Final report: Greenports project

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Content

Summary

The Greenports study (2019-2020) has analysed a number of technical and economic aspects of a **LARGE SCALE** power-to-gas installation in a port environment.
The study has *not* focused on the need for hydrogen in the future energy & feedstock market as such, several other studies and roadmaps have focused on that aspect and have come with quantitative estimates of the future need for hydrogen and green molecules in general, both for energy supply and for feedstock. As such, offtake of hydrogen in the future is considered as a certainty.
Instead, the Greenports study has studied the "**HOW**" question, i.e. how can we implement the domestic hydrogen production & distribution of hydrogen in the best possible way.

Port environments have ideal assets to develop large-scale hydrogen ecosystems, as they are important energy hubs, with both large scale production of (renewable) energy and infrastructure for import of energy. In many cases also large industrial clusters are present in the port with several large energy & feedstock consumers. In Flanders, the port of Zeebrugge is identified as an optimal location for large-scale power-to-gas projects.

The main results of the project, described in this final report, are the following:

- A 5MW-20MW **PEM ELECTROLYSER BUILDING BLOCK** has been developed to enable electrolyser installations of > 100MW scale.

- The **POWER ELECTRONICS** and more specifically the performance of the alternate to direct current rectifiers required to couple large scale electrolysers to the high voltage electricity grid, have been analysed. An **ACTIVE RECTIFIER** topology is proposed that provides sufficient reactive power control and is also able to delivering fast responses as required to supply ancillary services to the grid. Simulation of the behaviour of this rectifier circuit in a simulation model built for this purpose, shows full compliance with grid code requirements for electrolyser setups up to 500MW. Using this rectifier circuit avoids bulky and expensive filters and additional equipment to compensate reactive power induced by large electrolysers.

- Technical requirements of **GRID SERVICES** and the ability of the electrolysers to provide these services have been analysed, as well as the economic viability. Electrolysers have the flexibility to technically tackle efficiently all flexibility needs. However on mid (>3year) and long term, the **ANCILLARY SERVICE MARKET IS LIMITED** and more cost effective technologies exist reducing the expected value of the revenue pool. Hence grid services as such will not justify the installation of an electrolyser. On short term however, it can help the business case to some extent. Congestion might be an interesting source of revenue, but no major congestion issues are expected on Belgian network before 2030.

- The **DISTRIBUTION AND STORAGE** of the hydrogen produced in a large central installation (<=100MW) in the port towards inland distributed hydrogen refuelling stations has been analysed and the costs have been quantified. **TRUCK TRANSPORT** is the most cost-effective way to transport the hydrogen, compared to train and ship. Cost prices vary between 1,2€/kg and 2,5€/kg for transport over a distance of 5-300 km, depending on the scenario. The option to transport hydrogen via a pipeline could be economically the best solution and should be assessed case by case, in particular for large hydrogen demanding end-users (tons/day), since the logistics of truck transport could be a limiting factor.

- The **ECONOMICS FOR THE POWER-TO-GAS CASE** – the cost of green hydrogen compared to alternative pathways i.e. hydrogen from natural gas with CCS- for 2030 and 2040 are analysed, given the specific Belgian situation and the estimated evolution of the Belgian electricity prices. The conclusion is that before **2030**, with the assumed CO2 prices and considering the predicted evolution of the electricity wholesale price, it might be challenging for PtG to become competitive with hydrogen made from natural gas (incl. CCS) **WITHOUT ADDITIONAL SUPPORT.** There is not enough low cost electricity in the system yet to compensate the CAPEX costs. **BETWEEN 2030 AND 2040** the share of renewables in the electricity mix becomes high enough for **PTG TO PRODUCE COMPETITIVELY**, operating flexibly and sourcing low-cost electricity.
  As the Green Deal emphasizes the strong need for green molecules, the **REGULATORY FRAMEWORK** will have to be shaped in such a way that this cost gap in 2030 can be overcome. Mechanisms like taxes, renewable subsidies, grid tariffs, future value of the gas GOs… or the possibility to purchase the power from a RES producer via a PPA can considerably change the analysis..

  The balance of domestic hydrogen production versus **IMPORT** of hydrogen will be determined by cost price considerations and local supply of electricity (a.o. the European offshore grid).

- A **CALCULATION TOOL** is built to compare the business case for a “small” inland hydrogen user, supplied by a large scale **CENTRAL** in the port installation versus a small scale hydrogen production installation **ONSITE** at the user’s premises.

- The main drivers for the business case are: **AMBITIOUS CO_2 TARGETS** and penalties for non-compliance, adequate **CARBON PRICING** that will guide the consumer towards low carbon solutions, **VALORISATION** of renewable hydrogen through certification and trade of **GUARANTEES OF ORIGIN** and the availability of **AFFORDABLE RENEWABLE ELECTRICITY** (e.g. EU offshore grid). **INTER-TEMPORAL HEDGING OPPORTUNITIES** originating from the highly variable electricity price might support the business case.

- The **PORT OF ZEEBRUGGE** has analysed the possible locations for hydrogen production and a local hydrogen pipeline, next to the planned hydrogen backbone as foreseen by Fluxys. Specific port regulations for storage of hydrogen have been summarised.

By the end of this project, the different partners all have announced **LARGE SCALE POWER-TO-GAS PROJECTS IN THE BELGIAN PORTS** (Zeebrugge, Antwerp & Ghent).
Feasibility studies and detailed analyses are currently running for the different cases.

Introduction

The Greenports project proposal was initiated in 2017 and submitted to Flux50/VLAIO as an explorative study to investigate the optimal conditions for large scale power-to-gas projects in seaports, connected to offshore (and onshore) wind parks.
At the time of submission of this project idea, no concrete plans for hydrogen projects on hydrogen production in the Belgian ports were announced yet. The original idea was to conduct both a generic study on the different aspects of a power-to-gas projects in a typical port environment AND perform a specific feasibility study for a (limited scale) pilot case in the port of Zeebrugge.

However, between the submission of the project idea in October 2017 and the actual start of the project in November 2018, another project was started by two consortium partners, comprising a detailed feasibility study for an industrial scale power-to-gas project in the port of Zeebrugge. As a consequence of this initiative, it was decided to focus the Greenports project on the generic part and to analyse the different elements of large scale power-to-gas installations connected to large wind parks in more general terms.

The Greenports study analyses a number of technical and economic aspects of a large scale power-to-gas installation in a port environment.

The following topics have been studied in the project :

- **UPSCALING OF THE ELECTROLYSER TECHNOLOGY** from 10MW scale to > 100MW scale, by developing 5MW-20MW building blocks.
- The **ELECTRICAL COUPLING BETWEEN A LARGE SCALE ELECTROLYSER, THE WIND PARKS AND THE GRID**, with focus on the power electronics issues.
- The possibility for a large scale electrolyser to provide **GRID SERVICES** and playing a role in solving possible **CONGESTION ISSUES** and storage of (temporary) surplus electricity that will be available with increasing capacity of renewable energy.
- The **DISTRIBUTION AND STORAGE** of the hydrogen produced in a large central installation in the port towards inland distributed hydrogen refuelling stations
- The economics for the power-to-gas case – the **COST OF GREEN HYDROGEN** compared to alternative pathways, i.e. hydrogen from natural gas with CCS- **FOR 2030-2040**, given the specific Belgian situation and the estimated evolution of the Belgian electricity prices.
- Comparison of the business case for a “small” inland hydrogen user, supplied by a large scale **CENTRAL** in the port installation **VERSUS A SMALL SCALE HYDROGEN PRODUCTION INSTALLATION ONSITE** at the user’s premises.
- The available and missing **REGULATION** for power-to-gas in Flanders and recommendations regarding the required incentives and required legislative framework to enable (profitable) operation of a power-to-gas plant in Flanders.

1 Situating the project – project scope

1.1 Growing attention for hydrogen in EU, Belgium and Flanders

Numerous studies and analyses have been published in the recent months, indicating that hydrogen and derived carriers are essential for supply of energy and feedstock in a carbon neutral future.

In July 2020, the European Commission came up with its **HYDROGEN STRATEGY**. The plan, with the necessary investment impulses, stresses the importance of hydrogen and shows the way for the European hydrogen industry.

Also in Belgium and Flanders, strong ambitions exist to develop a hydrogen ecosystem, which can create new economic opportunities for our region in the global growing market for hydrogen technology and applications.

In September 2020, hydrogen was clearly mentioned in the **FLEMISH RECOVERY POLICY** document and it was announced that around 125 million euros would be available for hydrogen initiatives in the coming year (a.o. for projects participating in the Hydrogen IPCEI initiative).

On November 13, an integrated **FLEMISH HYDROGEN VISION** was proposed by the Minister of Economy and Innovation. In line with the European hydrogen strategy, a number of priorities for hydrogen in Flanders are being put forward, e.g., as molecules in the Flemish industrial and energy supply, as well as to make the transport sector more sustainable.

Also in the government agreement at Belgian federal level, the production of green hydrogen is put forward for industries and freight transport where electrification is not possible. The development of an **H_2 AND CO_2 BACKBONE** with maximum reuse of the natural gas infrastructure is mentioned as an important asset for enabling the energy transition.

1.2 Port environment as the ideal location for hydrogen hubs

Port environments have ideal assets to develop large-scale hydrogen ecosystems.

They usually are important **ENERGY HUBS**, with both large scale production of (renewable) energy and infrastructure for import of energy. In many cases also large **INDUSTRIAL CLUSTERS** are present in the port with several large energy & feedstock consumers.

In Flanders, the **PORT OF ZEEBRUGGE**[1] is identified as an optimal location for large-scale power-to-gas projects, especially because of its important position as energy hub. It has the **HIGHEST CAPACITY GAS PIPELINES** in Belgium, including connections with Norway and UK, and with a LNG import terminal. Injection of hydrogen in the existing natural gas pipeline network or storage of (liquid) hydrogen in large terminals can be future activities within the port.
It is also the location where most of the power generated in the (currently installed) **OFFSHORE WIND PARKS** comes to land. Also onshore wind parks are available in the port.
Additionally, the port is also a **LOGISTIC CENTRE** where several mobility applications of hydrogen will arise. Regarding industrial use of hydrogen, the port of Zeebrugge has no important large scale

[1] To be merged with port of Antwerp into "Port of Antwerp-Bruges"

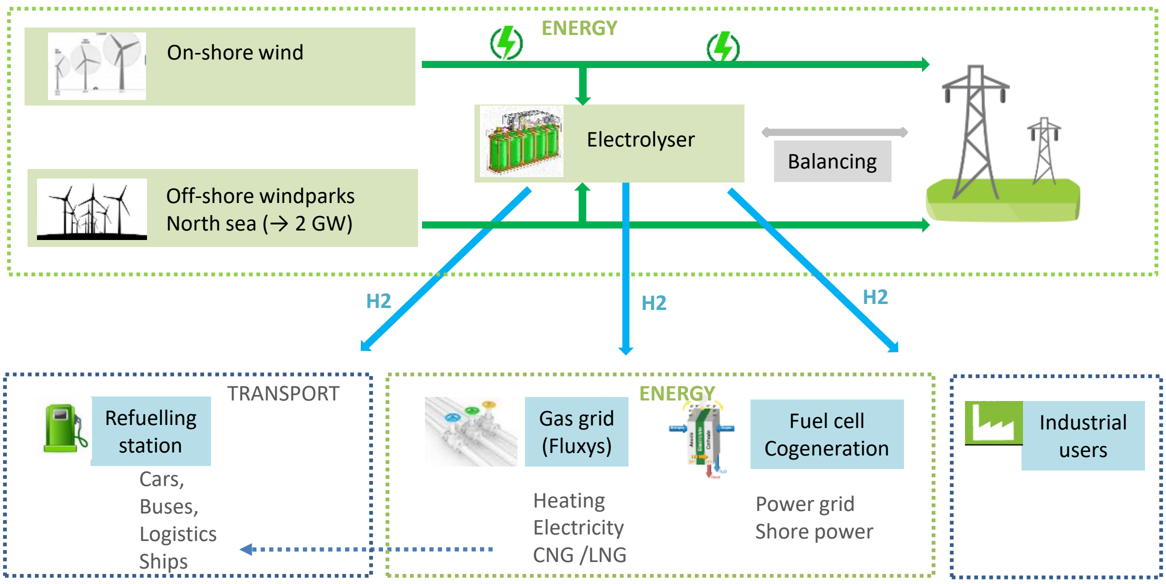
customers, such that providing a link (pipeline) with the industrial cluster in the port of Antwerp - where the main (future) hydrogen users are located – will be required.

1.3 Project scope, objectives and work-packages

This Greenports study has *not* focused on **THE NEED FOR HYDROGEN** in the future energy & feedstock market as such, several other studies and roadmaps have focused on that aspect and have come with quantitative estimates of the future need for hydrogen and green molecules in general, both for energy supply and for feedstock. Several studies predict that about **HALF OF THE ENERGY DEMAND** in Belgium, as is the case for Europe, will be supplied and used in the form of molecules[2] which may be **HYDROGEN MOLECULES BUT ALSO DERIVED HYDROGEN CARRIERS**[3].
As such, offtake of hydrogen in the future is considered as a certainty. However, the cost price at which the hydrogen can be produced locally in Belgium, compared to the price at which it will be available by import from renewable energy production in countries with more abundant sources, will determine whether local production can be competitive with imported hydrogen (carriers). Anyway, import of hydrogen will be needed to accommodate the large envisaged volumes of molecules based on hydrogen[4].
Instead, the Greenports study has studied **THE "HOW" QUESTION**, i.e. how can we implement the domestic hydrogen production & distribution of hydrogen in the best possible way.

The project has studied the technical and economic options for the power-to-gas technology in Flanders/Belgium, with a focus on future possibilities in the port of Zeebrugge.

The scope of the study is the typical port environment where large scale renewable energy production and energy infrastructure is available; the study will focus on the specific case of the port of Zeebrugge, but can translated to other energy hubs of green electricity and natural gas.



[2] E.g. https://www.plan.be/publications/publication-2056-nl-fuel_for_the_future_more_molecules_deep_electrification_of_belgium_s_energy_system_by_2050

[3] E.g. Why the Carbon-Neutral Energy Transition Will Imply the Use of Lots of Carbon, Jan Mertens & al, Journal of Carbon Research, June 2020.

[4] E.g. Final report of the Hydrogen Import Coalition, https://www.waterstofnet.eu/_asset/_public/H2Importcoalitie/Waterstofimportcoalitie.pdf

The concept that has been analysed in this study is the coupling of an electrolyser to both onshore and offshore wind turbines, in different scenarios with respect to the installed **ELECTROLYSER CAPACITY (FROM 1 TO 100 MW).**
The interfaces of the electrolyser with the wind turbines on the one hand and the grid on the other hand are analysed, and the effect of different solutions on the energy efficiency, cost and revenues of the total system have been analysed.

The results of the project, described in this final report, are the following:

- A strategy for upscaling of the electrolyser technology from 10MW scale to > 100MW scale.
- Analysis of the coupling between the electrolyser, the wind park and the grid
- A model for distribution and storage of the hydrogen produced in a large central installation in the port towards inland distributed hydrogen refuelling stations
- An economic model for the integration of power-to-gas in the overall energy system.
- A calculation tool that compares the cost price of hydrogen for an inland customer in two different situations: hydrogen centrally produced in a large scale port installation and transported via trucks or pipeline to the user versus a small scale hydrogen production installation onsite at the user's premises.
- An overview of the available and missing regulation for power-to-gas in Flanders and recommendations regarding the required incentives (e.g. valorisation of green gas) and required legislative framework (e.g. adaptation of grid fees, requirements on hydrogen storage/distribution) to enable (profitable) operation of a power-to-gas plant in Flanders.

1.4 Project partners

Cummins is a global technology company designing, manufacturing, distributing and servicing a broad portfolio of reliable, clean power solutions; including diesel, natural gas, hybrid, electric and hydrogen solutions. Through the acquisition of **Hydrogenics** in 2019, Cummins is leading in the manufacturing of water electrolysis solutions (for onsite hydrogen generation) and hydrogen fuel cell systems (for heavy-duty electric vehicles including buses, trucks and trains). Cummins serves customers in more than 190 countries and territories around the world and employs more than 60.000 employees. Water electrolysers are currently developed and manufactured in Flanders (Oevel) and in Canada (Mississauga).

Elia is Belgium's high-voltage **transmission system operator** (30 kV to 380 kV), operating over 8,000 km of lines and underground cables throughout Belgium. They play a crucial role in transmitting the electricity from the generators to the distribution system. Its main activities include managing grid infrastructure (maintaining and developing high-voltage installations) and electrical system (monitoring flows, maintaining the balance between electricity consumption and generation 24/7, importing and exporting to and from neighbouring countries) as well as facilitating the market (developing services and mechanisms with a view to developing the electricity market at national and European level).
[Note: Elia is a supporting partner of this study, mainly providing information about the power grid. In that perspective Elia did not actively participate to the studies and did not receive any subsidy].

Eoly Energy is a **producer of renewable energy**. We have been investing in onshore wind energy projects since 1999. The first projects were realised within the Colruyt Group. We are convinced that it is not only important to invest in renewable production capacity, but also in ways to keep sustainable energy in the energy system as much as possible. That is why Eoly Energy has been developing expertise in hydrogen technology since 2010. We are currently developing a 25 MW electrolysis unit in Zeebrugge to convert sustainable energy into green hydrogen. All projects developed by Eoly Energy are carried out in collaboration with the Eoly cooperative. Local residents

are invited as a priority to become a cooperator. This is not a financial model, but a direct participation in the projects. We are convinced that within one generation we will be able to draw all our energy from renewable sources.
Colruyt group invests in the **Belgian offshore wind parks** though its share in the holding Parkwind (part of Virya Energy). Via Parkwind Colruyt Group participates in the operational offshore parks Belwind, Northwind and Nobelwind.

Engie Electrabel can rely on the expertise of the ENGIE Group, a global energy player and an expert in three fields: electricity, natural gas and energy services. Regarding renewable energy production in Belgium, Engie invests in onshore and offshore wind production. ENGIE Electrabel is also a pioneer of energy trading since the early days of market liberalization. It has nearly twenty years of experience in delivering innovative products and services, combining power and natural gas supply and hedging strategies. ENGIE has positioned itself as a major player in renewable hydrogen and operates along the entire length of the hydrogen value chain – from production of renewable energies to end use of hydrogen.

Fluxys, Headquartered in Belgium, is a fully independent gas infrastructure group with 1,200 employees active in gas transmission & storage and liquefied natural gas terminalling. Through its associated companies across Europe Fluxys operates 9,000 kilometers of pipeline and liquefied natural gas terminals totalling a yearly regasification capacity of 29 billion cubic meters. Among Fluxys' subsidiaries is Euronext listed Fluxys Belgium, owner and operator of the infrastructure for gas transmission & storage and liquefied natural gas terminalling in Belgium.
As a purpose-led company Fluxys together with its stakeholders contributes to a better society by shaping a bright energy future. Building on the unique assets of gas infrastructure and its commercial and technical expertise, Fluxys is committed to accommodate hydrogen, biomethane or any other carbon-neutral energy carriers.
[Note: Fluxys is a supporting partner of this study, mainly providing information about the power grid. In that perspective Fluxys did not actively participate to the studies and did not receive any subsidy].

MBZ (Maatschappij van de Brugse Zeehaven) is responsible as port authority for the management of port infrastructure and the issue of port areas. The port administration is also responsible for the optimal development of the port area, through coordination and spatial organization of the various activities. The organization and specific knowledge of the local conditions in the port management (see www.portofzeebrugge.be) are an important input for optimal integration of the project within the various activities in the port of Zeebrugge and the potential future utilization of hydrogen in the port of Zeebrugge.

WaterstofNet vzw is a knowledge and collaboration platform that has been developing pilot projects on sustainable hydrogen since 2009, together with companies and governments. Initially, the focus was almost exclusively on the application of hydrogen in transport, i.e. the first hydrogen filling stations, the first garbage truck and truck, buses…. Later, the scope has expanded to the broader role of hydrogen in a carbon-neutral society, such as for energy storage, as an energy carrier and raw material in industry and for energy supply & stoareg in the built environment.
In 2016, WaterstofNet founded the "Hydrogen Industry Cluster" (former IBN Power-to-Gas), a network of companies that want to collaborate on hydrogen as a storage medium for renewable energy and its use for zero-emission mobility, heat or industrial applications.

The **Electrical Energy Laboratory (EELAB) of Ghent University** has research experience on power electronics, renewable energy systems and the provision of ancillary services to the grid. This ICON project has allowed to further develop our research and experience on the provision of ancillary services in relation to renewable energy sources. The innovation presented in this project provides grid balancing with a power-to-gas system instead of using the wind turbines themselves. EELAB is a member of the Industrial Research Fund consortium EnerGhentIC (www.energhentic.ugent.be), the interdisciplinary community of Ghent University researchers working on the energy challenge. Since 2021, EnerGhentIC is also hosting the Hydrogen Platform of Ghent University, in collaboration with the CleanChem, ChemTech and Metals consortia.

The **Department of Economics of Ghent University** developed in recent years several tools to assess energy system dynamics– with a focus on electricity – and the contribution to system services of individual assets. The backbone of recent research is a flexible but very detailed dispatching model.

2 Upscaling of hydrogen production through PEM electrolysis

Lead Partner: Cummins – Hydrogenics

2.1 Objective

Cummins is aiming at developing its water electrolysis activities in Belgium, close to its existing manufacturing site in Oevel (Flanders). While the activity in Belgium has been mainly focused in the past on smaller-scale systems for industrial applications, Cummins has been looking to upscale its PEM (Proton Exchange Membrane) product offering to have a solution for the expected growth of the market, in need of electrolysis plants rated 100MW or more.

2.2 History

Hydrogenics/Cummins started the development of the PEM technology back in 1999. A small-scale commercial product (1-2 Nm^3/h) was released in 2003. The first large-area stack was then developed and matured by Hydrogenics/Cummins thanks to several important pilot projects since 2012. The first cell stack rated at 1.5 MW was built in 2014 and deployed in Germany (Hamburg) in 2015 with a consortium led by Uniper.

2.3 Development of building blocks

At the start of the project, the largest **SINGLE ELECTROLYSER** in the product portfolio was **2,5MW**, which was not large enough to be used as a building block in +100 MW projects.
In 2018, the first 2.4 MW PEM electrolyser (product HyLYZER® 500) was then installed and commissioned in Brunsbüttel, Germany (see image below). This was followed by several other containerized (outdoor) demonstration projects across Europe at the MW-scale. In 2018, the 2.5 MW Markham Energy Storage Facility near of Toronto (developed with Enbridge Gas) was the first indoor installation and was designed to be expanded to 5 MW.

Figure 1: 2.4MW PEM electrolyser in Germany

During the course of the project, the next **BUILDING BLOCK OF 5MW** was developed: the HyLYZER-1000 product in 2019 (Figure 2). The first commercial project with this product was built for Air Liquide in Becancour, with a **20MW** installation rated at 8,000 kg/day, which was commissioned end of 2020[5] (Figure 3).

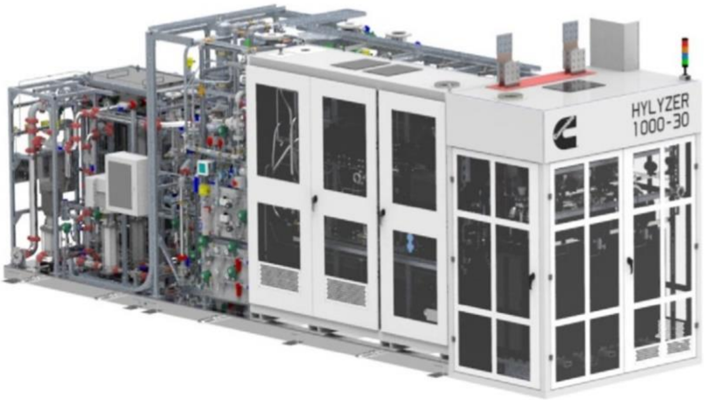


Figure 2: 5MW PEM electrolyser, product Hylyzer 1000

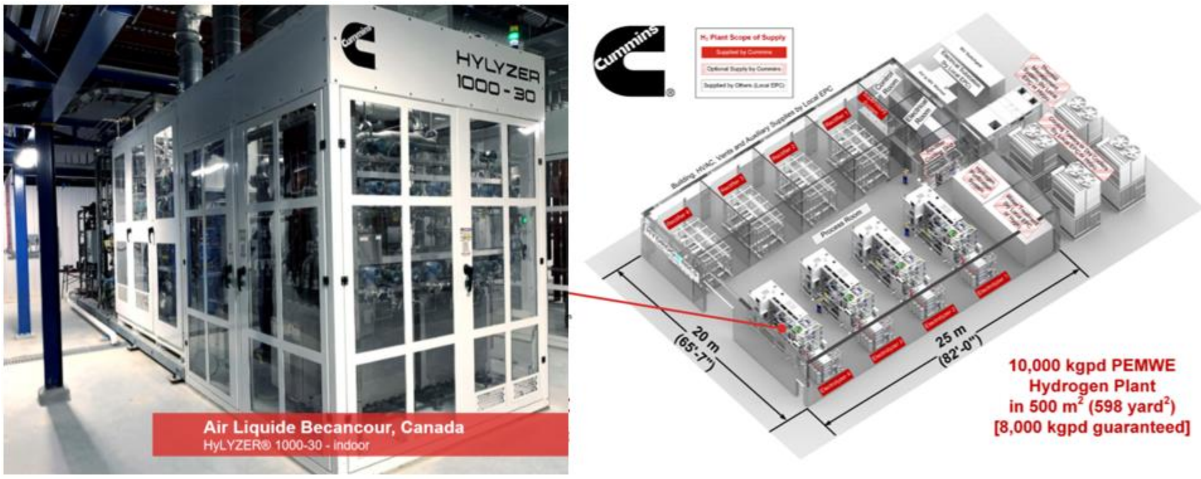
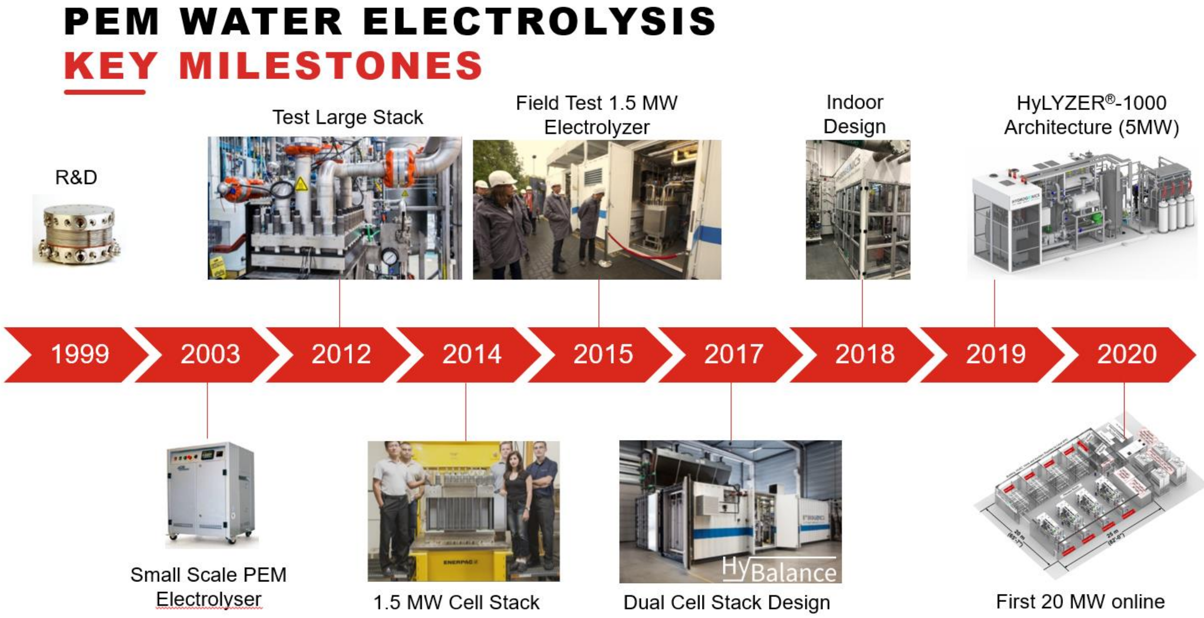


Figure 3: 20MW electrolyser plant, based on the Hylyzer 1000 product

[5] More info about this project can be found in the press: https://www.ledevoir.com/economie/591183/energie-air-liquide-a-commence-la-production-industrielle-d-hydrogene-vert-a-becancour

An overview of the key milestones for the development of Cummins' PEM technology is available here below.



Hydrogenics/Cummins PEM electrolysis technology development timeline

2.4 Follow-up/perspectives

From a product development perspective, Cummins plans to develop **LARGER ELECTROLYSER BUILDING BLOCKS** to better address the future 100 MW+ projects, but the details are confidential at this stage.

There are also plans to scale up the manufacturing capacity to meet the growth of the demand. Cummins has today its main manufacturing site in Flanders (Oevel) and has delivered an ambitious IPCEI project proposal to the BE authorities to establish **A GW FACTORY FOR PEM ELECTROLYSERS** in the Port of Antwerp (NextGen District). Cummins expects positive returns for Flanders and spillover effects on the entire hydrogen value chain.

3 Electrical connection of the (PEM) electrolyser to the wind park and the grid

Lead Partner: UGent

Electrolysers are complex systems and need variety of auxiliary equipment to function. There are systems like purifiers, chillers, compressors, valves, etc. to move the fluids in the system, but the core of the electrolyser is the polymer exchange membrane cell in which the water splitting occurs. This **POLYMER EXCHANGE MEMBRANE IS SUPPLIED WITH DIRECT CURRENT**, which splits the water molecule. In order to ensure a smooth and reliable operation of the stack, the supply current must be with very low ripple. Such requirements are satisfied by using **ALTERNATE TO DIRECT CURRENT RECTIFIERS**. Furthermore, in order to regulate the hydrogen production of the electrolyser, the rectifier must be able to provide variable output power i.e. it must be a controllable one. Nowadays, the majority of the electrolysers use **THYRISTOR- OR TRIAK-BASED RECTIFIERS** to control the power in the polymer exchange membrane. Although these types of components date from 1970's, they are very robust and efficient in such power applications (power from 1MW to 100MW). Nevertheless, they are not able to provide full control on the rectifier unit and this imposes some technical challenges with the connection of large scale electrolyser plants with the transmission grid. Despite the development of different thyristor rectifier configurations, to meet the **TRANSMISSION GRID REQUIREMENTS** and thus to avoid additional fees, specialised equipment must be installed, which is associated with **EXTRA INVESTMENT AND OPERATIONAL COSTS.**

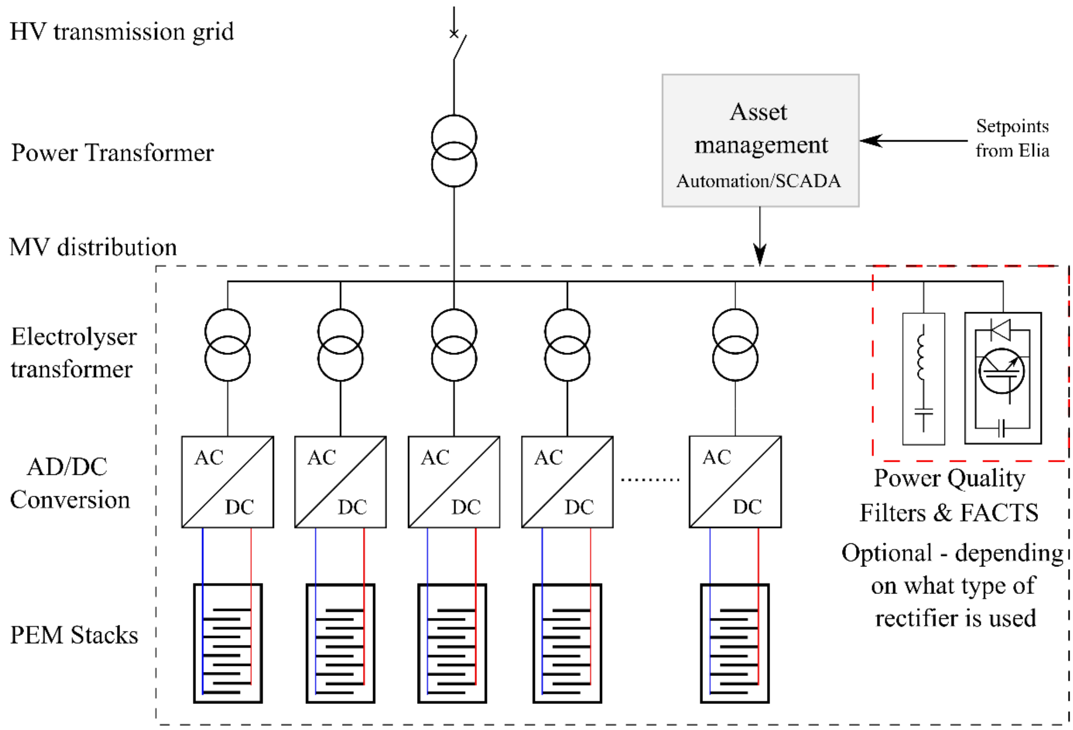


Figure 4 A simplified connection diagram of electrolysers to the public grid

A general overview of an electrolyser plant connection is depicted in Figure 4. To achieve the necessary hydrogen production, electrolysers in parallel are connected. Each electrolyser contains a transformer, rectifier, PEM stack and auxiliary equipment (currently not depicted in the figure). If thyristor rectifiers are used, **ADDITIONAL FILTERING AND REACTIVE POWER COMPENSATION** is needed so that the plant complies with the grid codes and standards. These filters can be active or passive type, but they do require additional footprint to the plant. It is estimated that for a 100MW plant, the size of this filter may require about 300 m^2. This size may vary depending on the used equipment, but it is more or less on this order of magnitude. They also need yearly maintenance between 150h to 250h depending on the size. The plant may be connected to the transmission or distribution grid, depending on the power ratings.

3.1 Rectifier topology performance comparison

In the GREENPORTS project and in particular Work Package 3, the scope was to investigate whether or not, **NEWER SEMICONDUCTOR DEVICES** such as the new generation of Insulated Gate Bipolar Transistors (IGBT) and Silicon Carbide Metal-Oxide Semiconductor Field-Effect Transistors (SiC MOSFET) are capable to provide the same high performance characteristics such as efficiency and reliability, but also **TO PROVIDE FULL CONTROLLABILITY OF THE RECTIFIER** so that the interconnection challenges are reduced or even eliminated. With the help of Greenports' partner Cummins-Hydrogenics, all requirements and characteristics of the rectifier unit were defined in the beginning of the project.

This work package is also a stepping stone to work package 4 where the **ANCILLARY SERVICES** to the grid are examined. To go beyond the state-of-the-art, new requirements were added to the rectifier unit. In order for the electrolysers to be able to provide these services, their dynamic behaviour needs to be examined. Consequently, **AN ELECTROLYSER MODEL WAS DEVELOPED** of the polymer exchange membrane stack to help with defining the dynamic challenges that rectifiers and electrolysers are facing to fulfil this task. Besides, scalability and repeatability to multi-megawatt electrolyser plants are also examined.

In the next part of the work package, a comprehensive literature review was carried out to determine promising power electronic devices and rectifier topologies. As a reference case, the classical thyristor topology was used. Many possible topologies that are able to satisfy the above requirements were selected and briefly described. From the listed solutions, the **CLASSICAL THREE-PHASE TOPOLOGY** presented in Figure 5 was selected, because of its simplicity and ease to control. Efficiency calculations based on existing components on the market were performed and it turned out that the new semiconductor devices were able to deliver only 1% lower efficiency compared to the thyristor rectifiers. Nevertheless, the efficiency of the additional equipment needed for the thyristor rectifiers was not taken into account.

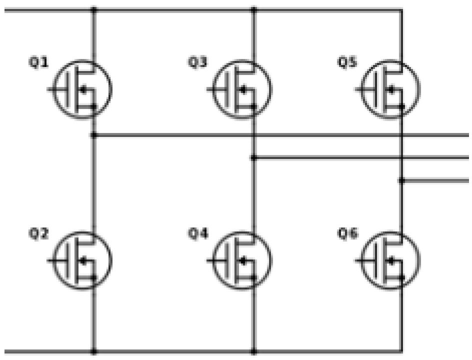


Figure 5: Three-phase full bridge active rectifier topology

Throughout the project duration, additional tasks were included in the work package. Key-performance indicators like footprint, cost comparison between the semiconductor devices implementation, availability and complexity were also briefly tackled. As of the dynamic response, different **TEST-CASES** were defined and examined by means of **SIMULATIONS**. A 5MW electrolyser was simulated under 0 and full power with rapid changes in the power settings as well as reactive power capabilities. Later this model was extended to **500MW** by connecting 25 electrolysers of 20MW each and simulations were carried out with the **REAL GRID PROPERTIES AT THE ZEEBRUGGE SITE**.

The conducted simulations showed that the fully controllable rectifiers are capable to ramp-up their power very fast and to satisfy the **REQUIREMENTS OF ELIA FOR PROVIDING PRIMARY AND SECONDARY RESERVES** invariantly of the power ratings as shown in **Fout! Verwijzingsbron niet gevonden.** Reactive power provision was also very easily provided with the **RECOMMENDED POWER FACTOR BY ELIA**.

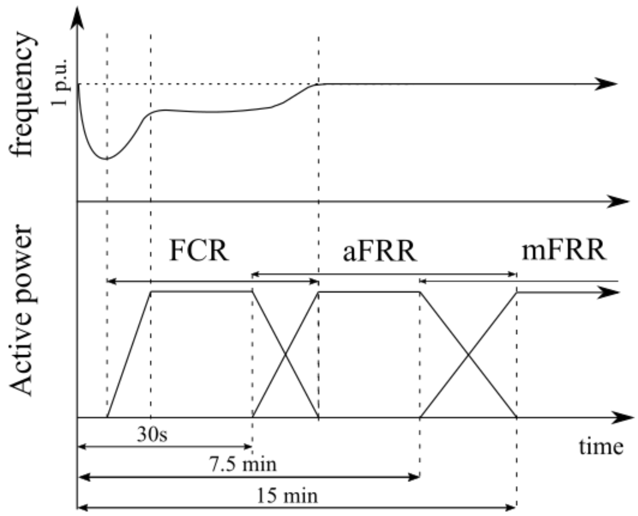


Figure 6 Time scale of the frequency related ancillary services

In addition, the fully controllable rectifier did not deteriorate the power quality at the point of common connection, which implies that no additional requirements like equipment nor fees will be charged to the electrolyser's owner. Unlike the fully controlled rectifiers, the **THYRISTOR RECTIFIERS HAVE A POOR POWER FACTOR** at full power, which tends to 0.9. This will cost the owners between 3.84 to 4.99 euro (depending on the zone connection) per MVAR[6] exchanged. Although the price difference between the fully controlled rectifier and the thyristor rectifier is about 3 times, in long term, the **SAVINGS IN REACTIVE POWER FEES PAY OFF** sooner and overall, from financial point of view the active rectifier becomes more attractive.

Fout! Verwijzingsbron niet gevonden. summarises the general requirements for connecting an electrolyser plant to the public grid. The listed power ratings and their connection to the respective voltage level are listed, but note that these are conditional values because they are case by case dependent. If a thyristor rectifier is selected, then additional equipment must be installed, which increases the footprint of the electrolyser plant. In addition to that, to compensate for the reactive power and avoid extra fees, STATic COMpensators (STATCOM) and distribution STACOMs (DATATCOM) must be integrated. Unlike the thyristor rectifiers, the active rectifiers do not suffer from this disadvantage. This not only helps to **REDUCE THE FOOTPRINT OF THE PLANT**, but also they

[6] The "MVAR-service" is the service voltage and reactive power control, see https://www.elia.be/en/public-consultation/20180910-public-consultation-on-the-mvar-incentive-study

require **LITTLE TO NO ANNUAL MAINTENANCE**. Invariant of the connection voltage level, the PEM stack voltage is always below 1 kV. Finally, some of the most important standards are listed as well.

Table 1: Requirements for connecting an electrolyser plant to the public grid

Power	<70 MVA	70-200 MVA	>200 MVA
Connection to the public grid*	Input voltage 6 to 36 kV	70-220 kV	>220 kV
Requirements to the Plant in terms of power quality	Thyristor rectifier - Harmonic filtration with passive or active filters - DSTATCOM – reactive power compensation**	Thyristor rectifier - Harmonic filtration with passive or active filters - STATCOM – reactive power compensation**	Thyristor rectifier - Harmonic filtration with passive or active filters - STATCOM – reactive power compensation**
	Active rectifier - none	Active rectifier - none	Active rectifier - none
Maximum voltage on the PEM stack	<1 kV	<1 kV	<1 kV
Compliant with standards:	- IEC 61000-3-7 - CEI 61000-3-6 - GC Synergrid C10/17	- IEC 61000-3-7 - CEI 61000-3-6 - GC Synergrid C10/17	- IEC 61000-3-7 - CEI 61000-3-6 - GC Synergrid C10/17

*The availability of the needed power is dependent on the particular location and must be coordinated with Elia

**Reactive power fees are paid if not installed

3.2 Recommendations

Based on the conducted research and contribution of the project consortium, the following rules can be defined for interconnecting electrolysers to the transmission grid with newer semiconductors:

1. The connection of the electrolyser must not deteriorate the power quality at the point of common connection.
The **TOTAL HARMONIC DISTORTION** must be kept below certain value. Elia complies with EN50160 which limits the total harmonic distortion in public grids up to 10%. The conducted examinations for 500MW system showed that the total harmonic distortion has risen with 1.8%, which is still low. All devices that are connected to the transmission grid must be also compliant with international standards IEC 61000-3-7 and CEI 61000-3-6, as well as the technical regulations for electricity set by the Belgian grid code Synergrid C10/17 “Power quality specifications for users connected to high-voltage grids”. The exact threshold of harmonic distortion must be consulted with Elia, because additional power quality studies and test may be necessary to ensure safe and reliable operation.

2. If the electrolyser plant is designed to **DELIVER MVAR SERVICE**, oversizing of the rectifier with 10% from the nominal power of the electrolyser unit is needed. This oversizing must be considered in the worst case scenario where the stack is at its end of life. This means that an increase of 2% of the CAPEX must be foreseen[7].

[7] According to “Techno-economic Analysis of PEM Electrolysis for Hydrogen Production, Strategic Analysis Inc. & NREL”, the electrolyser cost breakdown shows that the rectifier costs 20% of the total price. If an increase of 10% of the power is needed, then this roughly gives a 2% increase of the total electrolyser’s cost.

3. If the electrolyser owners decide to **PARTICIPATE IN FCR** (cfr chapter 4), then the electrolyser must be able to ramp up its power from **0% TO 100% IN ABOUT 30 SECONDS**. This is the most severe requirement to the electrolyser in order to qualify for ancillary service provision to the transmission system operator. This requirement in not valid for the other ancillary services like aFFR and mFRR.

4. Below power consumption of 70MW the connection voltage level is between 36 and 70kV. In the second case two conversions are needed from 70kV to 36kV (6-36kV) and then to 0.68kV. However, the lower the grid voltage, the higher **TRANSMISSION GRID COSTS** will be charged to the customer. Above 70MW the possible connections are 110kV, 220kV and 380kV. A 500MW electrolyser plant is only allowed to be connected at 380kV level.

5. Other requirements for connection loads to the transmission grid can be found on https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32016R1388&from=EN and https://issuu.com/elianv/docs/r3_f_etude_power_quality2

3.3 Conclusions

In this work package, a performance evaluation of an electrolyser equipped with an active rectifier is performed. Key performance indicators for providing ancillary services are examined. The results showed that both active rectifiers and thyristor rectifiers are capable of delivering fast response, however, the thyristor rectifiers are unable to provide any reactive power control. In order to keep the power quality within limits when using thyristor rectifiers, additional equipment integration such as filters and STATCOMs must be considered. However, this increases the footprint of the plant. Although the active rectifiers are more expensive compared to the thyristor ones, the former ones do not suffer from these disadvantages and require a smaller footprint. General recommendations are given at the end regarding the electrical compliance of the water electrolyser and its connection to the public electrical grid.

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4 Provision of grid services by electrolyser

Lead Partner: UGent- partner Engie

As wind farms are taking the place of the conventional electricity generation plants, new solutions are needed as balancing reserves. As a type of flexible demand, large responsive loads like electrolysers are able to provide new and flexible balancing services to the grid. Grid operators could ask large electrolysers to quickly ramp-up their consumption when there is an excess of renewable energy production. They also can command the electrolysers to reduce their consumption when the power generation is less than the electricity consumption of aggregated loads. This is achieved by their energy storage potential and manageable electricity consumption capabilities.
Particularly, the Proton Exchange Membrane (PEM) electrolysers have a great (technical) potential for the procurement of ancillary services. The very fast dynamics of the PEM electrolyser process enables them to react quickly to demand change signals sent by the system operators.
Besides the real time balancing market, also in the day ahead and intraday market, the flexibility of electrolysers could possibly play role, since they constitute a fast interruptible baseload that does not exist today in abundance at the demand side.

The purpose of work package 4 (WP4) was to investigate the **TECHNO-ECONOMIC ASPECTS OF PROVIDING GRID SERVICES** by the electrolysers. The first section gives an overview of the potential ancillary services, and the next two sections describe the main outcomes on the techno-economic aspects of producing hydrogen and offering grid services. Finally, the last section summarizes the main conclusions.

4.1 Potential grid services

This section aims at **IDENTIFYING THE POTENTIAL GRID SERVICES** that can be provided by the electrolysers. In the first part, a short introduction to electrical grid services and their technical requirements in the context of Belgian electrical system are given. The electrolysers' capability for providing grid services and a short conclusion are discussed further.

Electrical grid services are defined as a variety of functions that Transmission System Operators (TSOs) contract so that they can guarantee system stability and security. In Belgium, the Belgian TSO (Elia) has **BALANCE RESPONSIBLE PARTIES** (BRPs) at each grid access point in order to keep the quarter-hourly balance between generation and consumption. If BRPs are incapable to balance their customer portfolio, Elia itself takes the essential steps to balance the control area. As Elia does not own its own generation units, in such circumstances, it will ask power system players to provide ancillary services. Elia utilizes ancillary services to preserve **FREQUENCY AND VOLTAGE AT SUITABLE LEVELS**. A flexible load that can take action in response to TSO signals by increasing or decreasing its consumption can offer the same grid services as a generator decreasing or increasing its production, respectively. The potential of electrolysers as flexible loads to supply grid services is analysed in the next sections.

4.1.1 Grid services for frequency control

Frequency control is developed as a set of services to ensure that the grid frequency remains within a definite range of the nominal frequency at any time. In Europe, a general characterization of frequency control, as previously outlined in Figure 6, is made where different frequency control services are operated in a row at various time scales. The primary or **FREQUENCY CONTAINMENT RESERVE (FCR)** and secondary reserve or **AUTOMATIC FREQUENCY RESTORATION RESERVE** (aFRR) are activated automatically, while tertiary or **MANUAL FREQUENCY RESTORATION RESERVE** (mFRR) is activated manually.

4.1.1.1 *Primary reserve for frequency containment (R1 or FCR)*

If the frequency drops below 50 Hz because of a failure such as shutting down a Belgian power plant, the primary reserve is activated instantly to avoid a further drop in frequency and stabilize the system frequency. This reserve has to be **ACTIVATED IN 30S** and it needs to be online for a quite **SHORT PERIOD** (up to 15 minutes). The activation of the FCR reserve is done by a variation of the active power proportionally to a frequency deviation, with the effect to stabilize the frequency at a value different from nominal frequency (proportional law) and is operated decentralized by a local monitoring of the frequency deviation. The offered service must be 100% accessible during the supply period. Elia will pay a reservation fee for the service, based on the offered volume.

4.1.1.2 *Secondary reserve for automatic Frequency Restoration (R2 or aFRR)*

After the primary reserve stabilizes the frequency, in order to restore the frequency to 50 Hz, the secondary reserve automatically kicks in (between 30 seconds and 7.5 minutes) and remains active as long as it is necessary. aFRR is the most important and also the most complex power reserve balancing product due to **HIGH ACTIVATION FREQUENCY** and the **LARGE AMOUNT OF ENERGY** that should be activated [3]. Grid users that provide secondary reserve must have suitable facilities for communicating in real-time with Elia's control centre over dedicated SCADA connection and their units must comply with certain technical requirements. The activation of the reserve is done by following a signal sent from a central authority (usually the TSO) in contrast to the FCR which is managed in a decentralized way.

For aFRR service, as the purpose is not only to be able to provide a certain amount of power to the system for a short duration, but is also to be able to provide enough energy in a short duration to bring back the frequency to 50Hz, the service is split in two commitments contracted separately:

- **Capacity commitment**: the supplier of the service ensures, in day ahead or week ahead and for certain time block, that the asset is able to provide, at any moment during that time block, a certain amount of power which was prior contracted.
- **Activation commitment**: the supplier is activated to provide/absorb the energy at a certain price and must deliver the energy at a certain power and during a certain time.

The capacity commitment is an insurance paid by the grid ensuring there is always enough dispatchable power on the grid available to bring back the frequency to 50 Hz. The activation commitment ensure that there is enough energy in the system and that the operator will be remunerated to provide the energy.

4.1.1.3 *Tertiary reserve for manual Frequency Restoration (mFRR)*

After 15 minutes, if necessary, aFRR is replaced by the tertiary reserve, activated manually by Elia. mFRR enables Elia to cope with a significant or systematic unbalance in the control area and resolve major congestion problems. mFRR could be offered by generation or consumption units:

- **Production reserve:** Generation units, which have signed a contract for mFRR can inject the extra capacity.
- **Off-take reserve:** Grid users who have signed an interruptibility contract will reduce the off-taken energy.

Elia considers a payment to the grid user providing mFRR (expressed in €/MW/h of availability) for the energy supplied to Elia and to cover start-up costs.

Table 2 summarises the basic technical requirements of providing frequency services in Belgium[8].

Table 2: Requirements of frequency services

Product	Availability	Reaction time	Maximum time of activation	Minimum capacity	Total market volume in BE
FCR/R1	100% (15 min)	30 sec	Constant	1 MW	68 MW
aFRR/R2	100% (15 min)	7.5 min	Constant	1 MW	144 MW
MFRR/R3 reserved	100% (15 min)	15 min	Standard service: 8h/day, unlimited activations		
			Flex service: 2 h/ every 12h, maximum of 8 activations per month	1 MW	780 MW
mFRR/R3 non-reserved	Not outside offered periods	15 min	Depending on offer, maximum 2 hours	1 MW	

4.1.2 Voltage Control

While frequency is a system-wide parameter, voltage is a **LOCAL QUANTITY** closely coupled to the reactive power injection to network buses. Therefore, voltage control is fulfilled by **MANAGING REACTIVE POWER** at specific service points. Suppliers of this service are, synchronous generators, static compensation units, tap changing transformers, transmission lines, virtual power plants, and demand facilities with load shedding[9]. Devices interfaced with the grid through power electronic converters, such as wind turbines and PVs can also offer this service. The providers proposed price and also on the location of the supplier units within the high voltage grid have a decisive impact on Elia's decision to choose providers of the voltage control service. The reactive energy may be activated by the generation units automatically (primary control) or at Elia's request (centralised control). Generation units with a capacity of more than 25 MW must take part in primary voltage control. Payment for the reserved control bands is calculated based on a unit price, the volume contracted in MVar and the length of use. Voltage control services are represented by contracts of at least one year signed by Elia and the provider.

4.1.3 Congestion Management

Congestion management is chiefly a network planning-related issue. This service refers to **AVOIDING THE THERMAL OVERLOAD** of system components by decreasing the amount of power transferred. Comparable to voltage control, congestion management is also a **LOCATION-DEPENDENT** service. Phase-shifting transformers, on-load tap changers at substations, supplementary line regulators on feeders, and large flexible loads are some potential providers of the congestion management service.

Congestion management can be managed by dedicated product or service (like the Frequency Regulation services) or by a reduction of the size of the zonal area upon which the same wholesale price is formed (to capture by price difference the signal of congestion).

[8] mFRR product design note, 2020. See https://www.elia.be/-/media/project/elia/elia-site/electricity-market-and-system---document-library/balancing---balancing-services-and-bsp/2020/20200203_bsp-contract-mfrr_en.pdf

[9] MVar service design note, 2018. See https://www.elia.be/-/media/project/elia/elia-site/voltage-control/20181109_study-on-the-future-design-of-the-ancillary-service-of-voltage-and-reactive-power-control.pdf

4.2 Technical-economic viability of providing grid services

The potential of electrolysers to supply grid services could be recognized according to the service prerequisites and the capacities of electrolysers. According to the findings of Deliverable 4.1 and based on the discussions during internal meetings and sessions with project partners, FCR, aFRR, and MVar were identified as the most interesting services to be studied further.

4.2.1 Technical considerations

The conducted work investigated electrolysers compliance with the technical specifications of grid services and the effect of providing those services on the performance of the power system. Results revealed how the provision of FCR, aFRR and MVar by electrolysers improve the stability and power quality of the system. The intermittency of renewable energy sources were also regulated by adjusting the consumption of the electrolyser. These improvements are connected to the fast dynamics of the electrolysis process. However, the ability of electrical converters had a notable impact on the potential of electrolysers for offering MVar.

4.2.2 Short term considerations

The economic analysis used a general economic model that could be applied to P2G plants connected to both the transmission grid and wind farms. Considering the current market structure in Belgium, the results confirmed that **PARTICIPATION IN GRID SERVICES COULD**, in some cases, **IMPROVE THE ECONOMIC PERFORMANCE** of the P2G system and decrease the hydrogen production cost. However, the obtained results showed that the potential progressions, including the improvement of the electrolyser efficiency and decrease of capital costs (CAPEX) would impact the results. While new limitations originating from wind and other renewable energy resources could increase the need for grid services, the number of ancillary service providers is likely to rise, where the remuneration prices will possibly decrease in the long term. Thus, uncertainties in the development of grid services in terms of available sizes and rewards could also change the optimal solutions for the operation of P2G plants in future scenarios. More details about the economic analysis on the provision of grid services could be found in [10],[11].

4.2.3 Mid/long term market considerations

4.2.3.1 FCR/R1 market

The market is extremely small (70MW in Belgium, out of which only 21 MW must be procured in Belgium). And there is a tradeoff for the electrolyser between reducing it capacity to provide FCR or producing H_2, leading to the integration of an opportunity cost in the formation of the marginal cost for electrolyser to provide FCR. And, there is existing competing technology able to provide the service in standalone with a marginal cost near 0.

It remains a possibility to aggregate the electrolyser as a secondary asset with battery, providing only the service on an asymmetrical way but it reduce further the market volume and leaving only a fraction of the remuneration (as the major remuneration goes to the Battery itself).

[10] Dadkhah, A., Bozalakov, D., De Kooning, J. D., & Vandevelde, L. (2020, Jun). Optimal sizing and economic analysis of a hydrogen refuelling station providing frequency containment reserve. In 2020 IEEE International Conference on Environment and Electrical Engineering and 2020 IEEE Industrial and Commercial Power Systems Europe (EEEIC/I&CPS Europe) (pp. 1-6). IEEE.

[11] Dadkhah, A., Bozalakov, D., De Kooning, J. D., & Vandevelde, L. (2021). On the optimal planning of a hydrogen refuelling station participating in the electricity and balancing markets. International Journal of Hydrogen Energy, 46(2), 1488-1500.

Based on those elements, it is **NOT EXPECTED THAT FCR WILL BE A RELIABLE AND VALUABLE REVENUE STREAM** on the long term for electrolyser, even though it can constitute in the short term (<3 years) a good support to a business case.

4.2.3.2 aFFR/R2 market

The market size for aFRR service is rather limited (around 150MW) with different technology able to provide the services leading to a risk of market saturation.

As :

- the aggregation of electrolyser and renewables are able to provide the aFRR capacity service at a marginal cost near zero
- the market is small and might be quickly saturated,

the risk of market price collapse for the aFRR capacity market is important.

On the side of the aFRR activation market, the electrolyser will **NOT BE THE MOST COMPETITIVE SOLUTION** to provide the service on the mid, long term impacting the competitivity of this technology on that service.

It is therefore expected that, at mid and long term, electrolyser will play a role on the aFRR capacity market but with an important risk of revenue decrease compare to today market and will most likely not be competitive on aFRR activation market.

4.3 More granular power prices?

4.3.1 Transmission level

Today, wholesale market prices guide consumption, production and investment decisions and drive merchant business models. In particular, the European target model is based on a sequence of day-ahead, intraday and balancing markets and it relies on a zonal approach: network nodes are aggregated by zones and cross-zonal trade is feasible according to commercial transmission capacities. With a few exceptions, biddings zones typically correspond geographically to a country. Within a bidding zone, transmission capacity is assumed to be infinite (a "copperplate"). This **SIMPLIFIED REPRESENTATION OF THE GRID** creates already today the need for the TSO to intervene after markets have closed, because the market-based dispatch and associated flows cannot be accommodated by the available transmission capacity.

Such intervention is expected to grow with the need to decarbonize the energy system. The transmission grid of the 20th century was designed to accommodate mainly centralized thermal generation. It is less and less adapted to integrate the intermittent generation patterns of wind and photovoltaics capacity spread across the country. Furthermore, reinforcing and extending the grid is costly, takes time and often faces public opposition. This may ultimately trigger a **REDEFINITION OF BIDDING ZONES AND SMALLER BIDDING ZONES IN PARTICULAR**[12].

Hence, depending on location, this may create new business opportunities for hydrogen solutions (and other technologies) that are not "seen" by the market today. For instance, structurally lower prices would be seen in regions with a lot of renewable electricity generation but with limited transmission capacity available to evacuate this energy. This might render electrolysis interesting. However, after a discussion with the Belgian transmission system operator Elia, **NO MAJOR CONGESTION IS EXPECTED TO APPEAR ON THE BELGIAN TRANSMISSION GRID** up to 2030 at least.

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[12] Even if bidding zones are not revised, redispatch needs to happen with market-based mechanisms as the base case (non-market-based mechanisms are the exception), following Art.13 of Regulation (EU) 2019/943.

4.3.2 Distribution level

More PV and Wind capacity may also create new issues at distribution level. The traditional “fit and forget” approach to build enough distribution capacity to meet all loads will be too costly for society. A balance will need to be found between extending the grid and market-based adaptations of demand and supply.

As a matter of fact, Art.32 of Directive (EU) 2019/944 states that DSOs should procure flexibility services, i.e. buy services on a market. However, such markets are currently not well defined yet. There are different **LOCAL FLEXIBILITY MARKET** initiatives under investigation in European countries, but those are heterogeneous and differ widely in the integration with the wholesale markets.[13]

Although their design is different, such initiatives may ultimately lead to an energy pricing at distribution level, via market-based procurement of services to address local grid issues (congestion and voltage in particular). Again, that might also create new business opportunities for hydrogen solutions. However, the Flemish distribution system operator Fluvius expects **NO MAJOR CONGESTION ISSUES APPEARING UNTIL AT LEAST 2030 IN THEIR DISTRIBUTION NETWORK**.

In summary and according to the interviews held, one concludes that the outlook for services to address congestion issues at the Belgian transmission and the Flemish distribution systems is not promising for supporting electrolysis in the medium term up to 2030.

4.4 Conclusions

Technical requirements of grid services and the ability of the electrolysers to provide these services have been analysed, as well as the economic viability. The main conclusions of the techno-economic analysis can be summarized as follows:

ELECTROLYSERS HAVE THE FLEXIBILITY to technically tackle efficiently all flexibility means (from the quickest like FCR to the slowest (mFRR and congestion) and based on current market conditions have potential to deliver competitively those services. AFRR requires less crucial dynamic characteristics than FCR, but higher capacity and longer periods and seems the most interesting service for electrolysers.

However on mid (>3year) and long term, the **ANCILLARY SERVICE MARKET IS TOO NARROW** and more cost effective technologies exist reducing the expected value of the revenue pool. Hence grid services as such will not justify the installation of an electrolyser. On short term however, it can help the business case to some extent.

Congestion might be an interesting source of revenue, but **NO MAJOR CONGESTION ISSUES ARE EXPECTED** on Belgian network before 2030.

Elia sees the main function of the electrolysers and hydrogen, regarding the support of the grid, in having an emergency product provision when there is not sufficient energy produced from sun and wind. For the flexibility needs, Elia sees other solutions like batteries or even limited power curtailment as more interesting.

In conclusion, ancillary services cannot be considered as a reliable value pool to launch and support the emergence of electrolysers and following ELIA major congestion issues are expected to occur in a too far future to justify in the short and mid-term installing electrolysers for this purpose.

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[13] For a more detailed discussion, see: Directorate-General for Energy, Küpper, G., Jakeman, A., Staschus, K., Hadush, S. Y. (2020). “*Regulatory Priorities for Enabling Demand Side Flexibility*”. Publication Office of the European Union.

5 Storage & distribution of hydrogen

Lead Partner: Eoly & Colruyt

Storage and distribution of hydrogen from a central production plant to end customers is technical feasible. At this moment, **TRANSPORT OF PURE GASEOUS HYDROGEN** in storage containers with a pressure up to 500 bar is the most mature technology. Other storage options, like hydrates, MOF[14], LOHC[15]… are still in research phase, or are demonstrated on small scale. Not all data was available to carry out a full analysis. Another option, storing and transporting hydrogen in its liquid form, was also not withheld for further analysis, since literature data indicates that the cost of liquefaction is substantial and transport of liquid hydrogen is only economically viable for large distances (plus 400 km). **LIQUID HYDROGEN** is therefore not an option to transport locally produced hydrogen to a Belgian customer. Nevertheless, for the import of hydrogen, liquid hydrogen could be an option.

The further analysis of transporting gaseous hydrogen in a storage container (300 and 500 bar) focused on transport by truck, train and ship (Figure 7). The main scenario is transporting 1 storage container (containing 250 or 750 kg of useful hydrogen) to the end customer. These masses are selected, since storage containers with this capacity are available. The 750 kg useful hydrogen option, is, at this moment, the maximum mass that can be transported in a container for gaseous hydrogen. Two options to deliver the hydrogen on site were assessed: dropping the storage container off, or dumping the hydrogen in a stationary low-pressure storage at the customer's premise and retrieving the emptied storage container immediately. In the cost calculations, the compression cost, transport cost and delivery cost are accounted for.

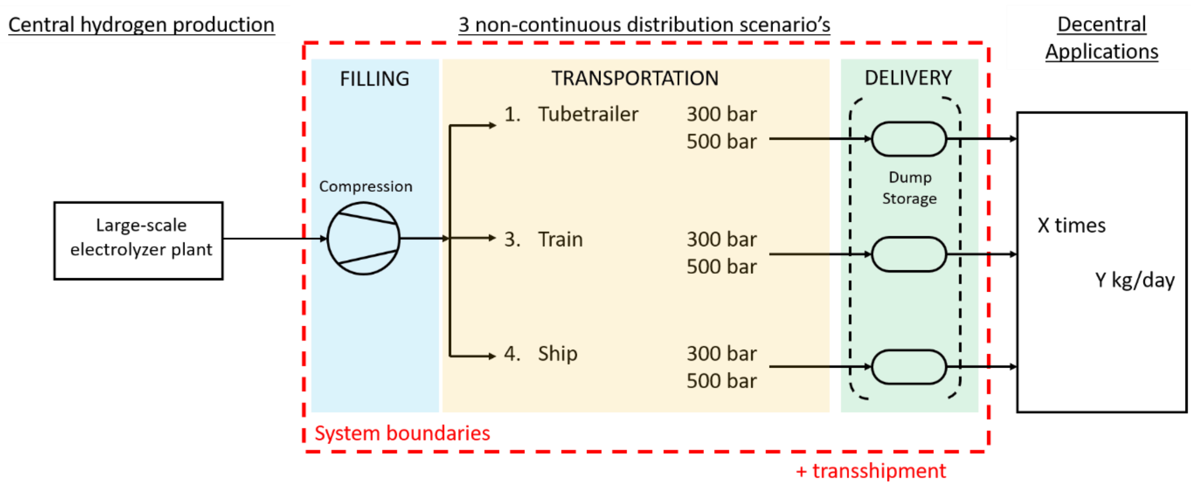

Figure 7: Overview of the transport scenario's assessed for truck, train and ship transport.

TRUCK TRANSPORT was for all assessed scenarios the most economical, since transport by train or ship takes more time, leading to a greater depreciation cost of the storage container. In addition, the transshipments needed for train and ship transport have a substantial impact on the overall cost. In

[14] Metal-Organic Frameworks (MOFs), high surface area solids that can adsorption hydrogen.

[15] Liquid Organic Hydrogen Carriers

Table 3, you find the derived overall costs, together with their uncertainty. The uncertainty was derived by means of a Monte Carlo analysis.

We can conclude that transporting 750 kg at once is more cost-effective than transporting just 250 kg, as expected. The cost of transporting a multiple of 750 kg can be derived by multiplying the given numbers. However, at some point, delivery of storage containers will not be possible due to logistics burdens and other options (local production, pipeline) could be a viable option.

It is assumed that containers dropped off by the end-customers are brought back after one day. With this assumption, cost for drop delivery of the same order of magnitude were attained as for the related dump storage scenarios. The type of end-application and the amount of hydrogen used daily, determine what delivery method is the most viable. If the operation of the end-application is depending on pressure, like for a hydrogen refueling station, dropping off the storage container could be the best option since the compression-energy can be preserved. Dumping hydrogen in a low-pressure storage destroys compression energy, which in some use cases needs to be recompensated.

Nevertheless, the amount of hydrogen that is daily used has also an impact on the choice of delivery method. In our calculations, we assume that the dropped container stays one day at the end-user premises and the end-user needs to pay a rent related to the depreciation cost of the container. This rent is in the order of magnitude of a few hundred euros per day. So if an end-customer uses less than 250 or 750 kg per day and the container stays days at the end-user premises, the rent can become more expensive than the cost to install and maintain a dump storage. This can be true even for pressure sensitive applications, such as refueling stations.

In Table 4 the division of the total cost for truck transport over filling, transport and delivery is given. Overall, the transport itself is the main cost contributor, and the part of compression and delivery are comparable with each other.

Within the study we also assessed **HYDROGEN TRANSPORT BY PIPELINE**. We calculated that a pipeline could transport hydrogen to an end-customer for 1.0-1.8 €/kg. This is a lower value than we found for truck, train and ship transport, but this can give a wrong impression. We did not take into account the same system boundaries and assumptions. In addition, no legislation or technical limitations, were accounted for.

Hydrogen pipelines cover a wide range: from small pipelines for hydrogen transport on a site, to industrial pipelines kilometers long connecting production and user sites. Transport by pipeline could be economically the best option in 2 main scenarios: 1. transporting hydrogen on the same site, related to small mass flow and/or small distances, or 2. transporting hydrogen over a long distance related with a high mass flow. In the second case, a high CAPEX investment will be needed, but due to the large throughput the price per kilogram of hydrogen transported could be the best option.

In conclusion, truck transport is preferred regarding cost, compared to train and ship. Due to the long transport time with ship or train, which can take days, and the related higher depreciation cost of the storage container, the cost of train and ship transport are higher.

The option to convey hydrogen via a pipeline could be economically the best solution and should be assessed case by case, in particular for the larger hydrogen demanding end-users (tons/day), since the logistics of truck transport could be a limiting factor.

Table 3: Cost of hydrogen transport with different modalities (over a mean distance of 60 km, with variation between 5 and 300 km)

	Truck				**Train**				**Ship**			
€/kg H_2	300 bar		500 bar		300 bar		500 bar		300 bar		500 bar	
	Drop	Dump	Drop	Dump	Drop	Dump	Drop	Dump	Drop	Dump	Drop	Dump
250 kg per day end-consumer	2.09±0.69	2.28±0.69	2.42±0.72	2.34±0.71	5. 73 ±0.64	5. 92 ±0.64	6. 33 ±0.68	6. 25 ±0.66	3.85±0.34	4.05±0.34	4.45±0.41	4.38±0.38
750 kg per day end-consumer	1.20±0.27	1.43±0.29	1.44±0.30	1.48±0.30	2.70±0.28	2.93±0.29	3.09±0.33	3. 13 ±0.32	2.07±0.22	2.30±0.22	2.46±0.28	2.50±0.26

Table 4: The division of the total cost over compression, transport and delivery for truck transport

		Truck			
	%	300 bar		500 bar	
		Drop	Dump	Drop	Dump
250 kg per day end consumer	Compression	18	16	20	20
	Transport	64	69	55	67
	Delivery	18	15	25	13
750 kg per day end consumer	Compression	31	26	33	32
	Transport	37	47	31	45
	Delivery	32	27	35	22

6 Economic attractiveness of Power-to-gas in Belgium

6.1 Economic attractiveness of power-to-gas in Belgium

Lead Partner: UGent

6.1.1 Opportunities and challenges for PtG

Hydrogen is getting renewed attention for the promising role it could play in the transition towards a low-carbon future.

Firstly, the current level of climate ambitions also requires emission reductions for hard-to-abate applications and sectors before 2050, where electrification is very costly or technically impossible. Hydrogen and hydrogen-derived products are leading options for some of these applications as they have better properties in terms of storage, handling and chemical reactions.

Secondly, production of hydrogen by conversion of electricity, Power-to-gas (PtG), could complement higher shares of intermittent renewable energy sources in the electricity system. Because electricity is not economically storable on a large scale and for long periods, unlike most other commodities, demand and supply have to match at any point in time for the stable operation of the power system. Adding this extra uncontrollable variability at the production side in the form of VRE to a demand for electricity that already has a strong daily and seasonal variability will make it even more challenging to balance the electricity system at all times. Thus increasing the value of elements in the power system that can modify production or consumption in response to variability or otherwise smoothen variability. Power-to-gas installations that can be operated flexibly can make use of resulting moments of RES surpluses or low-price moments.

Despite these opportunities the economics of green hydrogen remain challenging. Today production of green hydrogen with electricity is the most viable option, but 96% of hydrogen is still produced directly from fossil fuels mainly through reformation of natural gas and despite the many possible future applications it is almost exclusively used as chemical feed stock (for refineries and ammonia production). Deployment at scale in other applications crucially depends on the cost of the gas produced.

We have analysed at the **COST OF PTG TODAY**, identified the main factors that drive its attractiveness and look at the **FUTURE EVOLUTION OF THESE FACTORS**.

6.1.2 PtG vs fossil hydrogen production today

The attractiveness of PtG depends on it being the cheaper supply option. Currently the main method of hydrogen production in Belgium is Steam methane reforming (SMR). We aggregate all discounted costs over the lifetime of the installation and express per unit of production as the **LEVELIZED COST OF HYDROGEN**. This gives us a single value to compare cost of producing one unit for different production technologies.

6.1.2.1 *Using flexibility electrolyser to optimize costs*

An electrolyser can be operated flexibly, meaning it can adjust its production at any time. This is valuable when input electricity prices vary significantly every hour. By choosing his bid price the operator of a PtG plant can optimize the **TRADE-OFF** between more **OPERATING HOURS TO SPREAD FIXED COSTS** over and **LOWER INPUT COSTS FOR ELECTRICITY**. In all following calculations we use this optimized cost. The calculations are done for a PEM electrolyser; in paragraph 6.1.4 we also show the 2019 result for an alkaline electrolyser which is lower in cost price.

6.1.2.2 *Analysis PtG vs fossil hydrogen production today*

Figure 8 illustrates that PtG is still considerably more expensive than fossil production of hydrogen via steam methane reforming in Belgium today. By far the biggest difference makers are the input costs (electricity vs gas) and the investment costs (CAPEX).

The CO2 intensity of the different production methods is also indicated in the graph. If the Belgian electricity grid mix is used, the CO2 emissions of hydrogen produced with PtG are nearly as high as the CO2 emissions of SMR produced hydrogen. This stresses the fact that PtG production should go along with increased renewable energy capacity and smart operation of the PtG plant, i.e. produce when there is a high share of RE in the system.

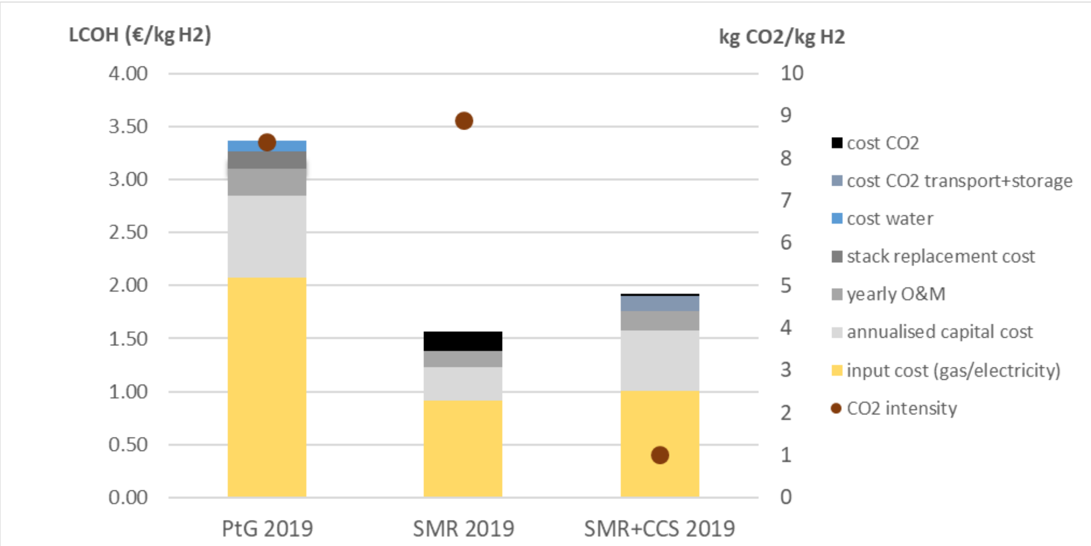

Figure 8: LCOH PtG (PEM electrolyser) vs SMR (+CCS). (Assumptions: historical 2019 electricity prices for BE. Overview assumptions PtG, SMR (+CCS) installation and costs see tables 4 and 5. Gas price: 5.76 €/GJ. CO2 price: 19.7 €/ton CO2. Optimized run hours for PtG: 8145h. Optimized average electricity costs PtG: 37 €/MWh); (Assumption CO2 intensity: grid electricity BE 2019 (source: CREG) 150 kgCO2/MWh).

Figure 9 shows the effects of the 3 main factors: **CO_2 PRICE, PTG SYSTEM COST (CAPEX) AND AVERAGE ELECTRICITY COST** on the levelized cost. It can be noted that at least 2 of the 3 have to change significantly for PtG to become competitive with SMR. When interpreting Figure 9 it is important to note that the number of operating hours is an important underlying parameter. Figure 10 illustrates how sensitivity to CAPEX and average electricity price change when the operating hours are fixed at 4500 instead of 8000. This is a more realistic situation when only relying on variable RES or surpluses/low electricity price moments.

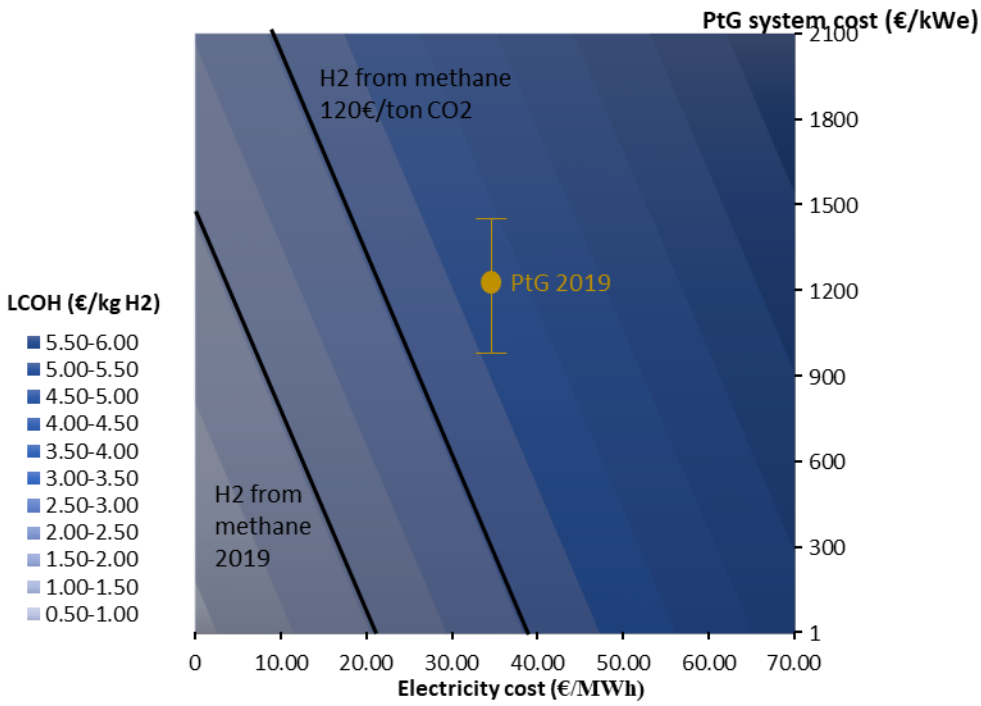

Figure 9: Relation PtG CAPEX (PEM electrolyser) and Electricity cost (PtG operating hours:8000). (Assumptions: historical 2019 electricity prices for BE. Overview assumptions PtG, SMR (+CCS) installation and costs see tables 4 and 5. Gas price: 5.76 €/GJ. CO_2 price 2019: 19.7 €/ton CO_2.

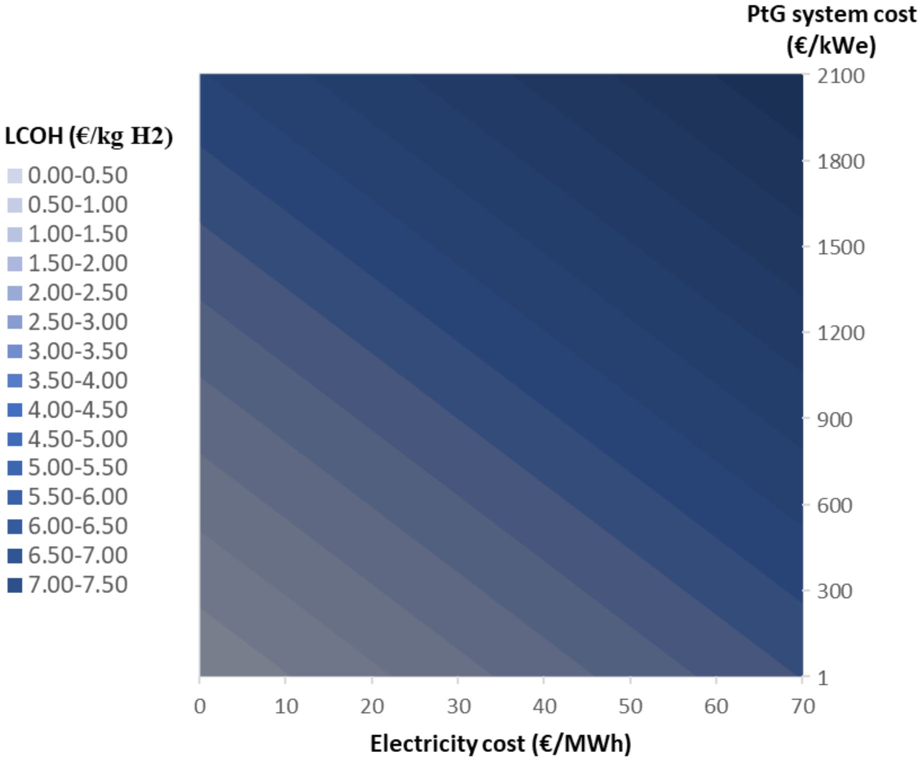

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Figure 10: Relation PtG CAPEX (PEM electrolyser) and Electricity cost for **4500 instead of 8000 operating hours**. (Assumptions: Overview assumptions PtG, SMR (+CCS) installation and costs see tables 4 and 5.

6.1.3 Assumptions future evolution PtG and fossil hydrogen production

With the transition towards a less GHG intensive energy system, changes to the electricity system will occur that will influence hourly electricity prices. At the same time ETS prices on emissions from fossil production routes will increase and experts claim there is significant room for CAPEX reduction for both electrolysers and CCS. These changes will gradually make power-to-gas and CCS more interesting compared to SMR without CCS. In this part we perform a scenario analysis to get an idea of which technology is likely to prevail and when.

6.1.3.1 Assumptions PtG and SMR+CCS system costs

For assumptions on the evolution of future costs, lifetime and efficiency of PtG and SMR+CCS plants we have reviewed recent studies specifying those. We have determined a low, mid and high scenario for the different parameters based on the ranges specified in those studies[16]. The assumptions are listed in Table 5 and Table 6. Different electrolyser technologies exist: alkaline, PEM and SOEC. We focus on PEM in this study as it is often deemed to most promising in other studies for electrolysis in the future and it is the focus technology of the technology partner in this project. SOEC still has some issues for commercialization. Alkaline electrolysers are a mature technology on the other hand and are significantly cheaper *today* compared to PEM. It is expected that PEM will catch up in the future though in terms of investment cost. For these reasons we include alkaline as a check for the analysis today but leave it out in future scenarios.

Table 5: overview of PtG assumptions

Time Period	2019	2030	2040
PtG total system cost PEM (2019 eur/kWe)			
low	900	550	350
mid	1200	900	650
high	1500	1250	1000
PtG system efficiency PEM (LHV)			
low	56%	61%	64%
mid	60%	65%	68%
high	63%	69%	72%
PtG stack lifetime PEM (hours)			
low	30000	60000	80000
mid	60000	75000	100000
high	90000	90000	120000
Time Period 2019	low	mid	high
PtG total system cost AEC (2019 eur/kWe)	500	950	1400
PtG system efficiency AEC (LHV)	63%	67%	70%
PtG stack lifetime AEC (hours)	60000	75000	90000
Time Period	All time periods		
Fixed operating cost	3% of CAPEX		
Variable cost: water	€ 0.1/kg		
Variable cost: electricity	optimized based on yearly electricity prices		
Discount rate (Wacc)	8%		
stack replacement costs (%of system cost)	40%		

Note: Prices in 2019 euros

Similar to the assumptions for PtG, we reviewed recent reports for assumptions on the evolution of SMR+CCS costs and performance. Unlike PtG no range was specified so we just assume the

[16] International Energy Agency, 2019; Cihlar et al., 2020; Glenk & Reichelstein, 2019

specified trajectory without a low, mid and high scenario for these assumptions. Table 6 lists the assumptions used for SMR (+CCS) used in our analysis.

Table 6: overview of SMR assumptions

SMR	2019	2030	2040
CAPEX	€ $850/kW_{H_2}$	€ $850/kW_{H_2}$	€ $850/kW_{H_2}$
Efficiency (LHV)	76%	76%	76%
Fixed operating cost	€ 40	€ 40	€ 40
Emission factor	$8.9\ kgCO_2/kgH_2$	$8.9\ kgCO_2/kgH_2$	$8.9\ kgCO_2/kgH_2$
SMR+CCS	2019	2030	2040
CAPEX	€$1550/kW_{H_2}$	€$1250/kW_{H_2}$	€$1200/kW_{H_2}$
Efficiency (LHV)	69%	69%	69%
Fixed operating cost	€50	€40	€ 35
Emission factor	$1\ kgCO_2/kgH_2$	$1\ kgCO_2/kgH_2$	$1\ kgCO_2/kgH_2$
CO_2 transport and storage cost	€17/ton CO_2	€17/ton CO_2	€17/ton CO_2

Note: Prices in 2019 euros

6.1.3.2 Assumptions future electricity prices, gas price and CO_2 price

The future electricity system and corresponding wholesale prices, future gas prices and future CO_2 price are all interlinked to some degree. Therefore it is important to use future scenarios over these 3 variables that are internally coherent. We base our analysis on the scenarios of the 2020 **TEN YEAR NETWORK DEVELOPMENT PLAN** of the European electricity and gas grid TSOs[17]. As we are interested in hourly prices we use the detailed scenario assumptions in a **EUROPEAN UNIT COMMITMENT ECONOMIC DISPATCH MODEL** (Plexos) for a representative climate year to come up with hourly future electricity prices.

Figure 11 and Figure 12 show the resulting **PRICE DURATION CURVES** for the **DIFFERENT FUTURE SCENARIOS,** respectively for 2030 and 2040. For each year 3 scenarios are used that differ in their underlying assumptions: the National Trends scenario (NT) is based on the members states national energy and climate plans and can be seen as the current policies scenario. The Distributed Energy (DE) and Global Ambition (GA) scenarios are more ambitious in there carbon reduction efforts in line with the COP 1.5°C targets. This implies an almost fully decarbonized electricity system by 2040. The DE and GA scenario differ in how these targets are reached. In DE the focus is more on decentralized technologies, while in GA the focus is more on centralized technologies.
Note that the resulting prices should not be seen as a prediction of future electricity prices, the uncertainty and number of underlying factors are simply too big to predict this. They are merely used to provide insight in some **GENERAL TRENDS AND EVOLUTIONS**.
Detailed information on all underlying assumptions for these scenarios can be consulted on the TYNDP website. Table 7 provides the **GAS PRICE AND CO2 PRICE ASSUMPTIONS** for the different years and scenarios. To keep consistency we use the same CO_2 prices for determination of the

[17] Ten Year Network Development Plan of ENTSOE, https://consultations.entsoe.eu/system-development/tyndp2020/; The TYNDP2020 scenarios also discuss PtG: for NT they assume PtG based on current national plans; for the DE and GA scenarios they assess the need for PtG top-down i.e. starting from assumptions on total gas demand, import share and decarbonization of the gas supply to come to an assumed need for PtG capacity. Our analysis differs in that it starts from the assumed electricity system and demand to look at economic viability of PtG in Belgium. It is important to note that the scenarios do not foresee extra electricity production in the grids for PtG production, making variations in scenario assumptions for gas decarbonization not influence our results.

electricity prices and the calculation of the SMR (+CCS) costs in every year and scenario. We run an additional sensitivity on the gas price in every scenario of +20% and -20%.

Table 7: overview of gas price and CO2 price assumptions (from TYNDP scenarios)

year	2019	2030			2040		
scenario		NT	DE	GA	NT	DE	GA
Natural gas (eur/GJ)	5.6		6.91			7.31	
CO_2 price (eur/tonCO_2)	19.7	27	53	35	75	100	80

Note: Prices in 2019 euros

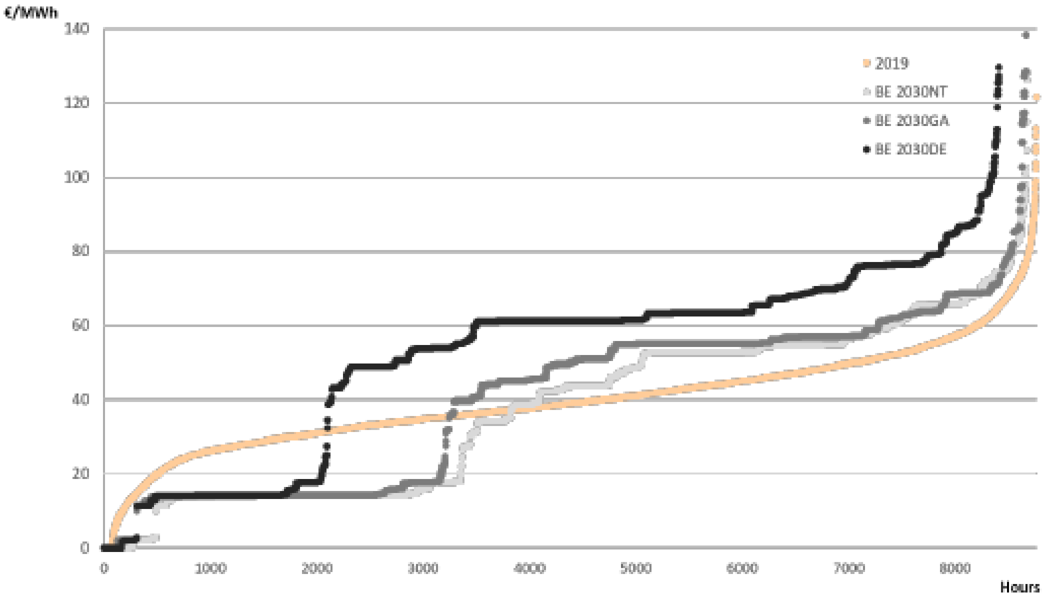

Figure 11: Modelled **2030** electricity prices for Belgium.

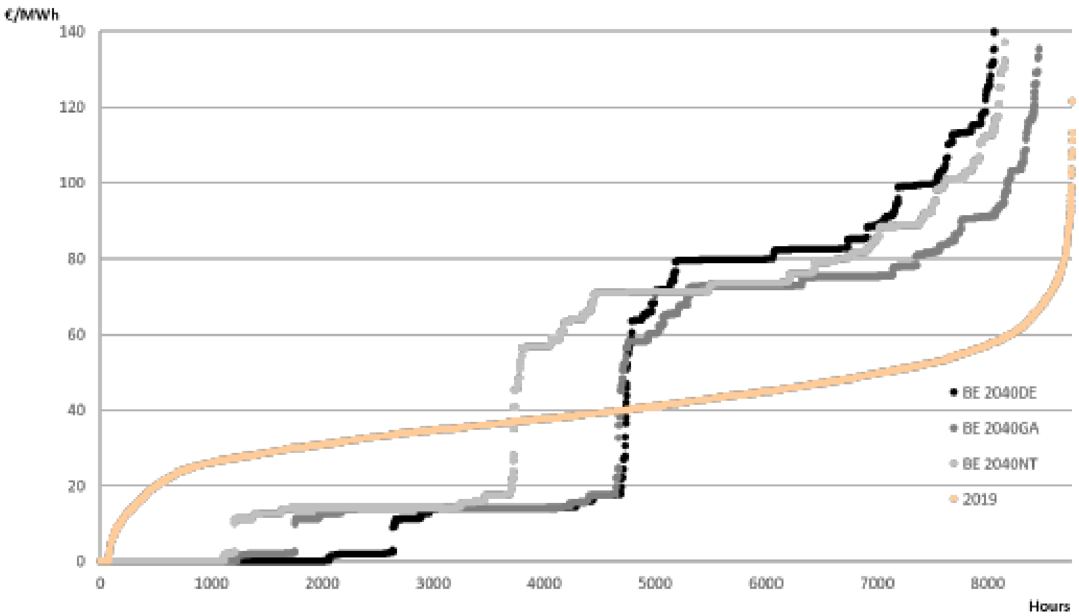

Figure 12: Modelled **2040** electricity prices for Belgium.

From the modelled electricity prices we notice that **VOLATILITY INCREASES**. The more ambitious and later the scenario the longer the low price moments and the higher the higher price moments. This seems a plausible result from the increased penetration of VRES in the system that produces at zero marginal cost and an increasing CO_2 price for the dispatchable fossil technologies.

6.1.4 Future evolution of PtG and SMR (+CCS)

Figure 13 shows the LCOHs of PtG today and in the future based on the modelled electricity prices and other assumptions. Under our assumptions **PTG IS NOT COMPETITIVE YET WITH SMR (+ CCS) IN 2030.** This can be attributed to the fact that periods of cheap electricity and the CO_2 penalty on fossil hydrogen production are not enough yet to compensate for electrolyser CAPEX costs. A stronger reduction in electrolyser CAPEX costs than assumed could lead to a trajectory of PtG competitiveness without additional support by 2030. CCS does become competitive with SMR without CCS in scenarios for which the CO_2 price surmounts 50 euros. If existing plants can be retrofitted with CCS this could be sooner.

Between 2030 and 2040 a flexibly operated PtG installation becomes competitive with SMR(+CCS) in all our scenarios due to abundantly present cheap electricity, a higher CO_2 penalty for fossil hydrogen production and further decreasing CAPEX costs for electrolysers. Only if CAPEX costs come down significantly less than assumed this might not be the case under the current decarbonization assumptions of the system.

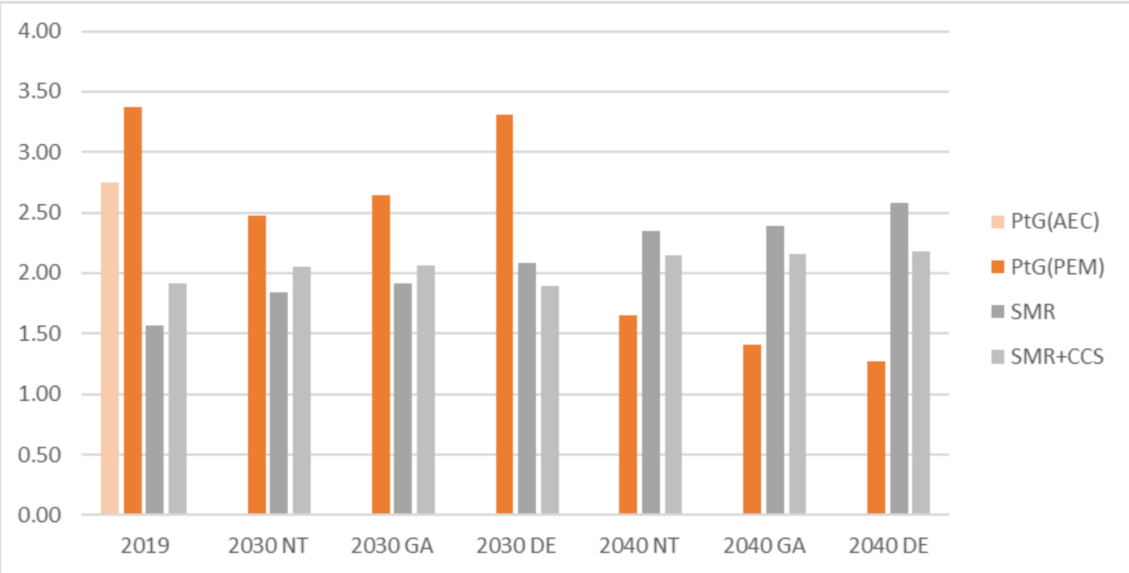

Figure 13: LCOH under different scenarios for future years. See the assumptions section for all underlying assumptions, from 2030 on PEM and AEC are assumed to have similar CAPEX.

Table 8 lists the optimized running hours that correspond to the PtG LCOHs in figure 18.

Table 8: Optimized running hours of the electrolyser to obtain minimal LCOH.

Running hrs (h)	**2019**	**2030 NT**	**2030 GA**	**2030 DE**	**2040 NT**	**2040 GA**	**2040 DE**
PtG(AEC)	7860	/	/	/	/	/	/
PtG(PEM)	8145	5076	4157	5072	3724	4671	4714

6.1.5 Conclusions

Flexible operation of the electrolyser is important for the competitiveness of power-to-gas.

Our analysis suggests that it might be challenging for PtG to become competitive before 2030 without **ADDITIONAL SUPPORT,** because there is not enough low cost electricity in the system yet to compensate the CAPEX costs. **BETWEEN 2030 AND 2040** the share of renewables in the electricity mix becomes big enough for **PTG TO PRODUCE COMPETITIVELY**, operating flexibly and sourcing low-cost electricity.
Based on our assumptions SMR+CCS can become competitive with SMR without CCS in 2030 if carbon prices reach around 50 euro/ton CO_2.

We did not consider additional surcharges e.g. taxes, renewable subsidies, grid tariffs… future value of the gas GOs… on top of the wholesale electricity price. Neither the possibility to purchase the power from a RES producer via a PPA instead of sourcing it directly from the wholesale market. These can be considerable and change the analysis
It looks certain that green hydrogen will play an important role in the energy transition at some point, given its importance to reduce emissions in difficult to decarbonize applications. In its recent hydrogen strategy the EU sets out ambitious targets to develop the necessary technology and scale up production. It is important however that the upscaling of this capacity goes together with strong decarbonisation of the electricity sector to effectively reduce CO_2 emissions.

Our analysis suggests that ambitious decarbonization of the electricity supply synergizes well with quicker viability of power-to-gas.

We have focused on a high-level system point of view approach to attractiveness of power-to-gas. Elements that were not considered like participation in the **CAPACITY REMUNERATION MECHANISM,** a **DEDICATED MARKET** for green hydrogen through binding targets for renewable fuels, guarantees of origin, participation in the **MODULAR OFFSHORE GRID** could potentially make power-to-gas attractive in the near-term.

In our analysis of the PtG becomes more attractive in Belgium after 2030, compared to steam methane reforming with CCS. Another important factor that will determine the attractiveness of local hydrogen production is the **COMPETITION WITH IMPORTED HYDROGEN** or derived carriers, from regions with more extended renewable energy sources.

6.2 Calculation model: centralised versus onsite H_2 production

Lead Partner: WaterstofNet

6.2.1 Purpose and scope of the "integrating" calculation model

The Greenports project focuses on large electrolyser installations in port regions, given the availability of both renewable energy production and energy transport (& storage i.e. terminals) infrastructure.

However, the user of the hydrogen will not always be located near the ports; transport and distribution of the hydrogen from the central production site to inland customers will be required. On the longer term, a hydrogen backbone will be built (cfr. paragraph 7.1.3 & 7.1.4), to transport the hydrogen -either produced in large installations or imported - from the ports to the large industrial clusters in Belgium. Whether a fine meshed hydrogen network, that can connect the backbone with smaller scale users, will become available in a later step is not clear yet.

Anyway, on short & medium term, **SMALLER INLAND CUSTOMERS** (industrial or mobility hydrogen users) that want to **BUY HYDROGEN FROM A CENTRAL PRODUCTION SITE**, will have to be supplied by trucks or dedicated pipelines. The cost that comes with the transport of the hydrogen is already discussed in chapter 5 and has shown to be between 1.2 and 2.4 EUR/kg when using trucks to distribute the hydrogen to end-users.

The scope of the Greenports was widened by developing a calculation tool that complements the work performed in the Greenports project (*centralised* hydrogen production) to **ASSESS THE VIABILITY OF A DECENTRALISED ELECTROLYSER**, coupled to a renewable energy source (onshore wind, solar) at the point of use.

The perspective for this tool is that, besides acquiring green hydrogen from centralised electrolysers or imported hydrogen, the end-user of green hydrogen can also decide to invest in a small, decentralised electrolyser at the point of use which uses locally available renewable energy (onshore wind or solar) to produce green hydrogen. With the development of this calculation tool we want to give an indication to a decentralised user, with a given demand profile, what the cost of decentralised, green production would be compared to buying green hydrogen from a centralised electrolyser unit and as such provide the conditions at which a cost-effective alternative can be considered locally, at the point of use.

In the **CENTRAL CASE**, the production itself will be at a lower cost mainly due to **RELATIVE LOWER INVESTMENT COSTS** (scaling effects) and **CHEAPER ELECTRICITY**. Continuous supply of hydrogen is secured in this case. On the other hand **COMPRESSION AND TRANSPORT COSTS** are significant, logistics may pose a risk towards uninterrupted operational services under increase demand and there is mark-up along the value chain

In the **DECENTRAL CASE** with local production, the production will be at a higher cost and larger local storage will have to be available. When the hydrogen production installation is **DIRECTLY COUPLED** to the renewable energy production this can be done **WITHOUT GRID COSTS**, however a **LOCAL BACK-UP OR TEMPORARY PRODUCTION FROM THE GRID** (with significant grid costs) will be required to overcome periods with limited available renewable energy.

Figure 14 shows schematically the central and decentral pathways, with the different blocks in the chain that are worked out in the calculation tool.

In the next paragraph the assumptions and calculation method are described and demonstrated via a practical use case.

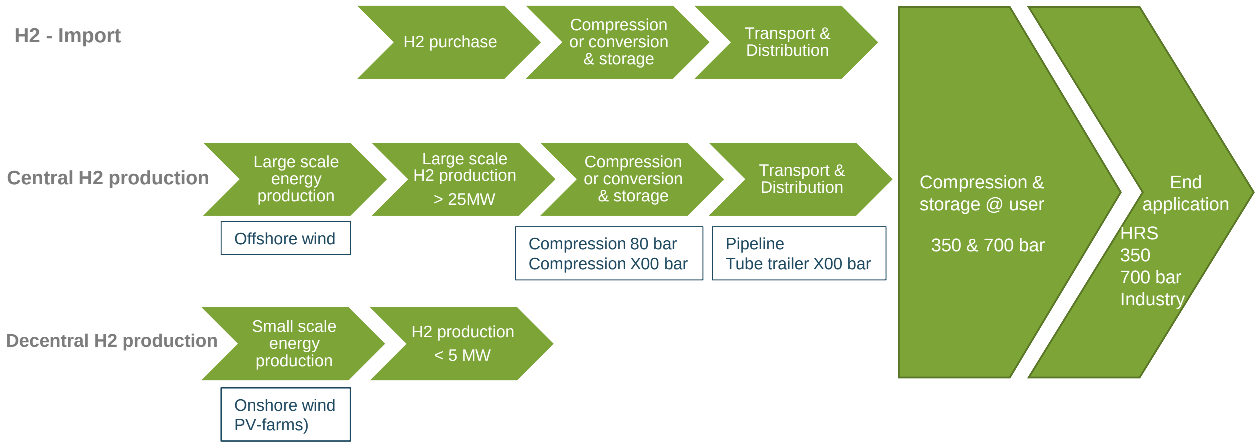

Figure 14: Different pathways for supply of hydrogen to an inland consumer of hydrogen

6.2.2 Set-up of the calculation tool

The tool that has been set-up is made to determine the levelized cost of hydrogen for a local hydrogen production unit. In order to facilitate the comparison with a centralised hydrogen production unit, a tube trailer call profile is determined which is called from a centralised tube trailer filling station. The costs associated to the distribution of hydrogen are then derived from the outcomes of the work performed in WP5 by closely pairing the assumptions and calls of the tube trailers.

For the decentralised scenario, the inputs, outputs and in-between calculated parameters are:

INPUT	• Energy production profile (hourly) wind & solar • Consumption profile hydrogen (hourly) for industrial or mobility user. • Estimated electrolyser capacity & local buffer size (CAPEX, OPEX) • Electricity price: tariffs for RE, renumeration of green certificates, grid electricity (including grid tariffs, based on BELPEX)
Calculation	• Kg of H_2 that can be produced per hour from wind/solar • Kg of H_2 that has to be produced from grid electricity to fulfil demand profile. • Kg of H_2 that has to be stored depending on storage assumptions (size and minimum payload) • Optimising electrolyser & buffer size by minimising the yearly exploitation costs (EUR/kg)
OUTPUT	• Optimal electrolyser capacity & buffer size for given demand profile • H_2 cost

6.2.3 Calculation approach

The calculation approach is depicted block-wise below:

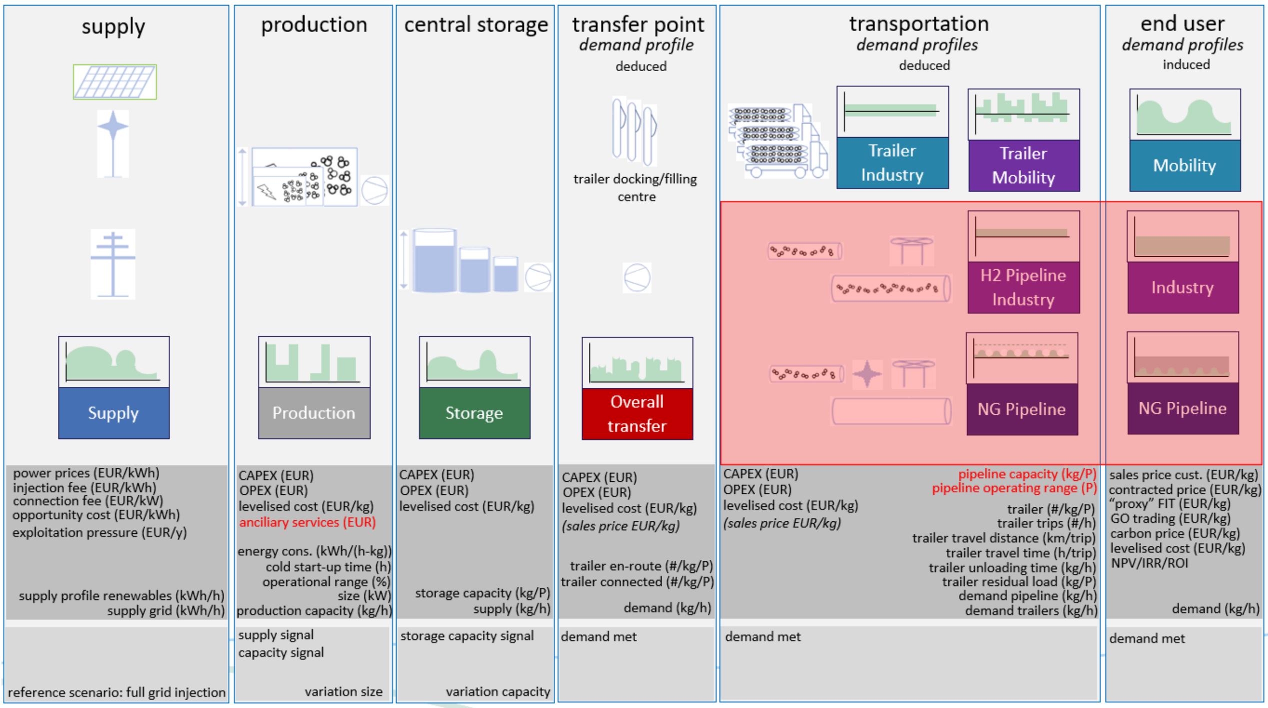

Figure 15: Block schematic of the calculation tool

The calculation tool connects and matches production and consumption profiles. It builds upon a case study in which a demand centre is considered to be a hydrogen refuelling station for heavy duty trucks. A typical hydrogen refuelling station[18] is taken as a starting point in which 25 trucks are refuelled on a daily basis. Applying a reference refuelling profile of a typical light duty refuelling station results in a weekly end-user refuelling profile in which roughly every hour a truck comes to refuel.

For the decentralised case, the demand is met by replenishing the low pressure buffer by the onsite electrolyser which is accompanied by a compressor in order to boost the pressure to 200 bar. The hydrogen is supplied by onshore windmills and/or a solar parc. The assumptions for hydrogen production are provided in the next section. To enable a comparative base for the centralised scenario, a tube trailer call-in profile is derived from the hydrogen demand profile for which the demand is met by a hydrogen supply through tube tailers. For a typical hydrogen refuelling station relying on this supply method, the low pressure buffer storage is used as a dump storage for the hydrogen tube trailer and the station must thus send signals to the hydrogen supplier that it must send a hydrogen tube trailer to the station when a prospective underrun of the low pressure buffer is near. The hydrogen demand profile at the station allows for such a prospective view into the state of charge of the low pressure buffer (because the refuelling profile is known), so when the minimum inlet pressure of the compressor situated in between the low and medium pressure buffer is expected to be reached, the model will derive a tube trailer call-in signal which also considers the required

[18] Such a station would have the following characteristics: 600 kg/day, 35 MPa with a technical set-up of a low pressure buffer (523 kg, 200 bar), a medium pressure buffer, (470 kg, 500 bar), a compressor (75 kW) and a cooler and a dispenser

travelling time and tube trailer handling time onsite. In this way, this refuelling profile (amount of hydrogen refuelled per 15 minutes) is converted into a call-in trailer profile for hydrogen tube trailers at a central point[19]. Such a call-in tube (/transportation) trailer profile can thus be best understood as the moment at which the hydrogen refuelling station gives a signal to the supplier of green hydrogen that it wants to call-in a hydrogen tube trailer to replenish the low pressure buffer. The call-in trailer profile translates towards a docking (/transfer point) profile of tube trailers at the centralised tube trailer docking station. In this tool, a refuelling station operator is able to derive a call-in trailer profile for the refuelling station he/she has or may want to acquire, its approximation towards a hydrogen tube trailer docking station and the hydrogen demand he/she has or may expect. However, the selection of trailer (pressure, payload) used to replenish the refuelling station and the travelling assumptions of the tube trailer are for the case study matched with the trailer assumptions used in WP5 to determine the distribution cost of the trailer. In this case, the 300 bar tube trailer with a pay-load of 250 kg offloading into a dump storage that is 120 kilometers away from the docking station is taken.

The hydrogen production profile is constructed from a typical renewable energy production profile from onshore wind or solar. Any 15-minute renewable energy production profile can be inserted[20]. It is assumed that the main aim is to produce renewable hydrogen and that the energy that cannot be utilised for hydrogen production is injected to the electricity grid. The selected size of electrolyser will then result in a hydrogen production profile which is shaped by the storage capacity that is selected. The capacity of the storage buffer (which is the lower pressure buffer in de decentralised case) and the must-run set-point for the storage buffer determine the hydrogen production profile that comprises: the renewable electricity used to make green hydrogen, the electricity that should be taken from the grid to satisfy the demand conditions or the storage conditions and the green electricity generated that is injected to the grid due to the fact that the storage is full and/or there is no hydrogen demand.

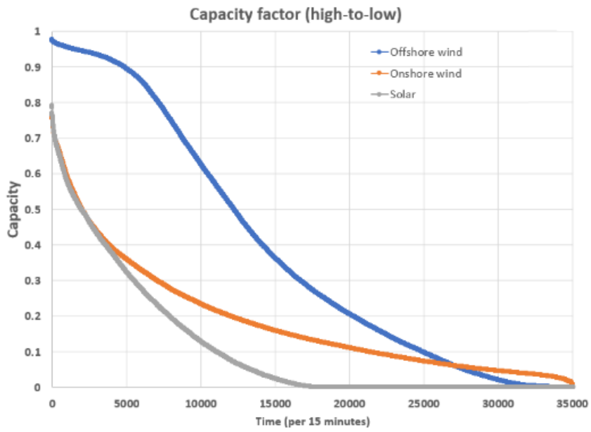

Figure 16: Average capacity factors of renewable energy profiles in Belgium

As an example to demonstrate the functionality of the model, a case study a 600 kg/day hydrogen refuelling station for heavy duty trucks with state of the art price and cost assumptions[21] was analysed. The levelized cost of hydrogen is defined as the price the owner of the RE production plant should receive to reach the break-even point compared to running

[19] Apply assumptions on distance to depot (120 km), onsite handling time (15 minutes), a traffic profile and a current trailer portfolio (200, 300 bar; payload 300 – 1000 kg)

[20] These profiles are derived from https://www.elia.be/en/grid-data/power-generation/wind-power-generation.

[21] 2017 BELPEX prices, the average renewable energy production profile in Belgium of 2017, applicable network tariffs of difference grid connection levels, green certificate prices, state of the art CAPEX and OPEX for electrolysers, storage and compressors for different sizes and pressures.

the same plant without electrolyser (and 100% injection of the produced electricity into the grid).

6.2.4 Results

In the calculation tool a large number of input parameters can be varied, such as demand and production profiles, size and capacities, to allow for tailoring to specific situations. It would therefore go beyond the scope of the Greenports project to make a full analysis of all different options and sensitivities.

For the case study that was highlighted (600 kg/day heavy duty, 35 MPa refuelling pressure), as an example, different scenarios were run for the decentralised scenario in which the sizes of the solar field (0 - 0.75 MW), onshore wind park (5 – 10 MW), electrolyser (1.5 – 2.5 MW) and low pressure buffer storage capacity (200 – 523 kg) are varied accordingly. For all these variations, the resulting levelized cost of hydrogen is calculated. For all cases, the percentage of the total operation time that the electrolyser can operate on renewables is indicated in the green rows of Table 9.

Table 9: Levelised cost of decentralised hydrogen production

Electrolyser share LCOH (EUR/kg)	1.4 – 1.7								
LCOH (EUR/kg)	**5.2**	**5.1**	**5.0**	**5.0**	**4.7**	**4.7**	**4.7**	**4.6**	**4.5**
Wind/solar (MW)	5/0	5/0	5/1	5/1	8/0	8/0	8/0	8/1	10/0
Electrolyser (MW)	1.5	2.5	2.5	2.5	1.5	2.5	2.5	2.5	2.5
Storage (kg, 200b)	523	523	523	200	523	523	200	200	200
Utilisation renewables (%)	84	91	91	87	68	73	69	69	69
Electrolyser Wind/solar (%)	55	60	65	62	70	78	74	77	74
Electrolyser - Grid (%)	45	40	35	38	30	22	26	23	26

The results of this example show that the levelized cost of hydrogen is between 4.5 and 5.2 EUR/kg for the decentralised case. The transport and distribution cost calculated in chapter 6 is performed in a very detailed manner and allows for a comparison with the trailer options and call-in trailer profile generated from this calculation tool. The transportation and distribution option being a trailer truck with an operating pressure of 300 bar and a capacity of 250 kg in a dump storage scenario (see Table 3Table 3) is very close to the hydrogen supply option applied and call-in trailer profile generated in this example and is shown to be around 2.1 EUR/kg. Therefore, if hydrogen from centralised production unit can be produced between 2.4 and 3.1 EUR/kg cost parity can be assumed for this example with the decentralised case.

If 500 bar tube trailers become commonly available, the transport cost can be further decreased (cfr Table 3) to 1,2€/kg and the allowed H_2 cost price for central production to reach cost parity with decentral production can be higher.

With this case study we have shown that the calculation tool provides useful results and that the tool can be used for a wide variety of case specific situations. Also it links to the results generated by the transport and distribution model results developed in chapter 6.

7 The role of hydrogen in the Belgian energy system

Fluxys and ELIA

7.1 Integration of offshore wind energy

7.1.1 Offshore wind power (to be) installed in the Belgian EEZ

The future capacity of offshore wind in the Belgian EEZ is limited. Besides the 2GW which has been installed already, an extra 2GW is planned to be installed in the coming years.

The question is whether the transport capacity for the produced electricity of the 4GW wind parks to shore and further inland will be sufficient to avoid congestion and facilitate the integration of wind power at the best possible cost. Conversion of part of the electricity to hydrogen at the wind park itself or at the landing location could be a possible solution to facilitate full integration of the produced electricity.

However, our national transport grid operator ELIA has developed a new high voltage connection, i.e. the **VENTILUS[22] PROJECT**, that will connect the new wind parks with the shore and will reinforce the electricity network in West-Flanders to transport the produced electricity. This reinforcement will also enable further growth of onshore wind production in this region.

[22] https://www.ventilus.be/p/drijfveren

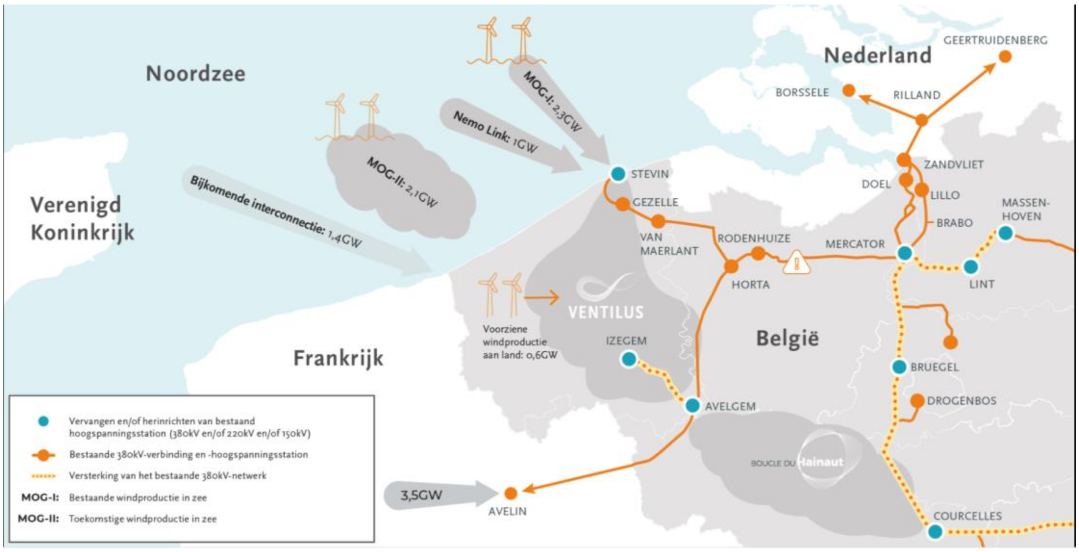

Figure 17: Existing and planned 380kV network of ELIA and interconnections with wind parks and neighbouring countries (https://www.ventilus.be/p/drijfveren)

Eight landing locations are possible within the foreseen Ventilus project[23], i.e. Koksijde, Ostend, Bredene, De Haan - Vosseslag, De Haan - Zwarte Kiezel, Wenduine-West, Wenduine-East or Zeebrugge.

ELIA claims that this Ventilus interconnection will be sufficient to enable integration of the planned extra 2GW of offshore wind energy into the Belgian electricity grid, without any significant congestion or need for curtailment,

However, it is not clear yet how the further expansion of the offshore wind capacity on the North Sea will evolve in the coming years , further ahead in time in terms of the modular offshore grid (cfr par. 7.1.2), the hybrid interconnections and other developments closer in time, and what the consequences for the Belgian electricity transport grid will be (further than 10 years ahead).

This expansion will be more and more planned on a coordinated Regional basis (energy policy, regulatory aspects and construction/engineering)with a pan-European and sector-coupled electricity grid focus in mind. In any case, it is expected that green molecules and more specifically hydrogen will become a main energy carrier of the future European energy system to complement green electrons. Hydrogen will play a key role in the integration of new renewable energy systems and therefore the EU hydrogen strategy has adopted the ambition to install at least 40 GW of renewable hydrogen electrolyser capacity by 2030. **THE OFFSHORE NETWORK DEVELOPMENT PLAN** for the North Seas by ENTSOE, foresees sector coupling and a significant amount of the RES energy is already reserved to be transported and landed as hydrogen and derived e-fuels[24].

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[23] https://www.ventilus.be/p/bouwstenen

[24] https://eepublicdownloads.blob.core.windows.net/public-cdn-container/tyndp-documents/IoSN2020/200810_RegIP2020_NS_beforeconsultation.pdf, bottom Page 32 (notice this is the version before consultation)

France, Germany and the Netherlands are developing ambitious plans to quick-start the hydrogen economy, with investments targets of 7 billion, 9 billion and 7 billion euros respectively.

Belgium has many assets to become a frontrunner too: our geographic location, interconnecting infrastructure, the Ports of Antwerp, North Sea Port and Zeebrugge, as well as strongly connected logistic-industrial hubs. Furthermore, some reconfigurations of the Fluxys NG infrastructure are being studied in order to accommodate hydrogen flow from off-shore production to inland consumption zones

7.1.2 The European electricity grid

In November 2020, the EU has published its **STRATEGY ON OFFSHORE ENERGY**[25]. The European Green Deal Communication fully recognises the potential of offshore wind in reaching the target of reduction of greenhouse-gas emissions with 55% by 2030 (compared to 1990). Offshore renewable energy is among the renewable technologies with the greatest potential to scale up.

Starting from today's installed offshore wind capacity of 12 GW, the Commission estimates to have an installed capacity of at least 60 GW by 2030 and 300 GW by 2050. Additionally, 40GW of ocean energy (wave, tidal or floating PV) should be installed in 2050.

However, this massive increase in offshore wind requires major investments in infrastructure. Huge investments are needed in offshore grid connections and also in the reinforcements of onshore grids.

Until now, most existing offshore wind farms have been deployed as **NATIONAL PROJECTS** connected directly to the shore via **RADIAL LINKS**.

In order to step up offshore renewable energy deployment in a cost efficient and sustainable way, a more rational grid planning with the development of a **MESHED GRID**[26] and the concepts of **HYBRID OFFSHORE WIND PROJECTS**[27] are key. An example of a hybrid project is the case in which an offshore wind grid connection is directly integrated with a cross-border interconnector (see the example of Kriegers Flag Combined Grid Solution[28])
These hybrid projects can bring together offshore energy generation and transmission in a cross-border setting, yielding significant savings in terms of costs and space use compared to the current approach relying on radial connections and separately develop cross-border electricity interconnectors for trade, without connecting offshore generation. Hybrid projects will form an intermediate step between smaller-scale national projects and a **FULLY MESHED,**

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[25] https://ec.europa.eu/energy/topics/renewable-energy/eu-strategy-offshore-renewable-energy_en

[26] As explained in 25: An offshore meshed grid would be similar to the onshore interlinked transmission grid system, where electricity can flow in many directions.

[27] Roland Berger GmbH (2019), Hybrid projects: How to reduce costs and space of offshore developments, North Seas Offshore energy Clusters study https://op.europa.eu/en/publication-detail/-/publication/59165f6d-802e-11e9-9f05-01aa75ed71a1

[28]https://www.50hertz.com/en/Grid/Griddevelopement/Offshoreprojects/CombinedGridSolution#:~:text=The%20so%2Dcalled%20Kriegers%20Flak,of%202016%2Fbeginning%20of%202017.

OFFSHORE ENERGY SYSTEM AND GRID. In this context, the interoperability of the various national off-shore systems is necessary.

Achieving this will require greater coordination among Member States TSOs and national regulatory authorities in the same sea basin on planning the grid infrastructure. At a later stage, offshore grid planning could eventually be a regional (e.g. North Sea level) or even a EU competence. **ADJUSTMENT OF THE REGULATORY FRAMEWORKS** of the different member states will be a necessary stepstone in this process.

The Commission will propose a framework under the revised TEN-E Regulation for long-term offshore grid planning by the TSOs, involving regulators and the Member States in each sea basin, including for hybrid projects (December 2020).

When offshore wind energy is produced at a larger scale, it needs to be transported to deep inland locations, across country borders. The increased peak generation capacity of renewable energy sources will, at times, significantly exceed demand. Successful integration of offshore wind requires cross sector integration including **OTHER ENERGY CARRIERS** (hydrogen, heat, etc.) to provide the required flexibility.

As stated by Wind Europe[29], it is likely that at least 5% and possibly up to 25% of the electricity will go into power to-x, mainly as power to hydrogen or other gases.

The optimal locations to implement power-to-gas installations in the future, for the most effective integration of offshore wind farms into the energy system, will depend on the physical design of the new European grids (modular offshore electricity and also the European hydrogen backbone) and on the design of the market policies and regulatory measures to them associated.

7.1.3 The European hydrogen backbone

From 2025 to 2030, hydrogen needs to become an intrinsic part of an integrated energy system with a strategic objective to install at least **40 GW OF RENEWABLE HYDROGEN ELECTROLYSERS** by 2030 and the production of up to 10 million tonnes of renewable hydrogen in the EU29. Local hydrogen clusters, such as remote areas or islands, or regional ecosystems – so-called “Hydrogen Valleys” – will develop, relying on local production of hydrogen based on decentralised renewable energy production and local demand, transported over short distances. In such cases, a **DEDICATED HYDROGEN INFRASTRUCTURE** can use hydrogen not only for industrial and transport applications, and electricity balancing, but also for the provision of heat for residential and commercial buildings. In this phase, the need for an **EU-WIDE LOGISTICAL INFRASTRUCTURE** will emerge, and steps will be taken to transport hydrogen from areas with large renewable potential to demand centres located possibly in other Member States. International trade can also develop, in particular with the EU’s neighbouring countries in Eastern Europe and in the Southern and Eastern Mediterranean countries.

Also imported hydrogen will be transported by such a backbone, leading to a security of supply for hydrogen consumers by connecting them to a multitude of sources and storage facilities enabling long term and seasonal regulation at the most affordable costs. A good part of this backbone will be built reusing retrofitted natural gas pipelines. The economy and cost-

[29] https://windeurope.org/wp-content/uploads/files/about-wind/reports/WindEurope-Our-Energy-Our-Future.pdf

competitiveness of pipeline transport joins in this way the enhanced efficiency brought by existing infrastructure reutilisation.

Recently a EU backbone has been presented by a number of EU TSOs.[30]

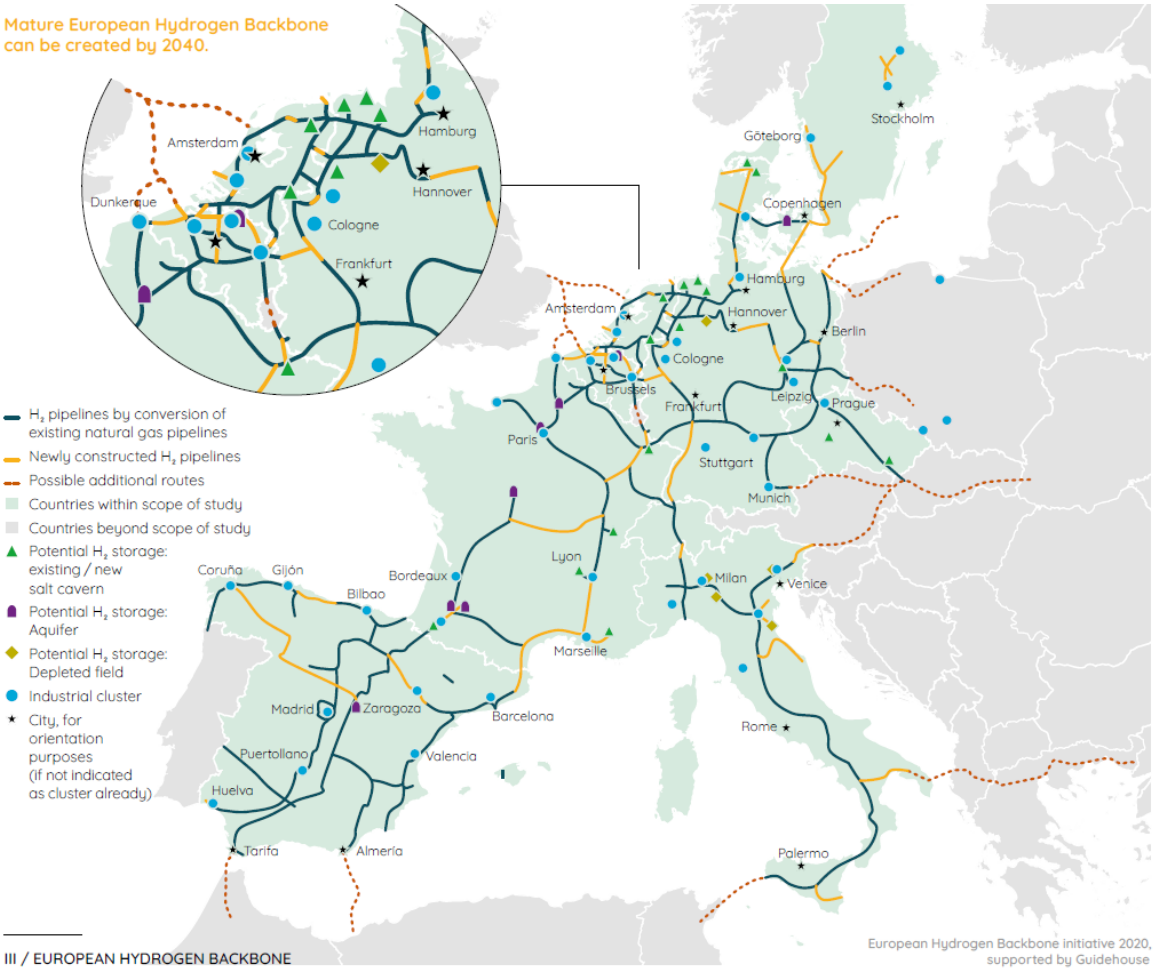

Figure 18: Proposed EU hydrogen backbone from reference[31]

For Belgium, Fluxys has proposed a trajectory for such a hydrogen backbone.

7.1.4 The Belgian hydrogen backbone

Seen this growing importance of hydrogen in the coming years, a dedicated hydrogen backbone will be required. Building such a backbone requires careful planning, design and building in a step-wise approach over many years in close collaboration with market players and neighbouring operators.

Fluxys is well placed to play a leading role in the development and operational management of a H_2 infrastructure backbone in Belgium for the following reasons:

[31] https://gasforclimate2050.eu/sdm_downloads/european-hydrogen-backbone/

- Unbundled neutral network operator assuring open access, transparent tariffs, interoperability and interconnection capacity, infrastructure scale and non-discriminatory treatment of all supply and demand players in the developing pan-European hydrogen market and economy;
- Optimal step-wise development of the H_2/ CO_2 backbone by repurposing existing natural gas pipelines and building-pace of the infrastructure as the market develops;
- Experience in managing interconnection points with neighbouring operators (TSO's, DSOs…) and in multilateral/multinational stakeholder collaboration;
- Fluxys participates already to a number of industrial projects that demonstrate the willingness of the industry to push projects forward. Fluxys has built trust towards potential project partners and can play a coordinating role between stakeholders.

Fluxys believes these criteria are key to act as a leading party in the development of a H_2 backbone..
The next Figure proposes Fluxys' long-term vision for the H_2/ CO_2 backbone in Belgium.

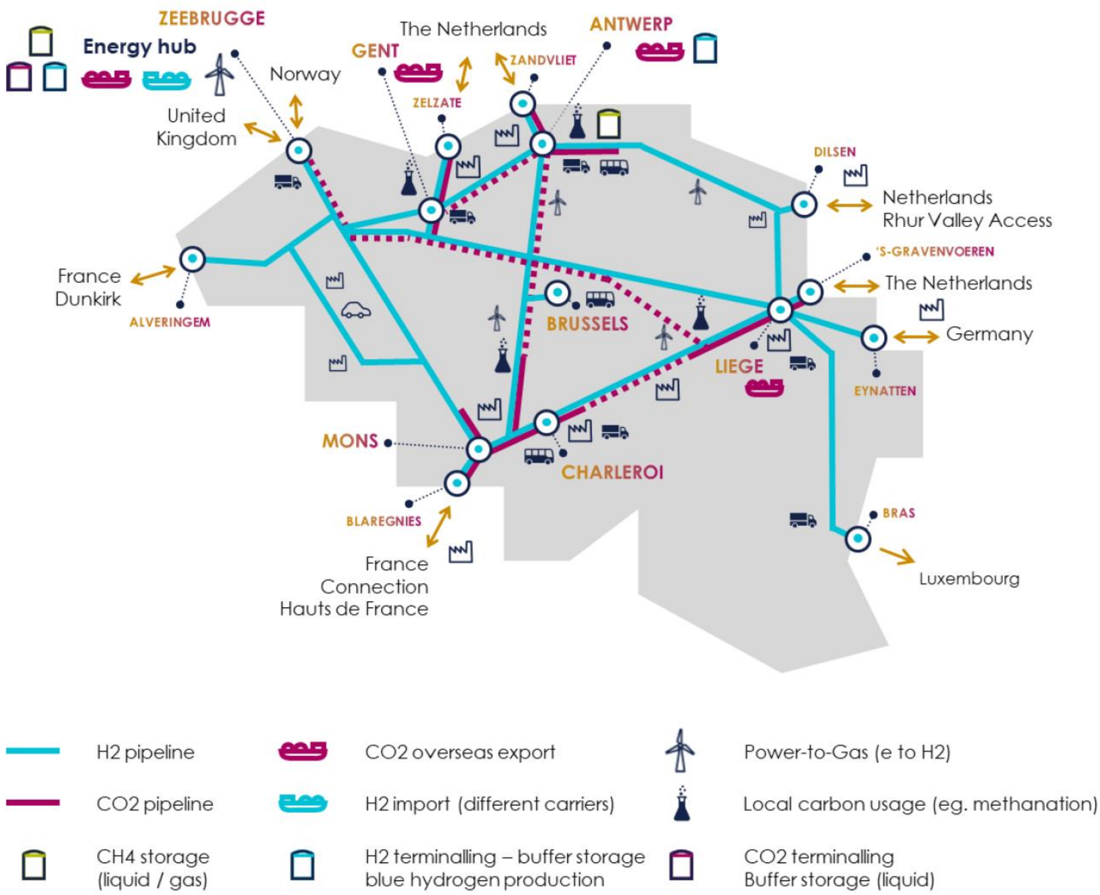

Figure 19: Fluxys' long-term vision for the H_2/ CO_2 backbone in Belgium

Furthermore, it must be noted that Fluxys has put in place a program with the ambition to get ready to inject 2% H_2 in its natural gas infrastructure by 2023. This is seen as a potential solution to already start transporting H_2, while the dedicated H_2 backbone is being developed and as a means to help the energy transition through decarbonisation.

10 Hydrogen policies, EU, BE & FL level

10.1 EU level

10.1.1 Green deal[32]

Europe will provide strong guidelines for hydrogen and related technologies in the coming years.

The European Commission presented the Green Deal in December 2019, following the Paris agreement. This action plan forms the policy framework for the coming years, with the central goal of **CLIMATE NEUTRALITY BY 2050**.

By means of the so-called "climate law", the European Commission intends to embed this objective in European legislation. The CO_2 **REDUCTION TARGET** for 2030, which has been tightened from 40% to **55%**, will also be included. The legal obligation to climate neutrality implies a large-scale review of climate-related policy documents in 2021.

As a result of the Green Deal, a number of important European directives will be revised in order to adjust the policy in the member states in accordance with the climate objectives for the coming decades. In 2021, the **Energy Taxation Directive** will be revised, for example to **scrap exemption rules for fossil fuels**. The **Emissions Trading System** is also being revised and is expected to cover more sectors (e.g. Maritime shipping) and impose stricter requirements for existing sectors. The **Renewable Energy Directive** will be revised again to reflect the more stringent CO_2 reduction targets.

In the context of the Green Deal, Europe sees, in addition to circularity and electrification, a **significant role for low-carbon molecular energy carriers - and hydrogen in particular**. The European Commission made this clear in its **energy system integration and hydrogen strategies**, which appeared in June:

Energy System Integration strategy[33]

Energy system integration is "the coordinated planning and operation of the energy system 'as a whole', across multiple energy carriers, infrastructures, and consumption sectors", based on three concepts:

- a more 'circular' energy system, with energy efficiency as the first priority
- a greater direct electrification of end-use sectors
- the **USE OF RENEWABLE AND LOW-CARBON FUELS, INCLUDING HYDROGEN**, for end-use applications where direct heating or electrification are not feasible, not efficient or have higher costs.

[32] European Commission, 2019. *The European Green Deal.* Retrieved from https://eur-lex.europa.eu/resource.html?uri=cellar:b828d165-1c22-11ea-8c1f-01aa75ed71a1.0002.02/DOC_1&format=PDF

[33] European Commission, 2020. *Powering a climate-neutral economy: An EU Strategy for Energy System Integration.* Retrieved from https://ec.europa.eu/energy/sites/ener/files/energy_system_integration_strategy_.pdf

Hydrogen strategy[34]

The hydrogen strategy states that sustainable hydrogen should primarily be used, at a first stage, as **FEEDSTOCK IN INDUSTRY.** The **TRANSPORT SECTOR** is also seen as a promising sector, with a focus on heavy and long-distance transport. Hydrogen can also be a building block of **SYNTHETIC FUELS** where necessary.

The hydrogen strategy has three phases, with a first phase between 2020-2024, the second between 2025-2030 and the third between 2030-2050. A gradual upscaling of the electrolysis capacity is foreseen from 6 GW in 2024 to 40 GW in 2030.

The first phase of the EU strategy aspires to the realization of large-scale electrolysis projects close to industry with a hydrogen demand. Transport applications can then be linked to these first "**HYDROGEN HUBS**". In a second phase, hydrogen clusters will be **INTERCONNECTED**, for example by converting the existing natural gas network or by constructing a new hydrogen network. Towards 2050, with even more own electrolysis capacity and also large-scale imports, hydrogen will form an **INTEGRATED PART OF THE ENERGY SYSTEM** and will be used on a large scale in sectors that are difficult to make carbon neutral.
The priority is **GREEN** hydrogen, but in the "transition phase" the European hydrogen strategy also supports the **LOW-CARBON** variant (H_2 production from natural gas with CO_2 capture).

Existing and new **INSTRUMENTS** must convert the objectives into an investment agenda:
- The Clean Hydrogen Alliance: an international collaboration between companies, governments and other stakeholders which will set an investment agenda and prepare concrete projects.
- Clean Hydrogen for Europe (successor to the Fuel Cells and Hydrogen Joint Undertaking)
- The ETS Innovation Fund
- The Green Deal Call
- The Next Generation EU recovery fund
- The Important Projects of Common European Interest (IPCEIs)

An **IPCEI HYDROGEN** is in preparation for the realization of large-scale hydrogen projects. IPCEI allows Member States to apply a relaxation of the normally applicable rules for applying state aid. In March 2020, the Belgian government launched the "expression of interest" for the IPCEI hydrogen. About twenty project proposals were submitted from Flanders, which are currently being evaluated. The EU IPCEI Hydrogen will be coordinated by Germany.

10.2 BE level

To help the EU reach its 2030 climate and energy targets, the "Regulation on the Governance of the Energy Union" sets common rules for planning, reporting and monitoring and ensures that EU planning and reporting are synchronised with the ambition cycles under the Paris Agreement.

EU Member States had to develop integrated **NATIONAL ENERGY AND CLIMATE PLANS** that were submitted by the end of 2019. The Commission has assessed these both at EU and Member

[34] European Commission, 2020. *A hydrogen strategy for a climate-neural Europe.* Retrieved from https://ec.europa.eu/energy/sites/ener/files/hydrogen_strategy.pdf

State level. An update of these plans is requested by the end of June 2023 in a draft form and by 30 June 2024 in a final form.

Member States were also required to develop **NATIONAL LONG-TERM STRATEGIES** and ensure consistency between these strategies and their national energy and climate plans. Belgium submitted its **LONG TERM STRATEGY FOR 2050** in Feb 2020[35]. The strategy is based on the long-term strategies developed by the Flemish, Walloon and Brussels governments for their respective regions (which have been included as an appendix to the Belgian long-term strategy), and on the vision document drawn up by the federal administration.

Hydrogen is an important pillar of the Long Term strategy. Hydrogen and derived synthetic fuels will play an important role in bringing several sectors such as industry, heavy duty transport and buildings to climate neutrality. Building infrastructure for transport of the hydrogen will be an essential task. Innovation & technological developments are required and will be supported by the federal and regional governments.

The federal government is preparing **A BELGIAN HYDROGEN STRATEGY,** which is expected by April 2021. The main focus will be on the development of an H_2 and CO_2 backbone with maximum reuse of the natural gas infrastructure.

Belgium also participates in international partnerships such as the **PENTA-LATERAL ENERGY FORUM**. This is a politically driven partnership of seven countries between governments, regulators, grid operators and market parties to complete the internal energy market. Hydrogen is high on the agenda.

10.3 FL level

The Flemish coalition agreement 2019-2024 and various policy documents (Economy, Energy, Mobility) underline the important role that hydrogen can play in our energy and climate transition. The coalition agreement even expresses a frontrunner ambition in Europe.

These outspoken ambitions were reinforced in September 2020 with the announcement that hydrogen will play an important role in the Flemish recovery policy. The allocation of aid to concrete projects in the pipeline is being examined. In the context of the recovery plan and the IPCEI support, around 125 million euros would go to hydrogen.

On November 13, an integrated **FLEMISH HYDROGEN VISION** has been published by the Minister of Economy and Innovation.

In line with the European hydrogen strategy, a number of priorities for hydrogen in Flanders are being put forward: as molecules for feedstock and energy supply to the industry and for making the transport sector more sustainable.

[35] https://klimaat.be/doc/national-lt-strategy-nl.pdf

11 Legislative framework

11.1 General considerations and recommendations

Today it is not yet possible to produce renewable and low-carbon hydrogen in an economically viable way. Fossil alternatives are much cheaper, partly because the cost contribution of CO_2 emissions into the final price is still very limited. Therefore, a number of stimulating measures will be necessary to kick-start the use of renewable and low carbon hydrogen in different sectors and enable its upscaling.

In the chapters below, we provide an overview of the most important policy recommendations that we propose for the national and regional level in order to create maximum opportunities for the development of renewable and low carbon hydrogen and its derived energy carriers. A link is made with the (expected) European Directives that will guide the Member States in the topic.

At the regulatory/legislative side it is important to carefully assess where to put the focus on regarding stimulating measures for hydrogen: production versus demand/use. Today a lot of focus is put on hydrogen production, however all the elements within the value chain are important including transmission and demand/use of hydrogen for industry but also for mobility and buildings. A balanced approach is required.

There is a need to develop a national legislative and regulatory framework for hydrogen already today in the anticipation of the incoming EU one. Germany (through the latest BNA survey on the topic)[36] already recognises (conclusions of the support document to the survey) that the best way to shape EU Policy and Regulation is by having first a clear and defined national one. The Belgian neighbouring countries (France, Netherlands), seem headed towards some very similar approach too. In the case of Belgium this implies the need for a Regional approach too (VL, WL, BXL).

11.1.1 Production of H_2

The price of renewable and low carbon hydrogen is still significantly higher than that of fossil hydrogen, both due to investment costs for production and renewable electricity costs. In the coming first phase of the roll-out of hydrogen, it is important to reduce these production costs for renewable and low carbon hydrogen (via technology scale-up) and provide the necessary instruments and policy framework for this.

Recommended measures are:

- (Partial) exemption from electricity end-user taxes/surcharges for hydrogen production via electrolysis, which are in fact energy conversion facilities (P2G),) insofar the hydrogen produced is to be reinjected into the gas grid (avoid double taxation with gas end-user taxes / surcharges) or stored to be used later on for electricity generation reinjected into the electricity grid (avoid double taxation). This

[36] https://www.bundesnetzagentur.de/DE/Sachgebiete/ElektrizitaetundGas/Unternehmen_Institutionen/NetzentwicklungundSmartGrid/Wasserstoff/wasserstoff_node.html

can also be extended to hydrogen production for other applications as is done in Germany[37].

- Further implementation of the Gas Guarantees of Origin system in Flanders and in Belgium, unconstrained expansion to low-carbon hydrogen and e-fuels, with cross-border and cross regional recognition. Maximum harmonization with current practices and systems. The goal is a unified EU system where carrier GO conversion is facilitated and unhindered by additional conditions/burdens.
- Level playing field in all policy incentives for all energy carriers, based on a full value chain (whole system approach) and objective carbon content evaluation. Equal merits and carrier GHG emissions should mean equal incentives allocated.
- Implementation of a "Carbon Contracts for Differences" System[38], accompanied by an auction/tender system in order to temporarily compensate for the lack of CO_2 cost effectiveness, or as an adjustable carbon tax, similar to the Netherlands[39].
- Setting of national targets and minimum quotas in terms of renewable and low carbon hydrogen production
- Support for R&D on production technologies and H_2 production CAPEX support

Relevant (future) EU directives: Revision of the Energy Tax Directive[40]; delegated acts & recast of the Renewable Energy Directive-II[41] in 2021, Revision of the ETS Directive

Note on certification and Guarantees of Origin for Green hydrogen:
In Flanders, legislation is in place to issue and consume GO's for green gas (biomethane, hydrogen from renewable origin) and green heat, and the different roles in the process are defined (Fluxys as production registrator, VREG for creation of GO's and data management in a central database). Cross-border trade will be done via the issuing body (hub) that connects all databases of the different countries

The EU project CertifHy[42] has provided the basis for a definition of "low carbon" and "green" hydrogen and has designed an operational (pilot) framework for guarantees of origin. Certification informs the consumers about the origin of the hydrogen and will facilitate the needs to meet regulatory requirements regarding CO_2 reduction. EU certification is important to develop the market for green hydrogen and enable hydrogen to play its role in the energy transition. A follow-up project[43] of CertifHy will now further develop harmonized Guarantees of Origin schemes across Europe and start with a pilot in a few Member States, including Belgium (Flanders + Wallonia), the Netherlands and Austria. There will also be a collaboration

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[37] See for example in Germany http://www.gesetze-im-internet.de/enwg_2005/__118.html: where electrolysers taken in use between 2011 and 2026 are free from grid contribution for a period of 20 years.

[38] See e.g. in https://www.iddri.org/sites/default/files/PDF/Publications/Catalogue%20Iddri/Etude/201910-ST0619-CCfDs_0.pdf

[39] See: https://carbonmarketwatch.org/2020/12/21/what-can-we-learn-from-the-dutch-national-carbon-tax/

[40] European Commission (n.d.), Revision of the Energy Tax Directive. Retrieved from https://ec.europa.eu/info/law/better-regulation/have-your-say/initiatives/12227-Revision-of-the-Energy-Tax-Directive-

[41] https://ec.europa.eu/jrc/en/jec/renewable-energy-recast-2030-red-ii

[42] www. Certifhy.eu

[43] https://certifhy.eu/images/media/files/201214_Press_release_CertifHy_3_Launch_EN_Final.pdf

with Morocco to see how a uniform system of GOs can be set up across EU borders, which is very interesting in view of future imports.

11.1.2 Terminalling and H_2 imports

Terminalling and H_2/H_2-derived carrier imports will be key to ensure European compliance with the decarbonisation objectives of 2050. Ports will play a key role on this, as the entry points for imported renewable and low carbon hydrogen produced in areas where the productivity of renewable energy sources is higher (due to more yearly hours of sunlight exposure and a higher prevalence of wind, or a big surplus of cheap hydro among others).

The Hydrogen Import Coalition[44] has just completed a study on this subject, titled "*Shipping sun and wind to Belgium is key in climate neutral economy*".[45] Its conclusions indicate that the import of these carriers is feasible already in the mid-term, that technology scale-up will be essential for its economics and that there is no "silver bullet". In this sense, several carriers would be feasible and we will probably see a combination of solutions plus a mix of import origins, further collaborating to security of supply via diversification (geo-strategically) and technologically too.

The above-mentioned study contains a series of recommendations of policies and actions for these hydrogen-based carrier imports to take place successfully within its Regulatory Section (Pages 29-31) which we will summarise and adapt here, for what is relevant in turn to this study (by selecting and partially quoting / adapting the contents of the pages cited above):

- A unified EU GO system as already mentioned in par. 11.1.1. is essential for import of hydrogen and H_2 based carriers.
- Timely EU RED-II provisions transposal into Federal and Regional Law will also be an essential key success factor for hydrogen carriers imports (see also 11.1.4.2).
- A Carbon Border Tax Adjustment mechanism will also be important in order to avoid carbon leakage
- A certain level of coordination at EU level for cooperation agreements with third party countries acting as exporters will probably yield better results than uncoordinated initiatives by the individual Member States

Relevant (EU) regulation on this subject will be: the EU RED-II expected recast, the EU Taxation Directive, the UN IPCC carbon accounting rules adaptation into EU Legislation in general[46] and all the Technical and Safety Standards for the transportation of hydrogen and its carriers

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[44] Deme, Engie, Exmar, Fluxys, Port of Antwerp, Port of Zeebrugge and Waterstofnet.

[45] https://www.waterstofnet.eu/_asset/_public/H2Importcoalitie/Waterstofimportcoalitie.pdf

[46] UN IPCC carbon origin accounting rules will require modifications at least for their EU application. Any non-biogenic carbon is deemed fossil by default. This means that (for example) for direct air capture of CO_2 using only renewable energy and incorporating this into a new circular carrier, the IPCC provides no incentives for this atmospheric abatement. The European Union is adapting these IPCC accounting rules at present day and imposing them onto Member States for the purpose of their National Energy and Climate Plans. The effect on the economic potential of circular carbon carriers (whether being imported or produced domestically) and carbon removal is not sufficiently constructive to adequately promote circular non-emission technologies; these rules need changes.

11.1.3 Transport & distribution of H_2

In order to link large-scale hydrogen production and imports to consumption, a hydrogen transport network is necessary. This latter will connect to the pan-European hydrogen backbone. Notice that production and consumption of hydrogen will often not be co-located and using electricity from the grid is not always possible due to capacity limitations, such that transport of the hydrogen from its optimal production location by ship/pipe will often be the most advantageous solution (especially if existing pipelines are retrofitted -as intended).

The mentioned hydrogen transport network should offer third party open-access to the grid, non-discriminatory transparent tariffs subject to regulatory overview, sufficient volume throughput at reasonable costs (scale), it should also be interoperable with similar interconnected systems at the neighbouring countries (for markets, quality and standards) and the gas transport network operator should also be unbundled from production to avoid conflict of interest in all these grid operational implementations.

Currently there are only private point-to-point fragmented hydrogen networks for industrial users mainly in Belgium, the Netherlands, France and Germany. These latter grids are specifically tailored to the needs of their different users (in terms of distributed volumes and quality). There is no open-access to them and their respective operators also produce the hydrogen they sell to their network users.

Simultaneously, a CO_2 transport network will also be necessary, to enable transport of captured CO_2 to definitive geological storage locations (CCS) or to CO_2 users (CCU). This is related to the hydrogen transport backbone in the sense that CO_2 can be combined with green H_2 to produce synthetic methane and recycle the carbon according to circular economy principles.
It is important to notice that the legislative framework that is needed for transport infrastructure is neutral to the origin of the hydrogen (which is a very different setting compared to production).

The main recommendations are:

- Development of EU and National regulation that would enable the development of open access to the transport networks of hydrogen and CO_2, guaranteeing transparent non-discriminatory prices for all users, interoperability of infrastructure with the neighbouring interconnected systems and optimal scale/throughput at the lowest possible costs for users, all avoiding market fragmentation
- Facilitation and promotion of retrofitting (efficiency first) and whole system approach full value chain complete CBA of alternatives in planning and incentives design (including transport and infrastructure dynamics), also cross-sector and cross-carrier (apply system integration foresight)
- Unbundling of transport and production to guarantee neutrality / public optimality in operational decisions regarding: quality, standards, product specifications, operational processes, etc… The neutrality of the system operator is the key factor in order to achieve a liquid hydrogen market.

Relevant (future) EU directives: Relevant (future) EU directives for transport exclusively: review of the regulation for Trans-European networks for Energy[47]foreseen in 2021, incoming Gas Package, etc.

11.1.4 Consumption of green H_2

11.1.4.1 In industrial applications

Large users of hydrogen in the large industrial clusters can obtain fossil hydrogen at very low rates. In a transition period, when green/low carbon hydrogen is still more expensive, extra stimuli are going to be needed to overcome the cost gap and motivate industry to use renewable and low carbon hydrogen. This is essential to enable scaling up of the production.

The recommendations are:

- Develop new instruments (such as "Carbon Contracts for Difference"- CCfD) to support new, non-competitive "low carbon" technologies[48]

  Since a certain maturity of the technology and different competitive suppliers should be available to use this kind of mechanism, also short term, (temporary) support schemes are needed to get the first large-scale hydrogen projects started. This should involve support to R&D (in general) to enhance the local technological development, (partial) CAPEX support for pilot/demo installations and also CAPEX/OPEX support for installations that lack CO_2 cost effectiveness in a transition period.

For the short term, the recommendation for the policy is:

- Development of a framework for specific operating aid from Flanders for first pilot projects on an industrial scale, taking into account the initial lower cost efficiency of such installations (a similar instrument is now developed in the Netherlands, besides the SDE++ system which is more a CCfD system)[49].
- Stimulate companies by extending/increasing the "Ecology Premium +" to applications other than transport via additions to the limitative technology list (e.g. electrolysis, fuel cells with heat recovery, ...)

Relevant EU communications and instruments: IPCEI[50] and ETS-IF[51] support

11.1.4.2 In transport applications

Hydrogen can be used in transport in various sectors (passenger transport, public transport, freight transport on road and inland waterways) and through different technologies (vehicles or ships with a fuel cell or combustion engine). Also the derived liquid fuels can be used as "e-fuels", which can then be mixed in during a transition period with fossil fuels (cfr. blending biofuels today), or as a full-fledged fuel can be deployed. Hydrogen in transport is specifically

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[47] https://ec.europa.eu/energy/topics/infrastructure/trans-european-networks-energy_en

[48] CCfD like mechanisms can be used either at the production side or the consumption side of the chain

[49] See Footnote **Fout! Bladwijzer niet gedefinieerd.** for the NL new carbon tax.

[50] https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A52014XC0620%2801%29

[51] https://ec.europa.eu/clima/policies/innovation-fund_en

suitable for: long-range, heavy-duty, convenience refuelling-time (like taxis or buses) and also for low-temperature environments. Hydrogen derived e-fuels and hydrogen directly can also be used for air-transport decarbonisation.

The following recommendations are formulated for transport policy:

- A definition of renewable and low carbon hydrogen as fuel that is fully GO-based with no additional artificial constraints applied to it (either geographical, resource, infrastructure or time-related) as is the case for sustainable electricity.
- The explicit inclusion of RFNBO's[52] in the Belgian fuel law, such as imposed by the REDII. These can be liquid, gaseous fuels or pure hydrogen. A fair level playing field, i.e. by using comparable multipliers for renewable and low carbon hydrogen fuel use in mobility as those for electricity.
- Development of an ambitious plan for the roll-out of a minimal network of refueling stations that has sufficient coverage for Flanders and Belgium in general, with focus on Belgium as an important hub in the international routes for hydrogen-based freight.
- Exemption from taxes and charges for zero-emission heavy transport, for example by lowering or cancelling the kilometre charge for the vehicles.
- The explicit inclusion of hydrogen fuel cell buses as an alternative for regional transport, better and more ambitious incorporation of hydrogen in public service vehicle fleets nation-wide.
- Support for pilot projects in inland navigation and development of a general legal framework for alternatives fuels (especially H_2 and methanol) and fuel cells / fuel engines for inland shipping (within CCNR framework).
- Keeping hydrogen excise duty free for mobility applications during a sufficient period of time is needed to meet the initially higher costs of hydrogen.

Relevant (future) EU directives: Renewable Energy Directive with target for renewable energy in transport, the Alternative Fuelling Infrastructure Directive[53], Regulation for emission of heavy duty[54] & light duty transport[55].

11.2 Main drivers for the business case of green hydrogen

The main driver for the business cases for power-to-gas is **TO CREATE DEMAND** for green hydrogen. This demand can be boosted by:

- Having a strong European policy with **STRINGENT CO_2 REDUCTION TARGETS** and significant penalties for non-compliance with these targets.
  As an example we can give the targets for CO_2 reduction for heavy duty vehicles, that stipulate 15% CO_2 reduction in 2025 and 30% in 2030[56]. Truck manufacturers must

[52] Renewable Fuels of Non-Biological Origin.

[53] Revision of the AFID https://www.europarl.europa.eu/RegData/etudes/BRIE/2020/652011/EPRS_BRI%282020%29652011_EN.pdf

[54] Regulation (EU) 2019/1242 of 20 June 2019 setting CO_2 emission performance standards for new heavy-duty vehicles

[55] https://ec.europa.eu/clima/policies/transport/vehicles/regulation_en

[56] Regulation (EU) 2019/1242 of 20 June 2019 setting CO_2 emission performance standards for new heavy-duty vehicles

demonstrate compliance on a fleetwide basis which provides the flexibility to sell high CO_2 emitters as long as their emissions can be offset by the sales of more efficient vehicles. Penalties for non-compliance have been put forward: For the first period, from 2025 to 2029, the penalty is EUR 2,550 per g CO_2/t-km whereas from 2030 onwards, the penalty is EUR 6,800 per-vehicle for each g CO_2/t-km of excess emissions.
It is clearly observed that all OEM's active in this application are very busy now with setting their strategy to comply with this regulation…

- Strengthening of **MARKET BASED REDUCTION POLICIES**, based on carbon pricing. The current ETS system with its large number of emission rights and several exemptions, leads to modest CO_2 prices are too low to really drive alternative pathways. The plans to make the ETS system more stringent, with an accelerated decline of the number of emission allowances and the extension to additional sectors such as shipping, which is a big GHG contributor, will also have a significant influence on the adoption of alternative fuels. Carbon border tax adjustment will be needed to protect our European market against carbon leakage, i.e. companies relocating their production outside of the EU.

Besides demand generation, sufficient and affordable supply of renewable energy is of course key in the case for green hydrogen. Due to the limited RE capacity in Belgium, import of energy will be needed.
The conditions and the cost price of imported green hydrogen (or derived carriers that are more cost-effective regarding their transport overseas), from regions with more abundant renewable energy sources, will have a large impact on the opportunities for domestic hydrogen production in Belgium. Estimated cost prices for imported hydrogen and derived hydrogen carriers have been published very recently by the "Hydrogen Import Coalition"[57].

[57] https://www.waterstofnet.eu/en/news/study-hydrogen-import-coalition-confirms-shipping-wind-and-solar-to-europe-is-feasible-from-2030

11.3 Implementation of hydrogen production plant and distribution at the port of Zeebrugge

The Port of Zeebrugge is situated at the Belgian coast and the main part of the electricity produced today by the actual wind farms in the Belgian Sea arrives on land at the west side of the port of Zeebrugge. The Port of Zeebrugge is also an important location for the import of natural gas to Belgium and North-west Europe with an LNG import terminal and the main pipelines at the east side of the port. Also is the port connected with the Air Liquide network of private hydrogen pipelines. The port of Zeebrugge is a clean port with a main focus on logistics and a low concentration of energy-intensive industrial activities. The port of Zeebrugge has multiple service providers for intermodal transport. The port of Zeebrugge was therefor found to be a promising location to host a production site for production of hydrogen out of renewable electricity.

11.3.1 Regulatory aspects

In principle, there are no general exclusions for hydrogen installations in the regional land use plans. They can be built in industrial, commercial or even residential areas. The most important requirement is that the function of the installation should be compatible with or related to the other functions in the area[58].

With regard to hydrogen production the safety aspect of the storage of hydrogen is one of the critical parameters to decide on the possible location: the QRA (“Quantified Risk analysis”) that is mandatory under the SEVESO requirements to obtain the environmental permit is used to decide on the conditions which will apply to the industrial installation given the different elements in the vicinity of the installation.

SEVESO establishments (https://www.lne.be/seveso-inrichtingen)

Seveso establishments are companies that have quantities of hazardous substances on their premises that exceed established threshold values.
With “presence” is meant: both the actual or anticipated presence in storage installations, in process installations, in pipes, ... (as raw material, intermediate, catalyst, solvent, end product, ...), and the presence that can arise when an industrial chemical process is out of control. For the anticipated presence, the maximum permitted quantity must be taken into account.
The legislation distinguishes **low and high threshold Seveso companies**, depending on the nature and amounts of dangerous substances that may be present in the company.

For a number of generic categories of hazardous substances on the one hand, and for a number of named hazardous substances on the other hand, two threshold values (in tons) were set: a high threshold value and a low threshold value.

[58] As indicated in the Royal Decree on the organization and the implementation of regional spatial plans https://codex.vlaanderen.be/Portals/Codex/documenten/1000635.html.

For hydrogen, the threshold values are given in the table below (extracted from Flemish Seveso website).

	Kolom 1		Kolom 2	Kolom 3
			Drempelwaarden (in ton)	
Nr.	Met naam genoemde gevaarlijke stoffen	CAS (1)	Lage drempel	Hoge drempel
15.	Waterstof	1333-74-0	5	50

Table 1: Limit values for SEVESO classification for hydrogen

• **High threshold** establishments are establishments where hazardous substances are present in quantities that are equal to or greater than at least one of the high threshold values. If no high threshold value is reached or exceeded, the device can still be a high threshold device by applying a summation rule.

• **Low threshold** establishments are establishments where hazardous substances are present in quantities that are equal to or greater than the low threshold value but smaller than the high threshold value. If none of the low threshold values are exceeded, the device can still be designated as a low threshold device by applying a summation rule.

It is implicitly assumed that high-threshold devices represent a greater danger than low-threshold devices. The obligations that the regulations impose on high-threshold establishments are therefore more far-reaching than those on low-threshold establishments.

Obligations for SEVESO establishments

High-threshold devices must:

• in the context of the **Cooperation Agreement** [Samenwerkingsakkoord [SWA3]:

o submit a notification (kennisgeving, Article 7 of the [SWA3]),
o prepare a prevention policy (preventiebeleid, Article 6 of the [SWA3]),
o introduce a safety management system to implement this policy (veiligheidsbeheersysteem, Article 6 of the [SWA3]),
o submit a SWA safety report (SWA-veiligheidsrapport, Article 8 of [SWA3]);

• in the context of the **Flemish environmental permit procedure**:

o submit an environmental safety report (omgevingsveiligheidsrapport).

Due to the obligation to draw up a safety report (Veiligheidsrapport, “VR”), high-threshold devices are also referred to as devices subject to VR or VR devices.

Low threshold devices must:

• in the context of the Cooperation Agreement [Samenwerkingsakkoord [SWA3]]:
o submit a notification (kennisgeving, Article 7 of the [SWA3]),
o prepare a prevention policy (preventiebeleid, Article 6 of the [SWA3]),
o introduce a safety management system to implement this policy (veiligheidsbeheersysteem , Article 6 of the [SWA3])

To avoid specific stringent requirements because of large quantities of hydrogen at the production site one can decide to use a high performant distribution system **and limit the amount of stored hydrogen at the production site**.

Looking at intermodal transport by **rail or by inland waterways** also specific implications arise when transporting larger amounts of hydrogen in a Flemish seaport.
On the one hand the trajectory for the permitting process might be different or to be adapted for the terminals handling the transport flows of hydrogen and in the other hand the operational regulations from the **port by-laws** applicable in the port have to be followed.

In the Flemish list of activities with environmental nuisance **a specific category (rubriek 48) is included for continuous flows, storage and handling of goods in seaports**. The category contains sub-categories depending on the nature and quantities if the goods, of which some refer to the thresholds of the Seveso-regulation. The permitting process might introduce similar requirements with respect to safety.
Even with **daily** intermodal transport the Seveso-thresholds are met and the specific requirements will apply. **Not even one intermodal terminal has this specific permit for the moment**. As intermodal transport of hydrogen seems not preferable from an economic point of view for the first hydrogen installations up to 100-500MW scale, as was already discussed in Chapter 5, and since the quantity of case dependent parameters, no additional research has been performed in this regard.

Within the port area, the port by-laws are applicable in order to safeguard the public order and safety of the port activities. One of the applicable regulations is the **regulation on cargo handling and storage.**

In order to transport and distribute the produced hydrogen out of the port, the applicable rules have to be followed. In the current port regulations only little attention is paid to hydrogen.

A few general issues that do apply:

- Art. 2.1.5 Notification obligation for port users
- Art. 2.1.6 Protection and safety measures
- Art. 5.1.1 Handling of goods

The 'Code' for the handling of dangerous goods also mentions the requirements for the treatment of 'packaged' hydrogen.

<u>UN1049 / 2.1 / HYDROGEN, COMPRESSED</u>: Direct treatment, may stay for 10 days at a recognised terminal if packed in a container. Extended stay possible up to max. 10 days.
<u>UN1966 / 2.1 / HYDROGEN, REFRIGERATED LIQUID</u>: Approval of the harbour master is required.
Article 2.4.3 of the 'Code' also states that the separation conditions between different kinds of packed dangerous goods as set out in the IMDG Code must be strictly followed.

As a point of interest we also looked in the International code of Gas Carriers (IGC) of IMO:

- Hydrogen is for the moment not included in IGC
- At the moment hydrogen is not transported in bulk by sea, but it seems there are some pilot projects on their way .

In case of a more defined specific project, when more information is available on the quantities of Hydrogen that in each scenario will be stored and transported in different locations of the production and distribution chain, a more detailed study has to be performed.

11.3.2 Possible localization of a hydrogen production site in Zeebrugge

As transport by truck or by pipeline are the most preferable ways of distributing hydrogen from a production plant in the port of Zeebrugge, some research has been performed to explore the configuration for a local hydrogen pipeline in the port of Zeebrugge in relation with a hydrogen backbone as mentioned in paragraph 8.1.3. which resulted in the picture below.

Figure 20: Possible configuration for a local hydrogen pipeline in the port of Zeebrugge in relation with a future hydrogen backbone

12 Conclusions and future outlook

The Greenports study has analysed a number of technical and economic aspects of a large scale power-to-gas installation in a port environment.

The main results and conclusion are the following:

- A 5MW-20MW **PEM ELECTROLYSER BUILDING BLOCK** has been developed to enable electrolyser installations of > 100MW scale.

- When **COUPLING LARGE SCALE ELECTROLYSERS TO THE GRID**, the power electronics and more specifically the performance of the alternate to direct current rectifiers is critical in order to meet the transmission grid requirements - i.e. the total harmonic distortion and reactive power control - and thus to avoid additional fees.
  An **ACTIVE RECTIFIER** topology is proposed that provides sufficient reactive power control and is also able to delivering fast responses as required to supply ancillary services to the grid. Simulation of the behaviour of this rectifier circuit in a simulation model built for this purpose, shows full compliance with grid code requirements for electrolyser setups up to 500MW. Using this rectifier circuit avoids bulky and expensive filters and additional equipment to compensate reactive power induced by large electrolysers.

- Technical requirements of **GRID SERVICES** and the ability of the electrolysers to provide these services have been analysed, as well as the economic viability. Electrolysers have the flexibility to technically tackle efficiently all flexibility needs. However on mid (>3year) and long term, the ancillary service **MARKET IS LIMITED** and more cost effective technologies exist reducing the expected value of the revenue pool. Hence grid services as such will not justify or support the installation of an electrolyser. On short term however, it can help the business case to some extent. Congestion might be an interesting source of revenue, but no major congestion issues are expected on Belgian network before 2030.

- The **DISTRIBUTION AND STORAGE** of the hydrogen produced in a large central installation (<=100MW) in the port towards inland distributed hydrogen refuelling stations has been analysed and the costs have been quantified. **TRUCK TRANSPORT** is the most cost-effective way to transport the hydrogen, compared to train and ship. Cost prices vary between 1,2€/kg and 2,5€/kg for transport over a distance of 5-300 km, depending on the scenario. The option to transport hydrogen via a pipeline could be economically the best solution and should be assessed case by case, in particular for large hydrogen demanding end-users (tons/day), since the logistics of truck transport could be a limiting factor..

- The **ECONOMICS FOR THE POWER-TO-GAS CASE** – the cost of green hydrogen compared to alternative pathways i.e. hydrogen from natural gas with CCS- for 2030 and 2040 are analysed, given the specific Belgian situation and the estimated evolution of the Belgian electricity prices. The conclusion is that before **2030**, with the assumed CO2 prices and considering the predicted evolution of the electricity wholesale price, it might be challenging for PtG to become competitive with hydrogen made from natural gas (incl. CCS) **WITHOUT ADDITIONAL SUPPORT.** There is not enough low cost electricity in the system yet to compensate the CAPEX costs. **BETWEEN 2030 AND 2040** the share of renewables in

the electricity mix becomes high enough for **PTG TO PRODUCE COMPETITIVELY**, operating flexibly and sourcing low-cost electricity.
As the Green Deal emphasizes the strong need for green molecules, the **REGULATORY FRAMEWORK** will have to be shaped in such a way that this cost gap in 2030 can be overcome.
Mechanisms like taxes, renewable subsidies, grid tariffs, future value of the gas GOs… or the possibility to purchase the power from a RES producer via a PPA can considerably change the analysis..

The balance of domestic hydrogen production versus **IMPORT** of hydrogen will be determined by cost price considerations and local supply of electricity (a.o. the European offshore grid).

- A **CALCULATION TOOL** is built to compare the business case for a "small" inland hydrogen user, supplied by a large scale **CENTRAL** in the port installation versus a small scale hydrogen production installation **ONSITE** at the user's premises.

- The main drivers for the business case are: **AMBITIOUS CO_2 TARGETS** and penalties for non-compliance, adequate **CARBON PRICING** that will guide the consumer towards low carbon solutions, **VALORISATION** of renewable hydrogen through certification and trade of **GUARANTEES OF ORIGIN** and the availability of **AFFORDABLE RENEWABLE ELECTRICITY** (e.g. EU offshore grid). New **INTER-TEMPORAL TRADING OPPORTUNITIES** and market mechanisms originating from the highly variable electricity price behaviour might support the business case.

- The **PORT OF ZEEBRUGGE** has analysed the possible locations for hydrogen production and a local hydrogen pipeline, next to the planned hydrogen backbone as foreseen by Fluxys. Specific port regulations for storage of hydrogen have been summarised.

By the end of this project, the different partners all have announced announced **LARGE SCALE POWER-TO-GAS PROJECTS IN THE BELGIAN PORTS** (Zeebrugge, Antwerp & Ghent)[59],[60],[61].
Feasibility studies and detailed analyses are currently running for the different cases.

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[59] https://portofzeebrugge.be/en/news-events/important-step-development-hydrogen-economy-plan-first-industrial-power-gas

[60] https://powertomethanolantwerp.com/

[61] https://northccuhub.eu/north-c-methanol/

13 Publications

- On the optimal planning of a hydrogen refuelling station participating in the electricity and balancing markets, Akbar Dadkhah, Dimitar Bozalakov, Jeroen D.M. De Kooning, Lieven Vandevelde *International Journal of Hydrogen Energy, Volume 46, Issue 2, 6 January 2021, Pages 1488-150*
- Optimal sizing and economic analysis of a hydrogen refuelling station providing frequency containment reserve, Akbar Dadkhah (UGent) , Dimitar Bozalakov (UGent) , Jeroen De Kooning (UGent) and Lieven Vandevelde (UGent), *2020 IEEE International Conference on Environment and Electrical Engineering, Proceedings.*

WaterstofNet
Open Manufacturing Campus
Slachthuisstraat 112 bus 1
2300 Turnhout
België

T +32 (0)14 40 12 19

Kantoor Nederland

Automotive Campus
Automotive Campus 30
5708 JZ Helmond
Nederland

Contact person: **Isabel François**

isabel.francois@waterstofnet.eu

WaterstofNet
WaterstofNet

WaterstofNet

waterstofnet.eu