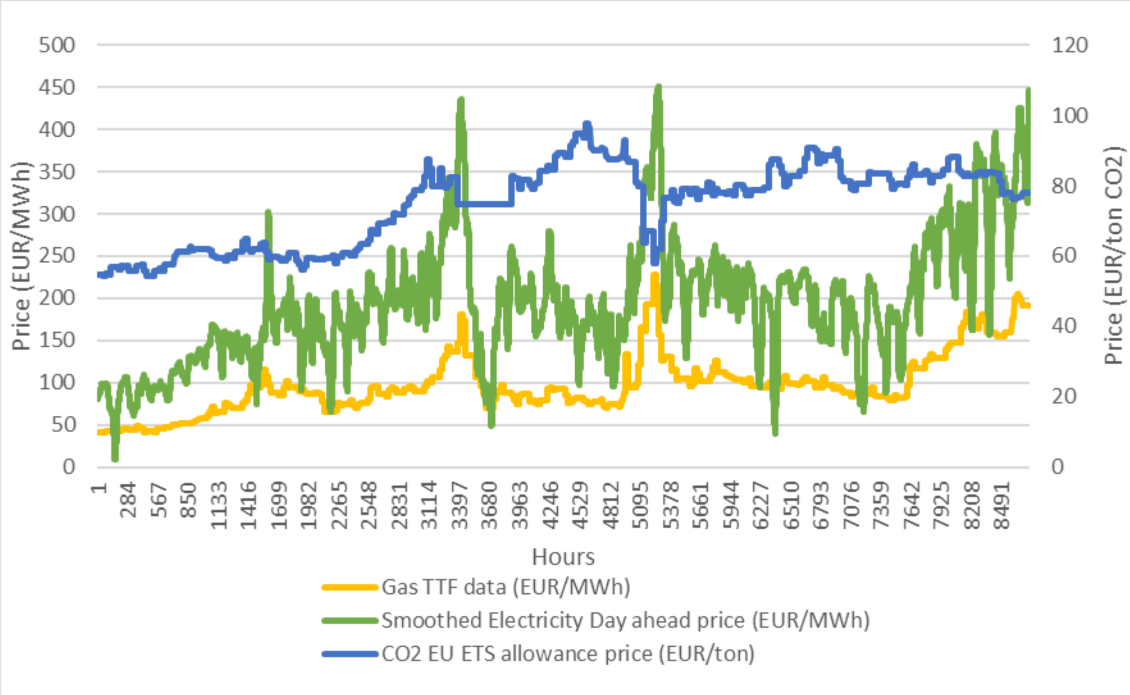


Figure 21: Historical prices over the period 1-8-2021 until 31-7-22 used as input

The willingness-to-pay for hydrogen from decentral industry is based on the TTF gas and ETS allowance costs that can be avoided by using the similar energy content by hydrogen instead of natural gas. The demand for hydrogen is based on a maximum allowed blending percentage of 10 vol% for a total energy demand of 350 TJ per year. 350 TJ is comparable to a natural gas demand of 10.1 million cubic meters (i.e., one medium/large plant or multiple small factories, given the information that an average glass plant uses 33 million m^3 and a ceramic plant uses on average 5 million m^3 of natural gas). 10 vol% of hydrogen blended in a total energy flow of 350 TJ results in 9.8 million cubic meters of natural gas demand and 90 tons of hydrogen per year. Assuming a stable demand pattern leads that the hourly hydrogen demand might not exceed around 10 kg per hour to not surpass the maximum blending limit. In the scenario's considering the SDE++ subsidy, the produced hydrogen results in a higher revenue for the sold hydrogen, since the subsidy provides support to the producer that is equal to the maximum tariff of 4.94 €/kg minus the price the industry is willing to pay [38]. In the hours that the market price is higher than the maximum subsidy tariff, no subsidy is received but only the market price (see Figure 22). For mobility a willingness-to-pay of 10 €/kg is assumed (although this number might be uncertain as the market is not mature yet), including additional revenues fuel suppliers can retrieve by obtaining and selling HBE's (*'Hernieuwbare Brandstof Eenheden'*) to compliance market established by the Dutch blending obligation for transport fuels. We assumed that roughly 2 €/kg is required by the HRS operator and 1 €/kg by the tube trailer operator, in order to supply the hydrogen cost effectively to the mobility market [39], meaning that 7 €/kg can be obtained by the electrolyser operator if the hydrogen is sold to the tube trailer for mobility

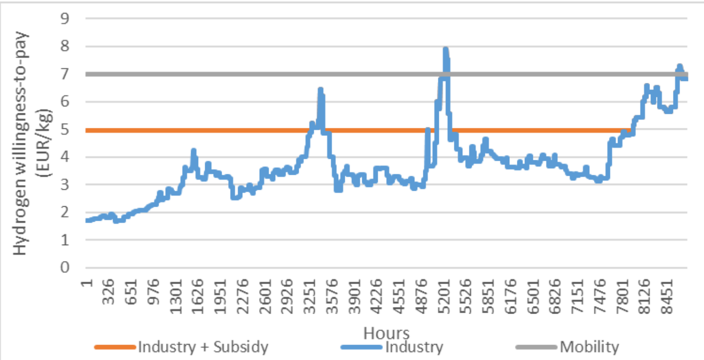


Figure 22: Willingness-to-pay for hydrogen in the industry and mobility market

purposes. The regional hydrogen demand is assumed to be similar as the hydrogen demand of the industry, just to provide an equal comparison between both. It is assumed that once per three days a tube trailer arrives at the local hydrogen production location to export the hydrogen and that filling the tube trailer should take no longer than two hours [35].

The amount of congestion hours is an input variable for the different scenarios that are ran. During the congestion hours the local renewable energy sources are assumed to not be able to supply electricity to the grid, which will be a reality if regulations are adopted that allow distribution grid operators to install upon 150% of renewables compared to their transport capacity [40]. As the amended regulations are not in place yet, there is no historical data on when congestion hours occur. Currently, if the grid is not sufficient to transport more electricity, installation and connection of new renewable energy projects is just postponed. In order to still analyse the impact that congestion might have in the future, we defined the congestion hours based on the load factor of solar and wind in that area. Hence, we assumed that the congestion hours take place during moments when most solar and wind energy is generated in the region.

Table 15: Overview of input data for installations

Installation	Capacity (unit)	CAPEX (unit)	Fixed OPEX (% of CAPEX/y)	Lifetime (years)	Water and electricity usage	Source
Wind turbine	3300 kW	€ 3,816,500	3.4%	25	-	[38] [36]
Solar panel	0.31 kWp	€ 131	2.1%	25	-	[38]
Electrolyser + BOP + grid connection	100 kW	€ 180,000	2.1%	15	57.8 kWh and 0.01 m^3 per kg H2 produced	[38]
Grid connection + 500 m cable	500 kW	€ 41,742.5	1.2%	20	-	[38] [41]
Compressor (to 200 bars)	100 kW	€ 267,700	5%	15	2 kWh and 0.001 m^3 per kg compressed	[42]
Compressed H2 storage tank (200 bars)	250 kg	€ 135,000	2%	25	-	[42]
Tube trailer filling facility	335 kg/h	€ 100,000	2%	10	-	[43]
Battery	100 kW	€ 20,000	1.4%	20	-	[38] [44]

The techno-economic data on the installations within the model are as much as possible retrieved from the expert and literature assumptions used by the Dutch SDE++ subsidies [38], as these values are assessed to be representative for the current situation in the Netherlands. If costs are in kW or kg, the total CAPEX per unit is calculated for the assumed size of a single unit. As a linear model is used, no scaling factor for installations is applied.

In order to determine how much wind turbines and solar panels could be installed, an available amount of space of 50 hectares is assumed. Given that the turbine model requires 62500 m^2 and a solar panel 3.33 m^2, a 26.4 MW wind farm or a 46.5 MWp solar field could be installed at maximum (or of course a combination of both). The electrolyser and balance of plant already includes compression capacity; therefore, it is perceived not to instal another compressor to deliver the hydrogen at 40 bars to the

GTS grid. For the hydrogen storage, compressed tank storage at 200 bars is assumed, which requires installation of an additional compressor to compress the hydrogen to 200 bars. The tube trailer filling facility is equal to a dispenser that enables the hydrogen to be released from the storage into the tube trailer. For the battery, the assumption is made that a 100kW battery could store 200kWh of electricity. Hence, that full storage capacity can be achieved in 2 hours which is typical for batteries available in the market [38]. For charging and discharging each an efficiency of 95% is assumed and the self-discharge is assumed to be 5% per month [44].

A.2 Decision variables and objective function

Based on the parameter values and the constraints, the model determines several capacity and operational decisions in order to maximize the annual profitability. An overview of the decision variables is shown in Table 16: Overview of decision variables of the model used. The hourly decision variables are the operational decisions to for example purchase the electricity at the most profitable moments, and to determine when to sell electricity as electricity or when to convert it to hydrogen and sell it to the most profitable market. The constraints in the model do determine that for example no more hydrogen can be sold than is demanded, that the amount of hydrogen produced should be equal to the right amount of electricity utilized at the same period and to balance all the flows throughout the installations. The capacity decision variables determine the optimal amount of capacity to be installed for each type of installation. Constraints determine that the installed capacities cannot be exceeded, for example that the electrolyser cannot utilize more electricity than capacity is installed.

Table 16: Overview of decision variables of the model used

Hourly decision variables *(for t=1:8760 hours, continuous and non-negative values)*
1. The amount of electricity (kWh) purchased from the day ahead market in hour *t* 2. The amount of generated wind electricity (kWh) sold to the grid in hour *t* 3. The amount of generated solar electricity (kWh) sold to the grid in hour *t* 4. The amount of generated wind electricity (kWh) utilized within the system in hour *t* 5. The amount of generated solar electricity (kWh) utilized within the system in hour *t* 6. The amount of generated wind electricity (kWh) curtailed in hour *t* 7. The amount of generated solar electricity (kWh) curtailed in hour *t* 8. The amount of electricity (kWh) utilized in the electrolyser in hour *t* 9. The amount of electricity (kWh) utilized in the compressor in hour *t* 10. The amount of electricity (kWh) used to charge the battery in hour *t* 11. The amount of electricity (kWh) discharged from the battery in hour *t* 12. The amount of electricity (kWh) stored in the battery during hour *t* 13. The amount of electricity (kWh) from the battery sold to the grid in hour *t* 14. The amount of electricity (kWh) from the battery utilized within the system in hour *t* 15. The amount of water (m^3) utilized in the electrolyser in hour *t* 16. The amount of water (m^3) utilized in the compressor in hour *t* 17. The amount of hydrogen (kg) produced by the electrolyser in hour *t* 18. The amount of hydrogen (kg) compressed by the compressor in hour *t* 19. The amount of hydrogen (kg) stored in the compressed tank during hour *t* 20. The amount of hydrogen (kg) sold to industry via the grid in hour *t* 21. The amount of hydrogen (kg) sold to industry via the grid in hour *t* after being stored 22. The amount of hydrogen (kg) sold to the mobility market in hour *t*
Capacity decision variables *(for k=1:8 types of installations, integer and non-negative values)*
1. The amount of units installed for installation *k*

The objective function of the model is to optimize the annual profits (see function below), which include the revenues of the total volumes of hydrogen sold and the total volumes of electricity sold during the year. The costs are determined by the total costs of purchased electricity from the grid, costs of purchasing water and the total annuity and maintenance costs of the installed installations.

$$\begin{aligned} &Annual\ profits \\ &\quad = hydrogen\ revenues + electricity\ revenues - electricity\ costs \\ &\quad - water\ costs - annuity\ costs - annual\ maintenance\ costs \end{aligned}$$

The annuity of a specific type of installation is determined by multiplying the capital recovery factor (CRF) with the total investment costs. The total investment costs are the amount of units installed for a specific type of installation *k* (x_k) multiplied by the investment costs for a single unit of *k* (see Table 16). The CRF can be calculated by the second part of the formula, where *i* is the interest rate and *n* is the number of annuities (i.e. the lifetime of installation *k*). In this study an interest rate of 2% is used.

$$Annuity_k = x_k \times investment\ costs_k \times \frac{i(1+i)^n}{(1+i)^n - 1}$$

Since the optimization was performed for a one year period, the levelized costs of electricity and hydrogen (LCOE and LCOH) was based on operational data of one year and the annualized investment costs. Therefore, only present costs were included in this calculation based on the one year period. Hence, the simplified levelized costs, or net costs of energy approach has been used to indicate the unit production costs resulted from the optimization analysis [45] [46].

$$LCOE = \frac{\sum_{k=1}^{3}(Annuity_k + Maintenance\ costs_k)}{electricity\ sold + electricity\ utilized}$$

$$for\ k\{1: wind\ turbines, 2: solar\ panels, 3: grid\ connections\}$$

$$LCOH = \frac{\sum_{k=4}^{7}(Annuity_k + Maintenance\ costs_k) + total\ water\ costs}{hydrogen\ sold}$$

$$for\ k\{4: electrolyser, 5: compressor, 6: storage\ tanks, 7: dispenser\}$$

The LCOE is retrieved by dividing the total annual costs of assets related to electricity generation by the utilized produced quantities of electricity. Hence, curtailed electricity is excluded from this as the value of this could not be captured. In order to calculate the LCOH, the annual costs of the hydrogen related assets are taken into account. As mentioned in the main text, electricity costs are not included in this LCOH measure because the LCOE is reported separately already and the assets of both electricity and hydrogen production were assumed to be owned by a single operator.

Appendix B – Extended discussion on results

B.1 Baseline

Extended description and analysis of results presented in Table 7:

- The model makes a decision on how much capacity of wind and solar parks it would install based on the required space available. As wind parks turn out to be a more profitable use of this space, in almost every scenario it is decided to install wind turbines instead of solar panels.
- In the case without congestion, when the wind park could supply the electricity to the grid, it is far more profitable to sell electricity, rather than installing additional electrolyser capacity and selling the hydrogen to industry. The wind parks make enormous profits compared to a potential scenario with 2019 prices, because the electricity price is very high in the analysed year. This is also the reason why under the 2022 conditions a wind park is still profitable, even if it has to curtail significant amounts of electricity. Without congestion, also a low amount of electricity is curtailed because of negative electricity prices.
- It is initially decided to curtail the produced electricity if congestion takes place and the wind park cannot deliver to the grid for a certain number of hours per year. In order to avoid all curtailment, a relatively large electrolyser needs be installed which only operates for low periods of time. With the electricity curtailed, the overall profitability decreases, however, if it is decided to install an electrolyser as well – which runs with low amount of load hours – the profitability decreases even further. Hence, as a whole it is more profitable to curtail the electricity rather than applying additional investments in an electrolyser which will not be utilized enough to gain more profits. When the amount of congestion hours increases, at some point enough operational hours are available to install an electrolyser to produce hydrogen and supply industry during moments when the willingness-to-pay (based on natural gas and CO_2 prices) is high enough to sell the hydrogen with profits. Under our assumptions, this situation occurs when the local electricity grid would be congested for 3000 hours, which we interpret as a significant amount of congestion[12]. In any case, it still means that under those conditions, local renewable hydrogen could be competitively delivered to industry compared to natural gas without any support for renewable electricity or hydrogen.
- In the cases of high congestion, the share of curtailed electricity is relatively high compared to electricity that is used for P2G. This has to do with the size of the wind park compared to the amount of hydrogen demand in industry. It turns out that the 10% hydrogen blend is a relatively low volume compared to the electricity supplied by a 26.4 MW windfarm. To illustrate, at 3000 hours of congestion, if a wind farm of 6.6 MW was assumed, 7% of electricity was used for P2G instead of 2%, and if the industrial demand would have been 5 times higher, 10% of electricity would have been used for P2G instead of 2% at 3000 congestion hours.
- When the CAPEX of the electrolyser decreases, the required utilization for economic operation reduces and therefore the amount of curtailed electricity due to congestion can be reduced further. However, the impact of a CAPEX reduction from 1800 €/kW to 1000 €/kW has a minor impact on the baseline case with 3000 congestion hours: the amount of electricity to the system (P2G) would increase from 2% to 4%.
- In any case where P2G is performed, the largest share of electricity is obtained from the windfarm itself, instead of electricity from the grid. This is because the electricity prices on the

[12] New regulations seem to indicate that up to 150% of renewable energy capacities are allowed to be connected to local grids. Based on this fact, it has yet to be determined how much 3000 hours of congestion actually translate to.

grid are very high (+-200 EUR/MWh) compared to the costs of electricity production by the owned wind turbines (36-168 EUR/MWh).

- There is no profitable option in installing renewable energy capacities and/or an electrolyser if the electricity grid operator cannot manage to provide a grid connection in time at all. This could have been done for example by an autonomous windfarm and electrolyser connection with a connection to the 40 bar RTL grid. Therefore, the outcome is that no windfarm nor electrolyser is installed at all, which is currently also the case in areas where there is no availability on the electricity grid and waiting times to connect are long.

B.2 Case including SDE++ subsidy, mobility market and battery (var. 1)

Extended description and analysis of results presented in Table 8:

- Under our assumed conditions, it is economically preferrable to install a battery over the option of hydrogen production for decentralized industry (incl. SDE++ subsidy) or mobility applications. This is because the investment costs of batteries are relatively low (200 €/kW) compared to the investment costs of an electrolyser (1800 €/kW) and therefore require less load hours before it is economical to do the investment. Moreover, utility batteries have a higher efficiency (≈90% roundtrip) than an electrolyser and its balance of plant (≈60%) and as discussed before, under the existing market conditions, the electricity can be sold for a better price than the hydrogen.
- Installation of a battery is considered even if there is no congestion at all. This is due to the relatively high market prices of electricity and its relatively large fluctuations compared to the costs of renewable electricity generation and storage in batteries. For example, if the electricity price would be 200 €/MWh and reach 300 €/MWh a few hours later, it is still cost effective to store this energy a bit longer under cost increases of ≈50 €/MWh and sell it for a significantly higher price some hours later. Under the former (2019) electricity market conditions, fluctuations of prices were generally between 30 and 50 €/MWh, meaning that the 20 €/MWh difference was not financially appealing enough to install storage capacity.
- A significantly larger share of curtailment can be avoided by the installation of batteries compared to an electrolyser. This is due to the same factors as mentioned before: lower investment costs, higher efficiency and higher market price of electricity compared to hydrogen. A less significant profit decrease is seen for the RES operator when it is deleteriously affected under more congestion hours since less electricity is curtailed and can even be stored until moments when electricity prices are higher.
- Significant sizes of batteries are installed for the wind park of 26.4 MW. The 80 MW battery means 160 MWh of energy storage which means that if the wind blows under maximum energy production capacity and no electricity can be sold to the grid, 6 hours of generation can be stored[13]. In case of 3000 congestion hours, it was decided to install storage capacity for 12 hours of the maximum generation capacity. Although these storage durations are not that long, it means that significant battery capacities are required to overcome congestion.
- Under 4000 congestion hours the model decides to not only install wind turbines but also solar panels in order to flatten out the production peaks and thereby decrease the required battery capacity. The decision to partly install solar panels instead of wind turbines results in that overall less electricity is generated, but also less energy storage is required which weights out the losses of producing less electricity.

[13] 160 MWh/26.4 MW ≈ 6 hours

- If there would be no timely available electricity grid connection for the renewable energy sources, it could still be (slightly) profitable to install an autonomous wind turbine and solar park dedicated for hydrogen production. The number of solar panels and wind turbines that can be profitably installed depends on the amount of hydrogen demand available. It's decided to install both wind turbines and solar panels in order to increase the electrolyser utilization rate (63%). These results suggest that if the waiting time for new solar and/or windfarms could take a few years, still initial capacity could be deployed based on the amount of local hydrogen demand. Later, an electricity grid connection could be added to optimize the profitability.

B.3 Case including SDE++ subsidy and mobility market

Extended description and analysis of results presented in Table 9:

- Compared to the baseline scenario there are received higher revenues per kg of hydrogen, therefore an electrolyser is installed already at 2000 hours of congestion: a lower utilization rate is required to operate the electrolyser profitable (which increases the costs per kg of produced hydrogen).
- There is a preference to sell the hydrogen to the mobility market, because in almost all the hours an higher price is received per kg of hydrogen in this market. If there would have been unlimited demand in the mobility market, all the hydrogen was sold to the mobility and nothing to industry. However, as this is not the case under our demand assumptions (assumed that the local demand of HRS' is equal to the local demand of industry), part of the hydrogen is sold to industry as well. Actually, there is even sold more hydrogen to industry than when no hydrogen would have been sold to the mobility market: This is because storage at 200 bars has to be installed as the tube trailer pick up the hydrogen once in a while. After moments that the hydrogen has been picked up by tube trailer, the storage can be used to store hydrogen for the industrial market as well, whereby it can utilize more demand than that it would have done without storage (which is too expensive to install for the industrial market alone). Hence, there seems to be a synergy of utilizing the hydrogen storage for both the industrial and mobility offtake.
- Also in this case matching supply and demand matters: the current assumed hydrogen demand is relatively low compared to the size of the wind park. If the demand would be 5 times higher at 3000 congestion hours 21% of electricity would be used for P2G instead of 10%. And if 6.6 MW wind farm would be installed instead of a 26.4 MW wind farm 31% of electricity would be used for P2G instead of 10%.
- Again, and also without the battery option, it could be (slightly) profitable to install a wind turbine and solar park, without any electricity grid connection, and dedicated for hydrogen production.
- The other results have comparable explanations as in the baseline case.

B.4 Case including SDE++ subsidy, mobility market and battery for P2G (var. 2)

For this case no extended description and analysis of results is available. The only single version of the description on results is shows in section 5.4.