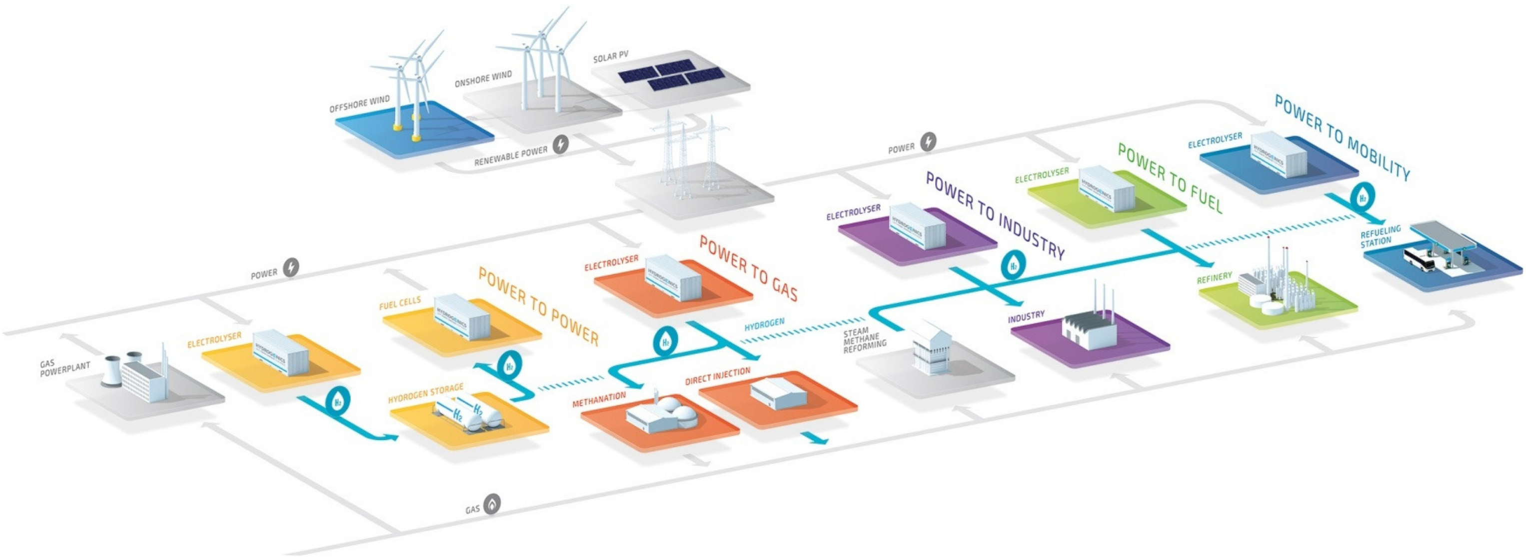
POWERTOGAS
Roadmap for Flanders




# FINAL REPORT

**October 2016**

www.power-to-gas.be

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## KEY METRICS FOR HYDROGEN PRODUCTION AND MOBILITY APPLICATIONS

**Cars and buses**

| FCEV | $H_2$ tank | $H_2$ consumption | Driving range | Annual driving distance | Annual $H_2$ consumption |
|---|---|---|---|---|---|
| Car (passenger) | 5 kg | 1 kg/100 km | 500 km | 15.000 km | 150 kg |
| Bus (12 m) | 35 kg | 10 kg/100 km | 350 km | 60.000 km | 9 tons |

**Hydrogen production from electrolysis**

- **Power:** 1 MW electrolyser > 200 $Nm^3/h$ $H_2$ > ± 18 kg/h $H_2$
- **Energy:** 1 kg $H_2$ > 11.1 $Nm^3$ > ± 10 liters demineralized water > +/- 55 kWh of electricity

**Renewable hydrogen for transport applications**

| | Solar PV | On shore wind | Off shore wind |
|---|---|---|---|
| Project size (MW) | 1 | 5 | 325 |
| Annual energy yield (GWh/MW) | 1 | 2,2 | 3,3 |
| Annual energy production (GWh) | 1 | 11 | 1.073 |
| Annual hydrogen production (tons) | 18 | 200 | 19.500 |
| # Buses (12 m) | 3 | 33 | 3.250 |
| # Car (passenger) | 121 | 1.333 | 130.000 |

NB: These are indicative figures only, provided for back of the envelope calculations. They might slightly differ from the values used in the current study.

# 1. PREFACE

In the past two years a broad consortium has put great effort into drawing a roadmap for Power-to-Gas in the Flanders region. This has been a very relevant task in the light of a number of recent developments, the most important one being the COP21 agreement reached in Paris last December which urges us to take immediate steps to decarbonisation around 2050. In a decarbonised economy hydrogen could play a key role in several markets, such as mobility, demand for feedstock in industry and production of high temperature heat. However, we must admit that there are yet many uncertainties whether the potential of hydrogen will be fully exploited or not. One certainty is that electricity will become more and more sustainable in the future, mainly due to the large increase in wind and solar power generation where tremendous cost reductions are, and will be realised. This also leads to the challenge of how to deal with the intermittency which is a result of the weather dependence of these renewable sources. Power-to-gas as conceptual idea has a large potential to become a 'bridge' between electricity and commodity/feedstock markets, thus providing flexibility and enabling the conversion of sustainable electricity into sustainable products. From a practical point of view there still is a great challenge for Power-to-Gas technology where innovation must bring down cost and improve both efficiency and lifetime.

Flanders has potential to play a dominant role in these developments, given the fact that there is a strong hydrogen industry cluster present, including supportive industries and companies. Furthermore it seems that stakeholders in Flanders, from industry, knowledge institutions and governments, have an ambition to support these developments and create new sustainable economic activities at the same time.

So far what was missing was a roadmap which could help to analyse how the opportunities that arise from both the climate challenge and the willingness of stakeholders to take next steps could be capitalised on as far as hydrogen and Power-to-Gas is concerned. What steps should be taken, how and when? This report fills the gap! It has been conducted by industry and with industry, with great support from the government which makes it a valuable 'product' on how Flanders should act to harvest the broad potential of Power-to-Gas and hydrogen.

The most important takeaways from this roadmap are:

- Short-term focus should be on utilisation of renewable hydrogen in industry, the use of renewable hydrogen for mobility, and Power-to-Gas as a key technology to move from renewable electricity to hydrogen and other products
- Political commitment is needed to get this off the ground in the Flanders region as policy and regulation are important enablers
- Actions mentioned in the roadmap for the time span 2020 – 2030 – 2050 should be read carefully and can give valuable guidance to policy makers
- Demonstration projects are needed to bring roadmaps into action, to generate (public) attention and to gain useful practical experience

We, the Advisory Committee which provided input during the period that this roadmap was made, are proud that we have been part of this process in Flanders. We hope that this roadmap is the start of a new challenge that will be taken on by all stakeholders leading to sustainable economic development in the Flanders region as well as decarbonisation in 2050.

**By Michael Ball (Shell), Jörg Gigler (TKI Gas) and André Jurres (NPG Energy).**

# 2. INTRODUCTION

## 2.1. Background

The production of renewable electricity from wind and solar energy in Europe and consequently in Flanders (Belgium) increases due to their unique benefits for $CO_2$ reduction.

**Figure 1: Monthly green certificate delivery in Flanders per technology 2003-2015[1]**

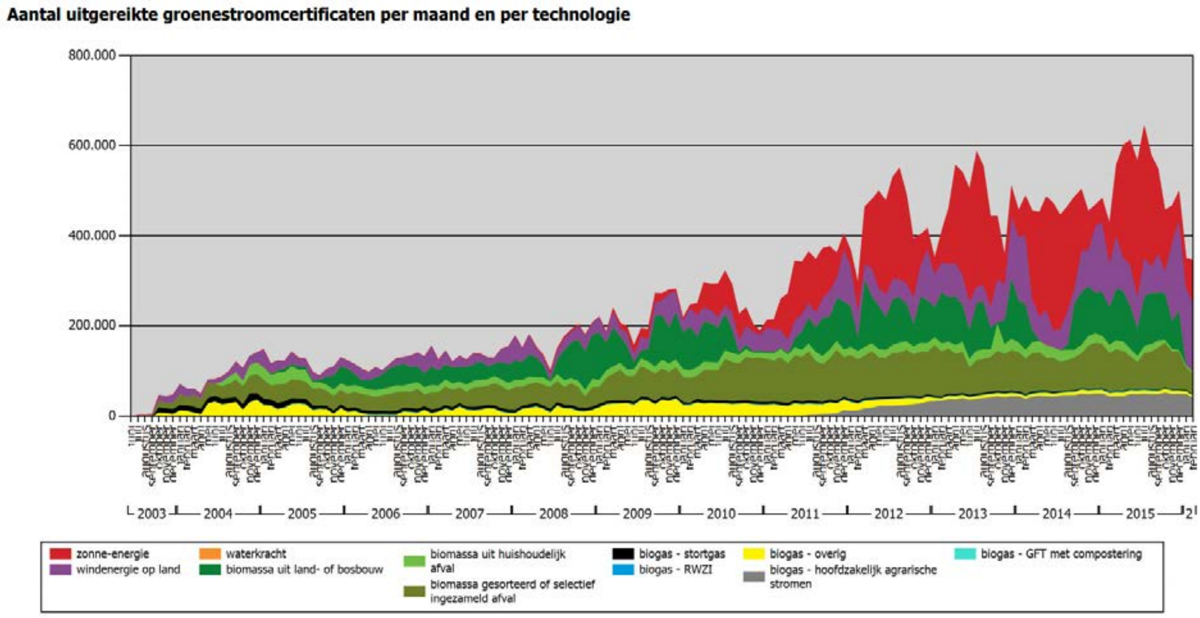
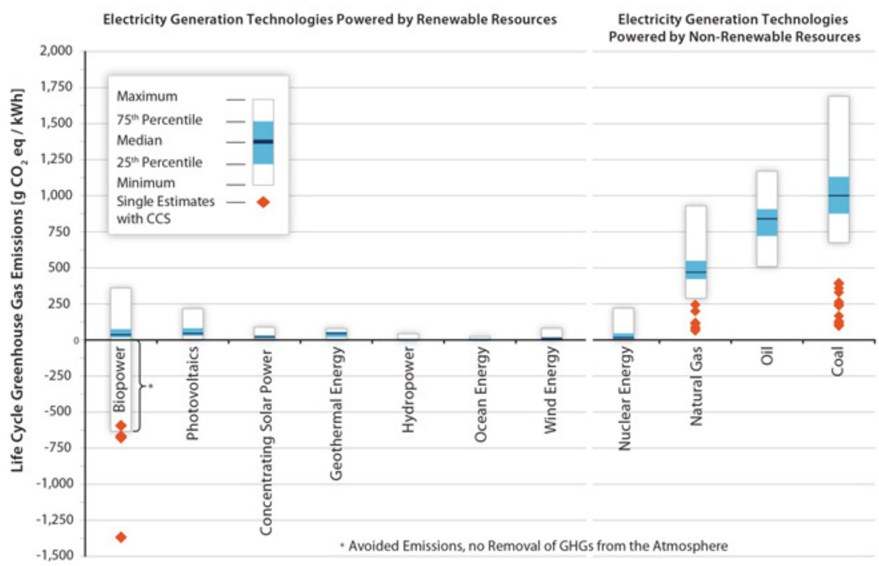



**Figure 2: GHG emissions of electricity generation technologies[2]**




These fluctuating and weather dependent renewable energy sources, feed their electricity into the existing electricity grid. Hence, the management of intermittent energy sources is becoming an increasing challenge for the grid operators and induces extra investments in distribution and

[1] Source: VREG, NB: 1 GC = 1 MWh
[2] Source: (Edenhofer & Pichs-Madruga, 2011)

transmission networks, additional need for grid flexibility by using tools such as smart grids, demand side management and energy storage.

Massive RES deployment however is not possible without energy storage and especially seasonal large storage will expect new approaches.

Among the various energy storage technologies (such as batteries, flywheels, hydropower, compressed-air energy storage), Power-to-Gas offers the possibility to store green electricity for long (seasonal) periods in the form of hydrogen ($H_2$), thanks to water electrolysis. There are different possibilities to recover the energy from the hydrogen: it can be converted back to electricity, it can be injected into the natural gas grid (in the form of hydrogen of synthetic natural gas), it can be used for mobility purposes (for Fuel Cell vehicles or low carbon fuels) or even as a way to decarbonise the chemical sector.

At the same time, national policies and private initiatives against climate change are being re-enforced in all regions, especially after the COP21 meeting in Paris in December 2015. The need for decarbonisation of the overall energy system is more stringent than ever and solutions are being evaluated. Hydrogen produced via water electrolysis from renewable power (wind and solar) is often presented as one of the most promising solutions to achieve high levels of decarbonisation[3], especially in the transport and industrial sectors. The use of $CO_2$ by capturing (CCS) combined with green hydrogen from electrolysis will further alleviate the $CO_2$ burden with the generation of new sustainable fuels or chemicals.

Several recent studies mention a high potential for water electrolysis in a GW scale already before 2030 as a response to future higher RES.

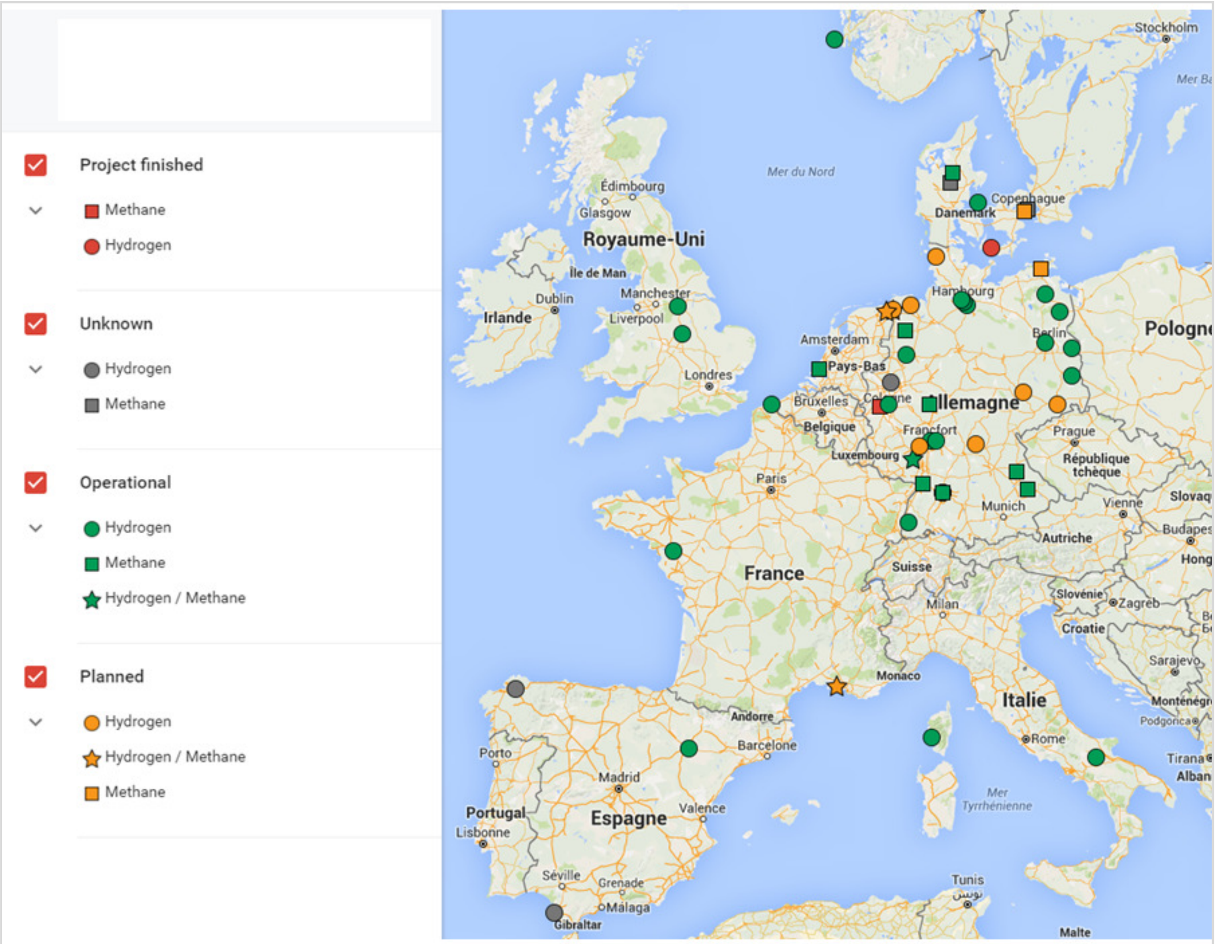
**Table 1: Selection of studies presenting a potential for Power-to-Gas technologies**

| **Publication** | **Potential for water electrolysis (Power-to-Gas)** |
|---|---|
| "Study of the requirement for electricity storage in Germany", Agora Energiewende | GER: 16 GW (2023), 80 GW (2033) and 130 GW (2050) |
| Commercialisation of Energy Storage in Europe*, Mc Kinsey, FCH-JU, 2014* | GER: 170 GW by 2050 (all energy storage) |
| "Reduction of $CO_2$ emissions by addition of hydrogen to natural gas" by Haines, Polman and de Laat, in IEA Greenhouse Gas Control Technologies Volume 1 | UK: 23.5 GW of electrolysis in 2050 |
| "Study of hydrogen and methanation as processes for capturing the value of excess electricity" Report by ADEME GRTGaz and GRDF, France | FR: 1.2-1.4 GW of Power-to-Gas plant in France by 2030 and up to 24 GW by 2050 |
| "The role of Power-to-Gas in the future Dutch energy system" ECN and DNVGL for TKI Gas, 2014 | HOL: 20 GW of installed Power-to-Gas capacity if deep $CO_2$ emission reduction targets in the energy system (-80% to -95% by 2050) |
| Effects of large-scale Power-to-Gas conversion on the power, gas and carbon sectors and their interactions, KULeuven, 2014 | BE: 7 GW Power-to-Methane potential a 100% RES scenario |

[3] Prof. Dr. Hans-Martin Henning, The role of Power-to-Gas in achieving Germany's climate policy targets with a special focus on concepts for road based mobility, Fraunhofer Institute for Solar Energy Systems ISE, 2015

At the same time dozens of Power-to-Gas demonstration projects (in the range between a few kW and 6 MW) have been developed in Europe to demonstrate the effectiveness and the efficiency of the electrolysis technologies (PEM, alkaline) and to test several concepts like the storage of hydrogen for mobility purposes or the injection of hydrogen or synthetic methane in gas grids. A project database is available on the website of the European Power-to-Gas Platform: www.europeanpowertogas.com

**Figure 3: Overview of existing Power-to-Gas demonstration projects in Europe[4]**




## 2.2. Project objectives

The project 'Roadmaps for economic challenges: Power-to-Gas Flanders' has analysed and prioritized the different Power-to-Gas options available today and has determined how the Flemish industry could position itself in this promising market (in Flanders and worldwide).

The following objectives were part of the study:

- Description of what Power-to-Gas is, the technologies in presence and the application fields
- Definition of business models for various valorisation routes (Power-to-Power, Power-to-Gas, Power-to-Mobility, Power-to-Fuels and Power-to-Industry);

[4] Source: www.europeanpowertogas.com

- Actual and future outlook of these business models (technological and economical) with a medium (2030) and long term perspective (2050);
- Development and prioritization of a set of recommendations for successful implementation of the Power-to-Gas concept in Flanders and abroad (appropriate regulatory framework);
- Definition of a Flemish value chain and creation of an industrial cluster around Power-to-Gas.

### 2.3. Project consortium

Members of the project consortium include the following companies with activities in Flanders: Colruyt, Eandis, Elia, Fluxys Belgium, Hydrogenics, Sustesco, Umicore and WaterstofNet.

- Colruyt Group: retail Company in Belgium, producer of renewable power (wind, solar and cogeneration), construction and exploitation of fuel stations (DATS24) and end-user of hydrogen in logistic applications (forklifts).
- Eandis: natural gas and electricity distribution systems operator.
- ELIA: Belgian electricity transport system operator.
- Fluxys Belgium: natural gas transport system operator.
- Hydrogenics: global leading manufacturer of electrolysers and fuel cell technologies.
- Sustesco: consulting in sustainable energy applications.
- Umicore: development of catalysts for electrolysis and fuel cells.
- WaterstofNet: together with industry and governmental authorities, WaterstofNet develops sustainable hydrogen projects for transport and energy storage applications in Flanders and the Netherlands.

### 2.4. Project timing and funding

This project has started in October 2014 and ended in January 2016. It has received funding from the Flemish Region (reference: NIB.2013.CALL.001).

### 2.5. Project methodology

This project was led by the industrial players present in the consortium. A core group including Colruyt, Hydrogenics, Sustesco, WaterstofNet has provided most of the effort of this study. All project partners have collaborated with inputs and have reviewed each deliverable. In total, 13 full project meetings were held during the project, with a status on the project progress and group discussions on most important topics. Also, an external board was formed to provide external advice and guidance on the project methodology and the results. This external board comprised: Michael Ball from Shell Global Solutions International, Jörg Gigler from TKI Gas and André Jurres from NPG Energy.

For the need of this study, an extensive literature review has been performed with more than 300 publications listed in a database. Out of these numerous publications, 10 have been selected as primary source of information for our roadmap (see Annex 4: Literature review: top 10 publications).

# 3. INTERNATIONAL, EU, BELGIAN AND FLEMISH ENERGY POLICIES

The long term European strategy to reduce greenhouse emissions towards 2050 will be an important incentive to develop the Power-to-Gas technology and market in the near future.

On global level, the 2015 Paris Climate Conference resulted in a universal binding agreement to limit global temperature increase below 2°C and to pursue efforts to keep the increase below 1.5°C

The European long term strategy defines quantified targets for reduction of greenhouse gas emissions, the increase in the share of renewable energy and energy savings.

**Table 2: EU sustainable energy objectives**

| year | 2020 | 2030 | 2050 |
|---|---|---|---|
| Reduction in GHG emissions (compared to 1990 level) | 20% | 40% | 80-95% |
| Share of renewable energy in total energy consumption | 20% | 27% | |
| Energy savings | 20% | 27% | |

In order to achieve these long term strategy results, the European commission published a large number of directives. A directive is a legal act of the EU which requires member states to achieve a particular result without dictating the means to reach that result. The interpretation of directives is thus a very important topic in the EU as member states could introduce different kind of regulations to implement the directive in their own country.

The European directives, identified as the most relevant for this Power-to-Gas roadmap, are the following.

**Table 3 : Relevant EU directives for Power-to-Gas applications**

| Directive | Subject | Remarks |
|---|---|---|
| Renewables Energy Directive (RED) 2009/28/EC | Promotion of the use of energy from renewable sources. Contribute to the European Union's climate and energy '20-20-20' package | 20% minimum share for renewables in EU-wide final energy consumption by 2020, as well as a specific 10% target for renewable energy in transport (RES-T), |
| Deployment of alternative fuels infrastructure 2014/94/EU | Minimum requirements for the build-up of alternative fuels infrastructure, including recharging points for electric vehicles and refuelling points for natural gas (LNG and CNG) and hydrogen. | |
| Energy Taxation Directive (ETD) 2003/96/EC | Community framework for the taxation of energy products and electricity | Proposal is to tax energy in a way that reflects both its CO2 emissions and its energy content. |

| | | |
|---|---|---|
| EU Emissions Trading System (EU ETS) ETS | Establishing a scheme for greenhouse gas emission allowance trading within the Community. | |
| Fuel Quality Directive (FQD) 2009/30/EC | Specification of petrol, diesel and gas-oil and introducing a mechanism to monitor and reduce greenhouse gas emissions | 6% reduction in the GHG content of road fuels by 2020 from their 2010 levels |
| Directive on Clean and Energy Efficient Vehicles (CEEV) 2009/33/EC | Promotion of clean and energy-efficient road transport vehicles | fiscal measures aimed at facilitating a more rapid penetration of fuel-efficient vehicles |
| Industrial Emissions Directive (IED) 2015/75/EU | Industrial emissions (integrated pollution prevention and control) | |
| Energy Efficiency Directive (EED) 2012/27/EU | Set of binding measures to help the EU reaching its 20% energy efficiency target by 2020 | |
| Air Quality Directive (AQD) 2008/50/EC | Ambient air quality and cleaner air for Europe | |

Remark: Another measure that could have a significant influence towards cleaner transport is a proposal for legislation imposing new tolls on trucks differentiated based on the "EURO class" of the vehicle. This means that companies using cleaner trucks would pay a reduced toll compared to those using diesel trucks.

Translation of these directives specifically for Belgium/Flanders are presented in the following table.

**Table 4: Sustainable energy policies in Belgium and Flanders**

| **European Directive** | **Resulting plan/directive for Flanders/Belgium** |
|---|---|
| European long term strategy 20%-20%-20% | Translated for Belgium into<br>• 13% (share of renewable energy)<br>• 15% (GHG emission reduction compared to 2005)<br>• 18% (reduction in primary energy consumption by 2020 relative to the Primes 2007 baseline |
| Renewables Energy Directive (RED)<br>10% target for renewable energy in transport (RES-T) | Mandatory blending of 8.5 vol% bio fuels (from Jan 1, 2017) |
| Deployment of alternative fuels infrastructure | Action plan 2015 : Clean power for transport for Flanders (with e.g. 20 HRS[5] & 300 CNG refuelling stations in Flanders by 2020) |
| Energy Efficiency Directive (EED) | Flemish Energy Efficiency Action Plan 2014 |

[5] HRS = Hydrogen Refuelling Station

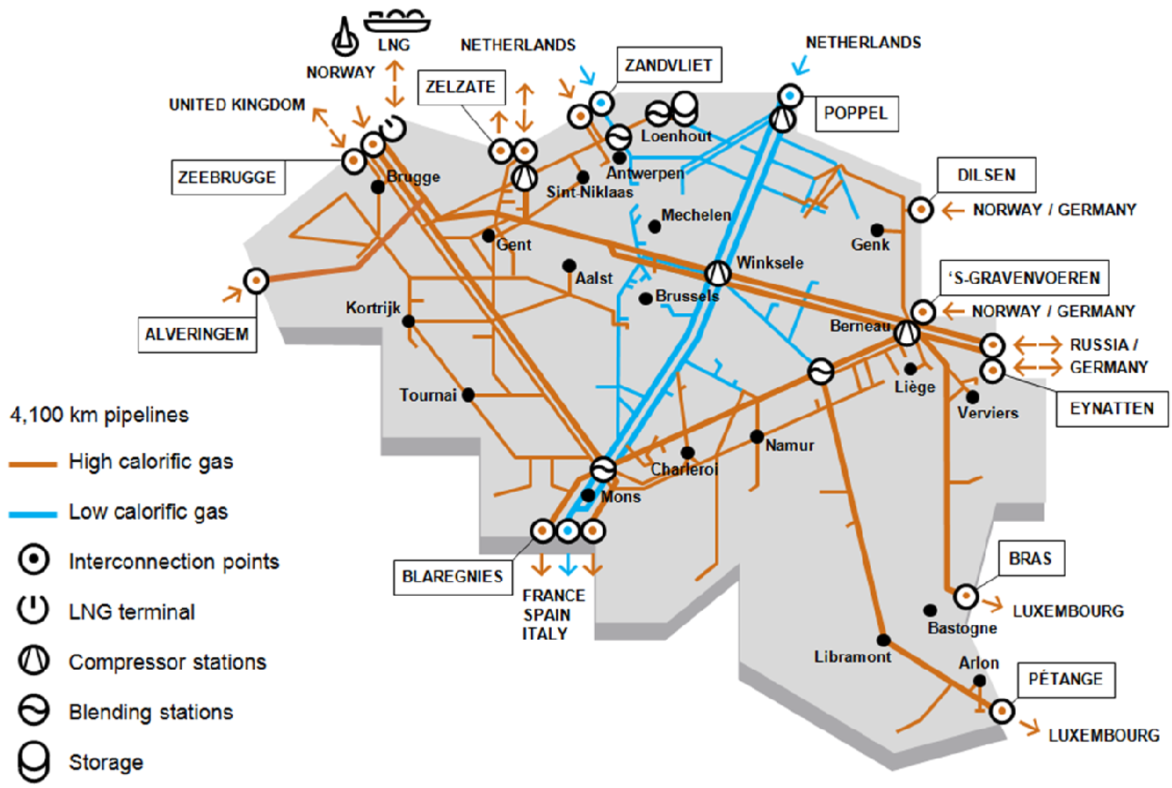
# 4. DESCRIPTION OF THE BELGIAN POWER, GAS, MOBILITY AND HYDROGEN MARKETS

## 4.1. Gas market

The Belgian natural gas transmission grid is operated by Fluxys Belgium, the company also operating the storage infrastructure in Belgium and the Zeebrugge LNG terminal.

The Belgian natural gas grid is one of the best-interconnected infrastructures in North-Western Europe. The 18 interconnection points on the Belgian grid providing access to natural gas flows from the United Kingdom, Norway, the Netherlands, Russia and LNG producing countries worldwide. The Belgian grid also serves as the crossroads for cross-border transmission flows of natural gas to the Netherlands, Germany, Luxembourg, France, the United Kingdom and Southern Europe.

**Figure 4: The gas transmission network in Belgium**[6]




The Belgian gas transmission infrastructure can be characterized as follows:

- Network length: 4.100 km
- Gas consumption in Belgium : 16.5 bcm per year (2015)
- Entry capacity: 121 bcm/y – Exit capacity: 80 bcm/y
- 230 industrial end users and power stations directly connected into the grid
- Connection to 17 distribution system operators responsible for distributing natural gas to homes and small or medium enterprises
- The Belgian grid is made up of two systems:

[6] Source: Fluxys Belgium

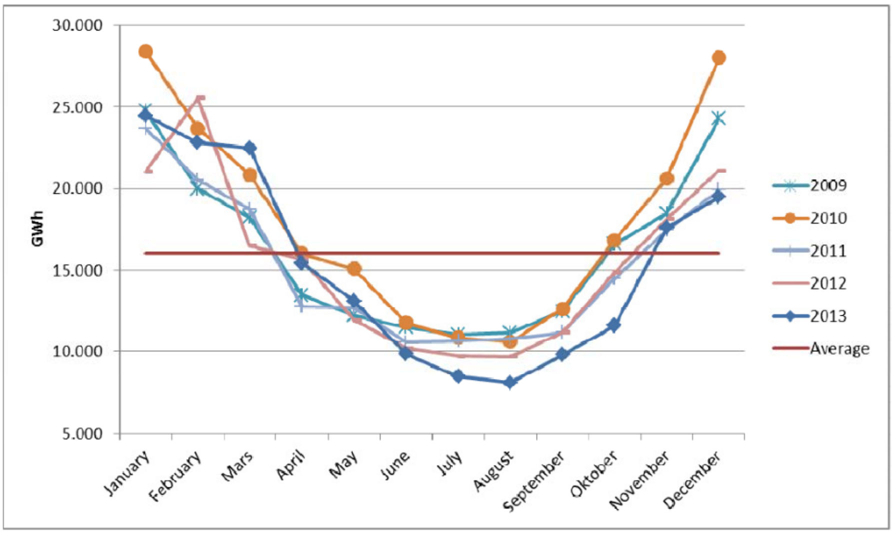
- o one for the transmission of low-calorific natural gas : single source is the Slochteren field in the Netherlands
- o one for the transmission of high-calorific natural gas: mix of natural gas from several sources: Norway, the United Kingdom, Russia and from various countries producing liquefied natural gas (LNG).

- Gas composition: methane (+/-90%), with some minor fractions of ethane and propane, and a non-negligible fraction of carbon dioxide and nitrogen (especially for low-calorific gas). In Annex 5, the average composition for natural gas from different sources over the year 2015 is shown.

In 2015, gas demand in Belgium amounted to ± 176 TWh, of which roughly 30% L-gas and 70% H-gas.

Most of the gas consumption on the distribution networks is used for heating and is very sensitive to outside temperatures. Therefore the number of degree days will have a significant influence on consumption. Consumption of industry is to a lesser extent influenced by outside temperatures. Gas demand in summer does not depend on outside temperatures and represents mainly gas demand for industry and power generation

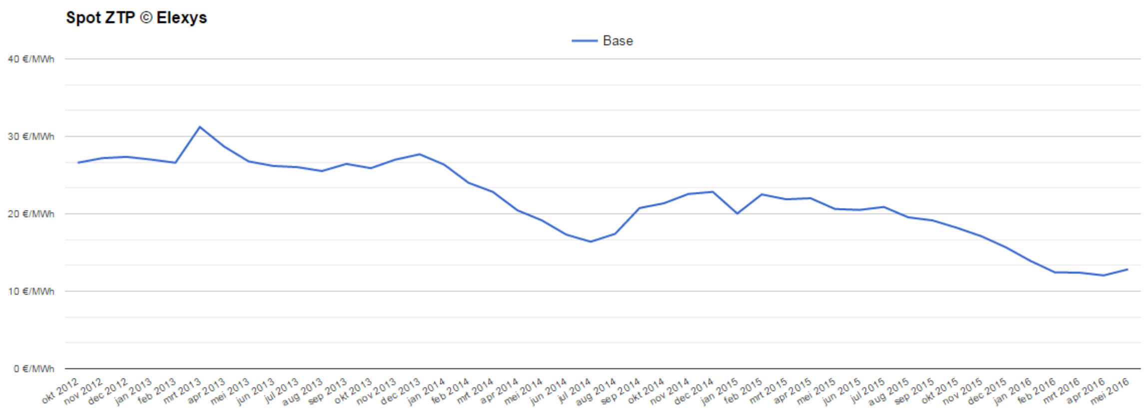
**Figure 5: Monthly gas consumption in Belgium[7]**




About 50% of the gas for the Belgian market is sourced through contracts with duration of more than 5 years between suppliers and producers. Around 40% of the gas is sourced via contracts shorter than one year. The contract duration however is no indication of oil-indexation: in Belgium as in the rest of North-West Europe 92% of gas is sourced at spot or hub-linked prices. Fluxys Belgium through its hub services facilitates both over the counter trading and exchange-based trading (offered by ICE Endex and Pegas) in Belgium

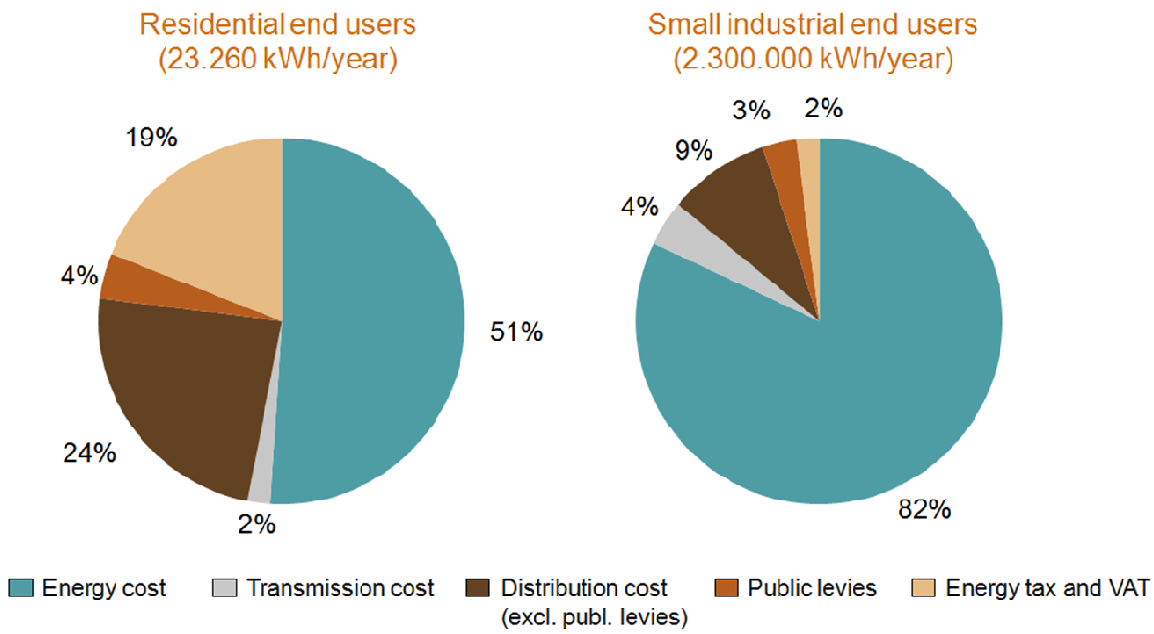
[7] Source: FOD Economie – Risk Assessment Belgium

**Figure 6: Evolution of gas prices in Belgium**[8]




In Figure 7, the breakdown of gas prices is shown for residential and small industrial users. Transport and distribution costs, levies and taxes represent only a limited share of the total gas price for all industrial customers.

**Figure 7: Breakdown of gas prices in Belgium**[9]



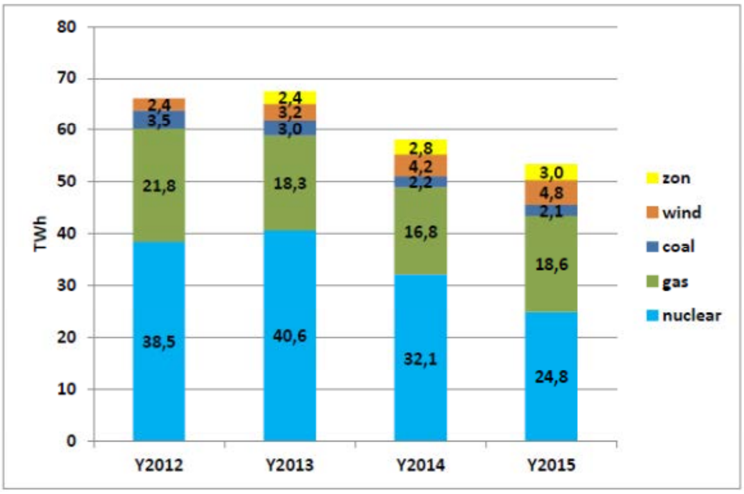

## 4.2. Power market

Power generation in Belgium is decreasing since 2010 and amounted 56.3 TWh in 2015. On the other hand, the import of electricity increased, reaching 20.8 TWh in 2015 (the highest level ever). Figure 8 provides an estimate of the annual amounts of power generated out of different fuel types over the past years. Due to the drop in nuclear power generation as a result of temporary shutdowns in Doel and Tihange, the share of nuclear production slightly decreased, however still reaching around 44% of the total share. The share of gas-fired power plants remains almost constant at 33%. Coal power plants, in the meantime mostly converted to biomass plants, produce about 4% of the energy. These

[8] Source: https://my.elexys.be
[9] Source : CREG, April 2015

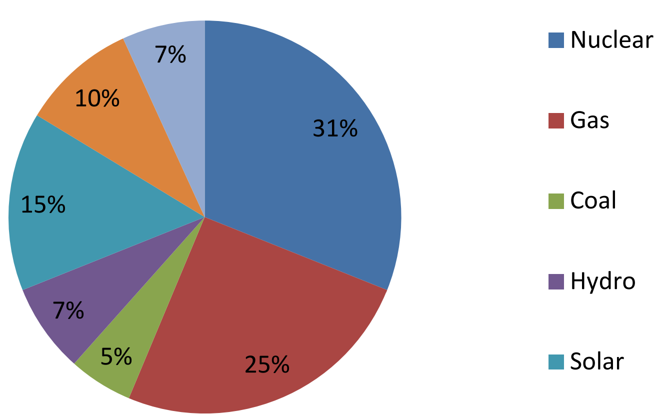
three 'conventional' power production plant types still produce more than 80% of the total electricity.

**Figure 8: Power generation in Belgium by energy source**[10]




Looking at production capacities, the total installed capacity (including the production capacities that are not connected to the Elia grid, such as the decentralised power production) amounts up to almost 19 GW. Nuclear power plants represent 31% of the national's total capacity (5,9 GW). The capacity of gas-fired power plants is decreasing, as some of the (older) units were temporarily or definitively stopped due to unfavourable market conditions, and amounts 4,8 GW or 25% of the total installed capacity. Hydro power plants stations and coal power plants represent 1,4 GW (7%) and 1,0 GW (5%) respectively (source: Elia). Looking at the intermittent power production technologies, the total installed capacity of solar energy in Belgium is 2,8 GW (15%) and the total installed capacity of wind power in Belgium is 1,8 GW (10%), of which 712 MW is installed offshore. Knowing that the peak demand of Belgium is about 13-14 GW, the installed capacity of intermittent renewable generation is not negligible.

**Figure 9: Installed power production capacity in Belgium (2015)**[11]




[10] Source: CREG
[11] Source: Compilation from Elia, Febeg and CREG.

The plan to phase-out nuclear power generation in Belgium has been subject to many political discussions and changes. However first set to be closed in 2015, the lifetime of the three oldest Belgian reactors - Doel-1, Doel-2 and Tihange-1, - was extended until 2025. The remaining Belgian reactors are set to be shut down in 2022 (Doel-3, Tihange-2), or in 2025 (Doel-4 and Tihange-3).

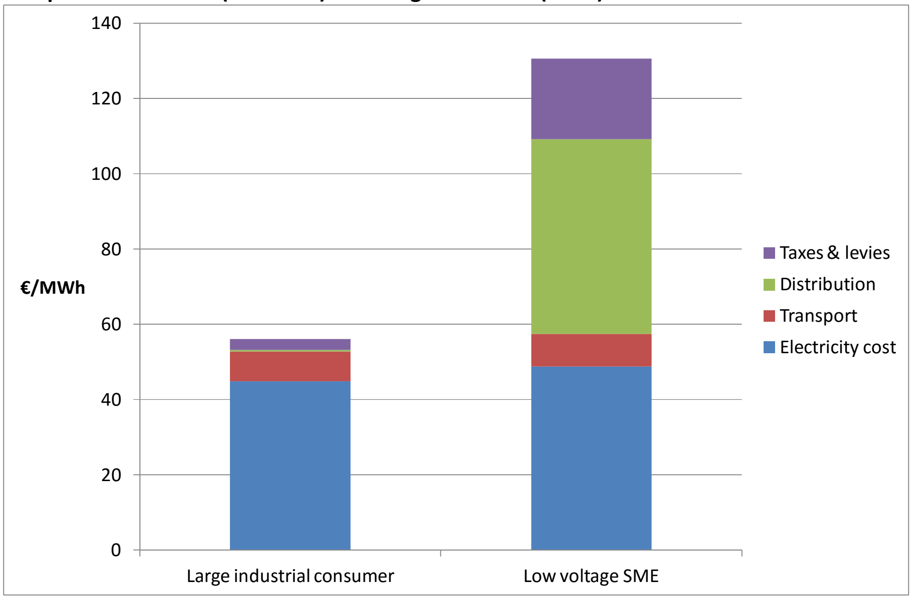
Power prices in Belgium are determined by the Belgian electricity spot market, BELPEX, which has been coupled to the French, Dutch and German electricity markets. For the year 2014, the average price at the BELPEX Day-Ahead Market (Belpex DAM) was 40,78 € per MWh. This average price is slightly lower than the average price at the Day-Ahead Market in the Netherlands (41,18€/MWh), but higher than the prices in other surrounding countries, like Germany (32,75 €/MWh) and France (35 €/MWh).

The intermittent character of wind and solar power also had an impact on the power prices. This is called the “cannibalisation effect” of wind power. It means that power prices at the Day-Ahead Market are lower during hours with lots of wind than during hours with less wind. It should be mentioned that a day-ahead market does not take into account real time variations of wind output, but only predictions made on the day before.  For Belgium, the “cannibalisation effect” in 2014 was 4.9%. As mentioned before, the average Belpex Day-Ahead price was 40,78 €/MWh (the ‘baseload average’), but a weighted average price (with the power production of wind turbines in Belgium as a weighing factor) was only 38,80 €/MWh, or 95.1% of the baseload average. In previous years, “cannibalisation effect” was also around 5%.

On top of the power prices at the wholesale markets, end consumers have to pay grid costs, taxes and levies. These costs depend on the voltage level to which a consumer is connected (lower costs for high voltage connections, higher costs for residential consumers, typically connected to low voltage grids). Besides, for large consumers there are some reductions on the costs for green certificates, CHP-certificates and ‘Federale bijdrage’. The higher the annual electricity consumption, the larger is the reduction. In Annex 7, the tariffs of these grid costs, taxes and levies as published on the CREG website are summarized.

This information has been used to calculate in Figure 10 the power price breakdown of two typical power consumers.

**Figure 10: Power price breakdown (VAT excl.) for a large industrial (36kV) and a small SME customer at low voltage**[12]




For the moment, most of these costs are consumption-driven (and therefore expressed in €/MWh). In the future however, most of the costs might be capacity-driven (and therefore expressed in €/kW). This means that instead of the annual amount of consumed electricity, the peak off take will become the determining factor for calculating the grid costs.

### 4.3. Mobility market

The total number of vehicles in Belgium is increasing continuously, and equalled 7,17 million in 2015, an increase of 1,4% compared to 2014 (source: FOD Economie). This includes 5,62 million passenger cars, of which 61,5% having diesel as a fuel, 37% having gasoline as a fuel, approximately 1% having gas as a fuel (CNG or LPG) and only a few thousands with electric motors. The European directive on alternative fuel infrastructures (Dir. 2014/94/EU) encourages member states to actively support the development of electricity, hydrogen and natural gas as alternative fuels for transport. In Belgium, the first translations of these EU requirements at regional level already positively influenced the number of vehicles running on alternative fuels in Flanders (road tax exemption for CNG cars and subsidies for new electric cars).

[12] Own calculation

**Figure 11: Total number of vehicles in Belgium between 2006 and 2015[13]**

| Op 1 augustus van het jaar | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | Evolutie 2015/2014 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Totaal voertuigenpark (met inbegrip van motorrijwielen** | **6.251.428** | **6.362.161** | **6.482.033** | **6.574.789** | **6.689.065** | **6.861.777** | **6.920.791** | **6.993.767** | **7.076.238** | **7.175.062** | **+1,4%** |
| Personenwagens | 4.976.286 | 5.048.723 | 5.130.578 | 5.192.566 | 5.276.283 | 5.407.015 | 5.443.807 | 5.493.472 | 5.555.499 | 5.623.579 | +1,2% |
| - rijdend op benzine | 2.330.471 | 2.247.799 | 2.161.807 | 2.092.472 | 2.035.578 | 2.005.481 | 1.981.861 | 1.992.418 | 2.029.688 | 2.091.327 | +3,0% |
| - rijdend op diesel | 2.570.671 | 2.730.958 | 2.903.238 | 3.038.521 | 3.181.431 | 3.341.480 | 3.400.646 | 3.438.030 | 3.458.424 | 3.457.526 | -0,0% |
| - rijdend op gas | 56.189 | 51.026 | 46.587 | 42.485 | 37.463 | 33.594 | 29.542 | 25.362 | 22.051 | 18.967 | -14,0% |
| - met elektrische motor | 13 | 8 | 10 | 10 | 36 | 162 | 647 | 919 | 1.792 | 2.871 | +60,2% |
| - niet nader bepaald | 18.942 | 18.932 | 18.936 | 19.078 | 21.775 | 26.298 | 31.111 | 36.743 | 43.544 | 52.888 | +21,5% |
| Autobussen en autocars | 15.329 | 15.479 | 15.992 | 16.061 | 16.226 | 16.100 | 16.031 | 15.822 | 15.976 | 16.094 | +0,7% |
| Vrachtwagens, bestelwagens, terreinwagens en tankwagens | 623.250 | 642.687 | 662.780 | 676.644 | 690.837 | 714.370 | 726.237 | 739.402 | 752.266 | 770.508 | +2,4% |
| Trekkers (a) | 47.164 | 48.060 | 49.109 | 47.418 | 46.673 | 46.844 | 46.774 | 45.000 | 44.693 | 44.851 | +0,4% |
| Landbouwtrekkers | 170.613 | 172.818 | 174.709 | 176.522 | 177.989 | 180.174 | 182.056 | 183.638 | 184.722 | 186.334 | +0,9% |
| Speciale voertuigen (b) | 59.022 | 59.651 | 60.585 | 61.638 | 62.142 | 63.316 | 64.562 | 65.640 | 66.570 | 67.910 | +2,0% |
| Motorrijwielen (c) | 359.764 | 374.743 | 388.280 | 403.940 | 418.915 | 433.958 | 441.324 | 450.793 | 456.512 | 465.786 | +2,0% |
| Inwoners per personenauto op 1 augustus (d) | 2,11 | 2,10 | 2,08 | 2,07 | 2,08 | 2,03 | 2,03 | 2,02 | 2,01 | 1,99 | |

The number of inhabitants per passenger car equals 1,99. Next to passenger cars, there are also approximately 770.000 trucks, 466.000 motors and 16.000 buses.

Fuel for all these vehicles is mainly sold in petrol stations all over the country. On January 1st, 2014, Belgium had 3178 petrol stations, which is about the same amount than the previous years. This means approximately one petrol station per 3500 inhabitants or per 1700 vehicles, and an average volume of fuel sold per petrol station of 2,15 million liters per year. Today, 50 petrol stations also provide compressed natural gas (CNG) as a fuel. Around 100 CNG stations are expected in Belgium by the end of 2017. The first Belgian H2-refuelling station has just been inaugurated in April 2016.

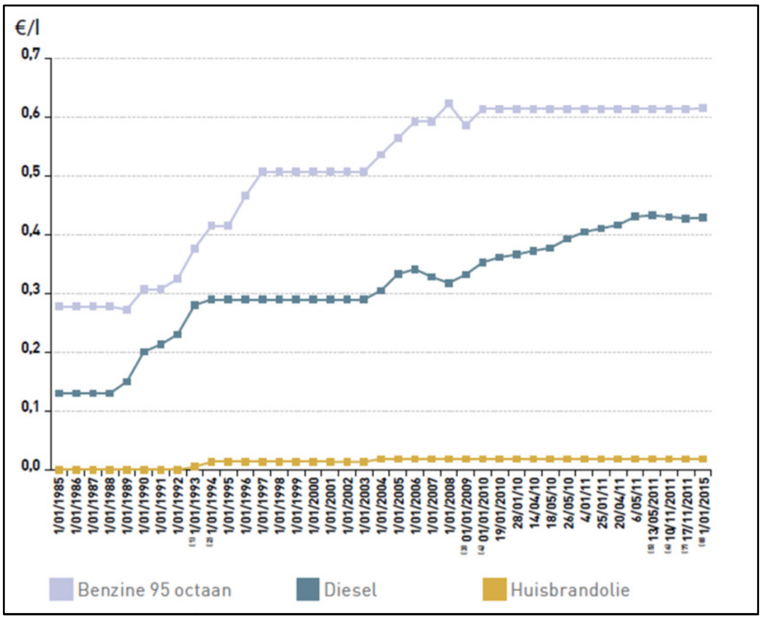
Fuel prices strongly depend on the oil prices at the international markets. However, also local government has a strong impact on fuel prices due to the taxes and levies applicable to the different types of transport fuels. In Belgium, maximum prices for transport fuels and other oil derivatives are calculated by the department of Energy of the Federal Government. The maximum prices consist of multiple components:

- The price ex-refinery: this is the real cost of the product, and is driven by the prices of the different oil derivatives at the Rotterdam market, which depend on the oil prices at the international markets, but also on the exchange rate EUR/USD (as oil and oil derivatives are mostly traded in US Dollars), the (seasonal) demand for certain derivatives, the refinery capacities for certain derivatives, etc.
- The maximum gross distribution margin: this covers all costs to bring the product from the refinery to the customer. This not only includes transport costs, but also storage costs, costs for distribution to the petrol stations or to the end-users, marketing costs, promotion costs,… The maximum gross distribution margin is fixed and does therefore not change when oil prices at the international markets vary.
- Levies and taxes, including the APETRA-fee (fee for the company that manages the strategic oil stocks of Belgium, and guarantees security of supply) and the BOFAS-fee (contribution to soil remediation in Belgium)

[13] Source: FOD Economie

- Excise duties: are fixed by government. The graph below illustrates that excise duties are high for transport fuels, especially gasoline (95 octane number) and to a lower extent also diesel. Fuels for heating purposes (cf. Huisbrandolie in the graph below), however very similar to diesel, have almost no excise duties.

**Figure 12: Evolution of excise duties**[14]




- VAT (Value Added Tax) equals 21% on any of the previous price components, including excise duty and other taxes and levies.

Current maximum prices (October 15th, 2015) for some transport fuels are presented in the table below. It can be noticed that excise duties are lower for diesel than for gasoline, and don't exist for liquefied petrol gas (LPG), neither for compressed natural gas (CNG).

**Table 5: Reference fuel prices in Belgium in 2015**[15]

| **Prices in €/liter** | Gasoline (95 octane number) | | | Diesel | | | LPG | | |
|---|---|---|---|---|---|---|---|---|---|
| Price ex-refinery | € | 0,3460 | *25,3%* | € | 0,3503 | *30,4%* | € | 0,2099 | *46,0%* |
| Gross distriution margin | € | 0,1586 | *11,6%* | € | 0,1621 | *14,1%* | € | 0,1670 | *36,6%* |
| Apetra | € | 0,0083 | *0,6%* | € | 0,0079 | *0,7%* | € | - | *0,0%* |
| Bofas | € | 0,0032 | *0,2%* | € | 0,0020 | *0,2%* | € | - | *0,0%* |
| Excise duty | € | 0,6152 | *44,9%* | € | 0,4288 | *37,3%* | € | - | *0,0%* |
| VAT | € | 0,2376 | *17,4%* | € | 0,1997 | *17,4%* | € | 0,0791 | *17,3%* |
| | **€** | **1,3689** | | **€** | **1,1508** | | **€** | **0,4560** | |

## 4.4. Hydrogen market

Worldwide, hydrogen is mostly (95%) generated onsite at the end user location, and only 5% is merchant hydrogen (free market). In Belgium, the situation is slightly different, due to Air Liquide's pipeline system for supplying hydrogen, oxygen, nitrogen and carbon monoxide in northern France, Belgium and the Netherlands. The pipeline subsystem has a  has a total length of more than 2.700 km, of which 964 km is dedicated to hydrogen (as of July 2006), being 187 km in the Netherlands, 613

[14] Source: Belgische Petroleum Federatie
[15] Data source: Belgische Petroleum Federatie

km in Belgium, and 164 km in France. Owned and operated by Air Liquide, it is the longest hydrogen pipeline network in the world. The diameter of most of the pipelines is primarily 100 millimetres; the working pressure is up to 100 bar.

**Figure 13: Air Liquide's pipeline infrastructure in Belgium, The Netherlands and North of France[16]**


The hydrogen market in Belgium was estimated to be 0,5 Mt (5,7 billion Nm³) per year in 2003[17], with the majority of the consumption located in Flanders, especially in the region of Antwerp, as is indicated in the table below.

**Table 6: Hydrogen consumption in Belgium in 2003[18]**

| Zone | Country | NUTS 1 | NUTS2 | bn $m^3$/year |
|---|---|---|---|---|
| | **Belgium** | Région Wallonne | Prov. Hainaut | 0.68 |
| | | | Prov. Liège | 0.37 |
| | | | Prov. Namur | 0.05 |
| | | *Total Région Wallonne* | | *1.10* |
| | | Vlaams Gewest | Antwerpen | 3.92 |
| | | | Prov. Limburg | 0.08 |
| | | | Prov. Oost-Vlaanderen | 0.59 |
| | | *Total Vlaams Gewest* | | *4.58* |
| | **Total Belgium** | | | **5.69** |

For reference: 3.200 electrolysers of 1 MW (200Nm³/h, operating time 8760 h per year) would be needed to produce the same yearly quantity of hydrogen.

Main hydrogen production sources are natural gas (via Steam Methane Reforming), petrochemicals (refining activity in the Port of Antwerp) and hydrogen as a by-product from large chlor-alkali electrolysis (Tessenderlo chemie).

[16] Source: Air Liquide
[17] Source: SRI CONSULTING, 2004
[18] Source: Industrial Excess Hydrogen Analysis, Roads2HyCom project

Considering an average selling price of hydrogen between 2 and 3 €/kg (mostly onsite production and pipeline delivery), this represents a market in Belgium of approximately 1 to 1.5 billion ($10^9$) euro.

It is very difficult to find detailed and specific information on hydrogen prices for industrial customers. To give an order of magnitude, hydrogen prices for various delivery modes are presented in the following table.

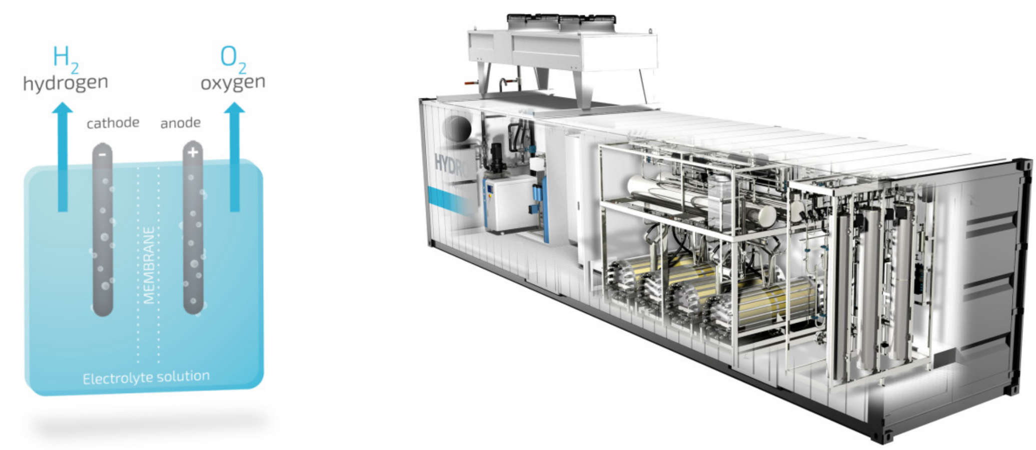
**Table 7: Hydrogen Prices by Delivery Mode**[19]

| Typical Hydrogen prices | Typical volume range in Nm³/h | Volume in Nm³/h | | | | | | | Unit |
|---|---|---|---|---|---|---|---|---|---|
| | | >100.000 | >10.000 | >1.000 | >100 | >10 | >1 | <1 | |
| Large Onsite SMR / Pipeline | 0 - 280.000 | 1,6 | 2 | 3,8 | | | | | USD/kg |
| New generation reformers | 10 - 10.000 | | 3,5 | 3,7 | 4,1 | | | | USD/kg |
| Bulk Liquid | 10 - 2.000 | | | 3,5 | 3,8-4,8 | 4,8-5,5 | | | USD/kg |
| Bulk gas | 10 - 200 | | | | 5,2-8,5 | 5,5-10,1 | 12,5 | | USD/kg |
| Cylinders | 0 - 100 | | | | 5,6 | 16 | 18 | 65 | USD/kg |

## 5. POWER-TO-GAS DEFINITION AND VARIOUS VALORISATION PATHWAYS

European energy policy has resulted in the increased integration of variable renewable energy sources. To keep the energy system in control, it needs to be balanced. Storing large quantities of renewable electricity in hydrogen (Power-to-Gas) is a solution. This is made possible by the electrolysis process, in which electrical energy is the main driving force for the dissociation of water ($H_2O$) molecules into hydrogen ($H_2$) and oxygen ($O_2$).

**Figure 14: Representation of the water electrolysis reaction and example of a 60Nm³/h electrolyser**

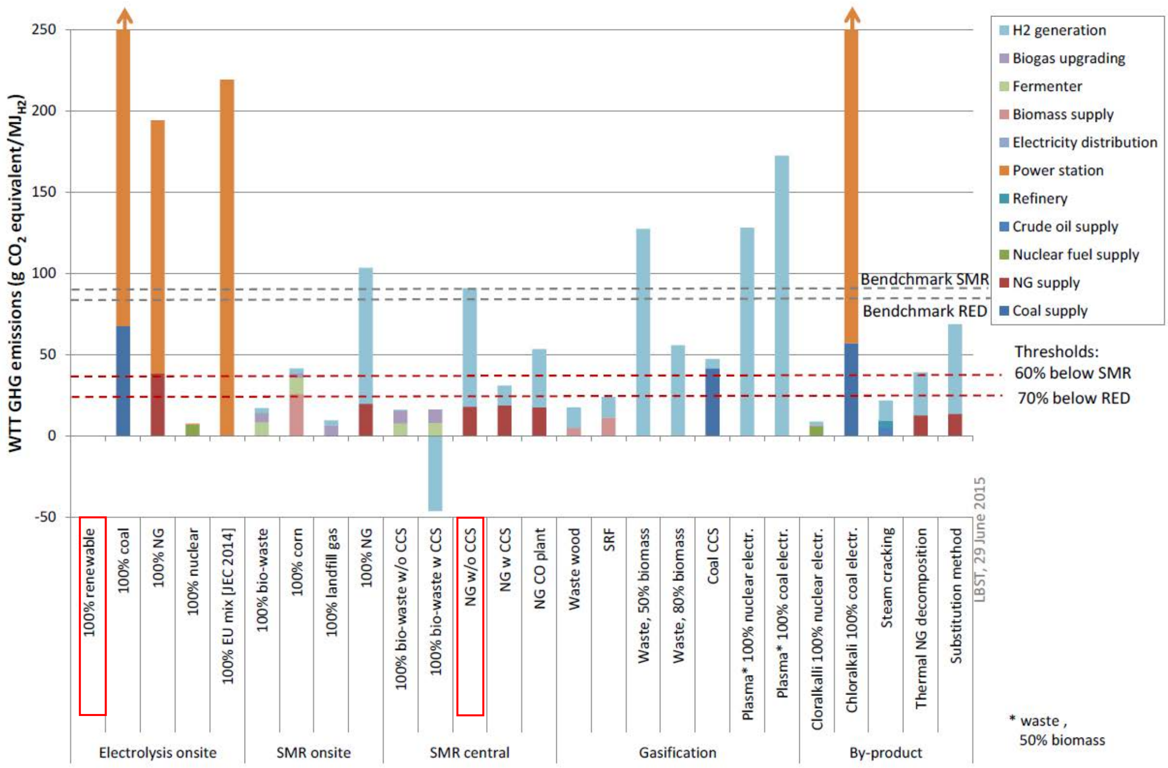



[19] Data source : Global Hydrogen – August 2014, Esprit Associates, Guy Keiths, Josef David, UK, 2014

## 5.1. Renewable Hydrogen

Related to the use of hydrogen as an energy carrier in the energy system, it is critical to distinguish different types of hydrogen, according to the associated GHG emissions in its production process and its renewable character. The EU CertifHy project has analysed this topic in depth and provides the information (see Figure 15) about GHG emissions for various production processes.

**Figure 15: GHG balance of selected hydrogen production pathways[20]**




The benchmark process is Steam Methane Reforming (SMR) without Carbon Capture and Storage (CCS) for which 91 g of $CO_2$ is emitted for each MJ of hydrogen. In comparison, hydrogen produced from an electrolyser powered by 100% renewable power has no GHG emissions associated to its production.

Discussions and terminology can start to be rather complex according to the energy mix and feedstock mix in the hydrogen production process. For the sake of simplification, **we have decided to use the terminology "Renewable Hydrogen" to refer to hydrogen produced from water electrolysis using 100% renewable power.**

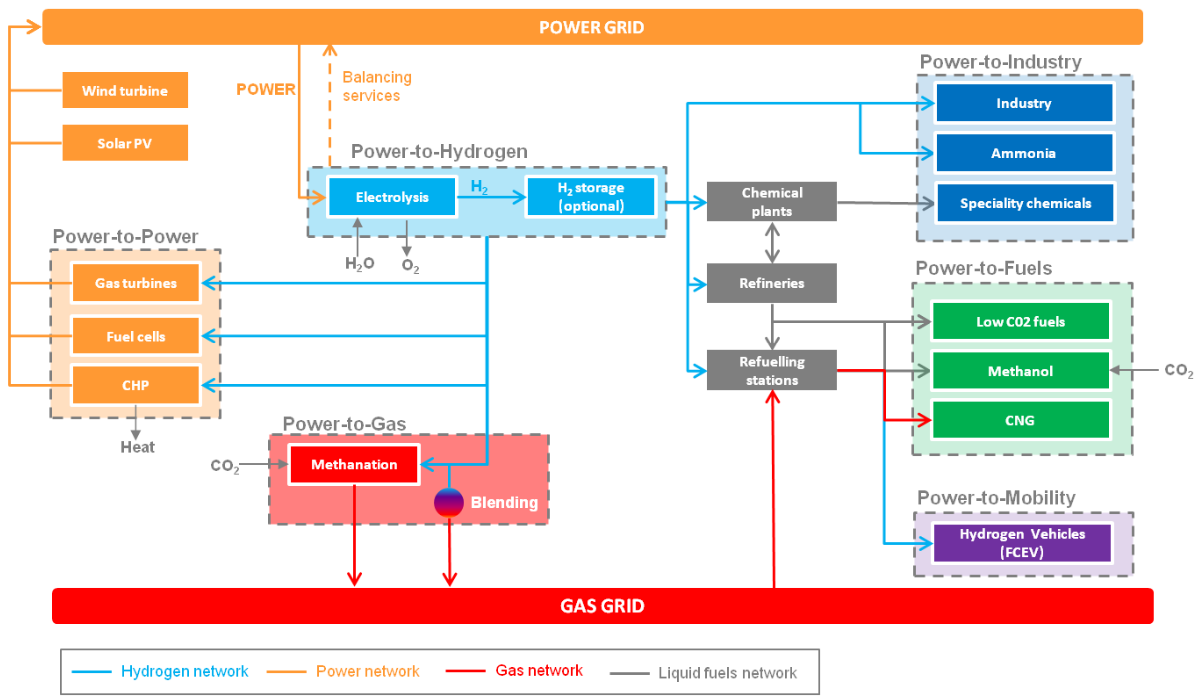
[20] Source: CertifHy, www.certifhy.eu, 2015

## 5.2. Power-to-Gas concept

Once it has been produced, Renewable Hydrogen can be used in different applications not only limited to the power sector:

- Power-to-Power (P2P): hydrogen can be used to produce electricity in a fuel cell or in a conventional gas turbine.
- Power-to-Gas (P2G): under certain conditions green hydrogen can be directly injected into the natural gas infrastructure, greening traditional natural gas applications (production of heat and hot water, production of electricity, mobility, feedstock for industrial processes, etc.). Hydrogen can also be converted into (green) methane by combining it with carbon dioxide ($CO_2$) captured from other industrial processes like the production of biogas.
- Power-to-Mobility (P2M): Hydrogen can be used in the mobility sector in hydrogen cars, buses, trucks, forklifts (Fuel Cell Electric Vehicles).
- Power-to-Fuels (P2F): Hydrogen can also be used in the mobility sector for the production of bio methanol (used as a blend with traditional fuels), biomethane (for CNG cars) and low carbon footprint fuels from the traditional refinery process.
- Power-to-Industry (P2I): hydrogen is an important industrial gas which can be used for the production of ammonia, in the petrochemical industry and/or the food industry. Green hydrogen can be used here as a way to decarbonise the chemical sector and make the best use of the renewable energy potential.

**Figure 16: Power-to-Gas valorisation pathways**



## 5.3. Selection of valorisation pathways for the Power-to-Gas roadmap in Flanders

Among all these valorisation pathways, the most relevant ones for Flanders are covered in this study.

**Table 8: Selected valorisation pathways for the Power-to-Gas Roadmap for Flanders**

| Case | Size electrolyser | Typical application | Reference product |
|---|---|---|---|
| **POWER-TO-INDUSTRY** | | | |
| **$PtH_{2\ (large)}$**: Power-to-Hydrogen (large scale) | 100 MW | $H_2$ as feedstock in large industry (Ammonia production or refinery) | $H_2$ produced with onsite SMR from $CH_4$ or $H_2$ delivered by pipeline |
| **$PtH_{2\ (small)}$**: Power-to-Hydrogen (small scale) | 1.2MW | $H_2$ as feedstock in small to medium size industry | $H_2$ delivered by tube trailers trucks |
| **POWER-TO-GAS** | | | |
| **$PtH_{2\ (blend)}$** : Power-to-Gas (direct injection) | 15 MW | Direct injection of hydrogen in gas grid | Natural gas from gas grid |
| **$PtCH_4$**: Power-to-Gas (methanation) | 15 MW | Transformation $H_2$ into SNG and injection in gas grid | Natural gas from gas grid |
| **POWER-TO-MOBILITY** | | | |
| **$PtFCEV_{(cars)}$**: Hydrogen Refuelling Station for cars | 500 kW | Hydrogen as a fuel for FCEV (cars) | Diesel |
| **$PtFCEV_{(buses)}$**: Hydrogen Refuelling Station for buses | 2.2 MW | Hydrogen as a fuel for FCEV (buses) | Diesel |
| **POWER-TO-FUELS** | | | |
| **$PtCH_3OH_{\ (fuel)}$**: Power-to-Methanol (as a fuel) | 50 MW | Partial substitution of diesel with bio-methanol produced from $H_2$ and $CO_2$ in a methanolisation process. | Diesel |
| **POWER-TO-POWER** | | | |
| **$PtP_{\ (small)}$**: Power-to-Power (small scale) | 500 kW | Hydrogen-based electrical energy storage in medium-sized industry with own renewable energy production (*prosumer*) | Power from the grid |
| **$PtP_{\ (large)}$**: Power-to-Power (large scale) | 400 MW | Hydrogen-based electrical energy storage (at utility scale) | Power from the grid |

# 6. POWER-TO-GAS BUSINESS MODEL

## 6.1. Structure of the business model

Based on assumptions (see below), a business case has been calculated for the different valorisation paths.

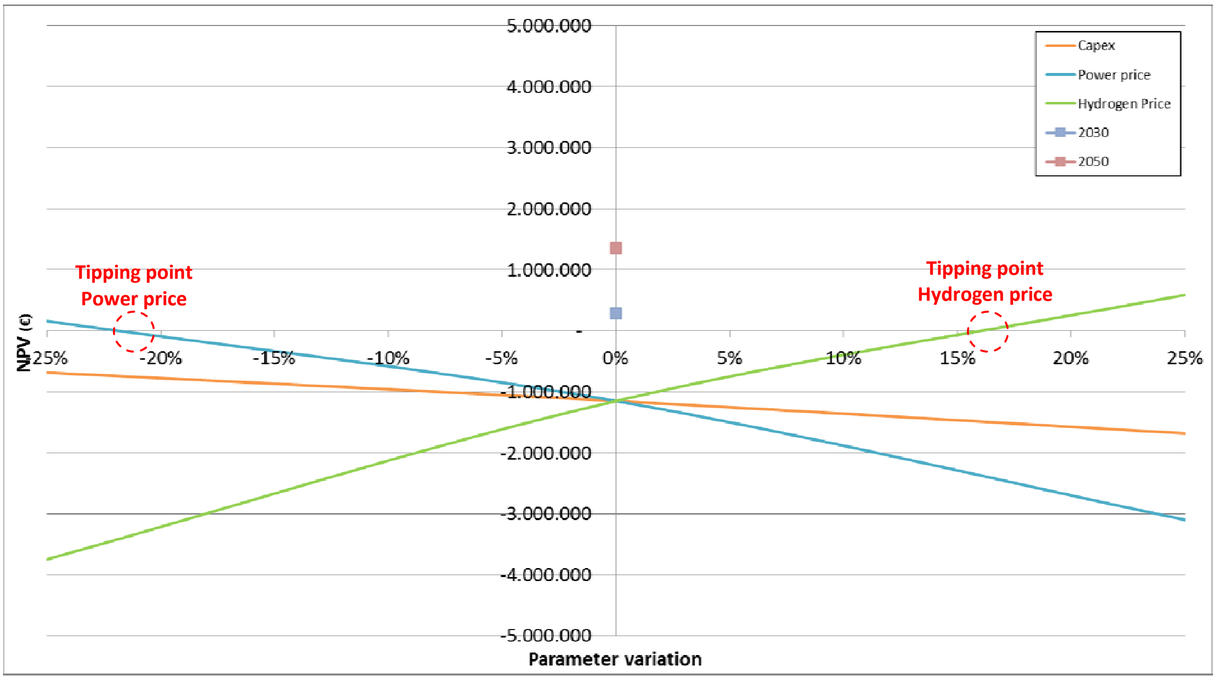
The same base case scenario has been applied in which:

- NPV and IRR are calculated post tax and pre-financing over a 20 years period, using a discount rate of 8% for NPV calculations.
- A taxation rate (for corporate taxes) of 33.99% and a linear depreciation over 20 years is assumed.

In the base case scenario, only the end-product revenue has been considered. Potential additional revenues such as avoided cost for $CO_2$ emission allowances, sales of oxygen, recovery of heat and provision of ancillary services have not been included, neither the societal benefits (non-monetized $CO_2$, air quality benefit).

On the base case scenario, being full load operation, a sensitivity analysis is done for the main cost (or revenue) drivers. Results of the sensitivity analysis are visualised in graphs like the one shown below (for the small scale industry case in 2015), indicating the NPV (in €) as a function of parameter variations (in %). The intersection points of the curves mark the base case for the given year (intersection points are also shown for 2030 and 2050). The slope of the curves show the impact of the given parameter: the steeper the curve, the stronger the influence on the profitability. Intersections of the curves with the horizontal axis show the tipping points, i.e. the values of a certain parameter at which the business case turns profitable.

**Figure 17: Tipping points graphs (example: small scale industry case in 2015 – full load)**



**How to read these graphs?**

Power price: to reach a profitable business case (NPV>0), the power price needs to decrease by a factor 23% in comparison to the base case assumptions. All other assumptions remain unchanged.

Hydrogen price: to reach a profitable business case (NPV>0), the hydrogen selling price needs to increase by a factor 16% in comparison to the base case assumptions. All other assumptions remain unchanged.

Though similar graphs were drawn for each valorisation path, and for 2015, 2030 and 2050, the graphs are not presented in this report. Instead, for each valorisation path the calculated tipping points are shown in a table like the one following. The actual values and expected values represent the base case scenario assumptions. The requirement columns represent the tipping points at which the base case scenario turns to profitability (NPV>0) by changing this specific parameter.

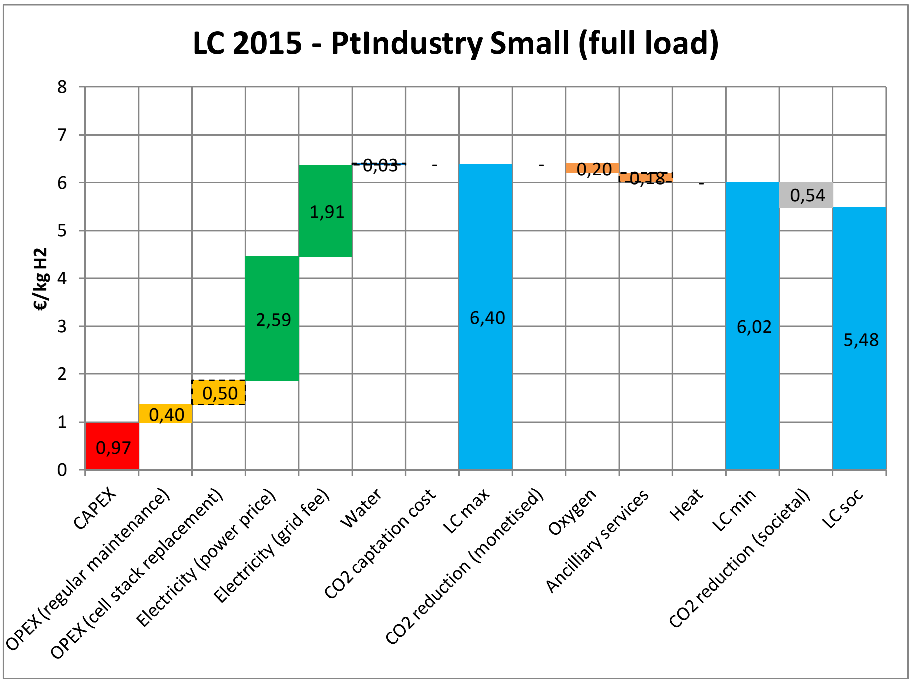
**Table 9: Tipping points table (example: small scale industry case in 2015 – full load)**

| | 2015 | | 2030 | | 2050 | |
|---|---|---|---|---|---|---|
| | Requirement | Actual value | Requirement | Expected value | Requirement | Expected value |
| Power price (all-in) | < 60,8 €/MWh | 77,82 €/MWh | < 88,4 €/MWh | 84,16 €/MWh | < 116,2 €/MWh | 95,76 €/MWh |
| Avoided purchasing cost of hydrogen | > 6,99 €/kg | 6,00 €/kg | > 6,47 €/kg | 6,71 €/kg | > 6,46 €/kg | 7,60 €/kg |
| CAPEX | < 0,77 M€ | 2,13 M€ | < 1,87 M€ | 1,53 M€ | < 2,62 M€ | 1,00 M€ |

Furthermore, a pre-tax levelized cost of the end-product is calculated, using a WACC of 5% over a 20 years period. Composition of the levelized cost also provides information on major cost drivers. Next to the base case levelized cost (also called 'LCmax'), a levelized cost including the additional revenues (monetized $CO_2$ revenues from EU ETS scheme, oxygen, heat valorisation and ancillary service) is calculated ('LCmin'). Finally, also the avoided societal cost of $CO_2$-emissions (non monetized part) is taken into account, leading to a levelized cost including additional benefits as well as the avoided societal costs, called 'LCsoc'.

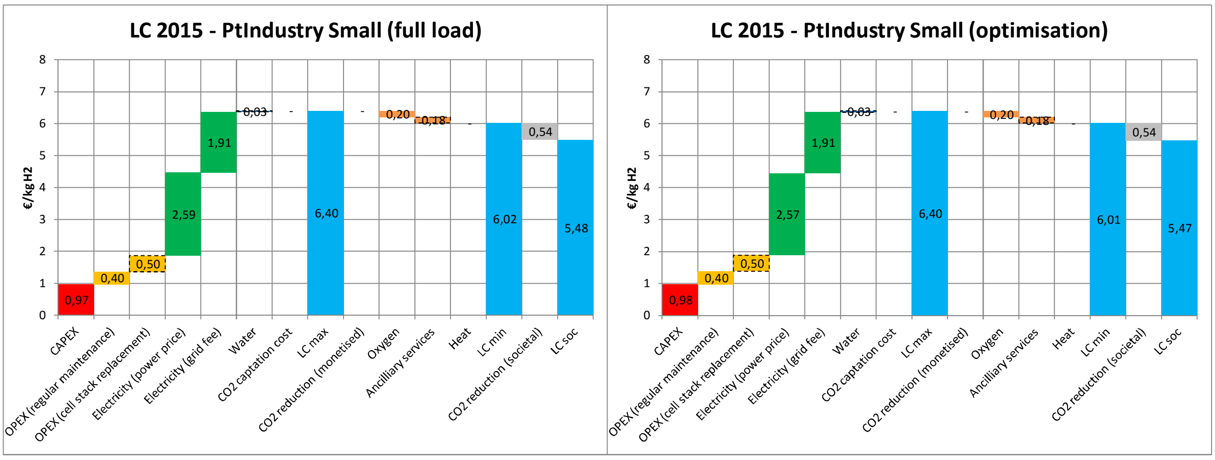
So-called 'waterfall-graphs' show the main composition of the levelized cost of the end product and visualise also LCmax, LCmin and LCsoc. These graphs also show to which extent costs and revenues contribute to the levelized cost of the end-product, and can therefore also give an indication of the sensitivity. An example of such a waterfall graph is shown below (for the small scale industry case in 2015).

**Figure 18: Waterfall graph (example: small scale industry case in 2015 – full load)**




As electricity prices are not constant over the year, it might be beneficial to run the electrolyser only during a given number of hours with the lowest prices (optimisation), instead of 8497 operating hours a year (full load) as assumed in previous paragraphs. Therefore, the optimal number of operating hours was calculated and a waterfall graph was drawn for this optimized number of operating hours.

**Figure 19: Waterfall graph (example: small scale industry case in 2050 – full load vs. optimisation)**




## 6.2. Building blocks and assumptions for 2015, 2030 and 2050

### *6.2.1. Electrolyser*

For the electrolyser, pressurized alkaline and PEM technologies have been considered. Most of the assumptions for the electrolyser technology were taken directly from Hydrogenics and from the literature. The main characteristics of the various building blocks for the electrolysers are described in the annexes (see Annex 6: General assumptions for business cases). Even if there are some small differences between alkaline and PEM technologies (output pressure, cold start time, lower operating limit, overload regime capability) which is favourable for the PEM, the main difference between the 2 technologies relies mainly on its expected development cost between 2015 and 2050.

Until 2030, the main evolutions expected for the alkaline technology are an increased size of the cell stack (from 1000 cm² to 2500 cm²) and an increased output pressure (from 10 to 60 bars). On the system cost, a significant cost decrease is expected from 2.000 €/kW to 1.200 €/kW, with a typical system size going from 300 kW to 1.5 MW. For the PEM technology, no real technology evolution is expected between 2015 and 2030 but rather a validation of the good performance (and behaviour) of PEM electrolyser, combined with a significant cost reduction due to supposed market uptake.

From 2030 to 2050, a further 45 % cost improvement for all technologies has been considered. This cost reduction is not related to real technology improvement, but rather to a supply chain improvement (industry consolidation, becoming its own supplier), a decreasing margin and a reduction of the overhead costs.

**Table 10: Overview of main electrolyser assumptions**

| | Unit | 2015 | 2030 | 2050 |
|---|---|---|---|---|
| Typical pressure | bar | 10-30 | 30-60 | 30-60 |
| Capex | €/kW | 1.000-2.000 | 700-1200 | 385-660 |
| Opex[21] | €/kW/year | 40-80 | 32-64 | 28-56 |
| System efficiency | kWh/Nm³ $H_2$ | 5,0-5,2 | 4,9-5,1 | 4,8-5,0 |
| Cell stack lifetime | hours | 40.000 | 50.000 | 60.000 |

In the Annex 6, more detailed assumptions for the electrolyser are presented, distinguishing a small scale alkaline, a MW scale PEM and a multi MW scale electrolyser.

These assumptions are in line with the study "Development of Water Electrolysis in the European Union" (Bertuccioli, et al., February 2014).

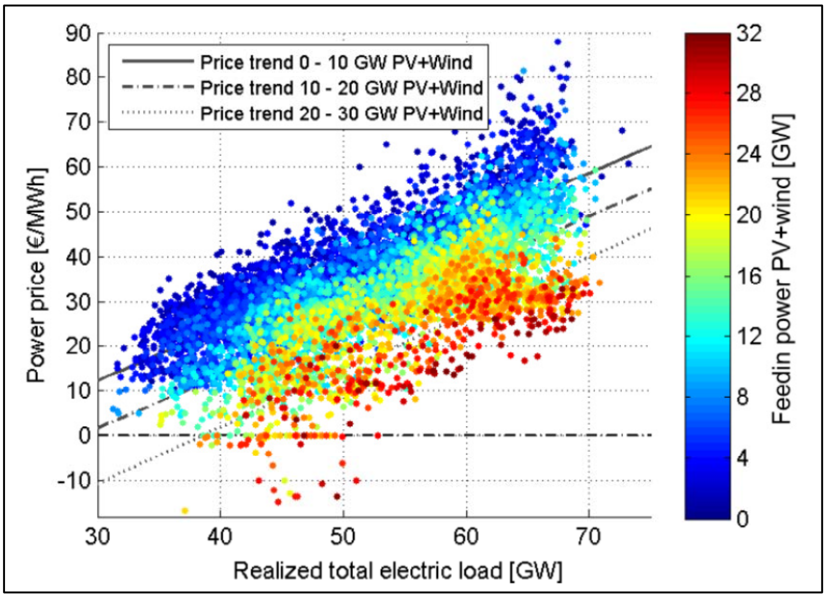
### 6.2.2. Power prices (price curve duration)

This section briefly explains how future electricity prices in Belgium were calculated. For more detailed information we refer to Annex 9 .

Intermittent renewable power has an impact on power prices (cannibalisation effect). To assess this impact, correlations should be made between power prices from traditional sources and power production from PV and wind. Below, an example is given for (a part of) Germany over the year 2014, showing the time-based correlation between EPEX spot market prices and the joint PV and wind energy feed in. It is clear that prices are higher when demand is higher, but also when the generated amounts of electricity out of PV and wind are lower (and vice versa). The trend lines for increasing amounts of electricity out of PV and wind are almost parallel, which illustrates the strong correlation between power prices and intermittent renewable energy production.

[21] 1/3 of the Opex was assumed to be fixed. 2/3 was assumed to be proportional to the number of operating hours per year (wear and spare parts)

**Figure 20: Correlation between power price, electric load and RES (wind + solar) feed-in power in Germany[22]**




In order to calculate actual prices and price duration curves for 2030 and 2050, not only the assumptions mentioned in Table 11 for the installed capacities of intermittent renewable energy in Belgium and the total power demand in Belgium need to be used, but also a reference point for the power price has to be given. This reference is the levelized cost of electricity in a (theoretical) situation when electricity demand is at its maximum and intermittent renewable energy generation is at zero. It is assumed that gas-fired power plants will be the reference technology for power generation in such a situation, at least for Belgium.

This levelized cost of electricity for gas fired power plants in Belgium is calculated based on techno-economic assumptions (investment cost, O&M cost, lifetime, efficiency,…) from VGB Powertech[23] and market assumptions (natural gas price, $CO_2$ emission allowance cost, annual operating hours,…) from Fraunhofer ISE[24]. For the market assumptions, low, mid and high scenarios are presented for 2030 and 2050, using the natural gas price assumptions described in section 6.2.5 (Other commodity prices) for 2030 and 2050. The table below shows the results of these calculations and also summarises the assumptions.

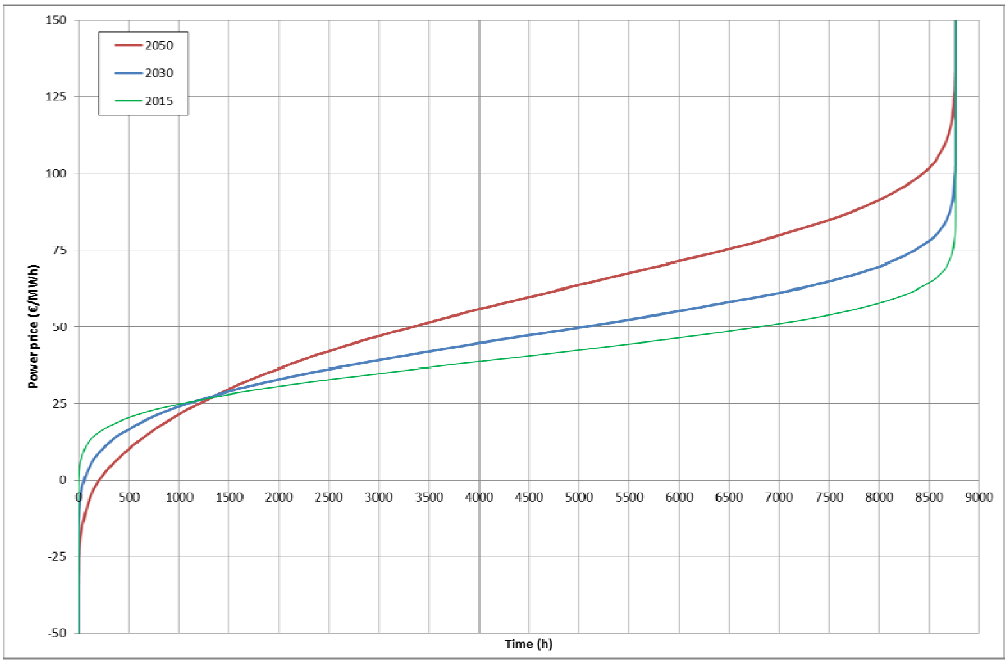
**Table 11: Main assumptions and results for future power prices in Belgium in 2030 and 2050**

| | 2015 | 2030 | | | 2050 | | |
|---|---|---|---|---|---|---|---|
| | | low | mid | high | low | mid | high |
| Total annual electricity consumption (TWh) | 88,3 | | 90,8 | | | 121,4 | |
| Minimum load (MW) | 6848 | | 7140 | | | 10627 | |
| Maximum load (MW) | 13821 | | 14113 | | | 17600 | |
| Average load (MW) | 10076 | | 10368 | | | 13854 | |
| On shore wind installed capacity (MW) | 1123 | | 4678 | | | 7213 | |
| Off shore wind installed capacity (MW) | 712 | | 3522 | | | 7687 | |
| PV sun installed capacity (MW) | 2818 | | 4800 | | | 10000 | |
| Levelised cost of electricity generation (€/MWh) | 71 | 83 | 95 | 110 | 113 | 129 | 147 |

[22] Source: EPEX
[23] (VGB PowerTech e.V., 2015)
[24] (Kost, et al., November 2013)

Using these assumptions, the price duration curves shown in the graph below can be generated.

**Figure 21: Estimated power price duration curve for Belgium in 2030 and 2050.**




As shown in the curves, the average electricity prices in Belgium tend to go up in the near future. On the other hand, the number of hours with (very) low prices also increases. The table below gives some numbers illustrating these trends.

**Table 12: Estimated future power prices in Belgium in 2030 and 2050.**

| Estimated future power prices in Belgium (€/MWh) | 2015 | 2030 | | | 2050 | | |
|---|---|---|---|---|---|---|---|
| | | low | mid | high | low | mid | high |
| Baseload power price (8760h/year) (€/Mwh) | 41 | 38 | 46 | 56 | 47 | 57 | 68 |
| Partload power price (6570h/year) (€/Mwh) | 35 | 31 | 39 | 48 | 37 | 46 | 57 |
| Partload power price (4380h/year) (€/Mwh) | 30 | 25 | 32 | 41 | 27 | 35 | 45 |

The table shows that for baseload power an increase is expected from 41 €/MWh in 2015 to 46 €/MWh in 2030 and 57 €/MWh in 2050 (MID-scenario). For half load, if the 4380 hours with lowest price can be considered, the increase is less significant (30 € in 2015, 32 € in 2030 and 35 € in 2050).

When interpreting the results, it should be taken into account that the calculation model does not include the future construction of large scale storage infrastructure, such a pumped hydro plant. However, it is found that the slope of the price duration curve is rather moderate in 2015, but gets steeper and steeper in 2030 and 2050. Steeper slopes indicate that there is a growing market, or even demand, for (large scale) storage facilities of electricity. In this respect, Power-to-Gas can certainly play its role.

However, it should be mentioned than energy storage technologies will impact the shape of the price duration curve (reduce the number of low and high price hours), making it less attractive for energy storage applications.

### *6.2.3. Ancillary services*

Ancillary services enable TSO Elia to maintain frequency and voltage at appropriate levels while managing balance and congestion in three different ways:

- Primary reserve (R1): Some production units can automatically detect frequency fluctuations (using frequency measurement and controller) and, where necessary, adjust production (up or down) automatically within 30 seconds. Primary reserve is delivered up to 15 minutes after the incident, after which the unit should immediately be ready to compensate a new incident. Only larger units (granularity: 1 MW) connected to grids with voltages above 36kV can apply for primary reserve.
- Secondary reserve (R2): The secondary reserve is automatically and continually activated both upstream and downstream (upward/downward regulation). It kicks in quickly (between 30 seconds and 15 minutes) and remains active as long as it is needed. Grid users that provide secondary reserve must have the appropriate facilities for communicating in real time with Elia's national control centre, and their production units must comply with certain technical requirements. Besides, only larger units (granularity: 1 MW) connected to grids with voltages above 36kV can apply.
- Tertiary reserve (R3): The tertiary reserve enables Elia to cope with a significant or systematic imbalance in the control area and/or resolve major congestion problems. The tertiary reserve has two components:
  - the tertiary production reserve: injection of extra capacity by producers who have signed a contract for tertiary reserve;
  - the tertiary off-take reserve: reduction in off-take by grid users who have signed an interruptible contract.

  Unlike the primary and secondary reserves, the tertiary reserve is activated manually at Elia's request. Reaction time is 15 minutes. Any grid user whose facilities comply with certain technical requirements can sign a contract with Elia to take part in the tertiary reserve. Also distribution grid users can apply for a sort of tertiary reserve (R3DP)

As Elia pays compensations for reservation of reserve capacity, and sometimes also for activation of it, this gives some opportunities for Power-to-Gas units, e.g. by adjusting the power off take (up or down) of a running electrolyser, or by stopping it upon request.

**Table 13: Overview of relevant ancillary services markets for Power-to-Gas applications**

| Type | Name | Connection required | Direction | Symetry | Reaction time | Duration | Reservation | Average price in 2015 (€/MW/h) | Activation fee | Type of activation | Via aggregators |
|---|---|---|---|---|---|---|---|---|---|---|---|
| R1 | Primary reserve | ELIA >36 kV | UP and DOWN | Symetrical | 15 sec | 15 min | Monthly auction | 28,37 | no | Automatic | no |
| R2 | Secondary reserve | ELIA | UP of DOWN | Asymetrical | 7,5 min | unlimited | Monthly auction | 10,6 | yes | Automatic | no |
| R3DP | Tertiary reserve - Dynamic profile | ELIA Distribution grid | UP | Asymetrical | 15 min | 2 hours | Annual | 3,07 | | Manual | yes |

For primary reserve, the average compensation in 2015 was 28,37 €/MW/h (symmetrical) and is determined by monthly auctions. For secondary reserve, the average compensation in 2015 was 10,6 €/MW/h (UP or DOWN). However, in both, penalties apply when the reserve is not permanently available. For R3DP, the compensation in 2015 was 3,07 €/MWh for maximally 40 activations of maximally 2 hours (yearly tender). Again, permanent availability is required, but it doesn't have to be availability on a unit basis: aggregation of more units is possible to reach the offered reserve capacity.

TSO Elia publishes regularly on its website information about ancillary market in Belgium, including the required volumes of each type of service (see Table 14), the structure of the remuneration scheme and the result of past auctions.

**Table 14: Required total volumes of ancillary markets in Belgium in 2015**[25]

| | Required total volumes for year 2015 [MW] |
|---|---|
| Primary Frequency Control (0s - 30s)<br>*R1 – symmetrical – 200mHz* | 83 MW |
| Secondary Frequency Control (30s – 15min)<br>*R2 – symmetrical* | 140 MW |
| Tertiary Frequency Control (15min)<br>*R3 production (PROD) + dynamic profile (DP)* | 400 MW |
| Tertiary Frequency Control<br>*From interruptible clients (ICH)* | 261 MW |

As a conclusion, possibilities for Power-to-Gas plants to generate extra revenues from ancillary services are rather limited. Only very big plants connected to high voltage grids and running continuously can offer part of their capacity for secondary reserve. For most Power-to-Gas plants, R3 (or R3DP) will therefore be the only option.

Ancillary services market might evolve drastically in the future with increasing amounts of RES delivering power to the grid. As there is no good basis to assume future prices for the ancillary services market in 2030 and 2050, we assumed future prices would remain equal to the ones in 2015.

For ancillary services, (large) projects connected to Elia grid are assumed to qualify for secondary reserve (R2), with a revenue of 10,6 €/kW/hour, on 80%[26] of the total capacity of the electrolyser, and smaller units connected to distribution grid are assumed to be in R3DP, with a revenue of 3,07 €/kW/hour, on the full capacity of the electrolyser.

It should be noted that seeing the ancillary market is an auctioning system, revenues are not guaranteed.

### *6.2.4. $CO_2$ prices*

Projections for future market prices for $CO_2$ emission allowances under EU ETS were made by Fraunhofer ISE[27] in their study 'Levelized Cost of Electricity – Renewable Energy Technologies'. For 2030 and 2050, a low, mid and high scenario is included in the study. The table below gives an overview of the $CO_2$ emission allowances prices used in this study.

**Table 15: $CO_2$ emission allowance cost assumption 2015-2030-2050**

| | 2015 | 2030 | | | 2050 | | |
|---|---|---|---|---|---|---|---|
| | | low | mid | high | low | mid | high |
| CO2 emission allowances cost (€/ton) | 5 | 28 | 35 | 42 | 40 | 47,5 | 55 |

[25] Source: ELIA

[26] We assumed that at least 80% of the electrolysis plant capacity could be available any time (considering maintenance requirements and unexpected outages).

[27] Source: (Kost, et al., November 2013)

The $CO_2$ total societal cost is assumed to be 80 €/ton in 2015, increasing to 145 €/ton in 2030 and 260 €/ton in 2050.

**Table 16: Total cost of $CO_2$ for society[28]**

| | Klimakosten in $EUR_{2010}$ / t $CO_2$ | | |
|---|---|---|---|
| | Kurzfristig 2010 | Mittelfristig 2030 | Langfristig 2050 |
| Unterer Wert | 40 | 70 | 130 |
| Mittlerer Wert | 80 | 145 | 260 |
| Oberer Wert | 120 | 215 | 390 |

### *6.2.5. Other commodity prices*

In this study, natural gas price projections from (Kost, et al., November 2013) has been used, in which the authors expected that market prices for natural gas will rise in the future, due to an increased scarcity of resources. For 2030, a low, mid and high scenario is included. For 2050, only one scenario is given, which we decided to use here as the mid case. The low and high cases are derived from the mid case by respectively reducing or adding 10% to mid case's results. The table below gives an overview of the natural gas prices used in this study.

**Table 17: Estimated future gas prices in Belgium in 2030 and 2050**

| | 2015 | 2030 | | | 2050 | | |
|---|---|---|---|---|---|---|---|
| | | low | mid | high | low | mid | high |
| Natural gas price (€/MWh LHV) | 25,0 | 28,7 | 32,5 | 36,3 | 42,3 | 47,0 | 51,7 |
| Natural gas price (€/MWh HHV) | 22,6 | 25,9 | 29,3 | 32,8 | 38,2 | 42,4 | 46,7 |

We should mention that at the beginning of this project (October 2014), natural gas price were in the range of 25 €/MWh. At the end of the project (January 2016), natural gas prices had dropped to +/- 12 €/MWh. Forecast of natural gas prices is complex and risky. In lack of a better reference, we decided to keep the original assumptions from (Kost, et al., November 2013) which should reflect the long-term price development of natural gas prices. This choice is obviously debatable.

For this study, it is assumed that the energy component (price ex-refinery) will have a similar increase as the commodity price for natural gas, that excise duty for diesel will be increased to the same amount as for gasoline, that excise duties will rise by 5% in 2030 and 10% in 2050 (all compared to 2015, and on top of the increase for diesel), and that all other price components will increase by 1% per year.  This leads to the prices in the table below.

**Table 18: Estimated future diesel prices in Belgium in 2030 and 2050**

| In €/l | 2015 | 2030 | 2050 |
|---|---|---|---|
| Diesel (incl. VAT) | 1,15 € | 1,57 € | 1,90 € |
| Diesel (excl. VAT) | 0,95 € | 1,30 € | 1,57 € |

For all calculations further in this study, all prices are considered excluding VAT. For buses, a 10% price discount will be taken into account due to the large consumption.

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28 Source: Umweltbundesamt (UBA), Schätzung der umweltkosten In den bereichen energie Und verkehr, 2012

For further use in this study, the prices for hydrogen presented in the table below are taken as a reference. As steam methane reforming is considered to be the price determining technology, price are expected to raise in the forthcoming years due to increased natural gas prices and CO2 emission allowances prices.

**Table 19: Estimated future hydrogen prices in Belgium in 2030 and 2050**

| *H2-price (€/kg)* | 2015 | 2030 | 2050 |
|---|---|---|---|
| **for on site SMR** | 2,05 | 2,72 | 3,59 |
| **for tube trailer delivery** | 6,00 | 6,71 | 7,60 |

The value of recovered heat is based on the natural gas price and a boiler efficiency of 90% on LHV.

Other assumptions for commodity prices are:

- Oxygen: 24,5 €/ton
- Demineralised water: 2,3 €/m³

#### *6.2.6. Other equipment*

For investment costs, operation and maintenance costs, efficiencies and other techno-economic assumptions of compression and storage equipment, methanation equipment, methanolisation equipment, hydrogen refuelling stations, fuel cells, gas cleaning and injection equipment reference is made to Annex 6: General assumptions for business cases.

### 6.3. Analysis of business cases

#### *6.3.1. Case 1: Power-to-Industry: hydrogen for industrial use (small scale)*

**Description**

For this case, we typically look at chemical or other process industry sites, with an annual hydrogen demand of a 2 million Nm³. This demand does not justify investment in a large scale steam reforming plant to generate hydrogen out of methane. Instead, hydrogen is bought externally and delivered by tube trailer. The hydrogen is used directly and continuously in the chemical or industrial processes (e.g. production of hydrogen bromide…)

Potential sites can be found in industrial areas with some chemical companies, which are not connected to a hydrogen pipeline, such as the port of Ghent, port of Terneuzen…

**Case specific assumptions**

For the calculation, following specific assumptions are made:

- Electrical power input of the electrolyser: 1.200 kW
- Annual operating hours of the electrolyser: 8497 (baseload operation @ 97% availability)
- Annual hydrogen demand: +/- 2.000.000 Nm³ at low pressure (20 bar)
- Type of electrolyser: small scale PEM
- Storage: CAPEX is considered for storage for at least 2 days of consumption, at medium pressure (200 bar). Neither compression costs nor OPEX are considered for this storage (as it is assumed that this storage is a tube trailer or similar, which will be exchanged and refilled externally when empty)
- No compression

- Civil works cost: 50.000 €
- Connection cost to the public power grid: 50.000 € (limited, as connection of the industrial plant already exists)
- Power price: according to price duration curves (mid scenario for 2030 and 2050) for Belgium as mentioned before (commodity) + 10% (supplier's margin) + 33,04 €/MWh (grid costs taxes and levies, as calculated for a 36 kV connected customer, with an annual off-take of 50 GWh, or approximately 5 times the consumption of the electrolyser)
- Avoided hydrogen purchasing cost (tube trailer delivery): 6.00 €/kg in 2015, 6.71 €/kg in 2030 and 7.60 €/kg in 2050
- The avoided emission of $CO_2$ amounts 1313 ton per year. This equals the emission of both a SMR-installation with a natural gas fired steam boiler with 90% efficiency and the transport of the hydrogen by means of tube trailers. The amount of $CO_2$ emitted by the electrolysis process is set at 0, as it is assumed that electricity coming from renewable energy sources is used as an input of the electrolyser. Per kilogram of generated hydrogen, the avoided emission of $CO_2$ equals 7,35 kg.

**Economic feasibility**

The considered pathway is close to be profitable at this moment. Although the operational result is (slightly) positive (EBITDA equals 100 k€), the NPV turns negative (-1.150 k€). The IRR equals -0,6% and the ratio of the NPV over the total CAPEX is -0,54.

For 2030 and 2050, this pathway shows positive results. In 2030, a NPV of 279 k€ and an IRR of 10,4% are expected. For 2050, this is 1,354 million euro and 23,7% respectively. Main changes between 2015 and 2050 are the CAPEX decrease (mainly on the electrolyser, but also on the storage), the OPEX decrease and the increase of the avoided purchasing cost for hydrogen. The variation of these parameters largely compensates the negative effect of increased power prices.

Power price, avoided purchasing cost of hydrogen and CAPEX are identified as the parameters with most impact on the economics. The table below summarises the tipping points (i.e. the values of these parameters that turn the business case positive) and compares them to the actual or expected values.

**Table 20: Tipping points (Power-to-Industry - small scale – full load)**

| | 2015 | | 2030 | | 2050 | |
|---|---|---|---|---|---|---|
| | Requirement | Actual value | Requirement | Expected value | Requirement | Expected value |
| Power price (all-in) | < 60,8 €/MWh | 77,82 €/MWh | < 88,4 €/MWh | 84,16 €/MWh | < 116,2 €/MWh | 95,76 €/MWh |
| Avoided purchasing cost of hydrogen | > 6,99 €/kg | 6,00 €/kg | > 6,47 €/kg | 6,71 €/kg | > 6,46 €/kg | 7,60 €/kg |
| CAPEX | < 0,77 M€ | 2,13 M€ | < 1,87 M€ | 1,53 M€ | < 2,62 M€ | 1,00 M€ |

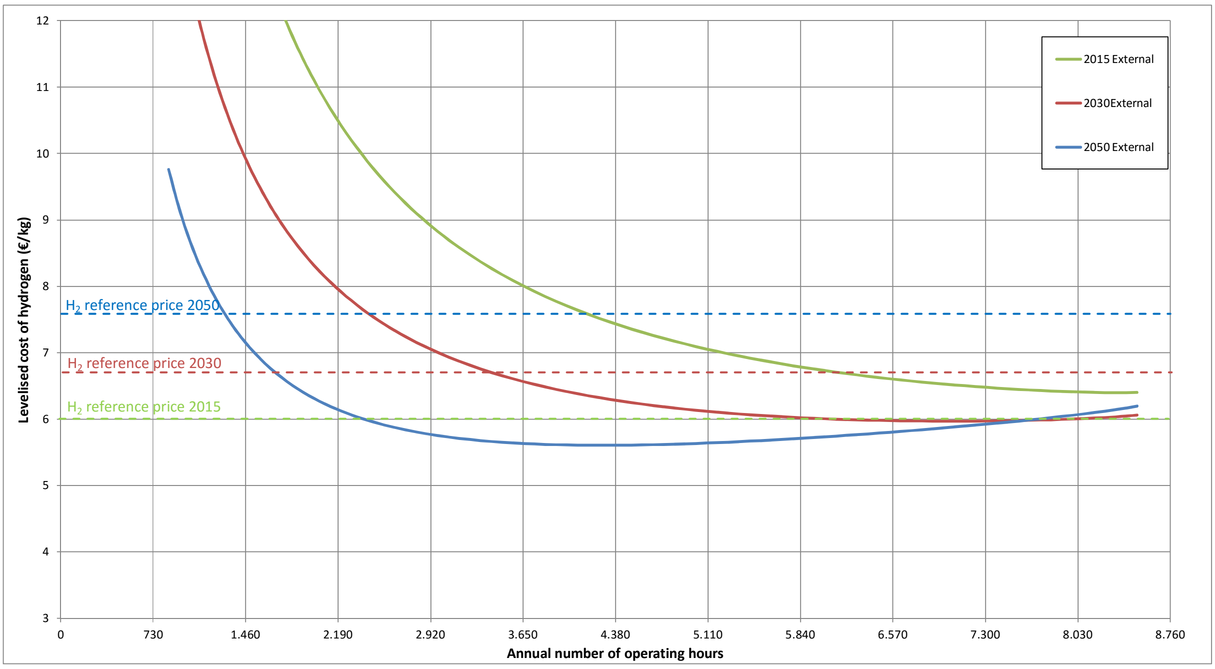
In 2015, only minor changes to power price (<60,8 €/MWh) or avoided purchasing cost of hydrogen (>6,99 €/kg $H_2$) are needed to turn the business case profitable. In 2030 and 2050, the business is clearly profitable with the expected value for power price and hydrogen cost.

**Optimisation of the operating hours**

As electricity prices are not constant over the year, it might be beneficial to run the electrolyser only during a given number of hours with the lowest prices (optimisation), instead of 8497 operating hours a year (full load) as assumed in previous paragraphs. In practice, the power price will mainly determine whether the electrolyser will be running at a given moment or not, as it makes no sense to run the electrolyser if the marginal cost to run an additional hour is higher than the marginal revenues.

To determine the optimal number of operating hours, the levelized cost of hydrogen can be calculated as a function of the number of operating hours, as is shown in the graph below.

**Figure 22: Levelized cost (LCmax) of hydrogen vs operating time (Power-to-Industry - small scale)**




For 2015, the levelized cost of hydrogen still increases as the number of operating hours decreases. As from 2030, on the other hand, an optimum can be reached at a lower number of operating hours, equalling approximately 7050 hours in 2030 and approximately 4250 hours in 2050. In this case, the lower electricity price largely compensates the lower utilisation rate. Optimisation of the operating hours therefore has the most significant impact in 2050.

**Sensitivity analysis**

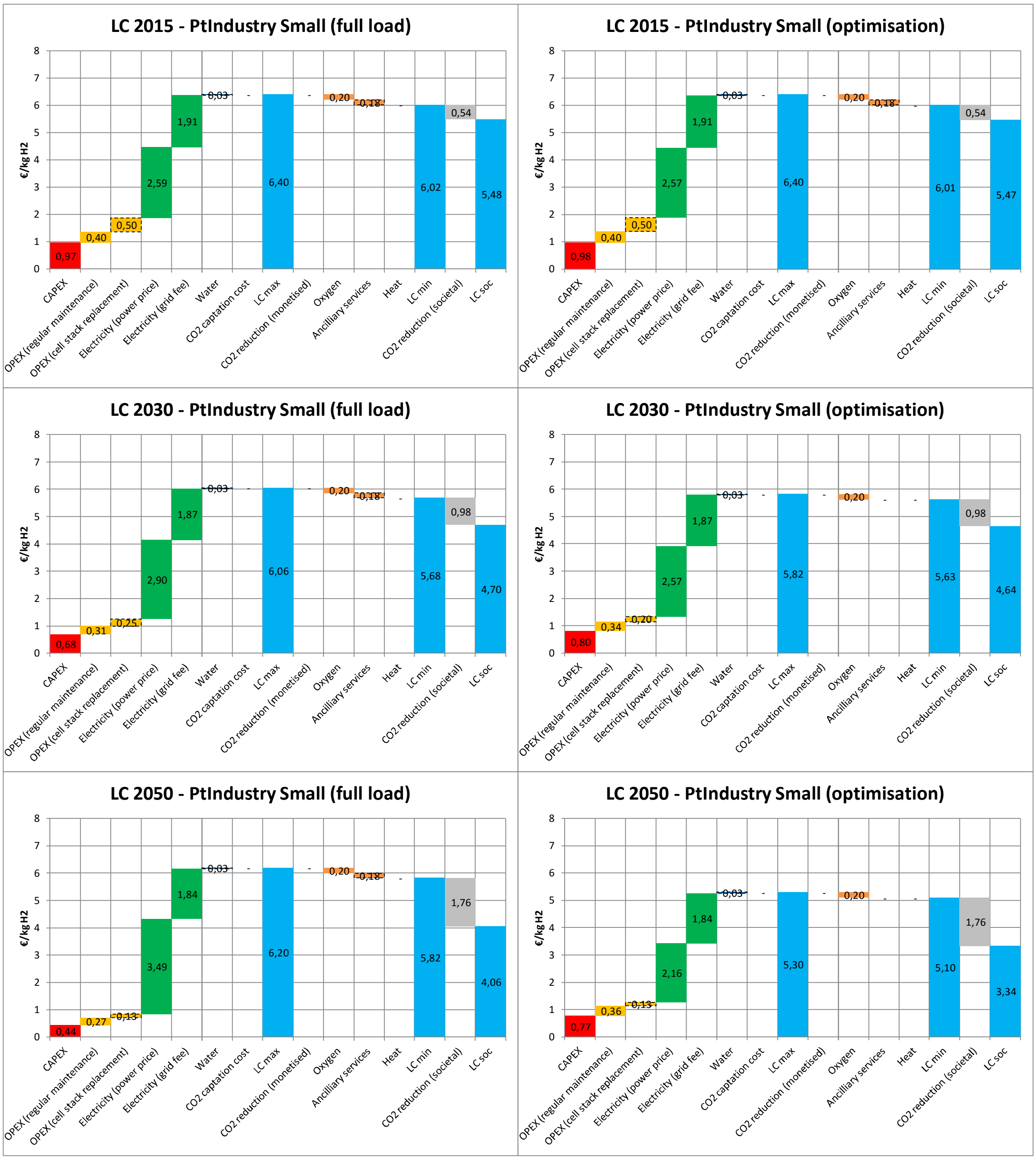
To indicate the impact of some other parameters, Figure 23 below show how the levelized cost of hydrogen is composed and evolves over time (2015, 2030, 2050). On the left hand side of the figure, the graphs for full load operation (8497 hours per year) are shown, whereas on the right hand side the graphs for the optimised number of operating hours, as mentioned above are shown.

On the cost side, electricity cost is by far the biggest part of the levelized cost, followed by CAPEX. Certainly for the cases with full load operation, OPEX is almost as important as CAPEX. In the early years, cell stack replacement is the main part of the OPEX counting for more than half of the total OPEX. Water cost is almost negligible. On the revenues side, selling the oxygen and providing ancillary services (in case of full load operation) could slightly increase economics.

Within the electricity cost, the grid costs represent a significant part (42% or 1,91 €/kg $H_2$ in 2015). If grid costs could be avoided completely, the levelized cost of hydrogen (LCmax) could be brought down from 6,4 €/kg to less than 4,5 €/kg in 2015. Similar decrease can be observed in 2030 and 2050. For local generation by means of wind turbines, a reduction of grid costs of only about 25% can be achieved, resulting in a LCmax of 5,9 €/kg.

As the cost of $CO_2$ -emission allowances is included in the purchasing cost of electricity (sourced externally) and the avoided purchasing cost of hydrogen (also bought externally), no separate revenue for the $CO_2$ emission reduction can be included. Including avoided societal costs of $CO_2$ emissions causes a reduction of 0,54 € per kg H2 on the levelized cost in 2015, but this reduction will increase significantly to 0,98 €/kg in 2030 and 1,76 €/kg in 2050.

**Figure 23: Detailed waterfall graphs for 2015, 2030 and 2050 (Power-to-Industry - small scale)**




## Conclusion

The considered base case is close to profitability at this moment, but should become fully profitable before 2030. The parameters that have most influence on the profitability are the avoided hydrogen purchasing cost and (to a slightly lower extent) the power price.

#### 6.3.2. Case 2: Power-to-Industry: hydrogen for industrial use (large scale)

**Description**

For this pathway, we typically look at refineries, chemical or process industry sites, with an annual hydrogen demand of a hundred million Nm³ and even more. These sites typically have on site hydrogen production by means of a large scale steam methane reforming plant, or are connected to the Air Liquide $H_2$ pipeline providing a continues flow of large volumes of hydrogen. The hydrogen is used directly and continuously in the chemical or industrial processes (e.g. ammonia production, hydrocarbon cracking,…) Potential sites can be found in large industrial areas, such as the port of Antwerp, along the Albert canal,…

**Case specific assumptions**

For the calculation, following specific assumptions are made:

- Electrical power input of the electrolyser: 100 MW
- Annual operating hours of the electrolyser: 8497 (baseload operation @ 97% availability)
- Annual hydrogen production: +/- 170.000.000 Nm³ at low pressure (20 bar)
- Type of electrolyser: large scale PEM
- No storage and no compression
- Civil works cost: 5.000.000 €
- Connection cost to the public power grid: 2.000.000 € (limited, as connection of the industrial plant already exists)
- Power price: according to price duration curves (mid scenario for 2030 and 2050) for Belgium as mentioned before (commodity) + 5% (supplier's margin) + 7,26 €/MWh (grid costs taxes and levies, as calculated for a 150 kV connected customer, with an annual offtake of 4 TWh)
- Avoided hydrogen production cost (on site SMR): 2,05 €/kg in 2015, 2,72 €/kg in 2030 and 3,59 €/kg in 2050
- The avoided emission of $CO_2$ amounts 103,7 kton per year. This equals the emission of an SMR-installation with a natural gas fired steam boiler with 90% efficiency. Per kilogram of generated hydrogen, the avoided emission of CO2 equals 6,92 kg.

**Economic feasibility**

The considered pathway is not profitable at this moment, neither in 2030 nor in 2050. The operational result (EBITDA) equals -22 million euro in 2015, improving to a (still negative) value of -12,3 million euro in 2030 and -4.85 million euro in 2050. NPV equals -323 million euro in 2015, -198 million euro in 2030 and -93 million euro in 2050. The ratio of the NPV over the total CAPEX increases from -3.01 in 2015 towards -2.56 in 2030 and -2.04 in 2050.

Main changes between 2015 and 2050 are the CAPEX decrease (mainly on the electrolyser), the OPEX decrease and the increase of the avoided purchasing cost for hydrogen. The variation of these parameters largely compensates the negative effect of increased power prices.

Power price, avoided purchasing cost of hydrogen and (to a much lower extent) CAPEX are identified as the parameters with most impact on the economics. The table below summarises the tipping points (i.e. the values of these parameters that turn the business case positive) and compares them to the actual or expected values. As EBITDA is negative and is expected to stay negative in 2030 and

2050, CAPEX should be negative in order to get a profitable solution. Therefore, no tipping points for CAPEX are calculated.

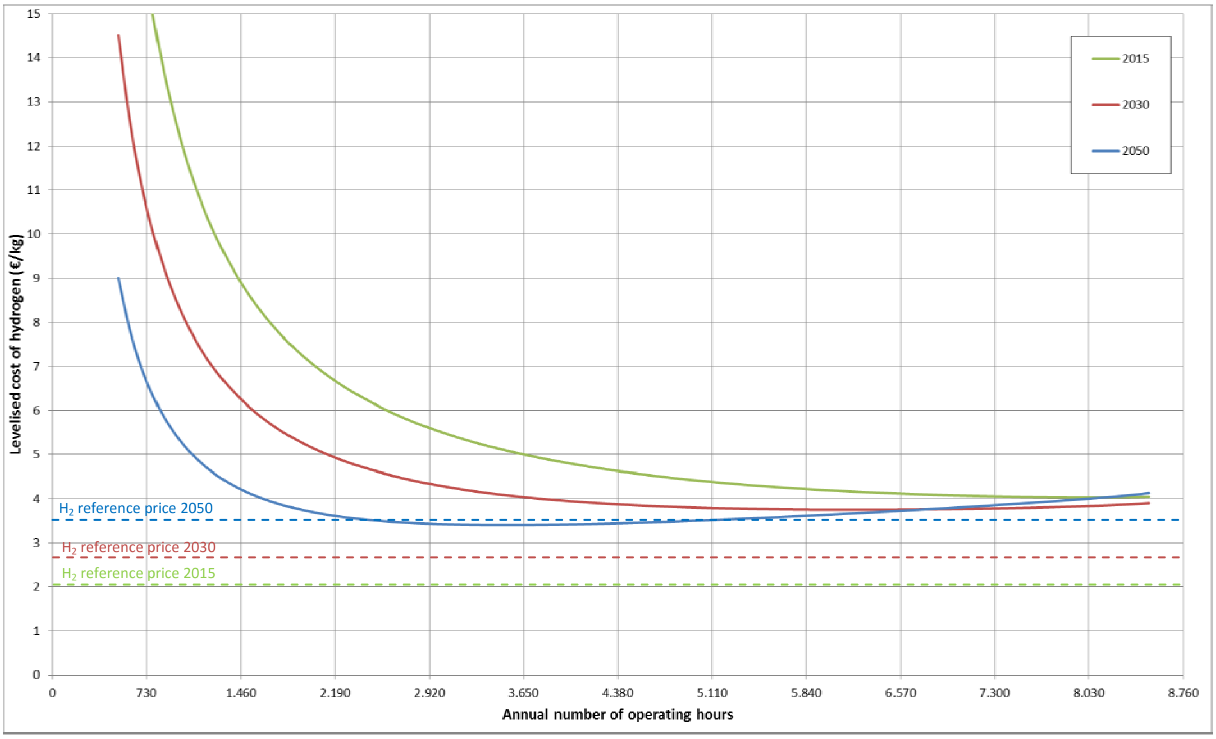
**Table 21: Tipping points (Power-to-Industry - large scale - full load)**

| | 2015 | | 2030 | | 2050 | |
|---|---|---|---|---|---|---|
| | Requirement | Actual value | Requirement | Expected value | Requirement | Expected value |
| Power price (all-in) | < 8 €/MWh | 50 €/MWh | < 30 €/MWh | 56 €/MWh | < 54,5 €/MWh | 67 €/MWh |
| Avoided purchasing cost of hydrogen | > 4,4 €/kg | 2,05 €/kg | > 4,14 €/kg | 2,72 €/kg | > 4,27 €/kg | 3,59 €/kg |

**Optimisation of the operating hours**

In the graph below, the levelized cost of hydrogen is shown as a function of the number of operating hours. It can be concluded that the number of operating hours at which the optimum (minimum for the levelized cost) is reached, equals approximately 8070 operating hours in 2015, and decreases towards approximately 6200 hours in 2030 and 3480 hours in 2050. In this case, the lower electricity price largely compensates the lower utilisation rate, leading to a lower levelized cost (decreasing LC max by about 25% from 4,1 €/kg to 3,4 €/kg), making the case profitable.

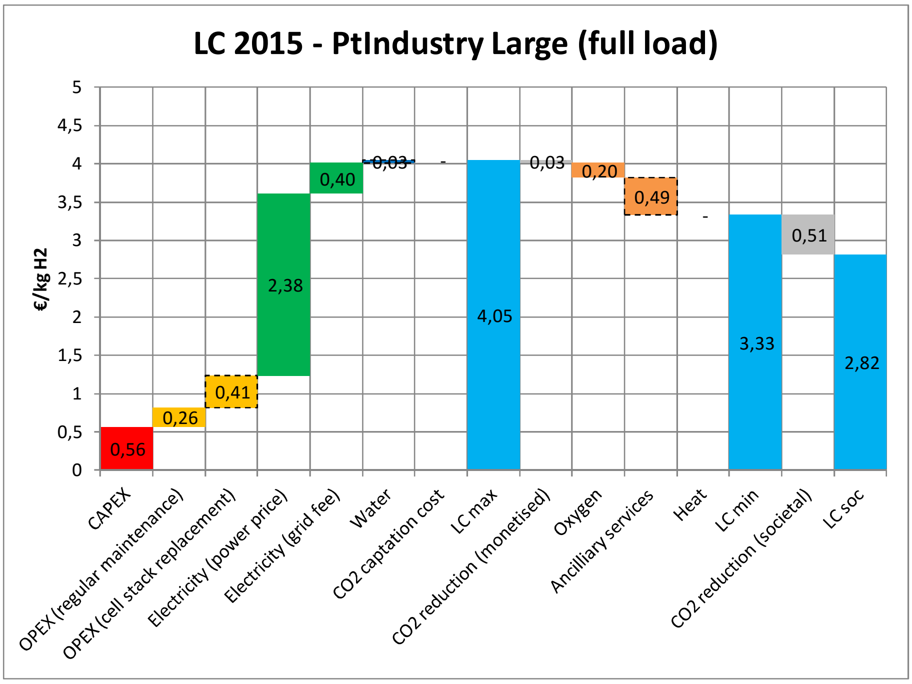
**Figure 24: Levelized cost of hydrogen vs. operating time (Power-to-Industry - large scale)**




**Sensitivity analysis**

The waterfall graph below shows how the levelized cost of hydrogen is composed (for full load operation in 2015). Other waterfall graphs (for 2030 and 2050, and for the optimised number of operating hours mentioned in previous paragraph) are shown in Annex 11.

**Figure 25: Waterfall graph 2015 (Power-to-Industry - large scale - full load)**




The graph shows that electricity cost is by far the biggest part of the levelized cost, with a minor share (+/-15%) for the grid costs, taxes and levies. Also on the cost side, OPEX is more important than CAPEX, with cell stack replacement being the main part of the OPEX in the early years, but decreasing later onwards. On the revenues side, selling the oxygen, providing ancillary services and avoided purchasing of $CO_2$ emission allowances could increase economics, turning EBITDA positive from 2030 onwards, and even turning NPV positive as from 2050 (which means the project is profitable, at an IRR of 16,6%).

As we consider that local production of hydrogen by steam methane reforming is replaced by the electrolyser, revenues for the selling or the avoided purchasing of $CO_2$ emission allowances is included in the calculation. For 2015, this has limited impact (0,03 €/kgH2), but due to increasing prices for emission allowances, the impact will increase to 0,24 €/kg in 2030 and 0,32 €/kg in 2050. Including avoided societal costs of $CO_2$ emissions (additional to the costs covered by the emission allowances, as explained above) causes a reduction of 0,51 € per kg H2 on the levelized cost in 2015, but this reduction will increase significantly to 0,75 €/kg in 2030 and 1,44 €/kg in 2050.

**Conclusion**

The considered base case is not profitable at this moment, and is not expected to be profitable in 2030. However, optimising the number of operating hours or including additional revenues can turn the case profitable in 2050. The parameters that have most influence on the profitability are the avoided hydrogen purchasing cost and the power price.

**Other industrial applications**

Next to Power-to-Hydrogen solutions, as described above, also an industrial Power-to-Methanol solution has been considered and calculated. As this solution is not profitable, and shows worse results than the cases described above, it will not be described in detail here. However, additional information can be found in Annex 18.

### *6.3.3. Case 3: Power-to-Gas: direct injection of hydrogen*

**Description**

For this pathway, large facilities for the conversion of (low cost) electricity into hydrogen are considered. The generated hydrogen is injected directly into the natural gas transport grid at high pressures. Potential sites will be located where hydrogen can be easily and massively injected into the high pressure natural gas grid, which means along the main high pressure natural gas pipelines or close to the port of Zeebrugge. In order to reduce connection and grid costs, it is also advantageous to have a transformer station for electricity close to the site to benefit from the highest possible voltage. Reference can be made to e.g. the E.On Falkenhagen project.

**Case specific assumptions**

For the calculation, following specific assumptions are made:

- Electrical power input of the electrolyser: 15 MW
- Annual operating hours of the electrolyser: 8497 (baseload operation @ 97% availability)
- Annual hydrogen production: +/- 25.000.000 Nm³ at low pressure (20 bar)
- Type of electrolyser: large scale PEM
- No storage
- Compression towards 70 bar, multiple compressors in parallel, each compressor having one stage, and with a total capacity equal to the electrolyser production capacity (3000 Nm³/h), specific investment cost 333 €/Nm³/h in 2015, decreasing later on)
- Civil works cost: 500.000 €
- Connection cost to the public power grid: 500.000 € (connection to a nearby situated transformer station is assumed)
- Connection cost to the public natural gas grid: 2.250.000 € (gas injection facility, including measurement, quality control, and safeties)
- Power price: according to price duration curves (mid scenario for 2030 and 2050) for Belgium as mentioned before (commodity) + 10% (supplier's margin) + 17,36 €/MWh (grid costs taxes and levies, as calculated for customer connected directly to 36kV transformer outlets, with an annual off-take of 120 GWh)
- Value of generated hydrogen per MWh HHV equal to natural gas price per MWh HHV: 22,6 €/MWh in 2015, 29,4 €/MWh in 2030 and 42,4 €/MWh in 2050
- The avoided emission of $CO_2$ amounts 18.245 ton per year. This equals the emission of the natural gas that is replaced by hydrogen. The injected hydrogen is considered to be emission-free energy. Per MWh of energy injected in the natural gas grid, the avoided emission of $CO_2$ equals 202 kg.

**Economic feasibility**

The considered pathway is not profitable at this moment, neither in 2030 nor in 2050. The operational result (EBITDA) equals -8,04 million euro in 2015, improving to a (still negative) value of -7,66 million euro in 2030 and -7,63 million euro in 2050. NPV equals -106 million euro in 2015, -97 million euro in 2030 and -92 million euro in 2050. The ratio of the NPV over the total CAPEX even decreases from -5,49 in 2015 towards -6,64 in 2030 and -9,38 in 2050.

Main changes between 2015 and 2050 are the CAPEX decrease (mainly on the electrolyser), the OPEX decrease, and the increase of the value of the hydrogen (due to increasing natural gas price on the market). The variation of these parameters compensates the negative effect of increased power prices, but is not sufficient to turn the case profitable.

Power price, natural gas price (to a lower extent), and CAPEX are identified as the parameters with most impact on the economics. The table below summarises the tipping points (i.e. the values of these parameters that turn the business case positive) and compares them to the actual or expected values. As EBITDA is negative and is expected to stay negative in 2030 and 2050, CAPEX should be negative in order to get a profitable solution. Therefore, no tipping points for CAPEX are calculated.

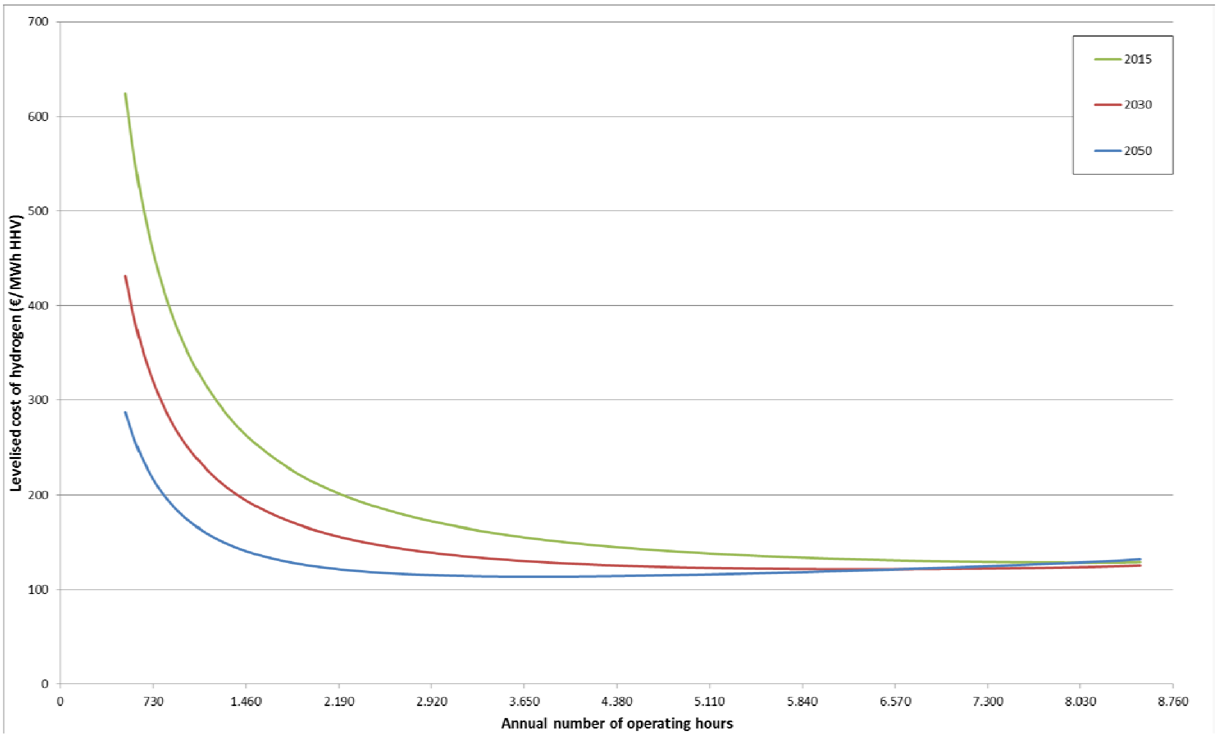
**Table 22: Tipping points (Power-to-Gas - direct injection of hydrogen - full load)**

| | 2015 | | 2030 | | 2050 | |
|---|---|---|---|---|---|---|
| | Requirement | Actual value | Requirement | Expected value | Requirement | Expected value |
| Power price (all-in) | < -14,7 €/MWh | 62,1 €/MWh | < -1,4 €/MWh | 68,5 €/MWh | < 14,5 €/MWh | 80,1 €/MWh |
| Natural gas price | > 135,5 €/MWh | 22,6 €/MWh | > 130,2 €/MWh | 29,4 €/MWh | > 135,2 €/MWh | 42,4 €/MWh |

**Optimisation of the operating hours**

For the sensitivity analysis on the operating hours, it is considered that no hydrogen is injected in case the electrolyser doesn't run, as there is no buffer. In the graph below, the levelized cost of hydrogen is shown as a function of the number of operating hours. The number of operating hours minimising the levelized cost, equals approximately 8070 hours in 2015; 6290 hours in 2030 and 3740 hours in 2050. In this case, the lower electricity price largely compensates the lower utilisation rate, leading to a 20% decrease of levelized cost in 2050.

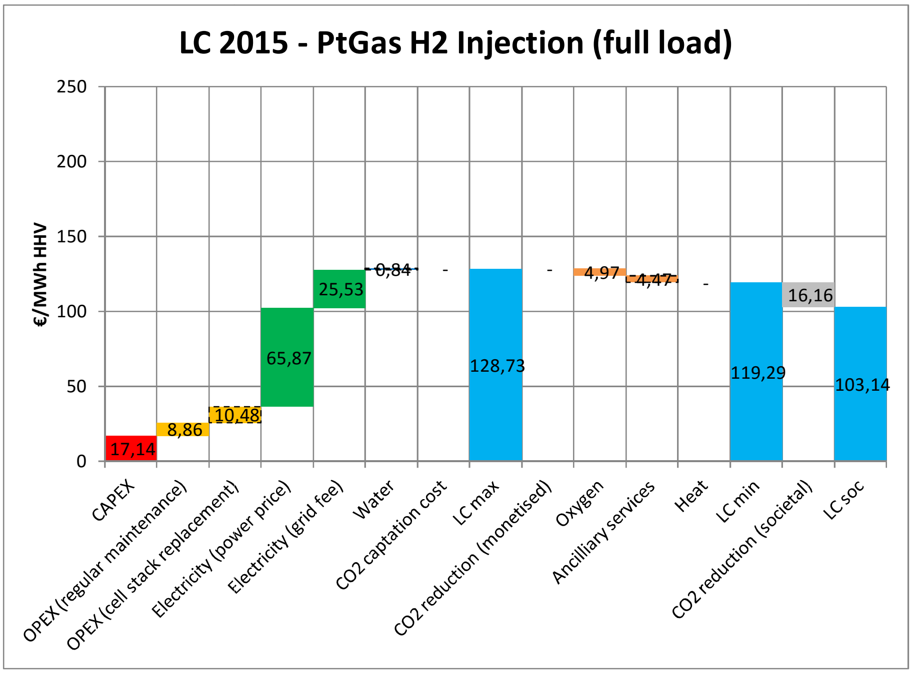
**Figure 26: Levelized cost of hydrogen vs operating time (Power-to-Gas - direct injection of hydrogen)**




### Sensitivity analysis

The waterfall graph below shows how the levelized cost of hydrogen (in /MWh HHV[29]) is composed (for full load operation in 2015). Other waterfall graphs (for 2030, 2050, and for the optimised number of operating hours mentioned in previous paragraph) are shown in Annex 12.

**Figure 27: Waterfall graph 2015 (Power-to-Gas - direct injection - full load)**




[29] HHV : High heating value

The graph shows that electricity cost is by far the biggest part of the levelized cost, with a significant share (+/-28%) for the grid costs, taxes and levies. Also on the cost side, OPEX is as important as CAPEX (even slightly more important), with cell stack replacement being the main part of the OPEX, representing more than half of total OPEX (54%) in 2015, but rapidly decreasing later on. On the revenues side, selling the oxygen and providing ancillary services could increase economics, however still giving a negative NPV.

It is assumed that the avoided CO2 -emissions take place at the site of the natural gas customer, so the owner of the Power-to-Gas plant will not directly benefit from them. Indirect benefits might however exist, as the selling price of hydrogen might be a bit higher than the natural gas price (due to its emission-free character). Including avoided societal costs of CO2 emissions causes a reduction of 16,2 € per MWh HHV of hydrogen on the levelized cost in 2015, but this reduction will increase significantly to 29,3 €/MWh in 2030 and 52,5 €/MWh in 2050.

**Conclusion**

The considered base case is not profitable at this moment, and is not expected to be profitable neither in 2030 or 2050. The parameters that have most influence on the profitability are the power price and (to a lower extent) the natural gas price. Only major changes to these parameters can turn this case positive.

#### *6.3.4. Case 4: Power-to-Gas: injection of Synthetic Natural Gas*

**Description**

In methanation projects, hydrogen produced by electrolysis is used directly and continuously in a reactor, where hydrogen and $CO_2$ will be combined to form methane, which is injected into the natural gas grid. Methanation can be done in a chemical way (catalytic reaction, cf. Sabatier-process) or in a biological way.

For both cases, we typically look at industrial sites emitting significant amounts of $CO_2$ that can be captured and reused. Also biogas plants (digesters…) can form suitable locations for a Power-to-Gas plant as raw biogas consists of both $CO_2$ and methane. So the methanation process can be used to convert the $CO_2$ produced by the biogas plant into biomethane (using hydrogen), leading to (almost) 100% biomethane as an output for the biogas plant. This biomethane can be injected directly in natural gas grids without any limit in terms of maximum concentration as natural gas is also mainly formed of methane. Due to recent developments, it is even possible to directly inject raw biogas in the methanation reactor without separating the $CO_2$ from the biomethane at the outlet of the biogas plant.

As chemical and biological methanation show very similar results, only the chemical methanation is described in detail below. For biological methanation, additional information can be found in Annex 19.

**Case specific assumptions**

For the calculation, following specific assumptions are made:

- Electrical power input of the electrolyser: 15 MW
- Annual operating hours of the electrolyser: 8497 (baseload operation @ 97% availability)
- Annual hydrogen production: +/- 25.000.000 Nm³ at low pressure (20 bar)

- Type of electrolyser: large scale PEM
- No storage
- Compression towards 70 bar, one compressor, one stage, compressor capacity equal to the electrolyser production capacity (3000 Nm³/h), specific investment cost 333 €/Nm³/h in 2015, decreasing later on)
- Civil works cost: 500.000 €
- Connection cost to the public power grid: 500.000 € (connection to a nearby situated transformer station is assumed)
- Connection cost to the public natural gas grid: 1.500.000 € (gas injection facility, including measurement, quality control, and safety)
- Power price: according to price duration curves (mid scenario for 2030 and 2050) for Belgium as mentioned before (commodity) + 10% (supplier's margin) + 17,36 €/MWh (grid costs taxes and levies, as calculated for customer connected directly to 36kV transformer outlets, with an annual off-take of 120 GWh)
- Value of generated methane per MWh HHV equal to natural gas price per MWh HHV: 22,6 €/MWh in 2015, 29,4 €/MWh in 2030 and 42,4 €/MWh in 2050
- The avoided emission of $CO_2$ amounts 15.256 ton per year. This the captured amount of $CO_2$ (12.604 ton) plus the avoided emission of a natural gas fired boiler with 90% efficiency (for generating the heat that is replaced by heat recovery from the (exothermal) methanation reaction). Per MWh of generated methane, the avoided emission of $CO_2$ equals 216 kg.

**Economic feasibility**

The considered pathway is not profitable at this moment; neither will it be in 2030 nor in 2050. The operational result (EBITDA) equals -9,87 million euro in 2015, improving to a (still negative) value of -9,49 million euro in 2030 and -9,53 million euro in 2050. NPV equals -140 million euro in 2015, -128 million euro in 2030 and -119 million euro in 2050. The ratio of the NPV over the total CAPEX even decreases from -4,17 in 2015 towards -4,95 in 2030 and -7,20 in 2050.

Main changes between 2015 and 2050 are the CAPEX decrease (mainly on the electrolyser, but also on the methanation unit), the OPEX decrease and the increase of the value of the methane (natural gas price). The variation of these parameters almost exactly compensates the negative effect of increased power prices.

Power price is identified as the parameter with most impact on the economics, followed by CAPEX, methane price and (to a lower extent) $CO_2$ capture cost. The table below summarises the tipping points (i.e. the values of these parameters that turn the business case positive) and compares them to the actual or expected values. As EBITDA is negative and is expected to stay negative in 2030 and 2050, CAPEX should be negative in order to get a profitable solution. Therefore, no tipping points for CAPEX are calculated.

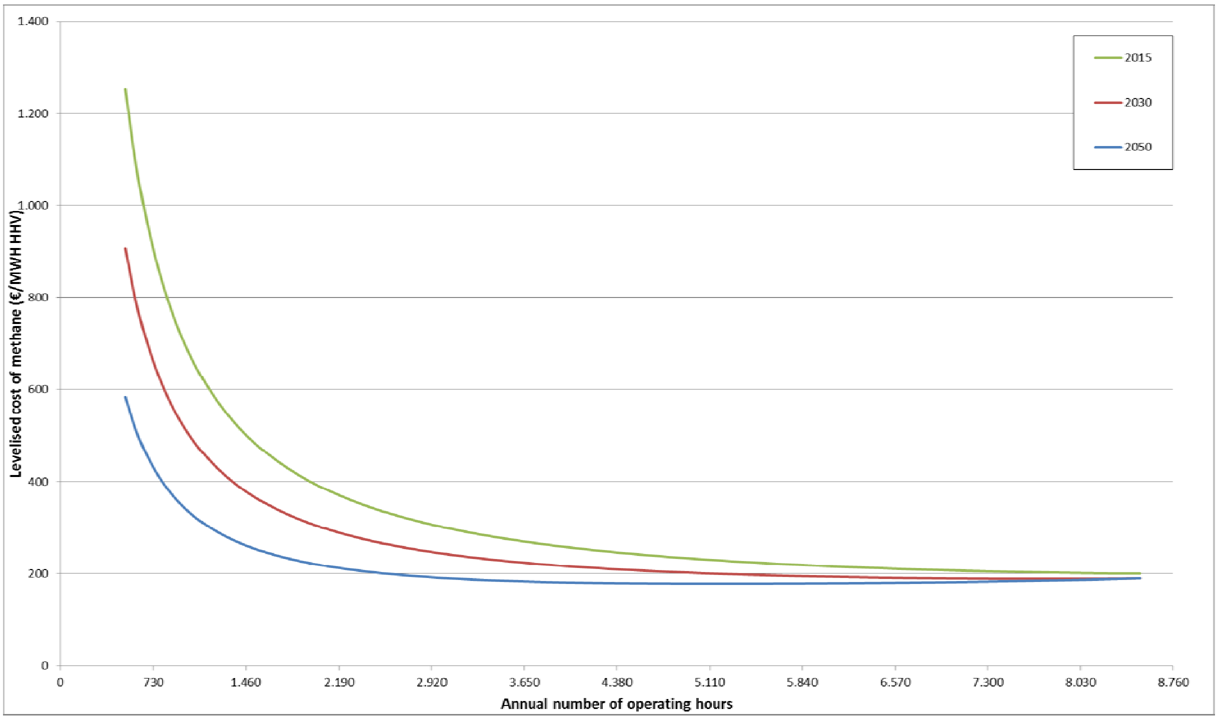
**Table 23: Tipping points (Power-to-Gas - injection of Synthetic Natural Gas - full load)**

| | 2015 | | 2030 | | 2050 | |
|---|---|---|---|---|---|---|
| | Requirement | Actual value | Requirement | Expected value | Requirement | Expected value |
| Power price (all-in) | < -40,4 €/MWh | 62,1 €/MWh | < -24,7 €/MWh | 68,5 €/MWh | < -5,5 €/MWh | 80,1 €/MWh |
| Natural gas price | > 215,4 €/MWh | 22,6 €/MWh | > 201,2 €/MWh | 29,4 €/MWh | > 197,1 €/MWh | 42,4 €/MWh |
| CO2 captation and filtration cost | < -1031€/ton | 50 €/ton | < -914 €/ton | 50 €/ton | < -817 €/ton | 50 €/ton |

### Optimisation of the operating hours

For the sensitivity analysis on the operating hours, it is considered that no methane is generated nor injected in case the electrolyser doesn't run, as there is no buffer. In the graph below, the levelized cost of methane is shown as a function of the number of operating hours. It can be concluded that in 2015, the levelized cost increases as the number of operating hours decreases. In 2030 and 2050 however, an optimum can be found. The number of operating hours minimising the levelized cost, equals approximately 7820 hours in 2030 and 5180 hours in 2050. In this case, the lower electricity price largely compensates the lower utilisation rate, reducing LC max by about 10% from 190 €/MWh HHV to 172 €/MWh HHV in 2050.

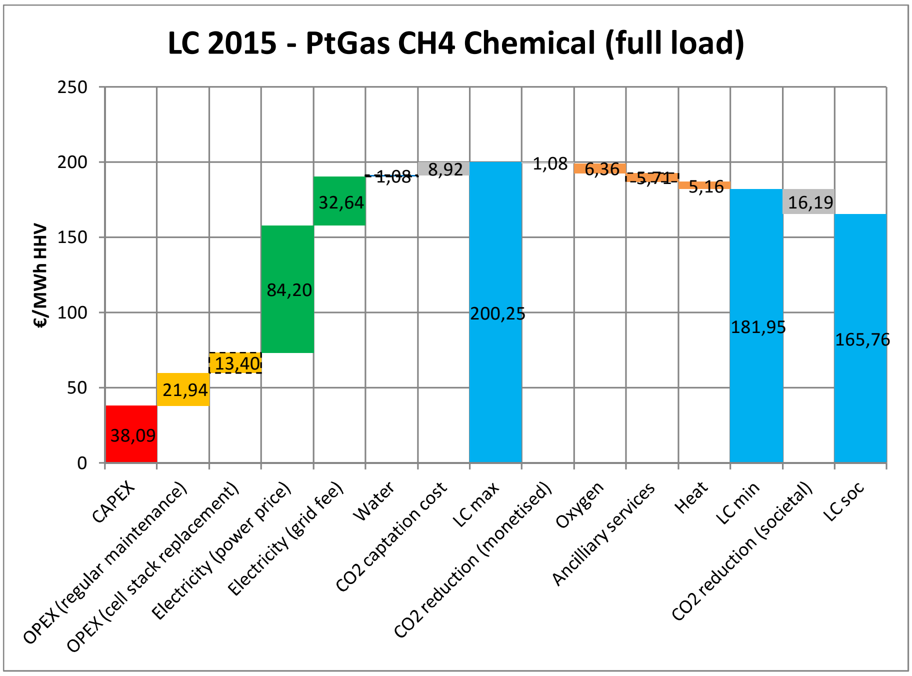
**Figure 28: Levelized cost of hydrogen vs operating time (Power-to-Gas: injection of Synthetic Natural Gas)**




### Sensitivity analysis

The waterfall graph below shows how the levelized cost of methane (in €/MWh HHV) is composed (for full load operation in 2015). Other waterfall graphs (for 2030 and 2050, and for the optimised number of operating hours mentioned in previous paragraph) are shown in Annex 13.

**Figure 29: Waterfall graph 2015 (Power-to-Gas: injection of Synthetic Natural Gas)**




The graph shows that electricity cost is by far the biggest part of the levelized cost, with a significant share (+/-28%) for the grid costs, taxes and levies. As for the other costs OPEX is as almost as important as CAPEX, with cell stack replacement as a significant part, representing 38% of total OPEX in 2015, but decreasing afterwards. On the revenues side, heat recovery, avoided purchase of $CO_2$ emission allowances, selling the oxygen and providing ancillary services could increase economics, however still giving a negative NPV.

As we consider that the captured CO2 is not directly emitted and that some on site CO2 -emission is avoided due to heat recovery, the selling (or the avoided purchasing) of CO2 emission allowances is included in the revenue calculation. For 2015, this has limited impact (1.08 €/MWh of methane), but due to increasing prices for emission allowances, the impact will increase to 7,56 €/MWh in 2030 and 10,25 €/MWh in 2050. Including avoided societal costs of CO2 emissions (additional to the costs covered by the emission allowances) causes a reduction of 16,2 € per MWh HHV of hydrogen on the levelized cost in 2015. This reduction will increase significantly to 23,7 €/MWh in 2030 and 45,9 €/MWh in 2050.

**Conclusion**

The considered base case is not profitable at this moment, and is not expected to be profitable in 2030 and 2050 neither. This is no surprise as the extra methanation step compared to direct hydrogen injection in gas grids requires more CAPEX and reduces the efficiency of the whole process translating into higher electricity consumption for the same energy output (synthetic methane). The parameters that have most influence on the profitability are the power price and (to a lower extent) the natural gas price. Only major changes to these parameters can turn this case positive.

#### 6.3.5. *Case 5: Power-to-Mobility: hydrogen refuelling station for cars*

**Description**

For this pathway, we typically look at traditional refuelling stations. Hydrogen is generated locally (decentralised), using electricity taken from the (low voltage) grid. The generated hydrogen is buffered during a couple of hours to match the varying refuelling schedule of the customers. The hydrogen is finally used in fuel cell electric vehicles (FCEV's). Reference is made to the Colruyt hydrogen refuelling station in Halle, and to many other European projects (Chic, High V.Lo City,…)

**Case specific assumptions**

For the calculation, following specific assumptions are made:

- Daily number of refuelling operations: 50
- Refilled quantity per operation: 4 kg
- Annual hydrogen production: 200 kg/day, or 73 ton per year, or +/- 800.000 Nm³
- Electrical power input of the electrolyser: 500 kW
- Annual operating hours of the electrolyser: 8497 (baseload operation @ 97% availability)
- Type of electrolyser: alkaline kW-scale
- Limited storage, for the output of half a day of electrolyser full load operation, being approximately 100 kg
- Compression towards 900 bar, multi-stage compressors, with a total capacity equal to the electrolyser production capacity (+/- 100 Nm³/h)
- Civil works cost: 100.000 €
- Connection cost to the public power grid: 50.000 € (limited, low voltage connection)
- Power price: according to price duration curves (mid scenario for 2030 and 2050) for Belgium as mentioned before (commodity) + 20% (supplier's margin) + 46,18 €/MWh (grid costs taxes and levies, as calculated for a 400V connected customer, with an annual off take of 5 GWh)
- Hydrogen selling price: 5 €/kg in 2015, 8,5 €/kg in 2030 and 11 €/kg and 2050. These values have been calculated considering:
  - hydrogen consumption in cars: 0,95 kg/100km in 2015; 0,76 kg/100km in 2015 and 0,71 kg/100km in 2015
  - Avoided fuel cost (diesel), including taxes but excluding VAT, based on a diesel consumption of 5l/100km: 4,75 €/100km in 2015; 6,49 €/100km in 2030 and 7,85 €/100km in 2050
- The avoided emission of $CO_2$ amounts 1.032 ton per year. This is the avoided emission of the combustion of diesel in the passenger cars. The avoided emission per 100km equals 13,4 kg.

**Economic feasibility**

The considered case is not profitable at this moment. The operational result is (slightly) negative (EBITDA equals -121 k€), which also makes the NPV negative (-3,8 million €). The ratio of the NPV over the total CAPEX is -1,58. For 2030 this case almost shows positive results. A positive EBITDA of 141 k€ however still leads to a slightly negative NPV (-309 k€) and to an IRR of 5,8%. For 2050, an EBITDA of 303 k€, a positive NPV of 1,25 million euro, and an IRR of 18,3% are expected, which implies the case is largely profitable.

Main changes between 2015 and 2050 are the CAPEX decrease (mainly on the electrolyser, but also on compression and storage), the OPEX decrease, and the increase of the avoided fuel cost (diesel). The variation of these parameters largely compensates the negative effect of increased power prices.

Fuel price and power price are the parameters with the steepest curves and therefore having the strongest influence on the profitability (where the influence of the latter one reduces later in time). The investment cost (CAPEX) has a lower influence on profitability. Hereunder tipping points (i.e. values of a certain parameter at which the business case turns profitable) are calculated.

**Table 24: Tipping points (HRS – cars – full load)**

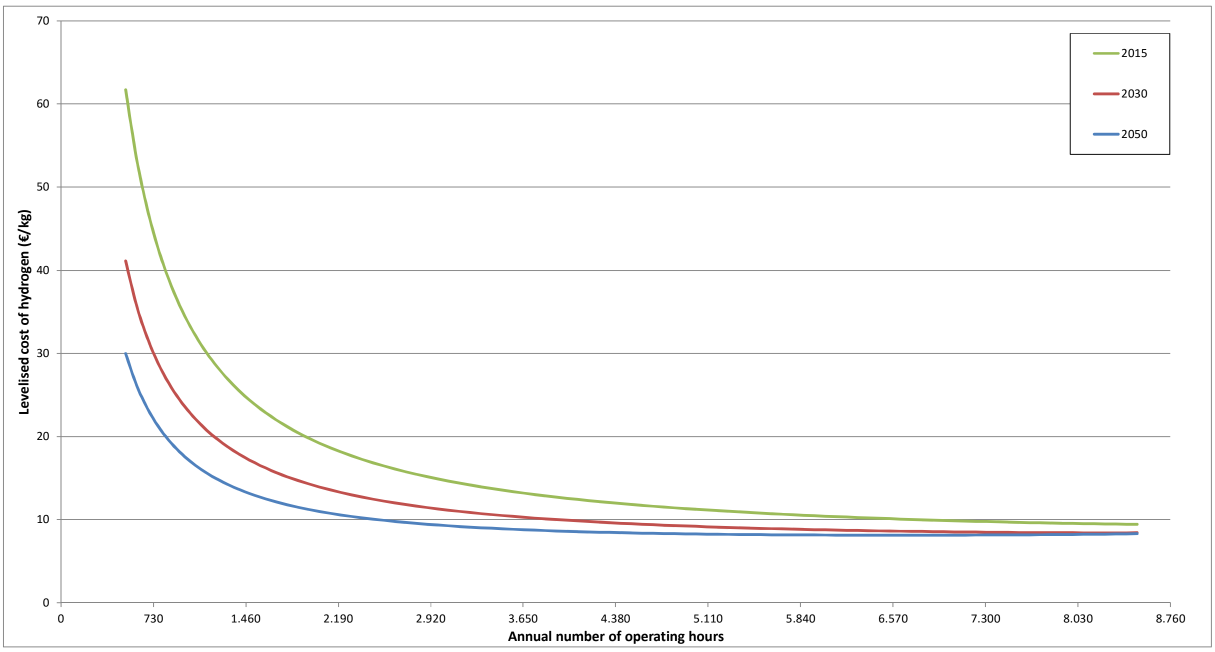
| | 2015 | | 2030 | | 2050 | |
|---|---|---|---|---|---|---|
| | Requirement | Actual value | Requirement | Expected value | Requirement | Expected value |
| Power price (all-in) | < -0,3 €/MWh | 95 €/MWh | < 92 €/MWh | 102 €/MWh | < 154 €/MWh | 114,6 €/MWh |
| Fuel price (€/100km) | > 9,9 €/100km | 4,75 €/100km | > 6,79 €/100km | 6,49 €/100km | > 6,15 €/100km | 7,85 €/100km |
| Fuel price (€/kg hydrogen) | >10,5 €/kg | 5 €/kg | >9,1 €/kg | 8,5 €/kg | >8,8 €/kg | 11 €/kg |
| Capex | < -1,39M€ | 2,5 M€ | < 1,26 M€ | 1,63M€ | < 2,7 M€ | 1,2M€ |

**Optimisation of the operating hours**

In the graph below, the levelized cost of hydrogen (per kg of hydrogen) is shown as a function of the number of operating hours. It can be concluded that in 2015, the levelized cost increases as the number of operating hours decreases. In 2030 and 2050 however, an optimum can be found. The number of operating hours minimising the levelized cost equals approximately 8240 hours in 2030 and 6630 hours in 2050. In this case (2050), the lower electricity price largely compensates the lower utilisation rate, although only leading to a 2,5% decrease of LC max from 8,3 €/kg to 8,12 €/kg.

It should be noted that in the case of optimising the number of operating hours, the electrolysers is assumed to be operating power price driven and not hydrogen demand driven, which could result in the unavailability of the hydrogen refuelling station or the need to source the hydrogen externally.

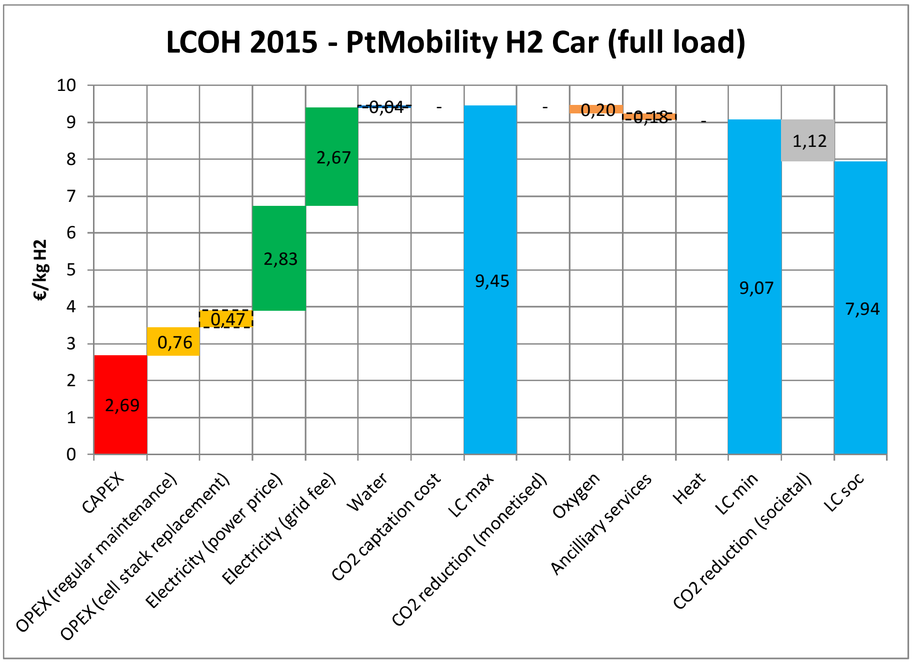
**Figure 30: Levelized cost of hydrogen vs operating time (HRS – cars)**



**Sensitivity analysis**

The waterfall graph below shows how the levelized cost of hydrogen as a fuel (expressed in €/kg $H_2$) is composed (for full load operation in 2015). Other waterfall graphs (for 2030 and 2050, and for the optimised number of operating hours mentioned in previous paragraph) are shown in Annex 14.

**Figure 31: Waterfall graph 2015 (HRS - cars - full load)**




The graph shows that electricity cost is by far the biggest part of the levelized cost, with the commodity price still representing the largest part, but grid costs however equalling almost the same amount (49% of total electricity cost). As for the other costs, OPEX is not negligible, but less important than CAPEX, with cell stack replacement representing a significant 38% of total OPEX in 2015, and decreasing later. On the revenues side, selling the oxygen and providing ancillary services could slightly increase economics, bringing the case at the limit of profitability in 2030 (NPV = -100 k€ and IRR = 7.3%), and turning the (already profitable) case a slightly more profitable one in 2050.

It is assumed that the avoided $CO_2$ emissions take place in traffic, so they cannot be monetised directly. However, including avoided societal costs of $CO_2$ emissions causes a reduction of 1,12 € per kg hydrogen on the levelized cost in 2015. This reduction will increase significantly reaching 2,55 €/kg hydrogen in 2030 and 4,87 €/ kg hydrogen in 2050. This still excludes avoided societal costs for emission of nitrogen oxides and fine particulates.

To allow the comparison of this case with other mobility cases (including conventional diesel), the levelized cost of hydrogen per 100 km has been calculated and detailed results are presented in the Annex 14. Unlike the waterfall graphs shown above (in €/kg hydrogen), these waterfall graphs (in €/100 km) include the expected increase of the efficiency of FCEV (mainly due to an increased fuel cell efficiency) between now, 2030 and 2050.

**Conclusion**

Considering a reference selling price for hydrogen of 5€/kg[30] in 2015, the business case is not profitable for 2015. To turn profitable already in 2015 a hydrogen selling price of 10,5 €/kg is required. The business case would be profitable with hydrogen selling price of 9,1 €/kg for 2030 which is close to the reference selling price of 8,5 €/kg[31]. In 2050, the business is expected to be profitable, due to an increased diesel cost and a lower levelized cost of hydrogen.

#### *6.3.6. Case 6: Power-to-Mobility: hydrogen refuelling station for buses*

**Description**

For this case, we typically look at bus depots, where around 25 (or more) buses are parked when they are not on the road. Hydrogen is generated locally (decentralised), using electricity taken from the (medium voltage) grid. The generated hydrogen is buffered during a couple of hours, in order to match the specific refuelling schedule of the buses. The buses have fuel cells to convert the hydrogen into electric power, which drives the engine of the bus. Potential sites can be found near large cities, where lots of buses are used for public transport. In Flanders, most depots of 'De Lijn' can be considered.

**Case specific assumptions**

For the calculation, the following specific assumptions are made:

- Number of refuelling operations: 25 per day
- Refilled quantity per operation: 35 kg
- Annual hydrogen production: 875 kg/day, or 323 ton per year, or +/- 3.500.000 Nm³
- Electrical power input of the electrolyser: 2.2 MW
- Annual operating hours of the electrolyser: 8497 (baseload operation @ 97% availability)
- Type of electrolyser: small scale PEM
- Limited storage, for the output of half a day of electrolyser full load operation, being approximately 450 kg
- Compression towards 450 bar, multi-stage compressor, with a total capacity equal to the electrolyser production capacity (420 Nm³/h)
- Civil works cost: 100.000 €
- Connection cost to the public power grid: 50.000 € (limited, low voltage connection)
- Power price: according to price duration curves (mid scenario for 2030 and 2050) for Belgium as mentioned before (commodity) + 15% (supplier's margin) + 45,01 €/MWh (grid costs taxes and levies, as calculated for a 400V connected customer (direct connection to LV transformer), with an annual off-take of 20 GWh)
- Hydrogen selling price: 4,5 €/kg in 2015, 7,7 €/kg in 2030 and 9,9 €/kg and 2050. These values have been calculated considering:
    - Hydrogen consumption in buses: 10 kg/100km in 2015; 8 kg/100km in 2030 and 7,5 kg/100km in 2050

[30] Reference price was based on diesel price of 0,95 €/l (excl. VAT), a diesel car consumption of 5l/100 km and a hydrogen consumption for FCEV (cars) of 0,95 kg/100 km.

[31] Reference price was based on diesel price of 1,30 €/l (excl. VAT), a diesel car consumption of 5l/100 km and a hydrogen consumption for FCEV (cars) of 0,76 kg/100 km.

  - Avoided fuel cost (diesel), including taxes but excluding VAT, based on a diesel consumption of 52,5 l/100km: 45 €/100km in 2015; 62 €/100km in 2030 and 75 €/100km in 2050
- The avoided emission of $CO_2$ amounts 4.487 ton per year. This the avoided emission of the combustion of diesel in the buses. The avoided emission of $CO_2$ per 100km equals 139 kg.

**Economic feasibility**

The considered case is not profitable at this moment, just profitable in 2030 and largely profitable in 2050. The operational result (EBITDA) equals -596 k€ in 2015, improving to a positive value of 463 k€ in 2030 and 1.092 k€ in 2050. NPV equals -12.4 million euro in 2015, 14 k€ in 2030 and 5,74 million euro in 2050. The ratio of the NPV over the total CAPEX increases from -2,08 in 2015 towards 0 in 2030 and 2,02 in 2050.

Main changes between 2015 and 2050 are the CAPEX decrease (mainly on the electrolyser, but also compression and storage), the OPEX decrease and the increase of the value of the generated hydrogen (referred to the diesel price). The variation of these parameters largely compensates the negative effect of increased power prices.

Fuel price and power price are the parameters with the strongest influence on the profitability. The investment cost (CAPEX) has a lower influence on profitability (certainly later on). Hereunder tipping points (i.e. values of a certain parameter at which the business case turns profitable) are shown.

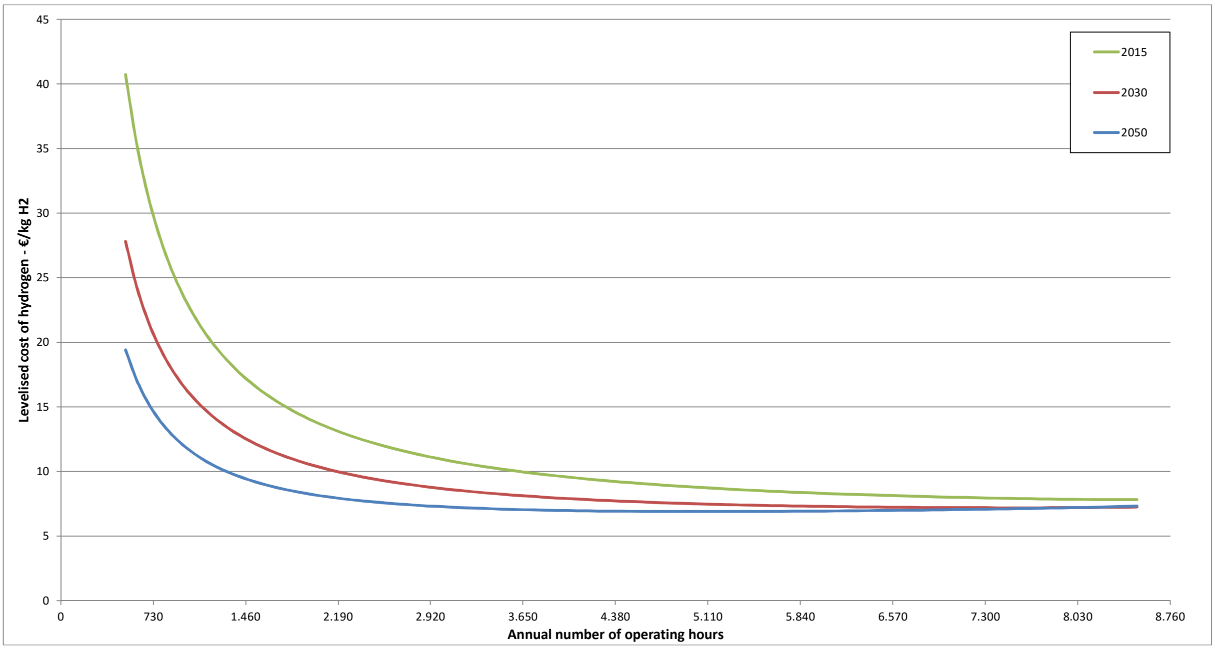
**Table 25: Tipping points (HRS – buses – full load)**

| | 2015 | | 2030 | | 2050 | |
|---|---|---|---|---|---|---|
| | Requirement | Actual value | Requirement | Expected value | Requirement | Expected value |
| Power price (all-in) | < 24,2 €/MWh | 91,8 €/MWh | < 98,6 €/MWh | 98,5 €/MWh | < 151,9 €/MWh | 110,6 €/MWh |
| Fuel price (€/100km) | >83,9 €/100km | 45,36 €/100km | >61,2 €/100km | 61,93 €/100km | >56,9 €/100km | 74,94 €/100km |
| Fuel price (€/kg hydrogen) | > 8,41 €/kg | 4,49 €/kg | > 7,66 €/kg | 7,67 €/kg | > 7,60 €/kg | 9,90 €/kg |
| Capex | < -6,42M€ | 5,97 M€ | < 4,13 M€ | 4,12 M€ | < 9,74 M€ | 2,85M€ |

**Optimisation of the operating hours**

In the graph below, the levelized cost of hydrogen (in €/kg hydrogen) is shown as a function of the number of operating hours. It can be concluded that in 2015, the levelized cost increases as the number of operating hours decreases. In 2030 and 2050 however, an optimum can be found. The number of operating hours minimising the levelized cost, equals approximately 7560 hours in 2030 and 5100 hours in 2050. In this case, the lower electricity price largely compensates the lower utilisation rate, although only decreasing LCmax by about 6% from 7,33 €/kg to 6,9 €/kg in 2050.

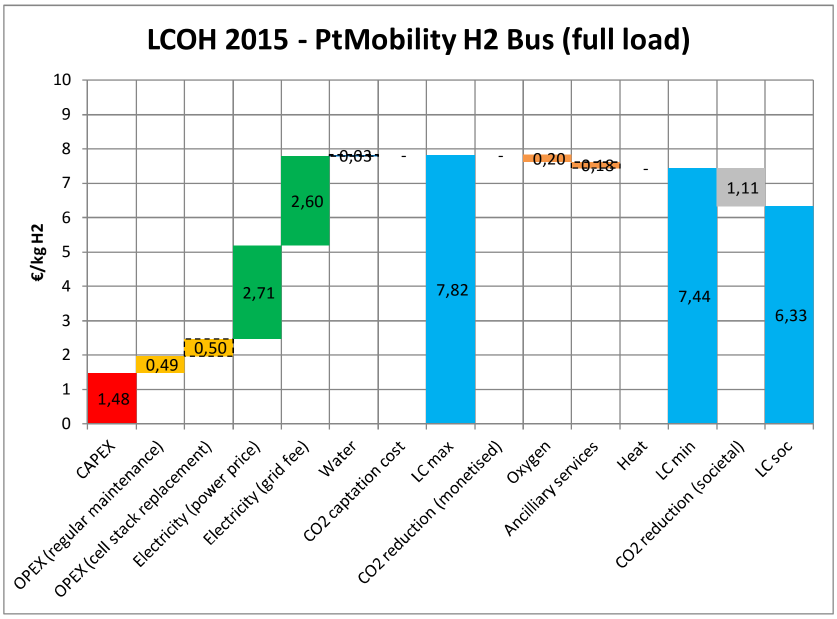
**Figure 32: Levelized cost of hydrogen vs operating time (HRS - buses)**




## Sensitivity analysis

The waterfall graph below shows how the levelized cost of hydrogen as a fuel (expressed in €/kg) is composed (for full load operation in 2015). Other waterfall graphs (for 2030 and 2050, and for the optimised number of operating hours mentioned in previous paragraph) are shown in Annex 15.

**Figure 33: Waterfall graph 2015 (HRS – buses)**




On the cost side, the graph shows that electricity cost represents the largest part of the total levelized cost (with commodity and grid costs each counting for almost the same amount), and OPEX is not negligible, but clearly less important than CAPEX. Within the OPEX, cell stack replacement is the major component, amounting to just above 50% of total OPEX in 2015, however decreasing significantly in 2030 and 2050.

It is assumed that the avoided $CO_2$ emissions take place in traffic, so they cannot be monetised directly. However, including avoided societal costs of $CO_2$ emissions causes a reduction of 1,11 €/kg on the levelized cost in 2015, but this reduction will increase significantly to 2,52 €/kg in 2030 and 4,81 €/kg in 2050. This still excludes avoided societal costs for emission of nitrogen oxides and fine particulates.

To allow the comparison of this case with other mobility cases (including conventional diesel), the levelized cost of hydrogen per 100 km has been calculated and detailed results are presented in the Annex 15. Unlike the waterfall graphs shown above (in €/kg hydrogen), these waterfall graphs (in €/100 km) include the expected increase of the efficiency of FCEV (mainly due to an increased fuel cell efficiency) between now, 2030 and 2050.

**Conclusion**

Considering a reference selling price for hydrogen of 4,5€/kg[32] in 2015, the business case is not profitable for 2015. To turn profitable already in 2015 a hydrogen selling price of 8,4 €/kg is required. The business case would be profitable with hydrogen selling price of 7,7 €/kg for 2030 which is exactly the reference selling price of 7,7 €/kg[33]. In 2050, the business is expected to be even more profitable, due to an increased diesel cost and a lower levelized cost of hydrogen.

#### *6.3.7. Case 7: Power-to-Fuel: methanol as fuel*

**Description**

For this case, we typically look at chemical or process industry sites emitting significant amounts of $CO_2$ that can be captured and reused. In a centralised production plant, all of the hydrogen produced is used directly and continuously in a process reactor, where hydrogen and $CO_2$ will react catalytically to form methanol. The methanol is then distributed to 'classic' refuelling stations (blended in diesel or pure). Reference can be made to Carbon Recycling International and their project in Iceland (see http://carbonrecycling.is/).

**Case specific assumptions**

For the calculation, following specific assumptions are made:

- Electrical power input of the electrolyser: 50 MW
- Annual operating hours of the electrolyser: 8497 (baseload operation @ 97% availability)
- Annual hydrogen production: +/- 85.000.000 Nm³ at low pressure (20 bar)
- Type of electrolyser: large scale PEM
- No storage
- No compression
- Civil works cost: 1.000.000 €
- Connection cost to the public power grid: 1.000.000 € (limited, as connection of the industrial plant already exists)
- Power price: according to price duration curves (mid scenario for 2030 and 2050) for Belgium as mentioned before (commodity) + 10% (supplier's margin) + 11,33 €/MWh (grid costs taxes

[32] Reference price was based on diesel price of 0,86 €/l (excl. VAT), a diesel car consumption of 52l/100 km and a hydrogen consumption for FCEV (buses) of 10 kg/100 km.

[33] Reference price was based on diesel price of 1,17 €/l (excl. VAT), a diesel car consumption of 52l/100 km and a hydrogen consumption for FCEV (bus) of 8 kg/100 km.

and levies, as calculated for a 70/36 kV connected customer (direct connection to HS transformer), with an annual off take of 500 GWh)

- Methanol fuel consumption in cars: 7,6 kg/100km
- $CO_2$ capture and purification cost: 50 €/ton
- Distribution cost (for bringing the methanol to the refuelling stations): 0.16 €/l
- Avoided fuel cost (diesel), including taxes but excluding VAT, based on a diesel consumption of 5l/100km: 4,75 €/100km in 2015; 6,49 €/100km in 2030 and 7,85 €/100km in 2050
- The avoided emission of $CO_2$ amounts 59.553 ton per year. This is the captured amount of $CO_2$ (56.019 ton) plus the avoided emission of a natural gas fired boiler with 90% efficiency (for generating the heat that is replaced by heat recovery from the (exothermal) methanation reaction). Per ton of generated methanol, the avoided emission of $CO_2$ equals 1,46 ton. The avoided emission per 100km equals 11,1 kg.

**Economic feasibility**

The considered pathway is not profitable at this moment, neither in 2030 nor in 2050. The operational result (EBITDA) equals -17,8 million euro in 2015, improving to a (still negative) value of -8,2 million euro in 2030 and -3,2 million euro in 2050. NPV equals -304 million euro in 2015, -174 million euro in 2030 and -85 million euro in 2050. The ratio of the NPV over the total CAPEX even increases from -2,71 in 2015 towards -2,04 in 2030 and -1,66 in 2050.

Main changes between 2015 and 2050 are the CAPEX decrease (mainly on the electrolyser, but also on the methanol plant), the OPEX decrease and the increase of the selling price for methanol. The variations of these parameters largely compensate the negative effect of increased power prices.

Fuel price is the parameter having the strongest influence on the profitability, but power price also has a strong influence. The investment cost (CAPEX) and the $CO_2$-capture cost have a much lower influence on profitability. Hereunder tipping points (i.e. values of a certain parameter at which the business case turns profitable) are calculated.

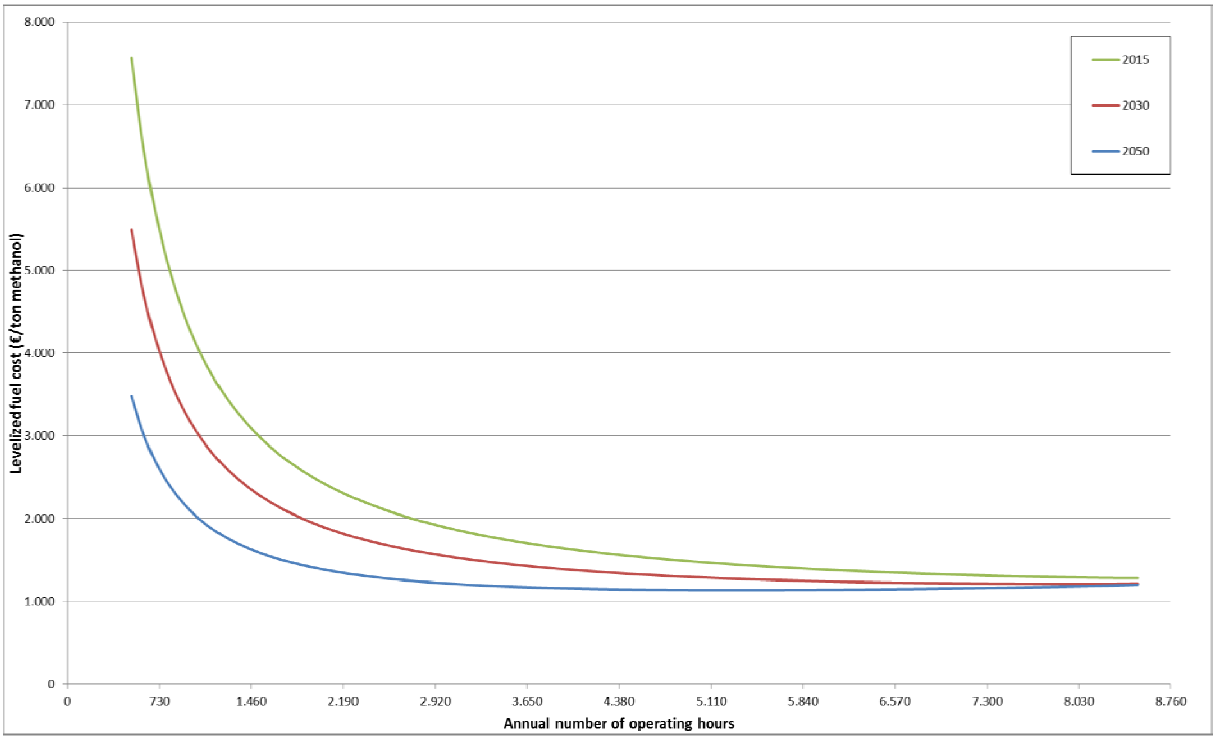
**Table 26: Tipping points (Power-to-Fuel: Methanol as fuel)**

| | 2015 | | 2030 | | 2050 | |
|---|---|---|---|---|---|---|
| | Requirement | Actual value | Requirement | Expected value | Requirement | Expected value |
| Power price (all-in) | < -15,4 €/MWh | 56,1 €/MWh | < 20,6 €/MWh | 62,5 €/MWh | < 53,1 €/MWh | 74,1 €/MWh |
| Fuel price (€/100km) | > 10,42 €/100km | 4,75 €/100km | > 9,74 €/100km | 6,49 €/100km | > 9,45 €/100km | 7,85 €/100km |
| Fuel price (€/ton methanol ) | > 1368 €/ton | 624 €/ton | > 1279 €/ton | 852 €/ton | > 1241 €/ton | 1031 €/ton |
| Capex | < -192 M€ | 112,1 M€ | < -89 M€ | 85,1 M€ | < -34 M€ | 51,3M€ |
| CO2 captation and filtration cost | < -492 €/ton | 50 €/ton | < -261 €/ton | 50 €/ton | < -103 €/ton | 50 €/ton |

**Optimisation of the operating hours**

For the sensitivity analysis of the operating hours, it is considered that no methanol is produced in case the electrolyser doesn't run, as there is no buffer for hydrogen. In the graph below, the levelized cost of methanol is shown as a function of the number of operating hours. It can be concluded that in 2015, the levelized cost increases as the number of operating hours decreases. In 2030 and 2050 however, an optimum can be found. The number of operating hours minimising the levelized cost, equals approximately 7900 hours in 2030 and 5350 hours in 2050. In this case, the lower electricity price largely compensates the lower utilisation rate, although LC max can only be decreased by about 5,5% from 1203 €/ton methanol to 1137 €/ton methanol in 2050.

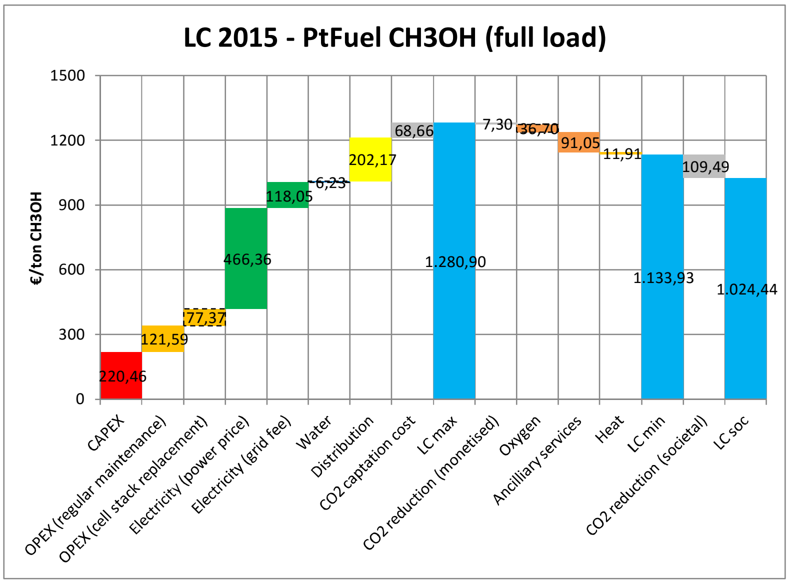
**Figure 34: Levelized cost of hydrogen vs operating time (Power-to-Mobility: Methanol as fuel)**




### Sensitivity analysis: other parameters

The waterfall graph below shows how the levelized cost of methanol as a fuel (expressed in €/ton methanol) is composed (for full load operation in 2015). Other waterfall graphs (for 2030 and 2050, and for the optimised number of operating hours mentioned in previous paragraph) are shown in Annex 16.

**Figure 35: Waterfall graph 2015 (Power-to-Mobility: Methanol as fuel – full load)**



The graph shows that, on the cost side, electricity cost still represents the largest part of the total levelized cost (with commodity price representing the largest part and grid costs only counting for less than 20%), OPEX is slightly less important than CAPEX, water cost is almost negligible, but distribution cost of the liquid fuel is significant in this case. Within the OPEX, cell stack replacement is significant, amounting to approximately 40% of total OPEX in 2015 and decreasing later. On the revenues side, selling the oxygen, providing ancillary services, heat recovery, and avoid purchasing $CO_2$ emission allowances could significantly increase economics, bringing EBITDA close to zero in 2030 and turning it positive in 2050. As a result, NPV remains negative in 2030, but turns positive in 2050 (giving an IRR of 8,4% for this case).

Indeed, as we consider that the captured $CO_2$ is not directly emitted and that some on site $CO_2$ emission is avoided due to heat recovery, the selling (or the avoided purchasing) of $CO_2$ emission allowances should be included in the revenue calculation for $CO_2$. For 2015, this has limited impact (7,3 €/ton), but due to increasing prices for emission allowances, the impact will increase to 51 €/ton in 2030, and 69 €/ton in 2050. Including avoided societal costs of $CO_2$ emissions (additional to the costs covered by the emission allowances, as explained above) causes a reduction of 109 €/ton on the levelized cost in 2015. This reduction will increase significantly to 161 €/ton in 2030, and 310 €/ton in 2050. This still excludes avoided societal costs for emission of nitrogen oxides and fine particulates, if any.

To allow the comparison of this case with other mobility cases (including conventional diesel), the levelized cost of methanol per 100 km has been calculated and detailed results are presented in the Annex 16.

**Conclusion**

The considered base case is not profitable at this moment, and is not expected to be profitable neither in 2030 nor 2050. The parameters that have most influence on the profitability are the power price and (to a lower extent) the natural gas price. For 2050, significant but realistic changes to these parameters can turn this case positive.

It should also be noted that no efficiency improvement at car level is included in this calculation, as a methanol blend in conventional fuels, burnt in conventional internal combustion engines, is assumed. Using methanol is a fuel in direct methanol fuel cells (DMFC) can, certainly in the future, give higher efficiencies than those obtained for internal combustion engines, which will strongly increase economics for methanol as a fuel.

#### *6.3.8. Case 8: Power-to-Power: hydrogen energy storage – small scale*

**Description**

For this case, we typically look at industrial or commercial sites, with on-site renewable energy production (wind and/or PV). When electricity production of the windmills/PV-panels exceeds local consumption, electricity is converted into hydrogen in an electrolyser, and stored on site. When local electricity demand exceeds the on-site renewable energy production, hydrogen is reconverted into electricity by means of a fuel cell. This allows the owner of the plant to reduce the injection of (excess) electricity into the grid, to reduce the electricity off take from the grid and to reduce grid costs. Reference can be made to the Don Quichote project (see http://www.don-quichote.eu/).

Power storage can also be done at a larger scale. In that case, we think about utility-owned plants that can be an alternative to the pumped hydro storage of Coo and Plate-Taille, or the so-called 'Energy Atol' in the North Sea. As large scale power storage projects show similar results than their small scale equivalents, large scale power storage is not described in detail in this report. However, some additional information can be found in Annex 20.

**Case specific assumptions**

For the calculation, following specific assumptions are made:

- Electrical power input of the electrolyser: 500 kW
- Type of electrolyser: Alkaline
- Electrical power output of the fuel cell: 120 kW
- Storage: 300kg of hydrogen, at 200 bar, at a cost of 225 €/kg (in 2015)
- Compression: one compressor, one stage, total capacity equal to the electrolyser output capacity (+/- 100 Nm³/h)
- On site renewable production: typical profile for a wind turbine with a rated power output of 2 MW
- On site power consumption: theoretical profile with an average consumption of 1500 kW peak and 300 kW off peak
- Annual operating hours of the electrolyser: 1334 (calculation based on capacities and profiles mentioned above)
- Annual hydrogen production: +/- 128.000 Nm³
- Civil works cost: 10.000 €
- Connection cost to the public power grid: 50.000 € (extension of on-site substation – no changes required to public grid connection)
- Power price:
  - Value of excess electricity: according to price duration curves (mid scenario for 2030 and 2050) for Belgium as mentioned before (commodity) - 5% (cannibalisation) -10% (supplier margin)
  - Avoided purchasing cost of electricity: according to price duration curves (mid scenario for 2030 and 2050) for Belgium as mentioned before (commodity) + 10% (supplier margin) + 37,90 €/MWh (grid costs taxes and levies, as calculated for a 10/12/15 kV connected customer, with an annual off take of 7,5 GWh)
- The avoided emission of $CO_2$ amounts 62 ton per year. This equals the avoided emission of electric power generation with the average Belgian production park (assuming an emission factor of 285 kg/MWh of electricity).

**Economic feasibility**

The considered case is not profitable at this moment, neither in 2030 nor in 2050. The operational result (EBITDA) equals -23.654 € in 2015, improving to a (still negative) value of -16.478 € in 2030 and -14.837 € in 2050. NPV equals -1,9 million euro in 2015, -1,25 million euro in 2030 and -0,9 million euro in 2050. The ratio of the NPV over the total CAPEX stays relatively constant (with little decrease), from -1,15 in 2015 towards -1,17 in 2030 and -1,22 in 2050.

Main changes between 2015 and 2050 are the CAPEX decrease (mainly on the electrolyser), the OPEX decrease and the increase of the avoided purchasing cost for hydrogen. The variation of these parameters largely compensates the negative effect of increased power prices.

Contrary to the cases described previously, the investment cost (CAPEX) is the parameter with the steepest curves and therefore having the strongest influence on the profitability. Power prices (for consumed and for generated power) have a similar but much lower influence on profitability. Hereunder tipping points (i.e. values of a certain parameter at which the business case turns profitable) are shown.

**Table 27: Tipping points (Power-to-Power: hydrogen energy storage – small scale)**

| | 2015 | | 2030 | | 2050 | |
|---|---|---|---|---|---|---|
| | Requirement | Actual value | Requirement | Expected value | Requirement | Expected value |
| Power price injection | < -279 €/MWh | 34,8 €/MWh | < -165 €/MWh | 39,7 €/MWh | < -98,3 €/MWh | 48,75 €/MWh |
| Power price offtake | > 1005 €/MWh | 82,7 €/MWh | > 560 €/MWh | 89 €/MWh | > 412 €/MWh | 100,6 €/MWh |

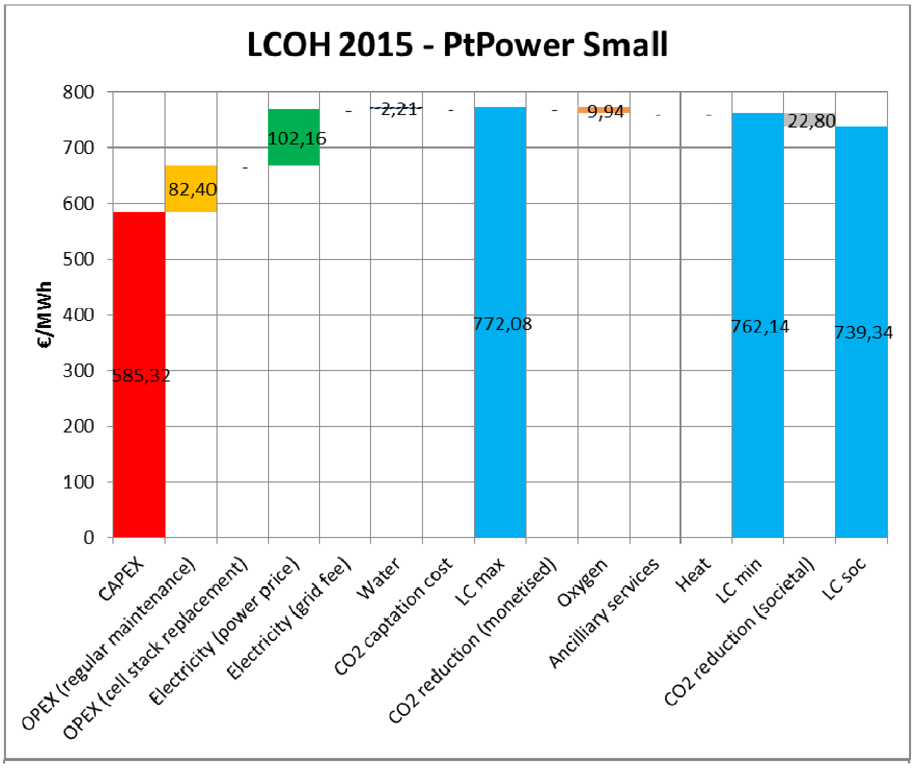
**Optimisation of the operating hours**

The economics of this particular case are driven by the local renewable energy production profile and the local power consumption profile. As it is quite obvious that changing the profiles will not only lead to a different number of operating hours of the electrolyser and the fuel cell, but also to different sizes/capacities of buffer, electrolyser and fuel cell, project-specific or even scenario-specific calculations will  be required for each individual case.

**Sensitivity analysis**

The waterfall graph below shows how the levelized cost of power storage (in €/MWh) is composed (for full load operation in 2015). Other waterfall graphs (for 2030 and 2050, and for the optimised number of operating hours mentioned in previous paragraph) are shown in Annex 17.

**Figure 36: Waterfall graph 2015 (Power-to-Power: hydrogen energy storage – small scale)**



On the cost side, the graph shows that CAPEX is the most important factor. OPEX (with no cost for cell stack replacement, as the number of operating hours is too low) and electricity cost are significant, whereas water cost is almost negligible. Within the electricity cost, only commodity price is counted (including 5% decrease for cannibalisation effect and 10% decrease for supplier margin) , as the consumed electricity is expected to be generated by local renewable power plants, such as wind turbines or photovoltaic panels. On the revenues side, selling the oxygen could slightly increase economics, but EBITDA and NPV remain negative, even in 2050.

Reduction of CO2 emissions can in this case not be monetised, as cost for CO2 emissions is already included in the power price. Including avoided societal costs of $CO_2$ emissions however causes a reduction of 22,8 €/MWh on the levelized cost in 2015, increasing significantly to 41,3 €/MWh in 2030 and 74,1 €/MWh in 2050.

**Conclusion**
The considered base case is not profitable at this moment, and is not expected to be profitable in 2030 and 2050 with assumed difference between the price for the consumed power and the value of the generated power.

## 6.4. Conclusions from business models and review of critical parameters

### *6.4.1. General comparison*

Above, several valorisation pathways and their economic feasibility were described. It can be concluded that none of the pathways is fully profitable at this moment. However, some might lead to positive results in the future, due to CAPEX decrease, OPEX decrease, increase of the value of the end-product, and possibly also due to (or even despite) some changes to other parameters.

Based on the assumed values for most of these parameters in 2030 and 2050, we can expect that the small scale industrial pathway ('Industry – Power-to-Hydrogen – Small Scale'), where hydrogen is generated locally to replace externally sourced (tube trailer delivered) hydrogen, will be the first to turn positive (before 2030). Also two of the mobility pathways, being Power-to-Methanol (as a fuel) and Power-to-Hydrogen for cars (FCEV's), are expected to turn profitable before 2050.

The table below summarises the results. Green colour indicates a profitable valorisation pathways, where orange colour means not profitable, but turning profitable in case of a 25% change to one of the main cost drivers (CAPEX, electricity price, value of the end product and, if applicable, $CO_2$ - capture and filtration cost), and red colour means not profitable at all, requiring major and unrealistic changes to one or more cost drivers to turn profitable.

**Table 28: Overview of profitability of different business cases in 2015, 2030 and 2050**

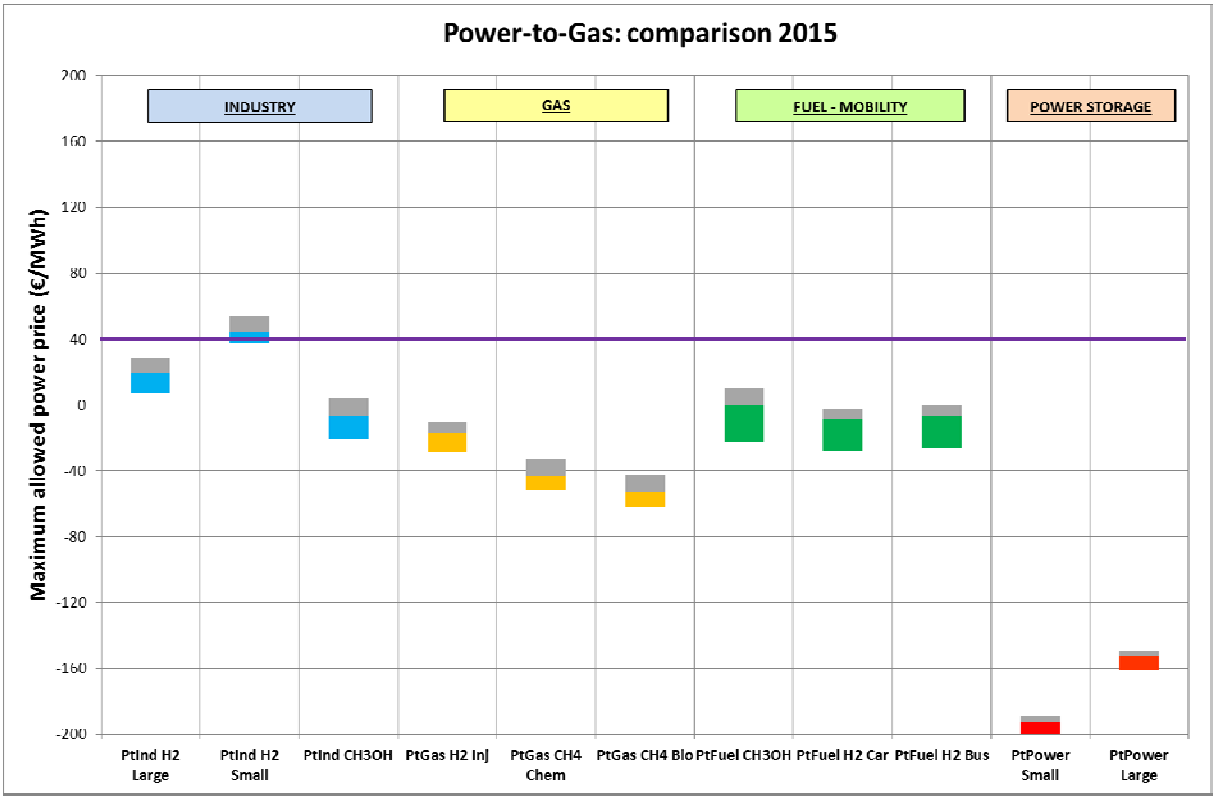
| | 2015 | 2030 | 2050 |
|---|---|---|---|
| Power-to-Industry - small Scale | | | |
| Power-to-Industry - large Scale | | | |
| | | | |
| Power-to-Gas - direct Injection | | | |
| Power-to-Gas - Synthetic Natural Gas (methanation) | | | |
| | | | |
| Power-to-Fuel - Methanol | | | |
| Power-to-Mobility - HRS for cars | | | |
| Power-to-Mobility - HRS for buses | | | |
| | | | |
| Power-to-Power - small scale | | | |
| *NB: This table refers to the analysis of the different business cases in a 'business as-usual' scenario assuming no fundamental policy changes.* | | | |

All of the calculated results for 2030 and 2050 depend on the correctness of the assumptions used in the calculations, and therefore have to be interpreted as indicative figures. As power price, operating time and initial investment have been identified as the main cost drivers in most cases, the calculated results will only be valid if these conditions are met in 2030 and 2050. The evolution of power prices is the most sensitive parameter, and it has been assumed that no dramatic changes would occur on the electricity market (electricity pricing, structure of grid costs, installed storage capacity, price duration curve). Of course, regulatory aspects and market development of hydrogen technologies will have significant impacts on the results. If fundamental changes in the structure of these markets, costs, technologies or regulatory framework will occur, updates of the business-cases will be required in order to calculate the actual economic feasibility of Power-to-Gas **concepts**

Another way to compare economic feasibility of the eleven valorisation pathways is by calculating the required commodity price for electricity to bring the levelized cost of the end product in line with the expected value of that same end product. As all of the described pathways use electricity as a starting point, this is a common point that can serve as a comparison. Required commodity price is calculated for continuous operation (97% availability), which means the maximum allowed market price for baseload electricity, excluding grid costs, taxes and levies.

Results are shown in the graphs below. The bottom of the coloured bar represents the maximum allowed power price for the base case, thus excluding revenues from oxygen production, heat recovery, providing ancillary services, and $CO_2$ emission allowances. The top of the coloured bar represents the maximum allowed power price if revenues from oxygen production, heat recovery, providing ancillary services, and $CO_2$ emission allowances were included. The top of the grey bar represents the maximum allowed power price if all societal costs of $CO_2$ emission could be monetised when avoiding the emission. Finally, the purple line represents actual baseload power price (excluding grid costs, taxes and levies).

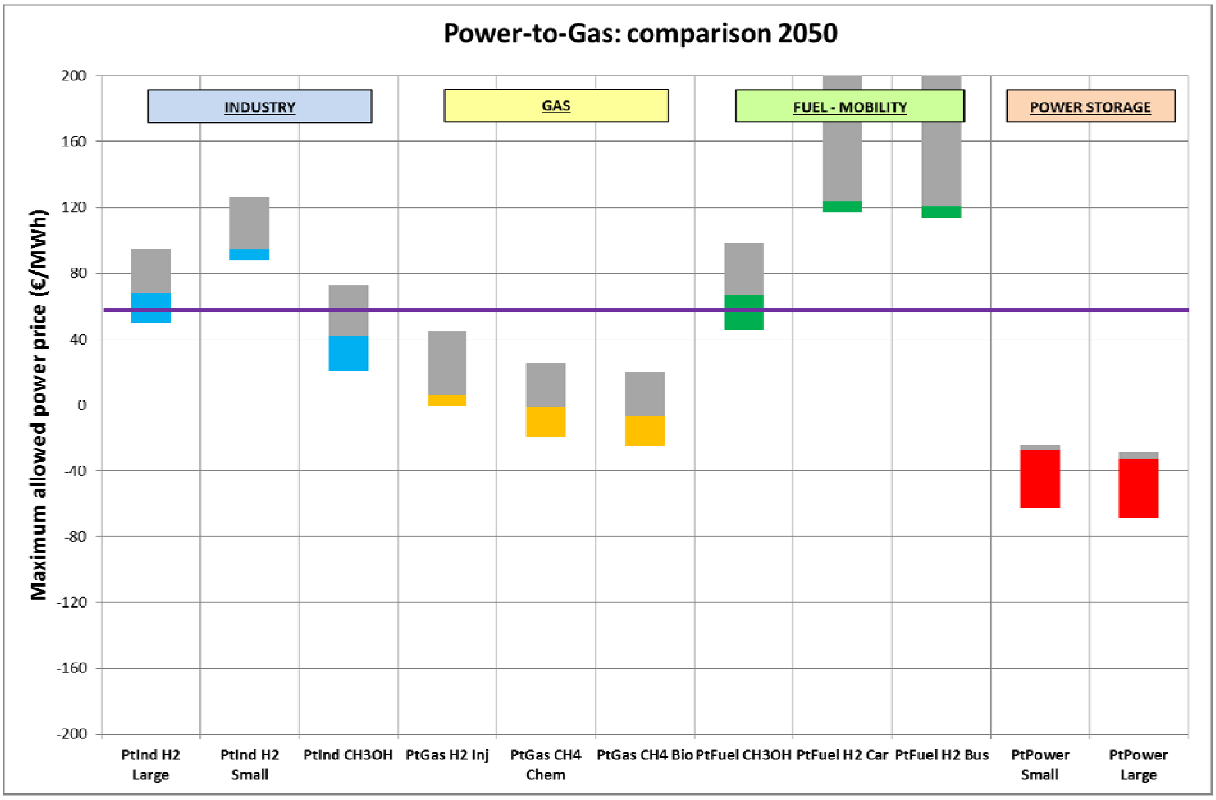
**Figure 37: Comparison of Power-to-Gas business cases - Maximum allowed power price for profitable case in 2015, compared to estimated average power price in 2015**




It is no surprise that only for the small scale industry valorisation pathway the maximum allowed power price comes close to the actual baseload power price (excluding grid costs, taxes and levies). In some cases, where additional benefits from oxygen production and ancillary services supply and the avoided societal cost of $CO_2$ emissions can (partially or fully) be taken into account, the maximum allowed power price might even exceed the actual baseload power price. So, already from 2015, the small scale industry valorisation pathway can reach break-even, at least when some additional revenues can be taken into account. It should however be mentioned that break-even means that the IRR equals the WACC (set at 5%), which will not be sufficient to convince companies to invest in a project. Other Power-to-Industry pathways and some Power-to-Mobility pathways have a maximum allowed baseload power price above zero, where certainly the power storage (Power-to-Power pathways) but also the hydrogen or methane injection in the gas grid (Power-to-Gas pathways) require negative power price all over the year to turn profitable.

As shown in the graph below, in 2050, the expected baseload power price is below the maximum allowed power price for the small scale industry pathway and all hydrogen mobility pathways, and in most cases also for the large scale industry pathway and the methanol fuel pathway (if some additional benefits can be realised). The industrial methanol pathway requires that avoided societal costs for $CO_2$ emissions are monetised, whereas all Power-to-Gas pathways and certainly the power storage pathways require baseload power prices that are far below the expected price (for methanation and power storage even below 0 €/MWh).

**Figure 38: Comparison of Power-to-Gas business cases - Maximum allowed power price for profitable case in 2050, compared to estimated average power price in 2050**

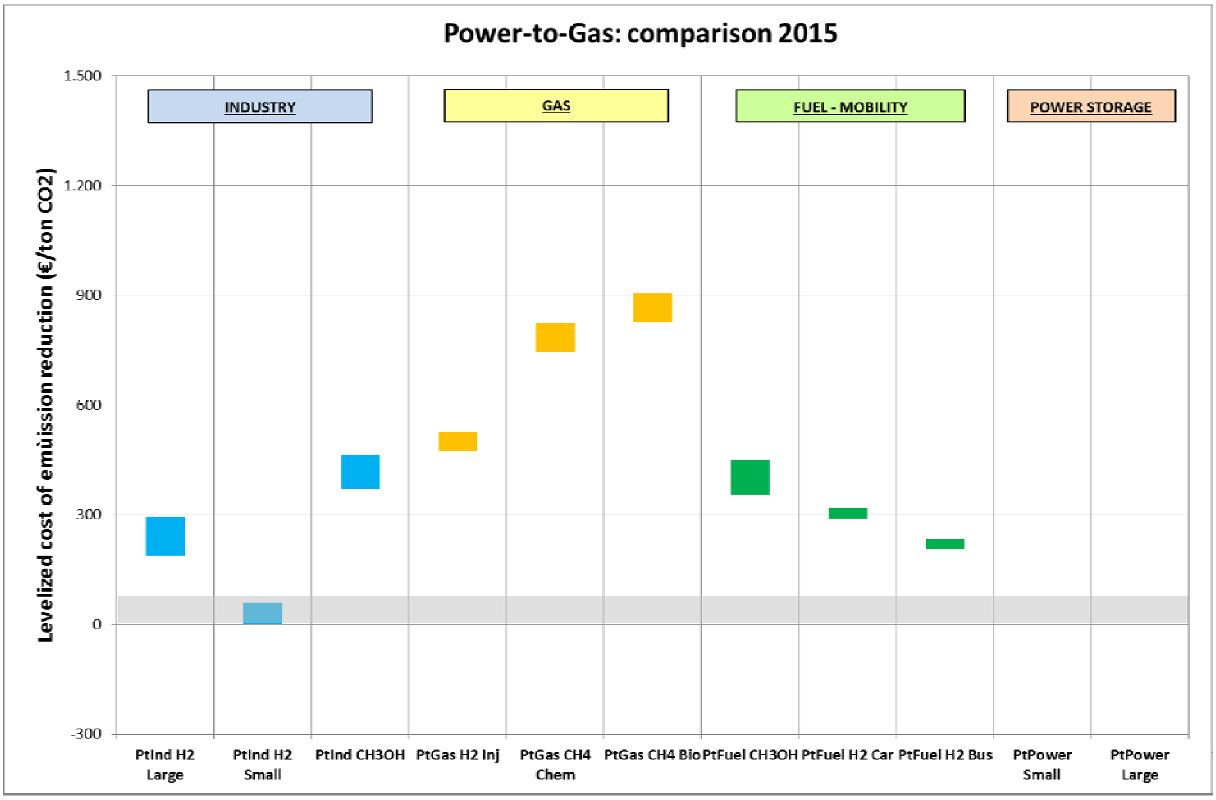



We could also calculate the levelized cost of avoiding a tonne of $CO_2$ emissions. Results of this calculation are shown in the graphs below, where the bottom of the bars shows the levelized cost of $CO_2$ emission reduction for the base case, thus excluding revenues from oxygen production, heat recovery and providing ancillary services. The top of the bars, on the other hand, represents the levelized cost of emission reduction if revenues from oxygen production, heat recovery and providing ancillary services were included.

Values in these graphs should be compared to either the price for $CO_2$ emission allowances (5 €/ton in 2015, 35 €/ton in 2030 and 47.5 €/ton in 2050) or the societal cost of the emission (80 €/ton in 2015, 145 €/ton in 2030 and 260 €/ton in 2050), representing respectively the bottom and the top of the grey rectangle in the graphs.

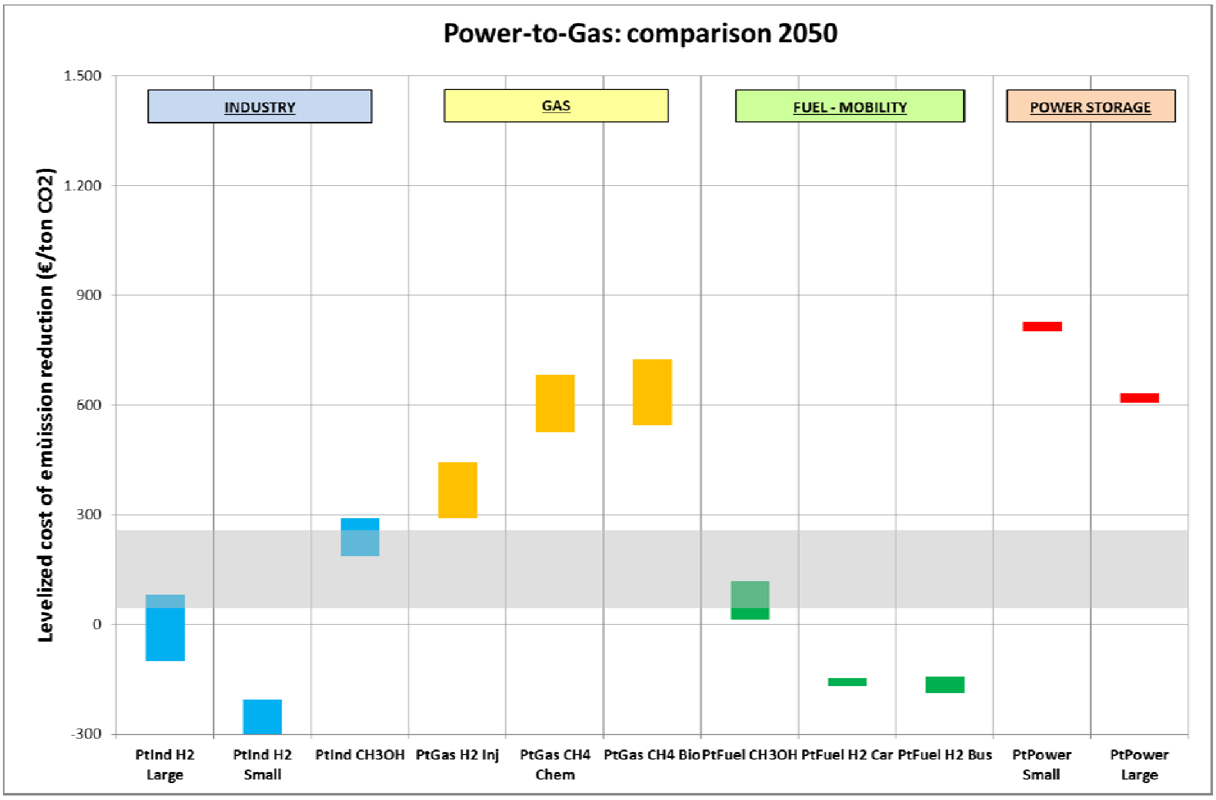
For 2015, only the small scale industry pathway shows levelized costs of $CO_2$ emission reduction below the societal cost of $CO_2$ emissions, and even below the price of $CO_2$ emission allowances when additional revenues from oxygen production and ancillary services can be taken into account and when the number of operating hours can be optimised. For all other pathways, levelized cost of CO2 emission reduction is way above the societal cost of $CO_2$ emission, with the power storage having by far the highest levelized cost (2384 – 2419 €/ton for the small scale power storage and 1825 – 1860 €/ton for the large scale power storage).

**Figure 39: Comparison of Power-to-Gas business cases – Levelized cost of $CO_2$ emission reduction in 2015, compared to estimated $CO_2$ cost in 2015**




For 2050, small scale industry, and all hydrogen mobility pathways have a levelized cost of emission reduction which is always below the price of $CO_2$ emission allowances. Large industry pathway and methanol fuel pathway most of the times also do, but require that some optimisation of operating hours is done or some additional revenues are taken into account. Such optimisation and additional revenues are also needed to bring the levelized cost of emission reduction in the industrial methanol pathway below the societal cost of $CO_2$ emissions. For all other pathways (being all pathways injecting hydrogen or methane in the gas grid, and all power storage pathways), levelized costs of emission reduction stays above societal cost of $CO_2$ emission.

**Figure 40: Comparison of Power-to-Gas business cases – Levelized cost of $CO_2$ emission reduction in 2050, compared to estimated $CO_2$ cost in 2050**




It can be concluded that calculating the levelized cost of $CO_2$ emission reduction for all the pathways, as an indication of their possible prioritisation with respect to climate change, shows the same trends as for the pure economic analysis, and presents the small scale industry case and the mobility cases as the most promising ones in the short or medium term.

### *6.4.2. Review of critical parameters*

Below, some of the parameters having the biggest impact on the business case results are discussed in more detail.

**Power prices**

Power price is in almost all of the cases by far the most influencing parameter on the economics, as power purchasing represents the largest cost of water electrolysis. Therefore, there is an interest to bring down the power price or at least the total power cost.

In this respect, using electricity generated by local (on site) power production, mostly from renewable sources like wind or solar can be considered. However, local renewable power production will almost never lead to full exemption of grid costs, taxes and levies, due to its intermittent character and the low number of equivalent full load hours of windmills or photovoltaic panels. A 25% reduction of grid costs, taxes and levies due to local power generation out of windmills (and photovoltaic's) can be considered more realistic for small projects. For larger projects, such a reduction is less likely, as the required power generation capacity and therefore also the needed surface area would be very large. Beside this, larger projects already have the lowest grid costs, so the impact of reducing (or avoiding) them will be smaller.

Another way of reducing the power price is to reduce the number of operating hours and operate the electrolyser only at the hours with the lowest power prices. This is explained below (see ‘Operating hours’).

**CAPEX**

In most of the cases described above, CAPEX has a lower impact on the economics than the power price, which was identified as the main cost driver. Only for the power storage cases (Power-to-Power), CAPEX was more important than power price. Though significant CAPEX reductions are expected in the next years, these reductions will in some cases not be sufficient to turn the case profitable.

**Operating hours**

Optimisation of the number of operating hours (i.e. reduction of the number of operating hours to decrease average power price, running only in the hours with the lowest power prices) makes almost no sense in 2015, but can improve economic feasibility afterwards, certainly for 2050. As the price duration curves for electricity get steeper then, the lower electricity price will largely compensate the lower utilisation rate. The reduction of the levelized cost of the end product varies between 3.5% and 25%, with the lowest impact for the mobility pathways (Power-to-Fuel) and the highest impact for the large scale industry pathway (Power-to-Industry).

**Other parameters**

The value of the end-product was found to be a main driver for profitability in many cases. Possible benefits, related to sale of produced oxygen, heat recovery, avoided purchasing of $CO_2$ emission allowances and providing ancillary services to the operator of the public electricity grid, wherever applicable, can surely have an impact on the feasibility of a project. However, these revenues will not be obtained for all projects, and their impact is always limited, compared to the costs. On the cost side, electricity cost and CAPEX were already described above, as being the most influencing parameters. Other costs, such as OPEX and water cost, are less important, the latter even almost negligible. Within the OPEX, the cell stack replacement cost always represents a significant part, in some cases even more than half of the total OPEX.

**Political dimension**

Some of the parameters can be influenced by laws and regulations. Exemptions from grid costs (for power consumption and/or gas injection) might significantly change the economics of some of the cases described above. Direct subsidies to lower the initial investment and reduce the capital risks could also have strong impact on the economics. Also for mobility cases, exemption for taxes and excise duties can have huge impact on the profitability of power-to-fuel projects. Justification for such governmental measures can be found in the $CO_2$ emission reduction, as well as in other emission reductions (NOx, particulates…), mostly in mobility.

# 7. COMPETITIVENESS AND MARKET POTENTIAL OF POWER-TO-GAS

## 7.1. Green Industry (Power-to-Industry)

As explained before, current industrial demand for hydrogen is mostly met by producing hydrogen through steam methane reforming, using natural gas (or possibly also biomethane) as an input product. Steam methane reforming could be done on site (for larger customers), but could also be centralised, requiring tube trailer deliveries of the hydrogen to the end-user (for smaller customers). However, in both cases, on site hydrogen production from water electrolysis can be an alternative, which reduces significantly natural gas consumption and therefore also carbon dioxide emissions.

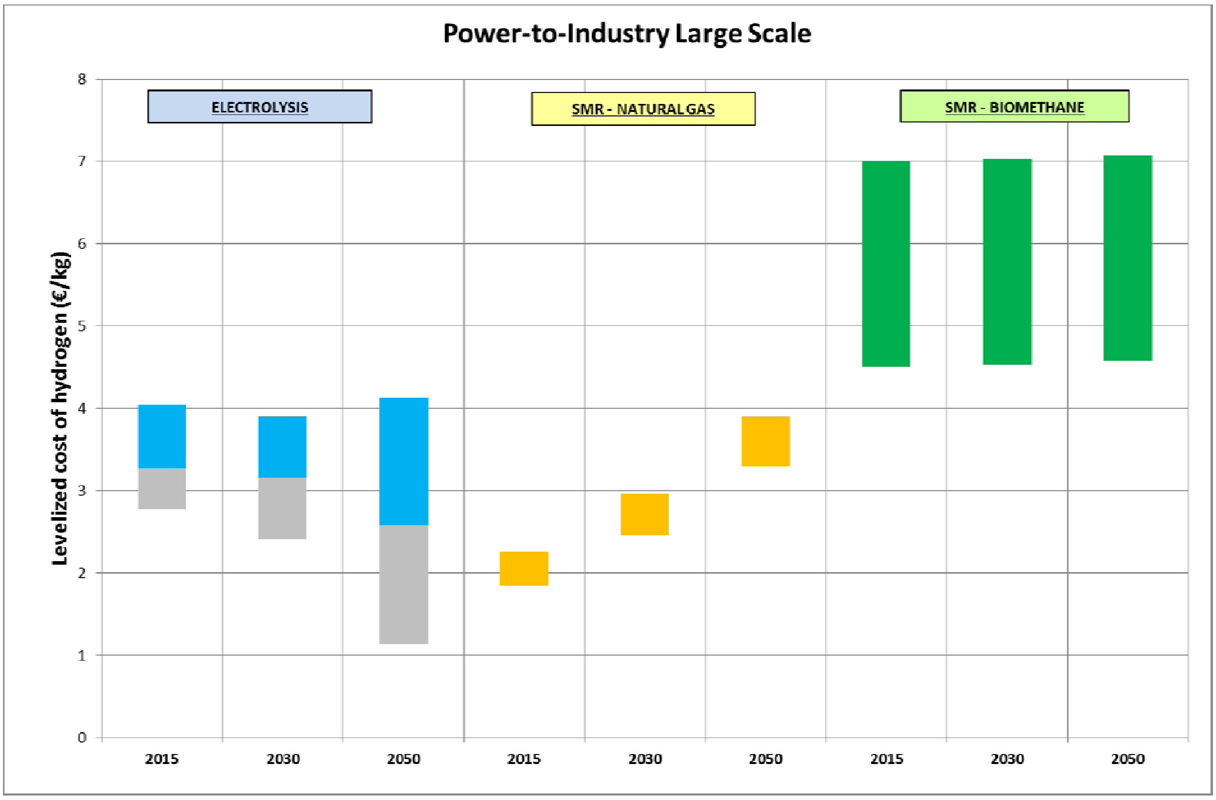
Strengths, weaknesses, opportunities and threats (SWOT) of hydrogen production from water electrolysis for industrial applications (large scale and small scale) are shown in the table below.

**Table 29: SWOT Green Industry**

| **STRENGTHS** | **WEAKNESSES** |
|---|---|
| • Onsite hydrogen production is already competitive when hydrogen delivery costs are high (remote location for central SMR production site)<br>• The industry is already familiar with hydrogen. | • Competitiveness of hydrogen production vs SMR production costs today<br>• Lowest cost in operating range between 2000-6000 hours. Need back up hydrogen the rest of the time! |
| **OPPORTUNITIES** | **THREATS** |
| • The industry is already consuming hydrogen in large quantities → There is an important potential to replace hydrogen from SMR by green hydrogen<br>• Existing hydrogen infrastructure in place in Belgium (hydrogen pipeline and gas suppliers presence in Belgium)<br>• Increasing cost for natural gas SMR if carbon pricing is applied | • Gas price evolution doesn't seem to increase at short/medium term<br>• $CO_2$ allowance price has little impact on hydrogen price from SMR |

In the graph below (Figure 41), levelized cost of hydrogen production (LCmax) from various technologies is shown for large scale hydrogen production. Steam methane reforming units are considered to run baseload, and for biomethane a price between 75 and 125 €/MWh HHV is assumed (for 2015, 2030 as well as 2050). For the electrolysis cases - the top of the coloured bar represents LCmax at full load operation; the bottom of the coloured bar represents LC min with optimised number of operating hours, and the bottom of the grey bar finally represents LCsoc (again with optimised number of operating hours). For the competing technologies (SMR with natural gas or biomethane), the bottom of the coloured bar represents the LOW scenario and the top the HIGH scenario.

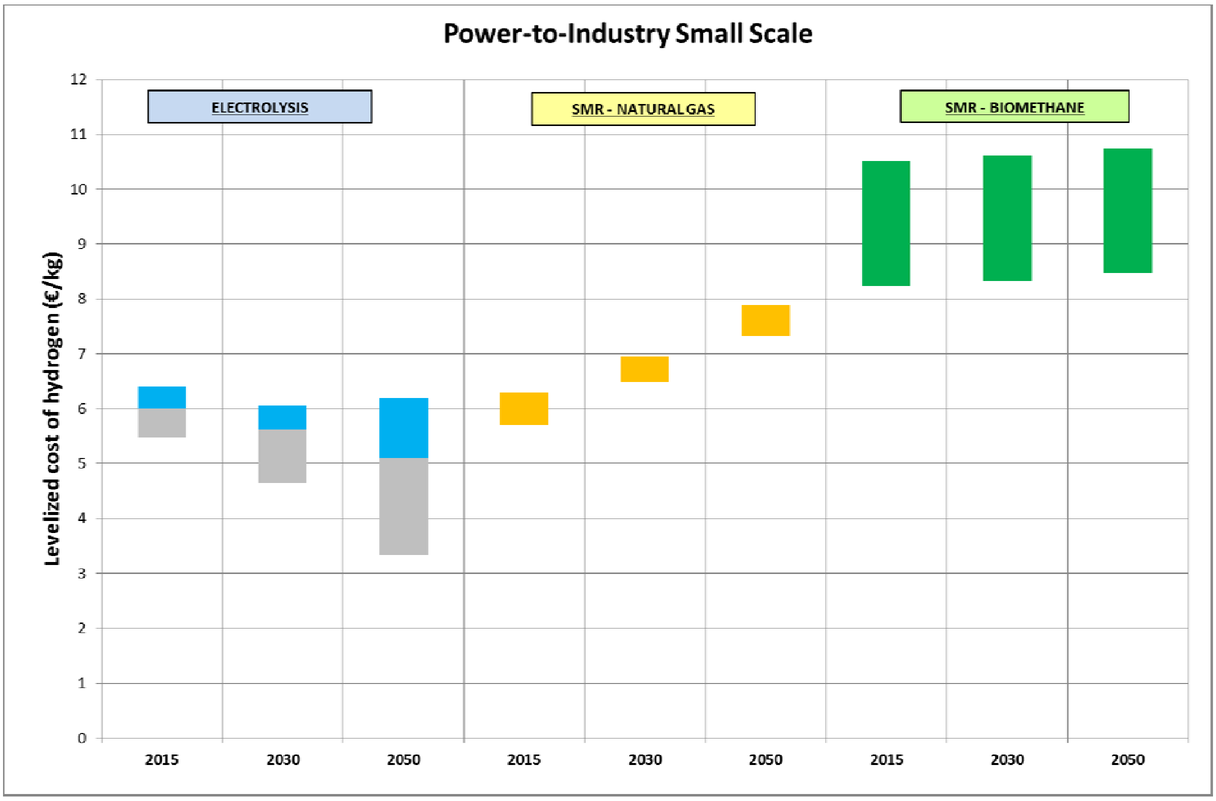
**Figure 41: Levelized cost of hydrogen production (large scale, with sensitivity)**




The levelized cost of hydrogen from electrolysis is always lower than the levelized cost of hydrogen from biomethane reforming. For large scale applications, opportunities to generate cheaper hydrogen from electrolysis compared to Steam Methane Reforming (SMR) will emerge after 2030, taking advantage of the lowest electricity prices. If societal benefits can also be taken into account, the hydrogen produced from large scale electrolysis is already competitive in 2030.

In the graph below (Figure 41), levelized cost of hydrogen production (LCmax) from various technologies is shown for small scale hydrogen production.

**Figure 42: Levelized cost of hydrogen production (small scale, with sensitivity)**




It can be concluded that in a lot of cases, the small scale electrolysis might already be competitive to natural gas SMR under specific circumstances in 2015, and will anyhow become more profitable in 2030 and 2050. Biomethane SMR is never competitive to electrolysis, but might be to natural gas if societal benefits are included (not shown on the graph).

## 7.2. Green Gas (Power-to-Gas)

Natural gas is very commonly used as a fuel for heating purposes, but also more and more for mobility (CNG), and as a base product in industry. Hydrogen from water electrolysis can be used to reduce carbon emissions from natural gas. Therefore, hydrogen can be injected directly into the natural gas grid, but hydrogen can also be used to generate methane (using $CO_2$ in the reaction process), which can also be injected in the natural gas grid. Both options are described below.

**Injection of hydrogen into the gas grid**

A study[34] on the Admissible hydrogen concentrations in natural gas systems showed that if an admixture of up to 10 % by volume of hydrogen to natural gas is possible in some parts of the systems, issues remain in some other important areas. Therefore a 10%vol concentration cannot be applied blindly and a case by case approach is recommended as not only the gas transport and distribution infrastructures but also downstream infrastructures using natural gas as a fuel (gas turbines…) or in contact with natural gas should be considered. In particular, the presence of underground porous rock storages and the UN ECE R110 specification used for steel tanks in natural gas vehicles lead to the adoption of a cautious approach with concentrations limited to 2%vol. For

[34] (Altfeld & Pinchbeck)

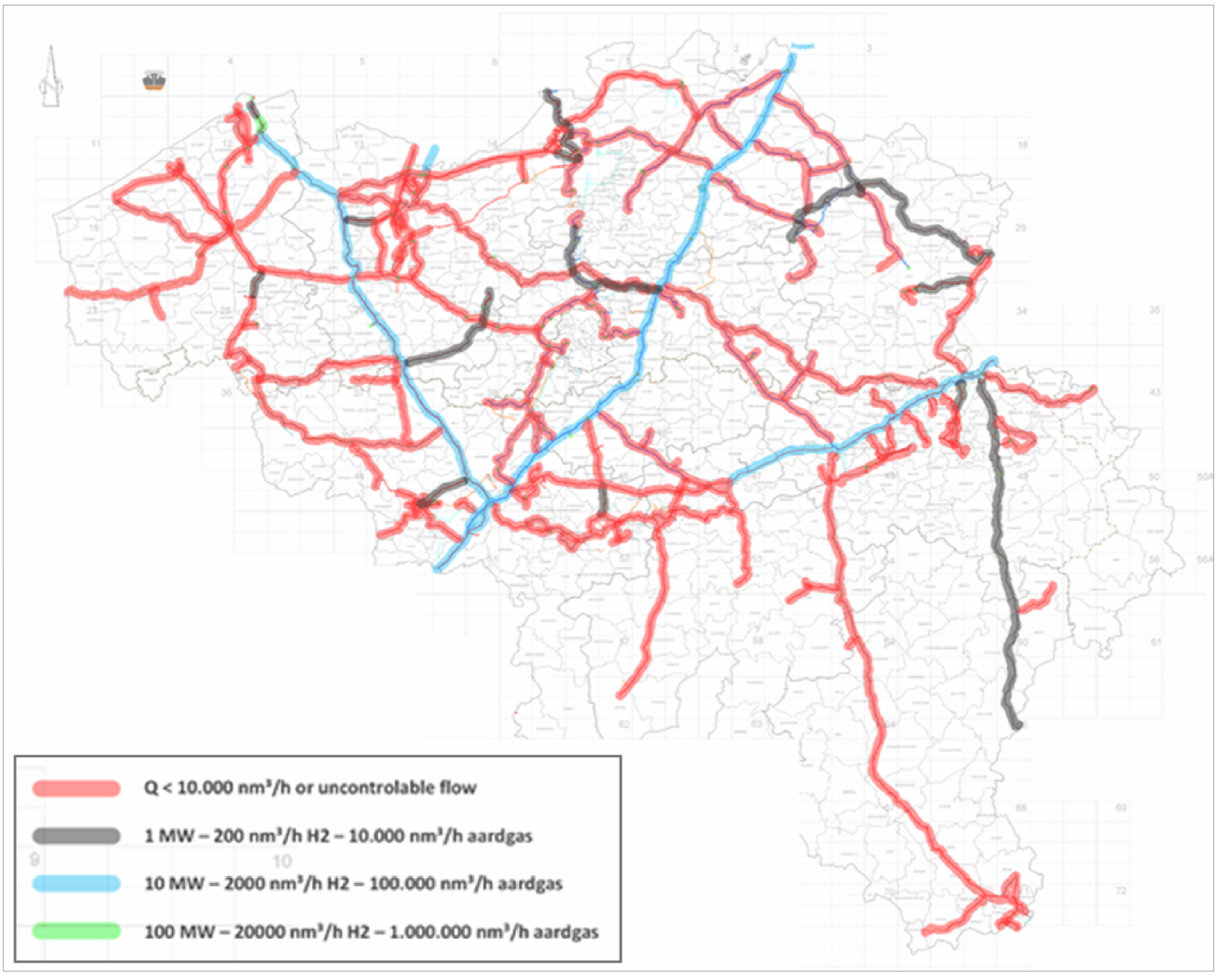
these reasons, in Belgium, it is generally accepted that a 2%vol is currently the maximum concentration to be allowed in gas grids.

On top of the volume fraction limitation, also the directions of the flows must be taken into account to avoid H2 build-ups leading to % above the 2% limit close to injection points.

This makes only a very limited number of pipelines suited for large injection rates of hydrogen. For Belgium, possibilities for hydrogen injection can be summarized as follows:

- Main pipeline from NL → FR: this line has the highest possibilities. The total amount of hydrogen that can be injected into this pipeline (with respect of the 2% limitation) corresponds to the installation of a total capacity of 10 $MW_e$ of electrolysers. See blue lines on the map below.
- The pipeline between Zeebrugge and Ville-sur-Haine (Mons - French border) and the pipeline between Berneau (Liège – German border) and Ville-sur-Haine (Mons – French border), which can handle up to a total of 10MWe of electrolyser capacity. See blue lines on the map below.
- Due to the important gas volumes coming directly from Norway, the area close to the Zeebrugge LNG terminal is the most interesting for the injection of hydrogen, with a theoretical total electrolyser capacity of up to 100 $MW_e$. See green line on the map below. Based on the volume typically observed, other parts of the transport grid could accept up to 1 $MW_e$ production units. See black lines on the map below.

**Figure 43: Gas flow technical possibilities to inject H2 in Fluxys Belgium gas transport infrastructures[35]**




Important remarks:

1. It must also be taken into account that hydrogen injection in our neighbouring countries, certainly if it's done close to the border, can negatively influence the maximum acceptable volumes and capacities in Belgium gas grids.
2. Before taking any decision concerning the injection of hydrogen in gas grids, a more detailed analysis is required (volumes to be injected, exact location, downstream gas users and potential impact on their processes and infrastructures, etc.).

**Injection of synthetic methane into the gas grid**

Methane, being the main component of natural gas, can be injected in large quantities into the natural gas grid. Therefore, unlike for hydrogen, no major restrictions apply to the number and the capacities of Power-to-Methane installations in Belgium.

Strengths, weaknesses, opportunities and threats (SWOT) of injection of hydrogen or synthetic methane in the gas grid are given in the table below.

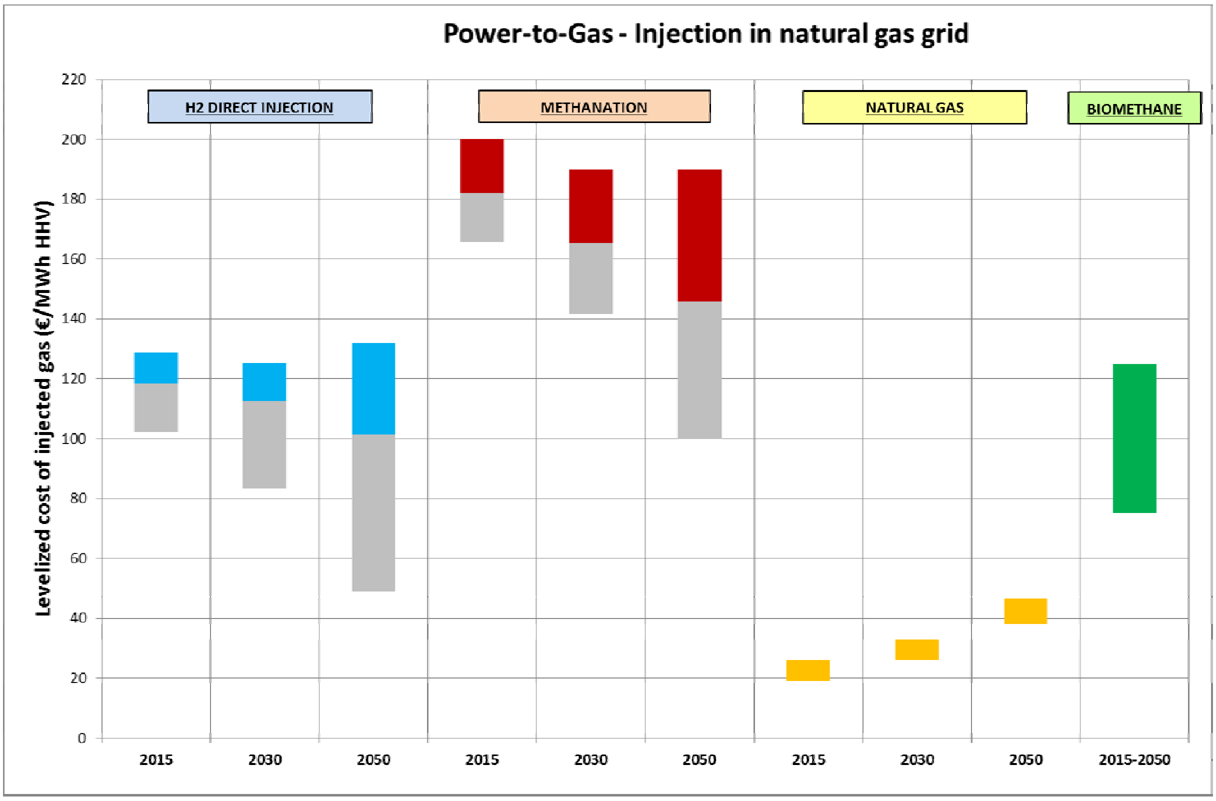
[35] Source: Fluxys Belgium, indicative information based on a 2%$_{vol}$ limitation

**Table 30: SWOT Green Gas**

| STRENGTHS | WEAKNESSES |
|---|---|
| • Very large storage potential in gas infrastructure (TWh range)<br>• Good synergies between the power and gas activities<br>• Almost unlimited potential for SNG injection in gas grid<br>• A lot of attention from the gas sector (only direct option with biomethane to green the gas)<br>• The cost per MWh for transporting energy is lower for pipelines than for the electricity grid | • Max. $H_2$ % allowed in gas grids limited to 2% in volume, but methanation could lift this limit up to 100%<br>• Possible sensitiveness to (variable) hydrogen concentration for specific applications (gas turbines, burners…) should be further analysed.<br>• Limitation in $\%_{vol}$ for hydrogen injection:<br>  o Problem with (low) gas consumption in summer<br>  o Difficult to guarantee a certain injection volume (link with local consumption and total number of injections points on the same pipeline)<br>  o $H_2$ injection in neighbouring countries might limit the potential in Belgium |
| **OPPORTUNITIES** | **THREATS** |
| • Many companies (utilities, DSO or energy suppliers) are active in both sectors (power and gas)<br>• Synergies with $CO_2$ capture and utilization<br>• Broader use of CNG as a fuel for mobility applications<br>• Interesting synergy with biogas production (upgrading to biomethane)<br>• Very high $CO_2$ price and the need to $CO_2$valorise could make Power-to-Gas very interesting | • 1st generation CNG tanks supposed to be certified up to 2%vol hydrogen concentration in CNG (currently under investigation in Germany)<br>• Ability of underground storages (porous rocks) to accept more than 2%vol Hydrogen still to be demonstrated (currently under investigation in Austria)<br>• Methane production requires a $CO_2$ source (cost, availability, green character) |

In the graph below, levelized costs of the injected gases from various technologies are shown and compared to expected natural gas and biomethane prices. The top of the coloured bar represents LCmax at full load operation; the bottom of the coloured bar represents LC min with optimised number of operating hours, and the bottom of the grey bar finally represents LCsoc (again with optimised number of operating hours). For natural gas and biomethane, the bottom of the coloured bar represents the LOW scenario and the top the HIGH scenario. For biomethane, this equals 75 €/MWh HHV and 125 €/MWh HHV respectively.

**Figure 44: Levelized cost of gas injection (with sensitivity)**




It can be concluded that the levelized cost of direct injection of hydrogen (from electrolysis) can – at least if some additional revenues and/or societal benefits are counted – be at the same level as the expected biomethane price (though for 2015 only at the level of the higher part of the biomethane price spread). The levelized cost of direct injection of hydrogen (from electrolysis) is largely above the expected natural gas price in 2015 and 2030. However, for 2050, the bottom levelized cost for direct injection of hydrogen (i.e. including additional revenues, operating hours optimisation and avoided societal costs) is only a little higher than the maximum expected price for natural gas (HIGH scenario). Injection of synthetic methane (generated out of hydrogen from electrolysis) always has a higher levelized cost than the expected natural gas price and in most cases also than the expected biomethane price. Only in 2015 - and only when additional revenues, operating hours optimisation and avoided societal costs are included - synthetic methane might be competitive compared to biomethane.

The methanation approach should therefore be considered when the maximum injection rate of hydrogen in natural gas (2%) is reached, postponing additional investments in methanation to the moment when it is unavoidably required.

### 7.3. Green Transport (Power-to-Mobility and Power-to-Fuel)

Hydrogen from water electrolysis can also play a role in making transport greener. Both the use of hydrogen in fuel cell electric vehicles (passenger cars, buses…) and 'traditional' vehicles using hydrogen derivates (synthetic methane, methanol…) as a fuel can be considered.

Strengths, weaknesses, opportunities and threats (SWOT) of hydrogen as a fuel for fuel cell electric vehicles (FCEV – cars and buses) are given in the table below.

**Table 31: SWOT Fuel Cell Electric Vehicle Mobility**

| STRENGTHS | WEAKNESSES |
| --- | --- |
| • Refuelling time is rather short: +/- 3 min<br>• Driving range is higher than most of EV's : 500km<br>• Technology of FCEV is based on EV's: increasing maturity, good public acceptance<br>• No emission at point-of-use (only water exhaust)<br>• Many synergies with EV's | • Need to compress hydrogen to 450 bar (buses) and 900 bar (cars) → safety + cost issue<br>• Important investment needed to put in place the hydrogen refuelling infrastructure<br>• Business case is very difficult for first HRS (not enough users at the beginning, low utilization)<br>• Lack of standards for HRS<br>• Well-to-wheel analysis shows better (x2) efficiency for EV's<br>• Cars are still more expensive than diesel or gasoline equivalent |
| **OPPORTUNITIES** | **THREATS** |
| • Some major car manufacturers (Toyota, Hyundai, Honda, …) are commercializing already FCEV and most of the major EU are planning to before 2020→ no more chicken-egg problem<br>• Hydrogen recognized in the Fuel Quality Directive as a "renewable liquid and gaseous fuel of non-biological origin"<br>• Many $H_2$ mobility plans already defined in major EU countries<br>• Support from Flemish government when buying FCEV's | • The location of fuel stations has to match existing local power grid infrastructure.<br>• Lack of FCEV's available on the market (not enough cars) leading to low utilization of HRS infrastructure<br>• Competition with EV's (increased range)<br>• The training of the automotive sector to FCEV represents a major challenge (but idem EV's)<br>• Public acceptance of hydrogen<br>• The general public is not used to handle hydrogen. |

The SWOT-analysis for methanol (generated using hydrogen from electrolysis) as a fuel is presented in the table below.

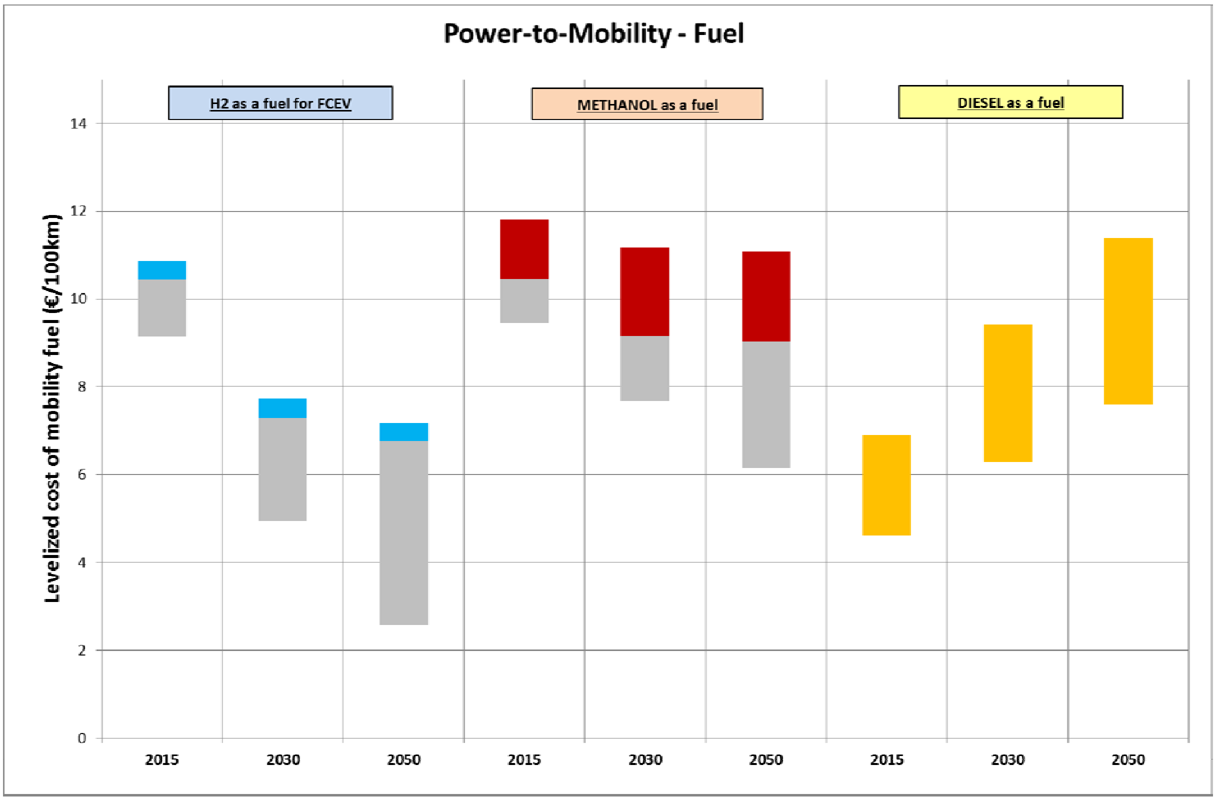
**Table 32: SWOT Green Methanol**

| **STRENGTHS** | **WEAKNESSES** |
|---|---|
| • Methanol can already be used for the production of bio-diesel or blended with gasoline<br>• Existing methanol market (=commodity market) | • Large-scale applications (multi-MW range)<br>• Business case is still difficult today. |
| **OPPORTUNITIES** | **THREATS** |
| • Hydrogen and derivates recognized in the Fuel Quality Directive as a “renewable liquid and gaseous fuel of non-biological origin”<br>• CertifHy EU project aims to define Green Hydrogen and to put in place a certification mechanism to support Green Hydrogen<br>• Synergies with $CO_2$ capture and utilization<br>• Methanol is mainly produced today from hydrogen via SMR → There is a important potential to replace hydrogen from SMR by green hydrogen | • Methanol production requires a $CO_2$ source (cost, availability...)<br>• Final product (methanol) is still a carbon intensive |

In the graph below, levelized costs of mobility fuels for cars (expressed in €/100km) from various technologies (based on electrolysis) are shown and compared to the expected diesel cost. It should be mentioned that only the fuel cost to drive 100 km is included, and not the investment cost for the car nor the service/maintenance cost of the car. Only passenger cars are considered. Contrary to the calculations of the economic feasibility described in section 6 of this report, in this case fuel price includes 21% VAT. Numbers shown will therefore be higher than the ones presented in section 6 of this report, but do reflect the actual fuel costs car drivers pay for a 100 km drive.

The top of the coloured bar represents LCmax at full load operation; the bottom of the coloured bar represents LC min with optimised number of operating hours, and the bottom of the grey bar finally represents LCsoc (again with optimised number of operating hours). For diesel, a ± 20% spread on the expected price is considered to represent possible price fluctuations..

**Figure 45: Levelized cost of mobility fuels (with sensitivity)**




For 2015, including additional revenues and avoided societal costs and/or optimizing operating hours cannot bring levelized cost of hydrogen or methanol as a fuel for cars below or even at the same level of the diesel cost. In 2030, levelized cost of methanol can reach the same level as the diesel cost, at least if additional revenues, optimised operating hours and/or avoided societal costs are taken into account. Levelized cost of hydrogen is always at the lower part of the diesel price spread, and can even drop below it when additional revenues, optimised operating hours and/or avoided societal costs are included. In 2050, methanol is competitive to diesel and can even do better if societal costs are included, where the levelized cost of hydrogen always drops below the expected diesel price (even below the lowest part of the spread).

It should however be mentioned that for the FCEV pathways a significant increase of conversion efficiency is assumed between now and 2050 (due to increased fuel cell efficiency from 50% in 2015 to 63% in 2030 and 67% in 2050), where for the methanol pathway conversion efficiency is expected to stay at the same level as today. This is because methanol is expected to be blended with conventional (fossil) fuels, and to be used in conventional internal combustion engines. The development of direct methane fuel cells (DMFC) might however also cause in increased conversion efficiency for the methanol pathway, bringing the levelized cost of mobility fuel (expressed in €/100km) for the methanol pathway closer to the values found for the FCEV pathway.

## 7.4. Hydrogen Energy Storage (Power-to-Power)

As electric power generation from renewable energy sources, and certainly intermittent sources like wind or solar, causes moments of excess and moments of shortage on the electricity market, electricity storage (or energy storage, re-convertible to electricity after storage) might help to meet demand and to reduce price peaks. Hydrogen can be used as energy storage, converting excess power into hydrogen through water electrolysis, and reconverting hydrogen into electric power by means of fuel cells.

Strengths, weaknesses, opportunities and threats of energy storage using hydrogen are shown in the table below.

**Table 33: SWOT Hydrogen-based Electrical Energy Storage**

| **STRENGTHS** | **WEAKNESSES** |
|---|---|
| • Power-to-power: the application needs only to comply with power regulation.<br>• Low self-discharge (good for long-term storage: weeks, months, seasons)<br>• Modular technology (electrolysers and fuel cells)<br>• High dynamic operation to provide grid services for the ancillary services market | • Low round-trip efficiency (30-40%)<br>• Hydrogen storage is needed (additional cost, safety aspects) |
| **OPPORTUNITIES** | **THREATS** |
| • Applications requiring long-term storage: off-grid applications with variable meteorological conditions (mountains), underground seasonal storage<br>• Optimization of the local gas grid capacity could eliminate grid investment costs<br>• Applications to be regulated together with other electrical energy storage applications | • Competitiveness with other energy storage applications, especially with Li-Ion batteries which show smashing costs<br>• Competition with other energy storage applications to provide grid services |

The levelized cost of electrical energy storage using hydrogen has been calculated in the range 500 to 800 €/MWh in 2015, falling to 250 to 350 €/MWh in 2050. Other energy storage technologies (batteries, pumped hydro ...) demonstrate lower levelized costs today and seem to stay more advantageous than hydrogen based electrical energy storage in the future.

Nevertheless, we expect that some very specific applications in remote areas, which require long term energy storage and high reliability, would demonstrate business cases close to profitability. However, these have not been calculated here as these are not expected to be found in Belgium.

# 8. THE ROLE OF THE GOVERNMENT TO SUPPORT A POWER-TO-GAS MARKET UPTAKE

## 8.1. Current legislative framework

In Flanders, the existing legislative framework on hydrogen is mainly focused on industrial applications. No regulations exist specifically for hydrogen refuelling stations, power to power units connected to the grid, or Power-to-Gas installations injecting hydrogen directly into the gas grids. In The Netherlands, specific guidelines were developed for hydrogen refuelling stations (cf. PGS 35).

As environment is a regional competency in Belgium, the Walloon, Brussels and Flemish regions have and will further develop separate sets of environmental rules.

The environmental regulation in Flanders is described in the "VlaRem" (Het Vlaams reglement betreffende de milieuvergunning). We found that VLAREM currently does not specifically cover hydrogen, for example under the paragraph 'gassen onder druk'. Concerning hydrogen refuelling stations, nothing is mentioned on the combination of compression, storage and dispensing.

Furthermore, permitting procedures are the responsibility of the province, and fire departments are responsible at the local level (cities of municipalities) for giving their opinion on safety. We noticed huge differences between local municipalities and fire departments in terms of procedure and of knowledge on hydrogen. There is also discrepancy between private and public refuelling and especially concerning the measurement of hydrogen (ijkwezen) and the invoicing (fiscal meter is required).

For more information about the Flemish regulation, please refer to https://navigator.emis.vito.be/.

## 8.2. Needed changes to regulatory framework

To develop and introduce new environmentally friendly technologies and systems to the market, a supportive regulatory framework is needed. With the help of project partners' own expertise and experiences, external studies, and based on regulatory developments in other countries, we made a list of supportive actions authorities could initiate. This list is a first basis for further discussion with the responsible authorities.

At European level, a number of required actions were identified[36] :

- Clarify the legal status of Power-to-Gas plants such that they are not considered as energy consumers (and are subject to taxes and fees), but rewarded for the service that they deliver in balancing the grid and solving the storage problem
- A European-harmonised regulation for injection of H2 into the NG grid should be defined, although the legal status of energy storage systems highly depends on national laws.
- Reconsider the classification of small scale electrolysers falling under the IED (Industrial Emissions Directive) that currently are treated as producers of chemicals on industrial scale. Taking electrolysis out of IED scope would simplify the permitting process.
- Certification for green hydrogen is an important element of the future business case both for pure hydrogen and for Hydrogen and Natural Gas mixture (H2NG). Certificates are used to

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ascertain the environmental value of energy produced by renewable sources, regardless of the delivery path.

- The EU Renewables Directive (RED) seeks to achieve a 10% share of renewables of the final energy consumption in transport by 2020. In case of multiple crediting of Power-to-Gas fuels under this quota, the production of hydrogen and biomethane for mobility can get extra earnings.

At a Belgian and Flemish levels, the following actions are recommended:

- Define ambitious and long-term targets for the development of renewables
- Define under which conditions the renewable and decarbonized character of Power-to-Gas could be recognized in legal, regulatory and fiscal texts in Flanders and Belgium. For example, integrate Power-to-Gas into fuel legislation.
- Implement most important EU directives (as listed above) which facilitate the Power-to-Gas market.
- Financial incentives e.g. exemption of grid fees for Power-to-Gas projects, stable feed-in-tariff for green hydrogen or biomethane, rewarding for available storage capacity investment grants to lower capex.
- Identify and reward flexibility of Power-to-Gas infrastructure to increase grid capacity required to integrate higher amounts of renewable electricity and to avoid extra grid strengthening investments.
- Allow E-TSO to invest in storage solutions
- Allow electrolysers to participate to the ancillary market in Belgium
- Implement the necessary policies to generate a market recognizing the benefits of reduced CO2 emissions, low noise, better air quality
- Include a separate 'waterstof' (hydrogen) section within VlaRem as it has already been done for natural gas and LPG. From this section, references can be used to link to relevant standards and norms.
- Reconsider the current inspection procedures and tests for hydrogen and align with norms, experiences and advices from component manufacturers.
- Develop standard designs for HRS in Belgium: some typical designs for HRS (small HRS, medium, large…)
- Support the market by:
    - Creating demand (within private sector) for hydrogen in mobility by facilitating car sharing programs, arranging agreements with binding targets with industry (e.g. taxi branch organisation, lease companies etc)
    - Creating demand (within public sector) for hydrogen in mobility by further supporting demonstration of hydrogen buses in Belgium with de Lijn and Van Hool, by involving Flemish municipalities, tenders for clean vehicles (H2, BEV's, CNG) in public administrations and ministries to show the example and act as a role model
    - in the short term, creating experimental area's in Belgium to further learn about Power-to-Gas by creating, exclusively for these projects, regulatory exemptions. Demonstrations could be located around niche markets
    - Requesting for feasibility studies within permitting procedures for new wind and solar farms in order to find a balance between required grid strengthening and storage options (e.g. Power-to-Gas solutions).
    - Developing awareness program around hydrogen and safety for specific target groups like fire brigades, permitting authorities, consumer related organisations, etc.

# 9. A POWER-TO-GAS ROADMAP FOR FLANDERS: THE WAY FORWARD

## 9.1. Introduction

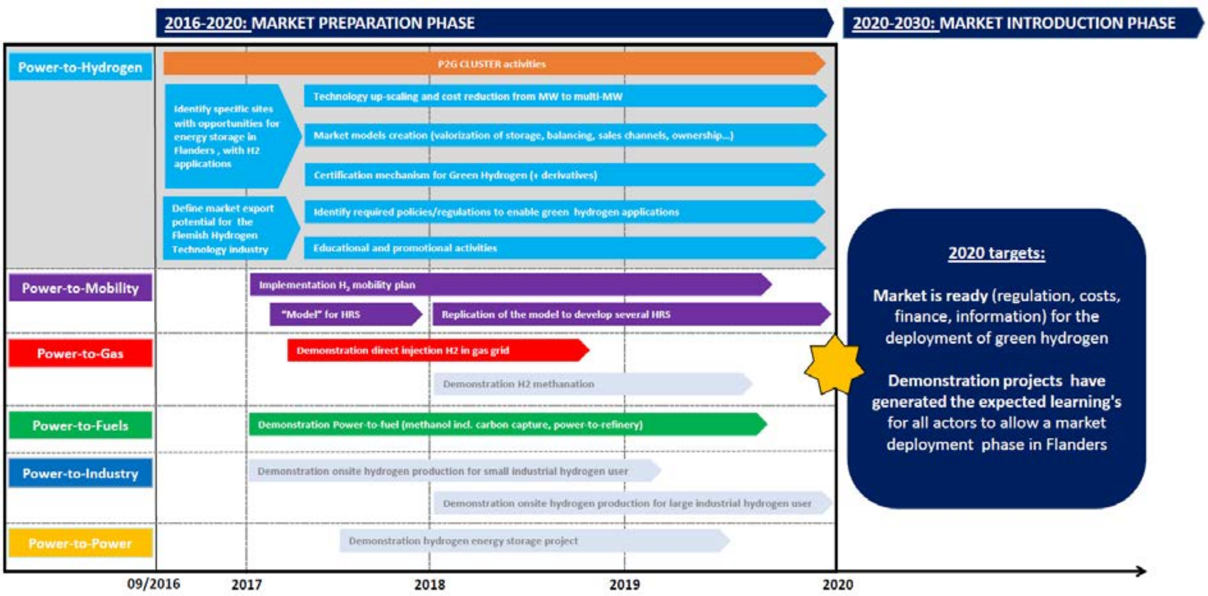
The project 'Power-to-Gas'-Roadmap for Flanders- has analysed and prioritized the different Power-to-Gas options available today and has determined how the Flemish industry could position itself in this promising market and how Flemish authorities could support the creation of a core competence to be valued in the rest of Europe. This exercise has been done within a consortium including Colruyt, Eandis, Elia, Fluxys Belgium, Hydrogenics, Sustesco, Umicore and WaterstofNet, with support of the Flemish Region (reference: NIB.2013.CALL.001).

The conclusions and recommendations of this roadmap have been presented in previous sections (in sections 7 and 8). One of the conclusions is that there is a need for hydrogen and Power-to-gas demonstration projects in Flanders to increase Flemish expertise and to develop markets and regulations.

Another observation is that there is already a strong hydrogen industry in place in Flanders with key international players having production sites in Flanders.  The same observation can be made for renewable energy production with large wind and solar production sites in the North Sea and in the ports of Antwerp and Ghent.

Figure 46 summarizes the proposed way forward. Based on four pathways (Power-to-Gas, Power-to-Mobility, Power-to-Industry, Power-to-Fuels) and a general pone (power-to-hydrogen) common to all and including the creation of a cluster organisation.

**Figure 46: Power-to-Gas Roadmap for Flanders until 2020**




For each pathway, we believe that, with enough support from authorities (regional or EU), demonstration projects could be developed in order to better analyse and understand the strengths and weaknesses of each solution, share experiences with all stakeholders and develop the fundament of the business models needed to really kick-start the market. In parallel, the necessary activities around the creation or modification regulations and the creation of market conditions need be carried on. On the top of the figure, a Power-to-Gas cluster is visualized. This organisation needs to be established to execute the roadmap with the help and collaboration of the authorities.

Then follow the 4 pathways. The pathway Power-to-Mobility, is phased according to the H2Mobility Belgium plan (part of TEN-T project Hit-2-Corridors) and divided in a market preparation, early market introduction - and a full market introduction phase. Within the first phase, the priority would be given to the definition of profitable business concept including captive fleets (cars, buses and/or forklifts) with a potential for replication. This project would start as soon as possible and replicated afterwards on several sites, taking into account the lessons learnt from this first project. Finally, in order to facilitate the early market introduction phase, the necessary regulatory and market conditions need to be set up, and the $H_2$ Mobility Plan should be implemented in accordance with the Clean Power for Transport objectives for Flanders.

The pathway around Power-to-Gas is built up around the development of a first demonstration project directly injecting hydrogen into the natural gas grid. At a later stage, a second demonstration project could focus on methanation of $H_2$ & $CO_2$ to produce methane to be injected also into the natural gas grid. By using the intermediate experiences from these demonstration projects, a political long term vision should be created; the necessary regulatory and market conditions should be discussed and implemented where needed.

For Power-to-Fuels, a demonstration project should be started considering the high potential of the transport market. This project could cover either the production of renewable methanol for the fuel market or the introduction of green hydrogen in a refinery in replacement of fossil hydrogen from Steam Methane Reforming, lowering the $CO_2$ footprint of traditional fuel refining process. This project should address a multi-MW scale project to be relevant for this sector.

For Power-to-Industry, a demonstration project could be foreseen focusing on the interaction between the electrolyser, the hydrogen demand from the small-scale hydrogen customer and the power market.

For the Power-to-Power track, a demonstration project could take place In a later stage, as soon as a specific application has been identified as promising.

It is important to mention that there is not commitment at this stage of any industrial partners for the realization of these projects. These should be further discussed and consortium should be formed to lead their realization.

## 9.2. The need for demonstration projects

***By realising demonstration projects in Flanders, participating companies can increase their expertise, push for the development of new regulation and generate state-of-the- art references for our industries.***

In the roadmap study, a number of business cases, came out as the most promising regarding the technical and economic feasibility, i.e. Power-to-Mobility ($H_2$ for transport), Power-to-Industry ($H_2$ to use in e.g. refinery) and Power-to-Gas (direct injection of $H_2$ into the natural gas grid).

Within the Power-to-Gas cluster, both the results of the roadmap as the specific needs and interests of the partners are taken as input to define a number of possible demonstration projects.

Below, three possible cases are listed. These cases have to be developed to real demonstration project proposals, by defining specific locations/applications in which these cases could be optimally applied. Technical and economic feasibility studies will be done to come to a number of proposed projects in Q1, 2017.

### *9.2.1. Power-to-Industry*

Conclusions of the roadmap: For small scale industry, the cost price of $H_2$ from electrolysis will be competitive with $H_2$ from SMR (centralised production and delivery by tube trailer) in 2030.

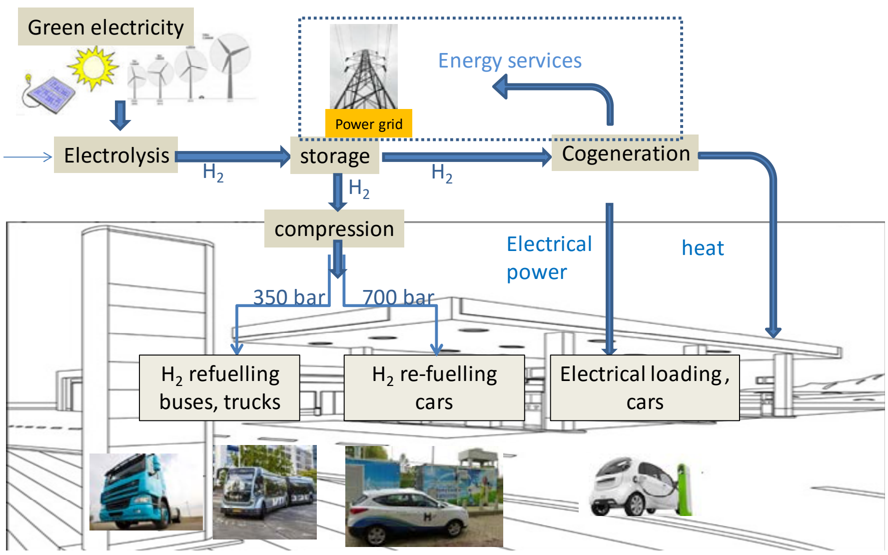
Within the cluster organisation as it is now, we did not yet identify an interested customer for this case. However, a demonstration project would be very interesting, possibly in combination with one of the other cases (e.g. electrolysis for combined use HRS/industrial $H_2$ supply – to have a secure $H_2$ customer in case the number of vehicles at the HRS is initially (too) limited).

### *9.2.2. Power-to-Mobility*

Conclusions of the roadmap: Mobility represents the most promising application for the use of green hydrogen and there is a political momentum in Europe and in Flanders on this topic. Nevertheless, the deployment of Hydrogen Refuelling Stations (HRS) remains very challenging (financing) and it is key to link the development of HRS to the development of FCEV vehicles to generate enough hydrogen demand and reasonable prices.

From the green electricity suppliers there is a clear drive for this case: they are currently experiencing a decrease in revenue due to a decreasing electricity price for RES and the dismantling of subsidies. The potential attractive fuels for transport market could create added value for their product.

**Figure 47: Concept Power-to-Mobility demonstration project**

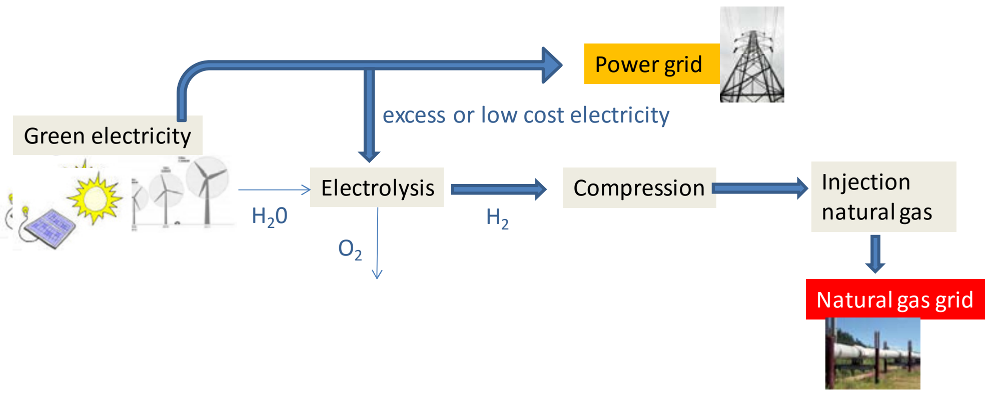


### 9.2.3. Power-to-Gas (direct injection)

Conclusions from the roadmap: direct injection of hydrogen in gas grids seems a promising option, with a competitiveness close to bio-methane already in 2015 and completely in 2030 and onwards. Via this case, we can define the importance of this market for Flanders and we can develop a vision regarding the legal framework needed for its development. The advantage of this case is that transport grids for natural gas are available and are capable of storing large quantities of $H_2$.

Moreover when hydrogen is injected into the gas grid it will increase the share of renewable energy in the natural gas grid, and from there in the end-use applications of transport, heat and industry. The optimal selection of the grid injection point that has sufficient capacity will result in a lower project cost and will benefit the overall grid capacity, power generation, and industry.

**Figure 48: Concept Power-to-Gas demonstration project**



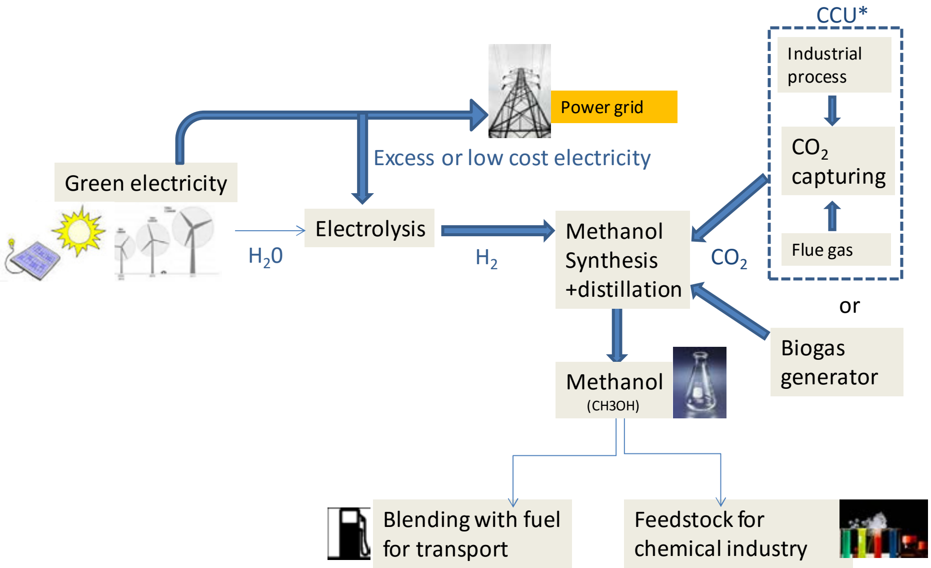

### 9.2.4. Power-to-Fuel (methanol)

The cost price of “green” methanol does not appear to become competitive with “grey” methanol: Power to methanol for industrial purposes (use as feedstock for chemical industry) is therefore not attractive on short term.

However, especially because of the directives concerning the required 8.5% biofuel blending in motor fuels (Fuel Quality Directive), power to methanol might be an interesting incentive for fuels. The condition for making this profitable is that using green methanol can be valorised, i.e. when it is recognised as biofuel (modification of regulatory framework required.)

Especially in the Port of Antwerp special interest exists for this case, given the presence of energy production and possible end-users on one location. Several possible sources of $CO_2$ are present on site (from bio-gas or from industrial processes/flue gases). Recycling of $CO_2$ (Carbon capturing) and using it in e.g. this power to methanol process, might become more interesting in the future if the costs for $CO_2$ emission rights would increase.

**Figure 49: Concept Power-to-Fuel demonstration project**




### *9.2.5. Multi-purpose demonstration project*

It might come out that a combination of the above-mentioned cases, i.e. to have a Power-to-Gas plant with different applications, is a more attractive option for the first demonstration projects. This would allow maximizing the operating hours, diversifying revenues streams and adding flexibility in the application. For instance, we can imagine a Power-to-Gas project combining the production of hydrogen for an industry, with the possibility to add an hydrogen refuelling station for mobility applications (cars, trucks, forklifts) and a direct injection of hydrogen in the gas (or hydrogen) grid for moments where there might be over production of hydrogen in comparison with the storage capacity.

## 9.3. The need for appropriate communication

The Power-to-Gas roadmap for Flanders project has identified a real potential to develop further hydrogen and Power-to-Gas in Flanders/Belgium. However, the communication challenges are numerous to generate government action and get public acceptance. The project has clearly noticed a lack of general information about hydrogen and Power-to-Gas among all stakeholders, except among hydrogen experts.

Next to the project results, the consortium has identified some key general messages that should be highlighted in all communication activities:

- Hydrogen technologies (electrolysers and fuel cells) are mature technologies already available on the market.
- Hydrogen is safe to use but should be handled with care as other fuels (gasoline, diesel, natural gas). The industry and the regulators have put all standards in place to allow a comfortable and safe experience for all users.
- Hydrogen cars are electrical cars with the electricity produced inside the car thanks to a fuel cell and a hydrogen storage tank.
- It is possible today to drive a hydrogen car which will only emit water with a driving range above 500 km.

- It is possible to refuel a hydrogen car in 3 minutes like conventional cars.
- Green hydrogen can be produced directly from renewable electricity such as wind and solar energy.
- Hydrogen mobility when based on green electricity is a totally carbon free solution and help to fight climate change.
- (Green) Hydrogen can be injected in limited quantities in natural gas grid to reduce carbon dioxide emissions.
- Hydrogen can be used to store excess of renewable energy as Hydrogen or when injected in gas grids.
- Power-to-gas technologies allow an increased interconnection between the various sectors: power sector, gas sector, industry sector and mobility sector.
- Hydrogen represents 75% of composition of the earth and can be produced almost everywhere from water, without compromising the water cycle.
- Green hydrogen has the potential to significantly decarbonize the industry.

Concerning the roadmap itself, the consortium has elaborated a communication plan structured in 3 phases:

**Phase I: General awareness creation and political involvement (2016)**

The objective of Phase I are the following:

- create general awareness among the strategic stakeholders (authorities, energy sector, regulators)
- demonstrate that hydrogen technologies and projects operates safely and are delivering according to expectations
- generate further interest to allow the creation of a Power-to-Gas cluster in Flanders and initiate the preparation of demonstration projects

Among others, the actions will be articulated around these actions:

- Dissemination of the results of the Power-to-Gas roadmap for Flanders
- Organization of events (conferences, visits to existing demonstration projects in Europe)
- Momentum creation about the first public hydrogen refuelling station in Belgium and $H_2$ Mobility Belgium
- Creation of a Power-to-Gas cluster in Flanders

**Phase II: Market preparation (2017-2019)**

The overall objective of Phase II is to prepare the market for a full commercial deployment.

The second phase will be articulated around the construction of public hydrogen refuelling stations in Flanders/Belgium, the growing activities of the cluster, the preparation of the demonstration projects, the launch of new FCEV vehicles, the first private purchases of FCEV cars by early adopters, success stories and the regulatory changes.

**<u>Phase III: Market deployment (2020-2025)</u>**

The overall objective of Phase III is to accompany the market development until a fully commercial market is created.

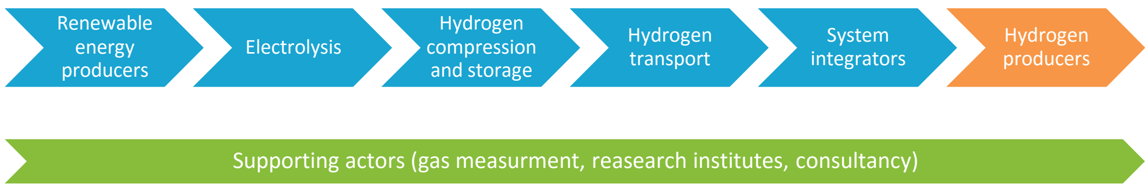
The third phase will be articulated about the generalization of hydrogen solutions for mobility applications (cars, trucks, buses and forklifts), for power and gas applications (energy storage and Power-to-Gas) and for industrial applications.

## 9.4. Power-to-Gas cluster in Flanders

To implement the Power-to-Gas roadmap, create a discussion forum with the most relevant actors in the sector and accompany the realization of demonstration projects, the creation of a Power-to-Gas Cluster has been suggested.

This cluster has been formed with a group of 20 companies active at various levels in the value chain: from energy production (wind, solar) over hydrogen technology (electrolysis, compressors) to end users (transport, chemistry).

**Figure 50: Power-to-Gas value chain**




Given the high diversity of the companies in the cluster, the added value of the cluster as an organisation that facilitates joint knowledge building is very high. Most of the partners have their expertise in only a small part of the chain, such that cooperation with other companies is absolutely necessary to obtain a stronger position in the Power-to-Gas market worldwide.

**Table 34: Power-to-Gas Cluster members**

| RES producers | Electrolysis | Hydrogen compression and storage | Hydrogen transport | System integrators | Hydrogen producers |
|---|---|---|---|---|---|
| Aspiravi<br>Polders Inv.Fonds<br>NPG Energy/Enevos<br>Terranova Solar<br>Colruyt/Eoly | Hydrogenics<br>Umicore | Atlas Copco | Air Liquide | Deme<br>Van Wingen<br>Eandis<br>Fluxys Belgium<br>Port Antwerp | Hyundai Belux<br>Toyota Motor Europe<br>VDL<br>PitPoint<br>E-Trucks<br>Colruyt Group<br>Shipit |

**Additional players** in Flanders and potential future new cluster members were identified and will further be approached.

Energy production:

- **Aspiravi:** Construction and exploitation of wind turbines (off-shore and on-shore) in several Flemish port and industry areas.
- **Polders Investeringsfonds:** Development and exploitation of several energy projects in the Port of Antwerp.
- **NPG Energy/Enevos:** Development of and investment in a wide variety of renewable energy projects: wind, solar and biomass.
- **Terranova Solar:** Production of solar energy with the largest solar installation of the Benelux in the Ghent Canal Zone.
- **Colruyt Group/Eoly**: production of green power through wind, solar and cogeneration.

Technology:

- **Hydrogenics:** expert in hydrogen production from renewable energy through electrolysis
- **Atlas Copco:** development of products and services for gas-compression
- **Van Wingen:** development of products and projects concerning cogeneration (also based on H2).
- **Deme:** construction of off-shore (wind) infrastructure: turbines, cabling..
- **Air Liquide:** development of products and services based on hydrogen (production, distribution, storage, application). Exploitation of largest underground H2 distribution network in the world.
- **Umicore:** development of catalysts for electrolysis and fuel cells.

End-users of hydrogen

- **Hyundai Belux:** manufacturer and supplier of cars on H2,distribution in Benelux
- **Toyota Motor Europe:** European development center for Toyota, supplier of cars on H2.
- **VDL:** development and manufacturing of heavy duty vehicles on H2 (buses – trucks).
- **E-trucks:** development and manufacturing of trucks with an electrical power train.
- **PitPoint:** construction and exploitation of fuel stations.
- **Colruyt-group:** construction and exploitation of fuel stations (DATS24), End-user of $H_2$ in logistic applications (forklifts).
- **Shipit**: Exploitation of ships for maritime transport.

Energy network administrators -

- **Eandis:** natural gas and electricity distribution systems operator.
- **Fluxys Belgium:** natural gas transport system operator.
- **Port of Antwerp:** operation of the port of Antwerp-area; realization of energy projects in the port of Antwerp in cooperation with private companies.

This cluster has requested funding from the Flemish government (Agio, decision on July 14). Activities of the cluster are knowledge exchange activities and realisation of demonstration projects (depending on available funding).

# 10. MAIN CONCLUSIONS OF THE ROADMAP

The production of renewable electricity from wind and solar energy in Europe - and consequently in Flanders (Belgium) - increases due to their unique benefits for $CO_2$ reduction. Massive RES deployment however is not possible without energy storage, and especially seasonal large storage will require new approaches. Among the various available energy storage technologies (such as batteries, flywheels, hydropower, compressed-air energy storage), Power-to-Gas offers the possibility to store green electricity for long (seasonal) periods in the form of hydrogen ($H_2$) directly used for other applications, or injected in natural gas grids.

The project 'Power-to-Gas' has analysed and prioritized the different Power-to-Gas options available today and has determined how the Flemish industry could position itself in this promising market (in Flanders and worldwide). The long term European strategy to reduce greenhouse emissions towards 2050 will be an important incentive to develop the Power-to-Gas technology and market in the near future.

The main conclusions of the Roadmap "Power-to-gas" can be summarized in following ten items and five recommendations:

**Conclusions:**

1. The hydrogen technologies such as electrolysis and fuels cells are mature technologies. However technology improvement capabilities and drastic cost reduction potential is still possible if developed at large scale.

2. The evolution of the future electricity price is uncertain and represents the main cost driver for the price of green hydrogen from water electrolysis. The operating time of the electrolysers is the second most important factor. Therefore, thinking that the economics will be met for Power-to-Gas plants only working when electricity is cheap (or even sold at negative prices) is an utopia and new business model and approaches have to be found.

3. Considering the Federal Plan Bureau[37] assumptions on the development of renewables in Belgium until 2050, excess of renewable power is not expected to be the main driver for Power-to-Gas applications due to the limited hours of occurrence. The main drivers for Power-to-Gas applications are the need for decarbonisation of the energy system (including the power, gas, transport and industrial sectors), the need for energy conversion technologies between these sectors and the availability of renewable power at low cost. Therefore, the future Power-to-Gas strongly depends on future policies on energy, decarbonisation and transport. If ambitious policies are targeted, Power-to-Gas will definitely play a significant role in this new energy landscape.

4. Power-to-Industry: Green hydrogen from onsite electrolysis will become competitive to delivered hydrogen (from centralised SMR) around 2030. For large scale applications, opportunities to generate cheaper green hydrogen from electrolysis will emerge before 2050, taking advantage of the lowest electricity prices (but no base load operation).

[37] (Devogelaer, April 2015)

5. Energy storage (Power-to-Power): Hydrogen storage is expected to be less attractive than other Electrical Energy Storage (EES) technologies such as batteries for EES for hours/days due to a relatively higher cost and lower round-trip efficiencies. However, when storage is needed for longer periods (weeks, months), hydrogen can represent a very attractive solution. Electrolysis can provide ancillary services and help balancing the power grid with more renewables.

6. Power-to-Gas: The technical potential for Power-to-Gas ($H_2$ blending or methanation) in Belgium is significant. On the short term, direct injection of hydrogen in natural gas grids (up to 2% in volume) seems the most promising option, with a competitiveness close to biomethane already in 2015 and completely in 2030 and onwards. Methanation routes combining hydrogen from electrolysis and $CO_2$ show much higher cost structures but have the advantage to better exploit the actual natural gas grids without modifications. Transport of either hydrogen or synthetic methane over the natural gas grid could also be studied as an alternative to electricity transport over high voltage lines.

7. Power-to-Mobility: Mobility represents the most promising application for the use of green hydrogen and there is a political momentum in Europe and in Flanders on this topic. Nevertheless, for hydrogen fuelled transport, the deployment of Hydrogen Refuelling Stations (HRS) remains very challenging (financing) and it is key to link the development of HRS to the development of FCEV vehicles to generate enough hydrogen demand and reasonable prices. Liquid fuels combining hydrogen with CO2 require an extra process step resulting in higher production cost, but might have advantages regarding transport and storage.

8. Power-to-Gas and Green Hydrogen represent many benefits for Flanders/ Belgium/ Europe such as the improvement of air quality, the reduction of $CO_2$ emissions, an improved energy security of supply position and the creation of jobs.

9. Green hydrogen and Power-to-Gas solutions represent many benefits for our economies and for the fight against climate change but they are not expected to be cheaper than the traditional brown hydrogen and fossil fuels (without the internalization of externalities). Hydrogen and Power-to-Gas solutions require political leadership and financial support to establish themselves sustainably in the future energy systems.

10. There is a huge need to raise awareness about green hydrogen and Power-to-Gas applications among all stakeholders groups (energy sector, political sector, general public). Communication messages should be carefully prepared.

**Recommendations:**

1. Hydrogen and Power-to-Gas demonstration projects are needed in Flanders to increase expertise, develop new regulation, gather stakeholders around specific initiatives and generate state-of-the art reference for our industries.

2. Regulatory changes are needed in Flanders to allow hydrogen and Power-to-Gas to be fully exploited.

3. There is already a strong hydrogen industry in place in Flanders with key international players having production sites in Flanders. Such companies will benefit from the development of hydrogen and Power-to-Gas with exporting possibilities leading to many job creations in Flanders.

4. The challenges ahead of hydrogen and Power-to-Gas are huge. The industry in Flanders needs to structure its actions in a Power-to-Gas Industry cluster for more effectiveness.

5. First actions need to start now (in 2016) if we want to be ready in time for the real market deployment of hydrogen technologies and Power-to-Gas projects, and benefit from this global opportunity.

# 11. ANNEXES

## ANNEX 1: LIST OF ACRONYMS AND ABBREVIATIONS

| | |
|---|---|
| **bcm** | Billion ($10^{12}$) Cubic Meter |
| **CAPEX** | Capital Expenditures |
| **CCS** | Carbon Capture and Storage |
| **$CH_3OH$** | Methanol |
| **$CH_4$** | Methane |
| **CNG** | Compressed Natural Gas |
| **$CO_2$** | Carbon Dioxide |
| **COP21** | 21st session of the Conference of the Parties |
| **DSO** | Distribution system operator |
| **EBITDA** | Earnings Before Interest, Taxes, Depreciation and Amortization |
| **ETS** | Emission Trading Scheme |
| **EU** | Europe Union / European |
| **EUR** | Euro |
| **EV** | Electrical Vehicle |
| **FCEV** | Fuel Cell Electric Vehicle |
| **FQD** | Fuel Quality Directive |
| **GHG** | Greenhouse Gas |
| **GW** | Gigawatt |
| **GWh** | Gigawatt-hour |
| **$H_2$** | Hydrogen |
| **$H_2O$** | Water |
| **H-gas** | High calorific gas |
| **H2NG** | Hydrogen and Natural Gas mixture |
| **HHV** | High heating value |
| **HRS** | Hydrogen Refuelling Station |
| **IRR** | Internal Rate of Return |
| **kW** | Kilowatt |
| **kWh** | Kilowatt-hour |
| **LCOH** | Levelized Cost of Hydrogen |
| **L-gas** | Low calorific gas |
| **LHV** | Low heating value |
| **LNG** | Liquefied Natural Gas |
| **LPG** | Liquefied Petroleum Gas |
| **MW** | Megawatt |
| **MWh** | Megawatt-hour |
| **$NO_X$** | Nitrogen oxides |
| **NPV** | Net Present Value |
| **OEM** | Original Equipment Manufacturer |
| **O&M** | Operation and Maintenance |
| **OPEX** | Operational Expenditures |
| **P2G or PtG** | Power-to-Gas |
| **P2I or PtI** | Power-to-Industry |
| **P2F or PtF** | Power-to-Fuels |
| **P2M or PtM** | Power-to-Mobility |
| **P2P or PtP** | Power-to-Power |

| | |
|---|---|
| **P2X or PtX** | Power-to-X |
| **PEM** | Proton exchange membrane |
| **PV** | Solar photovoltaic's |
| **$O_2$** | Oxygen |
| **R3DP** | Tertiary Reserve – Dynamic Profile |
| **R&D** | Research and development |
| **RES** | Renewable Energy Source |
| **RED** | Renewable Energy Directive |
| **RES** | Renewable Electricity Source |
| **SMR** | Steam Methane Reforming |
| **SNG** | Synthetic Natural Gas |
| **$SO_x$** | Sulphur oxides |
| **SWOT** | Strengths, Weaknesses, Opportunities And Threats |
| **T&D** | Transmission and distribution |
| **tpd** | Ton per day |
| **TSO** | Transmission system operator |
| **TWh** | Terawatt-hour |
| **USD** | US Dollar |
| **VAT** | Value Added Tax |
| **WACC** | Weighted Average Cost Of Capital |

## ANNEX 2: MAIN PHYSICAL PROPERTIES OF $H_2$, $CH_4$, $O_2$, $H_2O$, $CO_2$, $CH_3OH$

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **$H_2$ characteristics** | | | | | | | | | | |
| Density | 0,0899 | kg/Nm³ | 0,002 | kg/mol | | | | | | |
| LHV | 33,31 | kWh/kg | 2,99 | kWh/Nm³ | 10,78 | MJ/Nm³ | 120,21 | MJ/kg | 30,02 | kg/MWh |
| HHV | 39,42 | kWh/kg | 3,54 | kWh/Nm³ | 12,76 | MJ/Nm³ | 142,18 | MJ/kg | 25,37 | kg/MWh |
| **$CH_4$ characteristics** | | | | | | | | | | |
| Density | 0,667151 | kg/Nm³ | 0,016 | kg/mol | | | | | | |
| LHV | 13,98 | kWh/kg | 9,33 | kWh/Nm³ | 33,58 | MJ/Nm³ | 50 | MJ/kg | | |
| HHV | 15,42 | kWh/kg | 10,29 | kWh/Nm³ | 37,03 | MJ/Nm³ | 55,5 | MJ/kg | | |
| **$CO_2$ characteristics** | | | | | | | | | | |
| Density | 1,84 | kg/Nm3 | 0,044 | kg/mol | | | | | | |
| **$O_2$ characteristics** | | | | | | | | | | |
| Density | 1,43 | kg/Nm3 | 0,032 | kg/mol | | | | | | |
| **$H_2O$ characteristics** | | | | | | | | | | |
| Density | | | 0,018 | kg/mol | | | | | | |
| **$CH_3OH$ characteristics** | | | | | | | | | | |
| Density | 791,8 | kg/Nm³ | 0,032 | kg/mol | | | | | | |

## ANNEX 3: AVERAGE NATURAL GAS COMPOSITION IN BELGIUM IN 2015.

**QUALITIES OF THE NATURAL GAS TYPES SUPPLIED IN BELGIUM**

**ANNUAL AVERAGES 2015**

| QUALITY Ref. 1 | SYMBOL | UNIT | SLOCHTEREN (10) | SEGEO (20) | LNG (29) | IZTF (34) | ZPT (91) |
|---|---|---|---|---|---|---|---|
| **NATURAL GAS TYPE** | Reference location | | Poppel | s Gravenvoeren | Terminal | Zeebrugge | Ramskapelle |
| | Gas type | | L – gas | H – gas | H – gas | H – gas | H – gas |
| **GAS COMPOSITION** Ref.1 | | | | | | | |
| Nitrogen | $N_2$ | mol % | 11,246 | 1,741 | 0,457 | 1,769 | 1,329 |
| Carbon dioxide | $CO_2$ | mol % | 1,231 | 1,354 | 0,000 | 1,040 | 1,391 |
| Methane | C1 ($CH_4$) | mol % | 83,177 | 90,777 | 93,016 | 90,444 | 91,247 |
| Ethane | C2 ($C_2H_6$) | mol % | 3,415 | 4,806 | 6,299 | 5,218 | 4,488 |
| Propane | C3 ($C_3H_8$) | mol % | 0,575 | 0,895 | 0,179 | 1,042 | 0,935 |
| Iso-butane | iC4 | mol % | 0,091 | 0,138 | 0,019 | 0,159 | 0,280 |
| N-butane | nC4 | mol % | 0,112 | 0,146 | 0,028 | 0,174 | 0,140 |
| Iso-pentane | iC5 | mol % | 0,027 | 0,037 | 0,001 | 0,043 | 0,055 |
| N-pentane | nC5 | mol % | 0,025 | 0,029 | 0,000 | 0,034 | 0,030 |
| Hexane and superior HC | C6+ | mol % | 0,052 | 0,046 | 0,001 | 0,053 | 0,090 |
| Oxygen | O2 | mol % | 0,000 | 0,000 | 0,000 | 0,000 | 0,000 |
| Helium | He | mol % | 0,049 | 0,033 | 0,000 | 0,025 | 0,017 |
| **CALCULATED VALUES** Ref. 2 | | | | | | | |
| Gross Caloric Value | GCV | kJ /$m^3$ (n) | 36530,867 | 40975,661 | 41702,122 | 41373,494 | 41272,875 |
| Net Caloric Value | NCV | kJ /$m^3$ (n) | 32976,258 | 37004,300 | 37648,263 | 37371,987 | 37276,767 |
| Gross Caloric Value | GCV | kJ /$m^3$ (n) Min | 35030,310 | 39294,200 | 35120,800 | 40233,980 | 40823,150 |
| Gross Caloric Value | GCV | kJ /$m^3$ (n) Max | 37550,100 | 42040,610 | 43805,170 | 42618,980 | 42383,960 |
| Gross Caloric Value | GCV | kWh /$m^3$ (n) | 10,147 | 11,382 | 11,584 | 11,493 | 11,465 |
| Net Caloric Value | NCV | kWh /$m^3$ (n) | 9,160 | 10,279 | 10,458 | 10,381 | 10,355 |
| Wobbe index (GCV/vd) | W I | kJ /$m^3$ (n) | 45643 | 52298 | 54289 | 52735 | 52635 |
| Density | RON | kg / $m^3$ (n) | 0,8282 | 0,7937 | 0,7629 | 0,7958 | 0,7950 |
| Relative mass density | d | - | 0,6406 | 0,6139 | 0,5901 | 0,6155 | 0,6149 |
| Gross Caloric Value | GCV | kJ / kg | 44108 | 51628 | 54664 | 51988 | 51919 |
| Net Caloric Value | NCV | kJ / kg | 39816 | 46624 | 49349 | 46960 | 46892 |
| Ratio NCV / GCV | NCV / GCV | - | 0,9027 | 0,9031 | 0,9028 | 0,9033 | 0,9032 |
| **STOCHIOMETRIC COMBUSTION** Ref. 3 | | | | | | | |
| Stochiometric air requirement | a (moist air) | $m^3$ (n) air / $m^3$ (n) gas | 8,80 | 9,87 | 10,04 | 9,96 | 9,94 |
| Combustion prod. at stochiometric combustion (moist) | q st (moist air) | $m^3$ (n) comb.prod. / $m^3$ (n) gas | 9,76 | 10,83 | 11,00 | 10,93 | 10,91 |
| Combustion prod. at stochiometric combustion (dry) | q st (dry air) | $m^3$ (n) comb.prod. / $m^3$ (n) gas | 7,99 | 8,85 | 8,98 | 8,94 | 8,91 |
| Comb.prod. max.$CO_2$ | % $CO_2$ max | % m³ / m³ | 9,63 | 9,76 | 9,63 | 9,76 | 9,78 |
| Comb.prod. max.$CO_2$ | % $CO_2$ max | # mol / mol | 0,94 | 1,06 | 1,06 | 1,07 | 1,07 |
| Comb.prod. max. $H_2O$ | % $H_2O$ max | % m³ / m³ | 17,90 | 18,02 | 18,11 | 17,99 | 18,01 |
| Dry comb.prod. max.$CO_2$ | % $CO_2$ max | % m³ / m³ | 11,76 | 11,95 | 11,79 | 11,93 | 11,96 |
| **ADDITIONAL DATA** Ref. 3 | | | | | | | |
| Molar mass | Mol. Mass | kg / kmol | 18,519 | 17,740 | 17,053 | 17,787 | 17,768 |
| Weight percentage C | C mass % | % | 61,198 | 71,887 | 74,910 | 72,312 | 72,374 |
| Weight percentage H | H mass % | % | 19,660 | 22,921 | 24,340 | 23,032 | 23,025 |
| Weight percentage N | N mass % | % | 17,014 | 2,750 | 0,750 | 2,786 | 2,096 |
| Weight percentage O | O mass % | % | 2,128 | 2,442 | 0,000 | 1,870 | 2,505 |
| Specific $CO_2$ emission | - | kg $CO_2$/GJ | 56,312 | 56,491 | 55,619 | 56,419 | 56,550 |
| Specific $CO_2$ emission | - | kg $CO_2$/MWh | 202,723 | 203,368 | 200,228 | 203,108 | 203,582 |
| $H_2S$ Mean (ref. 1) | $H_2S$ | mg/m³ (n) | 0,62 | 2,49 | 0,82 | 0,88 | 2,13 |
| $H_2S$ Max (ref.1) | $H_2S$ | mg/m³ (n) | 1,55 | 4,10 | 4,64 | 4,71 | 4,95 |
| Total Sulfur Mean (ref.1) | S | mg/m³ (n) | 0,25 | 1,82 | 0,53 | 0,80 | 1,28 |
| Total Sulfur Max (ref.1) | S | mg/m³ (n) | 0,83 | 3,17 | 3,80 | 4,57 | 3,39 |

***The information above is given for information only.***

*Ref. [1] : Fluxys - Quality & Metrology*

*Ref. [2] : ISO 6976 - 1995 , reference temperature for the combustion enthalpy: 25 °C ; 1 m³ (n): at 0 °C and 1013.25 mbar*

*Ref. [3] : Reference temperature and pressure (0 °C and 1013.25 mbar) ; Fluxys*

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## ANNEX 4: LITERATURE REVIEW: TOP 10 PUBLICATIONS

| N° | Title | Auteurs | Source | year | Language | Geographical scope |
|---|---|---|---|---|---|---|
| 14 | Development of water electrolysis in the European Union | Bertuccioli L. et al. | FCH-JU, Belgium | 2014 | EN | Europe |
| 24 | Roadmap for the realisation of a wind hydrogen economy in the Lower Elbe region | LBST, Ernst & Young GmbH and Becker Büttner Held. | Chemcoast , Germany | 2013 | EN | Germany, Lower Elbe region |
| 41 | Systems analyses Power-to-gas- A technological review | Lukas Grond, Paula Schulze & Johan Holstein. | DNV KEMA , Netherlands | 2013 | EN | International |
| 48 | Exploring the role for Power-to-Gas in the future Dutch energy system | Jeroen de Joode, Bert Daniëls, Koen Smekens, Joost van Stralen, Francesco Dalla Longa, Koen Schoots, Ad Seebregts, Lukas Grond, Johan Holstein | ECN, DNV-GL, Netherlands | 2014 | EN | Netherlands |
| 120 | Roadmap Power-to-Gas | Juriaan Mieog, Ronald Eenkhoorn, Jörg Gigler | Royal Haskoning DHV, Netherlands | 2014 | NL | Netherlands, Groningen |
| 126 | Leading the Energy Transition: Hydrogen-Based Energy Conversion FactBook | Benoit Delcourt, Bruno Lajoie, Romain Debarre and Olivier Soupa | Schlumberger Institute, France | 2014 | EN | International |
| 179 | Screening naar de mogelijkheden van waterstofproductie bij elektriciteitsoverschotten en injectie in het aardgasnet | Peter Coenen, Kris Kessels | VITO, Belgium | 2013 | NL | International |
| 210 | Extended Flexibility Study – Power-to-Gas potential in 2025 and 2030 - Final Report | Thijs Slot, Pieter van der Wijk | DNV GL, Netherlands | 2014 | EN | Europe |
| 218 | Electricity Storage in the German Energy Transition | Daniel Fürstenwerth, Lars Waldmann | AGORA Energiewende, Germany | 2014 | EN | Germany |
| 219 | Hydrogen as an energy carrier | Prof. Albert Germain and al. | Royal Belgian Academy Council of Applied Science, Belgium | 2006 | EN | Belgium |

## ANNEX 5: GLOBAL HYDROGEN MARKET

The global demand for Hydrogen in 2010 was approximately 43 Mt (480 billion $Nm^3$) and is foreseen to become 53 Mt by 2030[38].

**Global hydrogen market [39]**


Chemistry and refineries consume about 93% of the total hydrogen demand, industry about 6%, and other applications (cooling in power plants) less than 1%. Europe represents 16% of the global hydrogen consumption with more or less the same breakdown for consumption.

One of the main consumers of hydrogen is the generation of ammonia. Ammonia is a key intermediate step in the production of fertilizers such as urea, ammonium nitrates or phosphates. Ammonia plants depend entirely on dedicated hydrogen production, mainly from steam reforming of natural gas and coal gasification. Typical ammonia production plants are large scale facilities using roughly 180 t $H_2$/day for $NH_3$ production of 1000 t/day.

Another main consumer is the refineries. Refineries both produce $H_2$ (as a by-product of catalytic reforming) and consume $H_2$ to reduce the sulphur content of oil fractions and to up-grade low quality heavy oil. On a macro level, the $H_2$ balance of refineries has turned from positive to negative and such trend is supposed to continue because of ever stringent becoming $SO_x$ regulations, the processing of heavier crudes and falling demand for heavy end-products and growing demand for

[38] Source: CertifHy

[39] Source: Hydrogenics, data source: The Hydrogen Economy, M. Ball, 2009

light products[40]. Most of the net hydrogen demand in refineries is supplied from large steam methane reforming units.

Hydrogen is most commonly generated by means of Steam Methane Reforming, using natural gas as an input product (48%), as a by-product from crude oil cracking in refineries (30%) and from coal gasification (18%). Water electrolysis only counts for 1%. The figure below summarises production and demand of hydrogen.

[40] (Benoit Delcourt, 2014)

## ANNEX 6: GENERAL ASSUMPTIONS FOR BUSINESS CASES

| Financial assumptions | |
|---|---|
| Depreciation period | 20 years |
| Discount rate (for NPV calc) | 8% |
| WACC | 5% |

| Item | *Unit* | 2015 | 2030 | 2050 |
|---|---|---|---|---|
| **Electrolysis** | | | | |
| **Alkaline kW-scale** | | | | |
| $H_2$ nominal production capacity | *Nm³/h* | 60 | 300 | 300 |
| Efficiency | *kWh/Nm³ $H_2$* | 5,2 | 5,1 | 5 |
| Electrical power | *kW* | 312 | 1.530 | 1.500 |
| Output pressure | *barg* | 10 | 60 | 60 |
| Water consumption with R/O | *liter / Nm³ $H_2$* | 1,3 | 1,3 | 1,3 |
| Price | *€* | 624.000 | 1.836.000 | 990.000 |
| Price/kW - SYSTEM | *€/kW* | 2.000 | 1.200 | 660 |
| OPEX | *€/kW/year* | 80 | 64 | 56 |
| Expected cell stack expected lifetime | *hours* | 60.000 | 60.000 | 60.000 |
| Cell stack cost / electrolyser cost | | 30% | 30% | 30% |
| **PEM - MW scale** | | | | |
| $H_2$ nominal production capacity | *Nm³/h* | 200 | 200 | 200 |
| Efficiency | *kWh/Nm³ $H_2$* | 5,2 | 5,1 | 5 |
| Electrical power | *kW* | 1.040 | 1.020 | 1.000 |
| Output pressure | *barg* | 30 | 30 | 30 |
| Water consumption with R/O | *liter / Nm³ $H_2$* | 1,3 | 1,3 | 1,3 |
| Price | *€* | 1.560.000 | 1.020.000 | 550.000 |
| Price/kW - SYSTEM | *€/kW* | 1.500 | 1.000 | 550 |
| OPEX | *€/kW/year* | 60 | 48 | 42 |
| Expected cell stack expected lifetime | *hours* | 40.000 | 50.000 | 60.000 |
| Cell stack cost / electrolyser cost | | 40% | 40% | 40% |
| **PEM - multi-MW scale** | | | | |
| $H_2$ nominal production capacity | *Nm³/h* | 3120 | 3120 | 3120 |
| Efficiency | *kWh/Nm³ $H_2$* | 5 | 4,9 | 4,8 |
| Electrical power | *kW* | 15.600 | 15.288 | 14.976 |
| Output pressure | *barg* | 30 | 30 | 30 |
| Water consumption with R/O | *liter / Nm³ $H_2$* | 1,3 | 1,3 | 1,3 |
| Price | *€* | 15.600.000 | 10.701.600 | 5.765.760 |
| Price/kW - SYSTEM | *€/kW* | 1.000 | 700 | 385 |
| OPEX | *€/kW/year* | 40 | 32 | 28 |
| Expected cell stack expected lifetime | *hours* | 40.000 | 50.000 | 60.000 |
| Cell stack cost / electrolyser cost | | 50% | 50% | 50% |

| | | | | |
|---|---|---|---|---|
| **Hydrogen compression** | | | | |
| **120 Nm3/h compressor (10 > 450 bar)** | | | | |
| CAPEX | *€* | 300.000 | 240.000 | 210.000 |
| OPEX | *€ / operating hour* | 1,0 | 0,8 | 0,7 |
| Electricity consumption | *kWh/Nm³* | 0,5 | 0,5 | 0,5 |
| **120 Nm3/h compressor (450 > 900 bar)** | | | | |
| CAPEX | *€* | 120.000 | 96.000 | 84.000 |
| OPEX | *€ / operating hour* | 1,4 | 1,1 | 1,0 |
| Electricity consumption | *kWh/Nm³* | 0,2 | 0,2 | 0,2 |
| **120 Nm3/h compressor (10> 200 bar)** | | | | |
| CAPEX | *€* | 1.000.000 | 800.000 | 700.000 |
| Electricity consumption | *kWh/Nm³* | 0,2 | 0,2 | 0,2 |
| **3000 Nm3/h compressor (30> 80 bar)** | | | | |
| CAPEX | *€* | 1.000.000 | 800.000 | 700.000 |
| Electricity consumption | *kWh/Nm³* | 0,2 | 0,2 | 0,2 |
| **Methanation** | | | | |
| **Catalytic methanation (Sabatier process)** | | | | |
| CAPEX | *€/kW elec* | 1000 | 800 | 500 |
| OPEX | *% CAPEX* | 5% | 5% | 5% |
| **Biological methanation** | | | | |
| CAPEX | *€/kW elec* | 1000 | 500 | 200 |
| OPEX | *% CAPEX* | 5% | 5% | 5% |
| **Methanolisation unit (without H2 production)** | | | | |
| MeOH production capacity | *tons /year* | 4.000 | 10.000 | 100.000 |
| Corresponding electrolyser size | *kW* | 5.000 | 12.500 | 125.000 |
| CAPEX MeOH - no H2 | *€/kW elec* | 1.200 | 960 | 600 |
| OPEX | *% CAPEX* | 5% | 5% | 5% |
| **Fuel cells for stationnary power** | | | | |
| Typical size | | 50 kW -1 MW | 50 kW -50 MW | 50 kW-100 MW |
| CAPEX | *€/kW* | 2.000 | 800 | 500 |
| Electrical effciciency | *% LHV* | 50% | 63% | 67% |
| **Hydrogen storage** | | | | |
| Storage at 200 bar | *€/kg H2* | 225 | 225 | 225 |
| Storage at 450 bar | *€/kg H2* | 1.600 | 960 | 768 |
| Storage at 900 bar | *€/kg H2* | 2.200 | 1.320 | 990 |
| **Hydrogen refueling station costs** | | | | |
| CAPEX (without electrolysis, compression and storage) | *€* | 700.000 | 420.000 | 315.000 |

| **Consumables, utilities and others** | | | | |
|---|---|---|---|---|
| Cost tap water | *€/m³* | 2,3 | 2,3 | 2,3 |
| Biomethane price | *€/MWh* | 75 | 75 | 75 |
| Oxygen selling price | *€/ton* | 24,5 | 24,5 | 24,5 |
| CO2 emission allowance cost | *€/ton* | 5,00 | 35,00 | 47,50 |
| CO2 total cost for society | *€/ton* | 80 | 145 | 260 |
| Natural gas price | *€/MWh HHV* | 22,6 | 29,4 | 42,4 |
| Heat value | *€/MWh* | 27,8 | 36,1 | 52,2 |
| Methanol market price | *€/ton* | 400 | 460 | 576 |
| Diesel price (at the pump) - cars | *€/liter* | 0,95 | 1,30 | 1,57 |
| Diesel price (at the pump) - buses | *€/liter* | 0,86 | 1,18 | 1,43 |
| Average electricity price (full load) on BELPEX | *€/MWh* | 40,7 | 46,5 | 57,0 |
| **Ancillary service remununeration** | | | | |
| R2 Secondary reserve market | *€/MW/h* | 10,6 | 10,6 | 10,6 |
| R3DP Tertiary reserve - Dynamic profile | *€/MW/h* | 3,07 | 3,07 | 3,07 |
| **Hydrogen benchmark prices (delivered)** | | | | |
| Large scale industrial customer | *€/kg* | 2,0 | 2,7 | 3,6 |
| Small scale industrial customer | *€/kg* | 6,0 | 6,7 | 7,6 |
| **Mobility** | | | | |
| **FCEV car** | | | | |
| Diesel fuel consumption for medium range car | *l/100km* | 5 | 5 | 5 |
| Hydrogen consumption for medium range FCEV car | *kg H2/100km* | 0,95 | 0,76 | 0,71 |
| **FCEV bus** | | | | |
| Diesel fuel consumption for a 12m bus | *l/100km* | 52 | 52 | 52 |
| Hydrogen consumption for a 12m FCEV bus | *kg H2/100km* | 10 | 8 | 7,5 |

# ANNEX 7: GRID COSTS, TAXES AND LEVIES FOR ELECTRICITY OFFTAKE IN FLANDERS IN 2015

Data source: CREG, 2015

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 |
|---|---|---|---|---|---|---|---|---|---|
| | 380/220/150 kV | Tfo HS | 70/36 kV | Tfo MS | 30/36 kV >5MVA | 30/36 kV <5MVA | 10/12/15 kV | Tfo LS | LS |
| **Transmissie** | | | | | | | | | |
| Gebruik van het net | 0 | 0 | 0 | 0 | 5,3706 | 5,3706 | 5,3706 | 5,3706 | 5,3706 |
| Systeembeheer | 0,5646 | 0,8213 | 1,1724 | 1,5495 | 1,5495 | 1,5819 | 1,5819 | 1,5819 | 1,6826 |
| Primaire regeling van de frequentie, regeling van het secundair evenwicht en de blackstart | 1,0013 | 1,0013 | 1,0013 | 1,0013 | 1,011 | 1,0322 | 1,0322 | 1,0322 | 1,0978 |
| Regeling van de spanning en van het reactief vermogen | 0,2093 | 0,2093 | 0,2093 | 0,2425 | 0,2425 | 0,2476 | 0,2476 | 0,2476 | 0,2633 |
| Opheffen van congesties | 0,0211 | 0,0211 | 0,0211 | 0,0211 | 0,0211 | 0,0215 | 0,0215 | 0,0215 | 0,0229 |
| Compensatie van de netverliezen | 0 | 0,13285 | 0,66745 | 0,6393 | 0,4969 | 0,5073 | 0,5073 | 0,5073 | 0,5396 |
| Financiering maatregelen ter bevordering van REG | 0,0616 | 0,0616 | 0,0616 | 0,0616 | 0,0616 | 0,0629 | 0,0629 | 0,0629 | 0,0669 |
| Financiering aansluiting offshore windturbineparken | 0,0629 | 0,0629 | 0,0629 | 0,0629 | 0,0629 | 0,0642 | 0,0642 | 0,0642 | 0,0683 |
| Toeslag groenestroomcertificaat | 3,9132 | 3,9132 | 3,9132 | 3,9132 | 3,9132 | 3,9951 | 3,9951 | 3,9951 | 4,2493 |
| Tsk in de aansluiting van install voor de productie van hernieuwbare energie | 0 | 0,5171 | 0,5171 | 0,5171 | 0,5171 | 0,5279 | 0,5279 | 0,5279 | 0,5615 |
| Federale bijdrage | 2,5588 | 2,5588 | 2,5588 | 2,5588 | 2,5588 | 2,5588 | 2,5588 | 2,5588 | 2,5588 |
| **Distributie** | | | | | | | | | |
| Gebruik van het net dag | 0 | 0 | 0 | 0 | 0 | 1,1599 | 1,1599 | 2,5925 | 0 |
| Tarief systeemdiensten | 0 | 0 | 0 | 0,2635 | 0,2635 | 0,2681 | 0,2681 | 0,269 | 0,7743 |
| Tarief openbare dienstverplichtingen | 0 | 0 | 0 | 0,0559 | 0,0559 | 5,0896 | 5,0896 | 11,7287 | 45,3101 |
| Tarief netverliezen | 0 | 0 | 0 | 0 | 0 | 0,7037 | 0,7037 | 0,8552 | 3,4381 |
| Toeslagen | 0 | 0 | 0 | 0,1514 | 0,1514 | 1,7283 | 1,7283 | 1,7638 | 2,3 |
| **Certificaten** | | | | | | | | | |
| Bijdrage groenstroomcertificaten | 15,581304 | 15,581304 | 15,581304 | 15,581304 | 15,581304 | 15,581304 | 15,581304 | 15,581304 | 15,581304 |
| Bijdrage warmtekrachtcertifcaten | 3,92 | 3,92 | 3,92 | 3,92 | 3,92 | 3,92 | 3,92 | 3,92 | 3,92 |
| Totaal tarief zonder reductie | 5,71 | 6,62 | 7,50 | 8,35 | 13,59 | 22,23 | 22,23 | 30,49 | 65,61 |
| Totaal tarief voor reductie federaal | 2,62 | 2,62 | 2,62 | 2,62 | 2,62 | 2,62 | 2,62 | 2,62 | 2,63 |
| Totaal tarief voor reductie groen | 15,64 | 15,64 | 15,64 | 15,64 | 15,64 | 15,64 | 15,64 | 15,64 | 15,65 |
| Totaal tarief voor reductie wkk | 3,92 | 3,92 | 3,92 | 3,92 | 3,92 | 3,92 | 3,92 | 3,92 | 3,92 |
| Reductie nacht | | -0,0585 | -0,3106 | -0,2981 | | -0,5061 | -0,5061 | -1,1087 | |

## ANNEX 8: ENERGY SCENARIO FOR BELGIUM IN 2030 AND 2050

The Working Paper 3-15 ‘2030 Climate and Energy Framework for Belgium - Impact assessment of a selection of policy scenarios up to 2050’ from the Federal Planning Bureau includes several scenarios for the installed capacities of different types of power production facilities, including onshore wind, offshore wind and photovoltaic’s, which are the most relevant for this study, as they are the most intermittent. From these installed capacities and historical production profiles, numbers for the amounts of electricity produced out of intermittent renewable energy can be calculated.

In this study only the GHG40 scenario is considered. This scenario is compatible with both the stated 2030 (40%) and 2050 (between 80 and 95%) greenhouse gas emission reduction targets at EU level, and comprises a 26.5% EU RES development in terms of gross final energy consumption and 25.1% energy savings with respect to the 2007 Baseline projections by 2030. Results are shown in the table below.

| | **2030** | | | **2050** | | |
|---|---|---|---|---|---|---|
| | Onshore wind | Offshore wind | PV | Onshore wind | Offshore wind | PV |
| Installed capacity (MW) | 4678 | 3522 | 4800 | 7213 | 7687 | 10000 |
| Generated energy (GWh) | 9436 | 11882 | 4867 | 14549 | 25935 | 10140 |

Total electricity consumption in the Elia control area in 2014 was 80 TWh, a decrease of almost 2,5% compared to 2013 (source: FEBEG). This is the lowest demand for power capacity over the past ten years, except for 2009 when Belgium experienced an economic crisis. The power capacity demand was up to 13,821 MW in 2014. The minimum capacity demand in 2012 was 6,848 MW, which results in a baseload of 60 TWh, 75% of total consumption.

The previously mentioned Working Paper of the Federal Planning Bureau also gives the predicted electricity demand in Belgium in 2030 and 2050. Up until 2030, demand is relatively stable (for all scenarios), including a very humble annual average growth rate between 0.0% and 0.1%. Main reason for this quasi stabilization is the implementation of the Energy Efficiency Directive and the rather successful application of different energy efficiency measures. After 2030 however, a sharp increase in electricity demand can be observed. This surge is not only caused by the increasing number of households as well as the intensified growth in industrial activity (volume effect pulling demand upwards), but also by climate-driven phenomena, such as a fuel switch away from fossil fuels towards among others electricity, the development of electro mobility and the use of electricity in the production of hydrogen through electrolysis of water. Average annual growth rates in the 2030-2050 period reach 1.5% (average over the different scenarios), and called-up electrical power reaches 125 TWh in 2050.

Next to the annual demand volumes, also the demand profiles shall have an influence on power prices. It can be expected that demand side management and load shifting will show an increased importance in the forthcoming years. Therefore it is assumed that the difference between the minimal and the maximal load, observed over a given calendar year, will not increase as the demand volume increases.

## ANNEX 9: ESTIMATION OF FUTURE ELECTRICITY PRICES IN BELGIUM FOR 2030 AND 2050

A lot of parameters have influence on future energy prices, such as the economic climate, governmental policy, the electricity demand, the evolution of the power production park (phase out of nuclear, growth of renewables,...), the prices of combustibles (coal, gas,…), the cost of emissions ($CO_2$ and others) and many others.

**Electricity demand in Belgium in 2030 and 2050**

On October 17, 2014, the Federal Planning Bureau published the fifth edition of its triennial long-term energy outlook (Devogelaer, April 2015). The report describes a Reference scenario (REF) up to 2050 simulating the evolution of the Belgian energy system under current trends and adopted policies in the field of climate, energy and transport while integrating the 2020 Climate/Energy binding objectives. Analysing its results demonstrates the large discrepancy between this Reference and what is necessary to be on track for the EU 2030 Climate and Energy Framework as well as the low-carbon economy by 2050, hence the need for additional policies and measures. Because of this, the Federal Planning Bureau also analysed some policy driven scenarios that are compatible with both the 2030 and 2050 greenhouse gas emission reduction challenges outlined by the European Council are scrutinised. Results were published in Working Paper 3-15 '2030 Climate and Energy Framework for Belgium - Impact assessment of a selection of policy scenarios up to 2050'.

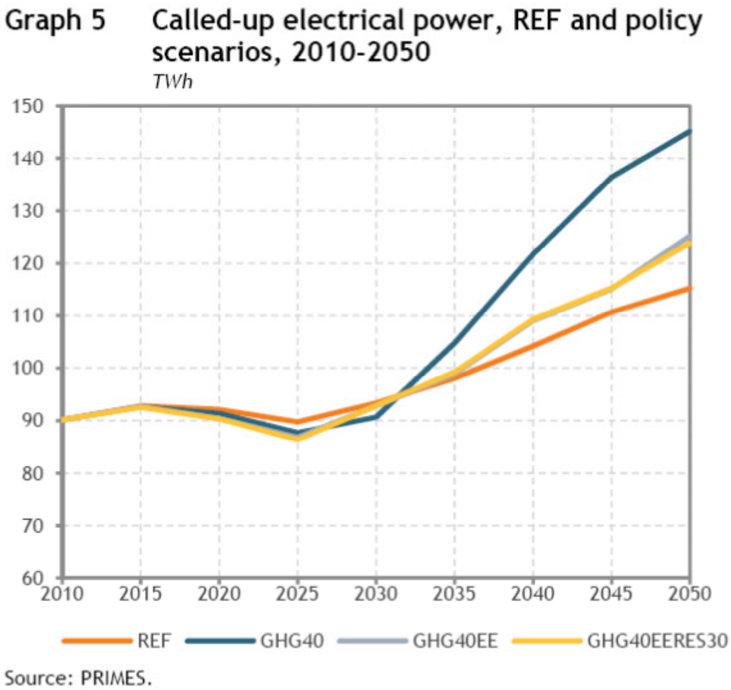
All policy driven scenarios for Belgium are compatible both with the stated 2030 (40%) and 2050 (between 80 and 95%) greenhouse gas emission reduction targets at EU level. The scenarios differ in the level of ambition in the field of energy efficiency and renewable energy deployment.

The three policy driven scenarios under investigation are:

- the GHG40 scenario comprising a 40% EU GHG reduction in 2030, as well as a 26.5% EU RES development in terms of gross final energy consumption and 25.1% energy savings with respect to the 2007 Baseline projections by 2030;
- the GHG40EE scenario assembling a 40% EU GHG reduction, a 26.4% EU RES development and 29.3% energy savings by 2030; and
- the GHG40EERES30 scenario for a 40% EU GHG reduction, a 30% EU RES development and 30.1% energy savings by 2030.

For the three policy driven scenarios, as well as for the reference scenario (a sort of business as usual reflecting the current policies relating to climate change and renewable energy), the Working Paper gives the predicted electricity demand in Belgium in 2030 and 2050, as illustrated in the graph below.

**Predicted electricity demand in Belgium in 2030 and 2050** [41]




Up until 2030, a similar evolution in all scenarios (including REF) can be noticed: demand is relatively stable. All GHG40 scenarios display a very humble annual average growth rate: between 0.0% and 0.1% in the period 2010-2030. Main reason for this quasi stabilization is the implementation of the Energy Efficiency Directive and the rather successful application of different energy efficiency measures.

After 2030, a sharp increase in electricity demand can be observed. This surge is caused by, amongst others, a volume effect inflicted by the increasing number of households as well as the intensified growth in industrial activity, pulling demand upwards. But what is more interesting, is that demand levels start to diverge. Noteworthy is that the GHG40 scenarios all display (way) higher demand patterns than REF, with average annual growth rates in the 2030-2050 period reaching 1.5% (GHG40EE and GHG40EERES30) and 2.4% (GHG40) (compared to 1.1% in REF). Three phenomena cause this divergence:

- a fuel switch prompted by the climate (and RES) target away from more expensive fossil fuels towards among others electricity, thereby boosting its demand;
- the development of electro mobility: although REF also accounted for some electric passenger transport, the penetration of electric vehicles (both plug-in hybrids and pure electric vehicles) in the GHG40 scenarios is considerably higher;
- the use of electricity in the production of hydrogen through electrolysis of water.

In 2050, highest demand is attained in GHG40, the scenario in which a sole GHG emission reduction target is implemented. By 2050, called-up electrical power reaches 145 TWh. GHG40EE and GHG40EERES30 also exhibit higher demand levels than REF but strand at around 125 TWh (compared to 115 TWh in REF). The electricity consumption of the EE scenarios is somewhat mitigated through

[41] Source: (Devogelaer, April 2015)

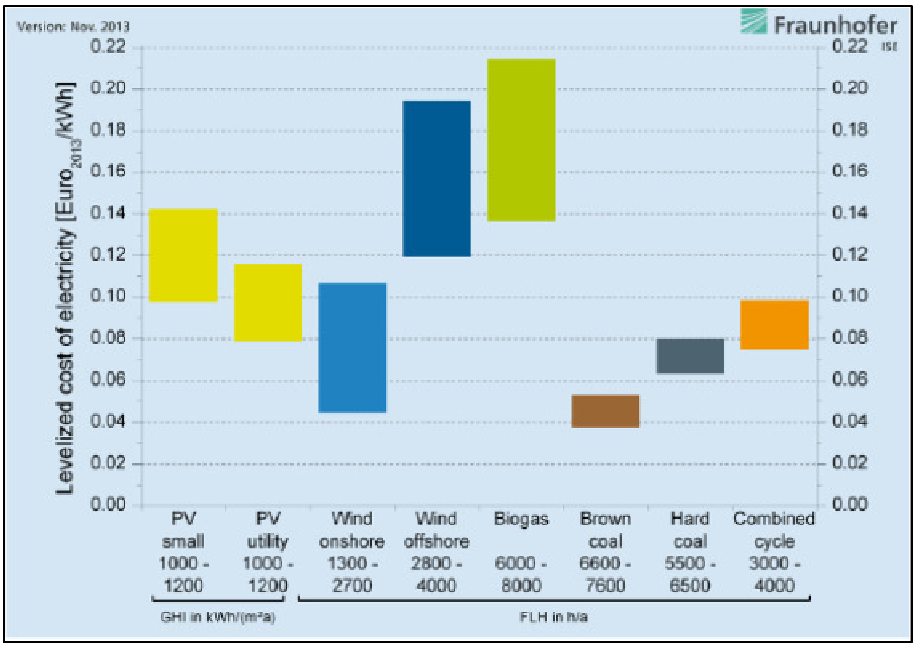
the application of rather ambitious energy efficiency initiatives, leading to the installation of more efficient, hence less consuming, electrical apparels and devices and the implementation of efficiency enhanced processes in the final demand sectors.

Next to the annual demand volumes, also the demand profiles shall have an influence on power prices. It can be expected that demand side management and load shifting will show an increased importance in the forthcoming years. Therefore it is assumed that the difference between the minimal and the maximal load, observed over a given calendar year, will not increase as the demand volume increases.

**Renewable energy in Belgium in 2030 and 2050**

Based on several international studies, it can be concluded that, amongst all technologies for renewable energy, onshore wind energy is closest to profitability today (without subsidies or any other government measures). The graph below, showing the levelized cost of electricity (expressed in €/MWh) for some renewable energy technologies and conventional power plants in Germany in 2013, illustrates this. It can therefore be expected that the existing potential for onshore wind energy in Belgium will be constructed over the forthcoming years. Other technologies are less 'into the market' nowadays, so their future increase will also depend on the evolution in economics (investment costs, subsidies…).

**Levelized cost of electricity** [42]




For the three policy driven scenarios, as well as for the reference scenario, the Working Paper from the Federal Planning Bureau includes the installed capacities of different types of power production facilities, as shown in the table below.

[42] Source: (Kost, et al., November 2013)

**Installed power generation capacity in Belgium in 2030 and 2050** [43]

Table 10 Installed capacity, REF and policy scenarios, 2010, 2030 and 2050
*GW*

| | 2010 | 2030 | | | | 2050 | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | REF | GHG40 | GHG40EE | GHG40EERES30 | REF | GHG40 | GHG40EE | GHG40EERES30 |
| Nuclear | 5.9 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Hydro | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| Wind | 0.9 | 7.6 | 8.2 | 7.6 | 9.2 | 12.5 | 14.9 | 13.7 | 15.3 |
| Solar | 0.9 | 4.8 | 4.8 | 4.8 | 4.8 | 9.2 | 10.0 | 7.7 | 6.4 |
| Biomass & waste | 1.1 | 1.5 | 1.5 | 1.5 | 2.0 | 2.4 | 3.0 | 2.9 | 3.5 |
| Geothermal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.1 | 0.1 | 0.1 | 0.1 |
| Coal | 1.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.0 | 0.0 | 0.0 | 0.0 |
| Natural gas | 5.8 | 11.8 | 11.1 | 11.4 | 10.6 | 14.6 | 15.2 | 11.7 | 10.6 |
| Other | 1.1 | 1.1 | 1.0 | 1.0 | 1.1 | 0.6 | 0.5 | 0.5 | 0.5 |
| Total | 17.0 | 27.2 | 27.0 | 26.8 | 28.1 | 39.5 | 43.9 | 36.7 | 36.6 |

Source: PRIMES.
Note: 'Other' stands for petroleum products and derived gases.

For this study, only wind (both onshore and offshore) and photovoltaic's are relevant, because they are the most intermittent. Installed capacities of onshore wind, offshore wind and photovoltaic's in the four scenarios are shown in the table below.

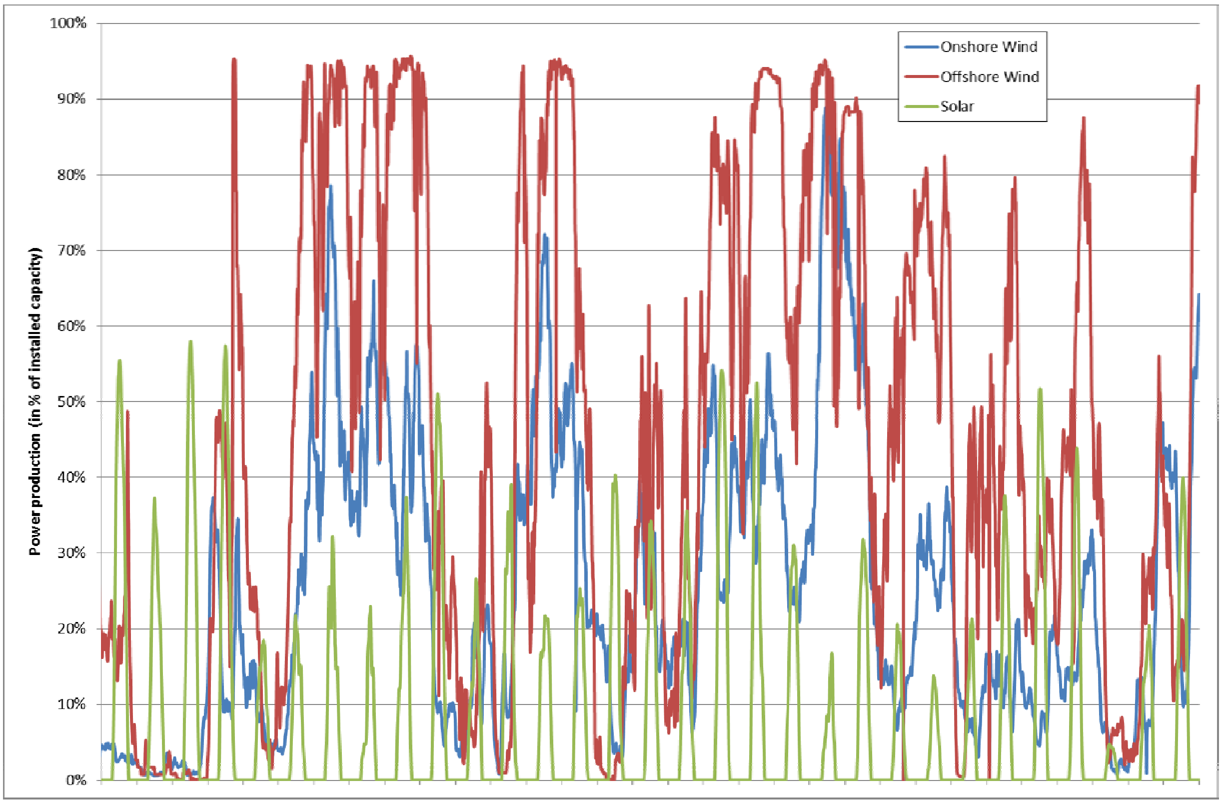
**Installed renewable power generation capacity in Belgium in 2030 and 2050** [44]

| | **Installed capacities in 2030 (MW)** | | | **Installed capacities in 2050 (MW)** | | |
|---|---|---|---|---|---|---|
| Scenario | *Onshore wind* | *Offshore wind* | *PV* | *Onshore wind* | *Offshore wind* | *PV* |
| **REF** | 4696 | 2904 | 4800 | 6839 | 5661 | 9200 |
| **GHG40** | 4678 | 3522 | 4800 | 7213 | 7687 | 10000 |
| **GHG40EE** | 4573 | 3027 | 4800 | 7312 | 6388 | 7700 |
| **GHG40EERES30** | 5098 | 4102 | 4800 | 7137 | 8163 | 6400 |

Based on historical production data, the production profiles for onshore wind, offshore wind and solar can be drawn. In the graph below, an example is given for October, showing high wind outputs on certain days (especially for offshore wind) and moderate solar outputs during daytime (as the sun is not that high any more this time of the year).

[43] Source: (Devogelaer, April 2015)
[44] Idem

**Typical production profile for onshore wind, offshore wind and solar (October)** [45]




These production profiles can be combined with the different scenarios for the installed capacities of onshore wind, offshore wind and photovoltaic's and results in following amounts of electricity produced out of intermittent renewable energy.

**Renewable energy production in Belgium in 2030 and 2050** [46]

| | **Generated energy in 2030 (GWh)** | | | **Generated energy in 2050 (GWh)** | | |
|---|---|---|---|---|---|---|
| Scenario | *Onshore wind* | *Offshore wind* | *PV* | *Onshore wind* | *Offshore wind* | *PV* |
| **REF** | 9472 | 9798 | 4867 | 13794 | 19100 | 9329 |
| **GHG40** | 9436 | 11882 | 4867 | 14549 | 25935 | 10140 |
| **GHG40EE** | 9224 | 10212 | 4867 | 14748 | 21554 | 7808 |
| **GHG40EERES30** | 10282 | 13841 | 4867 | 14396 | 27541 | 6490 |

It should be noticed that other studies, like the VITO study (Danielle Devogelaer, April 2013) , show much higher numbers for the installed capacities of intermittent renewable energy technologies, and therefore also of the electricity production out of these technologies.

Based on maximum capacities to be installed in Belgium in 2050 of 9 GW for onshore wind, 20GW for offshore wind and even 50 GW for photovoltaic's, this VITO study contains different scenarios in which the ambition levels for the share of renewable energy are fixed at values between 60% and

[45] Source: Colruyt
[46] Source: own calculation

85% in 2050, depending on the scenario. For the technologies that are of interest for this study, installed capacities are shown in the table below.

**Installed renewable power generation capacity in Belgium in 2030 and 2050: 3 scenarios from VITO [47]**

| | **Installed capacities in 2030 (MW)** | | | **Installed capacities in 2050 (MW)** | | |
|---|---|---|---|---|---|---|
| Scenario | *Onshore wind* | *Offshore wind* | *PV* | *Onshore wind* | *Offshore wind* | *PV* |
| **LOW** | 5304 | 7780 | 4000 | 9014 | 20000 | 24572 |
| **MID** | 5304 | 7935 | 4137 | 9014 | 20000 | 50000 |
| **HIGH** | 5304 | 8000 | 6571 | 9014 | 20000 | 50000 |

As a result, production volumes will at certain moments largely exceed the demand in Belgium. The VITO study therefore recognises these scenarios are only possible in case huge investments are made in storage capacity (up to 400 GWh), transmission grid infrastructure (up to 60 billion euro over the period 2030-2050) and reserve capacities for balancing services.

Therefore, the scenarios described by the Federal Planning Bureau are considered to be more realistic as a reference situation for the markets in which Power-to-Gas technologies should emerge. Further in this Roadmap Study, installed capacities of intermittent renewable energy technologies, and by extension also production volumes and production profiles, shall therefore be based on the Federal Planning Bureau scenarios.

**Impact of renewable energy share on power prices**

Previously, it was already shown that intermittent renewable power has an impact on power prices. To asses this impact, correlations are made between power prices and power production from PV and wind in different countries, also countries having a higher share of intermittent renewable energy than Belgium.

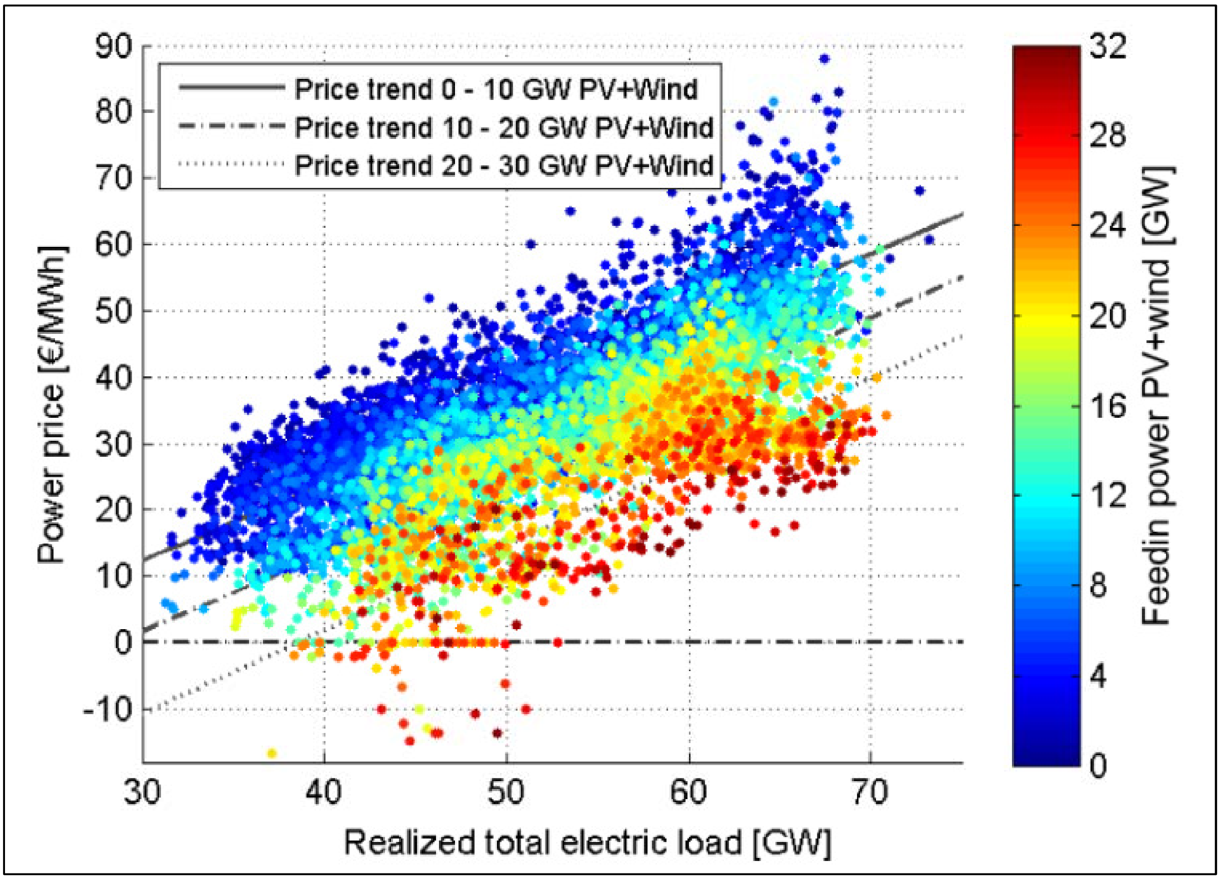
**Germany**

In Germany, almost half of the generated electricity comes from coal (brown coal and hard coal). Nuclear power plants still generate about 17% of total power and natural gas fired power plants only 6%. Renewable energy is very successful in Germany, and is responsible for 30,8% of total power generation and approximately 28% of power consumption. This also includes biomass, biogas and hydro, but still 15,8% of power consumption in Germany comes from locally generated wind and PV energy. The large share of – at least for the moment – cheap coal explains the relatively low electricity prices in Germany (32,76 €/MWh on average over the year 2014), but also the increasing amount of intermittent renewable energy has an influence on power prices in Germany.

The graph below shows the time-based correlation between EPEX spot market prices and the joint PV and wind energy feed in for (a part of) Germany over the year 2014. It is clear that prices are higher when the generated amounts of electricity out of PV and wind are lower, and vice versa. The trend lines for increasing amounts of electricity out of PV and wind are almost parallel, which illustrates the strong correlation between power prices and intermittent renewable energy production.

[47] Source: (Danielle Devogelaer, April 2013)

**Correlation between power price, electric load and RES (wind + solar) feed-in power in Germany [48]**




Remarkable is also that, at times with high electric load and low output from intermittent renewables, the power prices are at approximately 70 €/MWh. This might seem high, certainly when compared to average prices in Germany, but it can be explained easily. At those moments with high demand and low renewable output, the price of electricity is set by (fossil fuelled) peak power plants, and not by baseload operated or mid-merit power plants (like cogeneration plants, biomass plant, biogas plants or combined cycle power plants). The cost of generating electricity with peak power plants depends on the production park of the given country or region, but is usually rather high. Besides, in order to ensure availability of these peak power plants in the long term, not only the marginal cost of generating electricity should be considered, but the complete levelized cost of electricity generation.

**Denmark (Western part)**

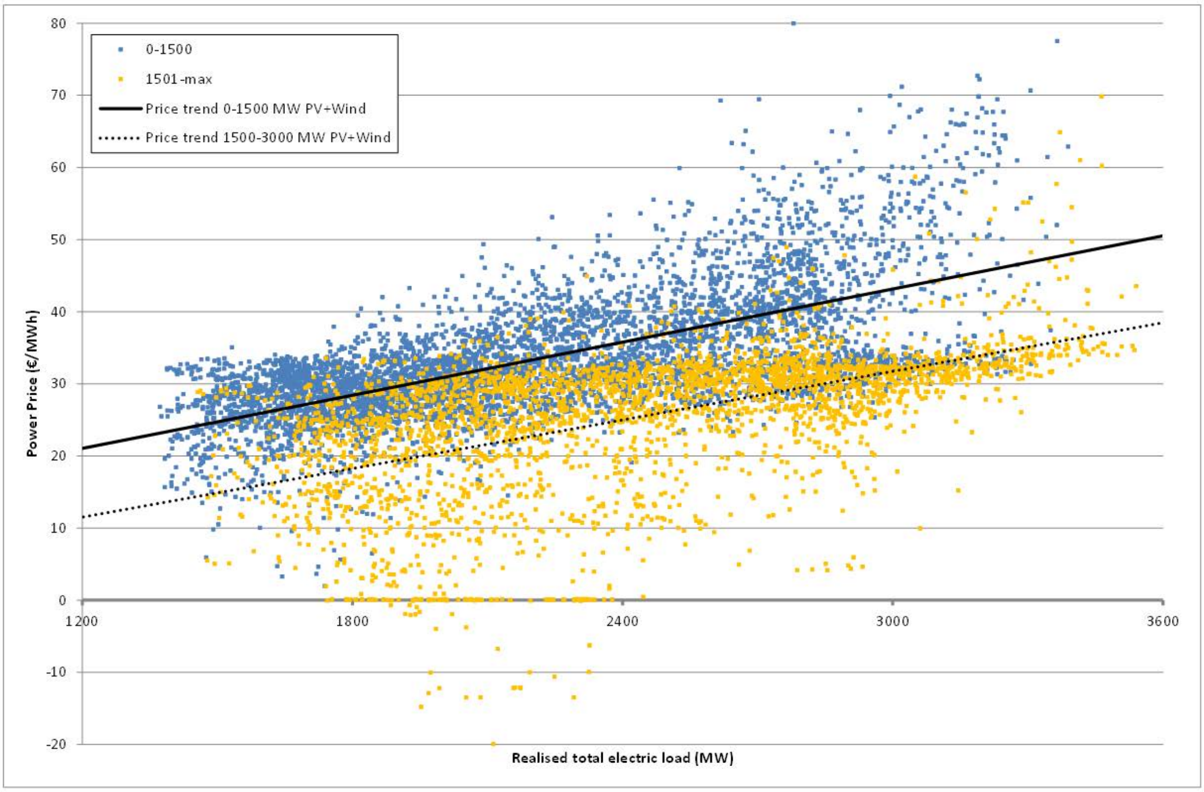
Also in the western part of Denmark (the part connected the European main land) wind and solar energy largely contributes to electric power generation. In 2014, more than 53% of electricity consumed in this region was produced out of locally generated wind or solar energy. Next to this, also biomass, biogas, natural gas and coal contribute to power generation. Denmark has no nuclear power and very limited hydro power.

With an average price of 30.67 €/MWh over the year 2014, spot market prices are rather low, which can be explained, as in Germany, by the high share of coal and (intermittent) renewables. The graph below shows the time-based correlation between spot market prices and the joint PV and wind

[48] Source: EPEX

energy production for the western part of Denmark over the year 2014. Again, the parallel curves for different outputs of intermittent renewables can be observed, though the slope of the curves is a little lower.

**Correlation between power price, electric load and RES (wind + solar) feed-in power in Denmark [49]**



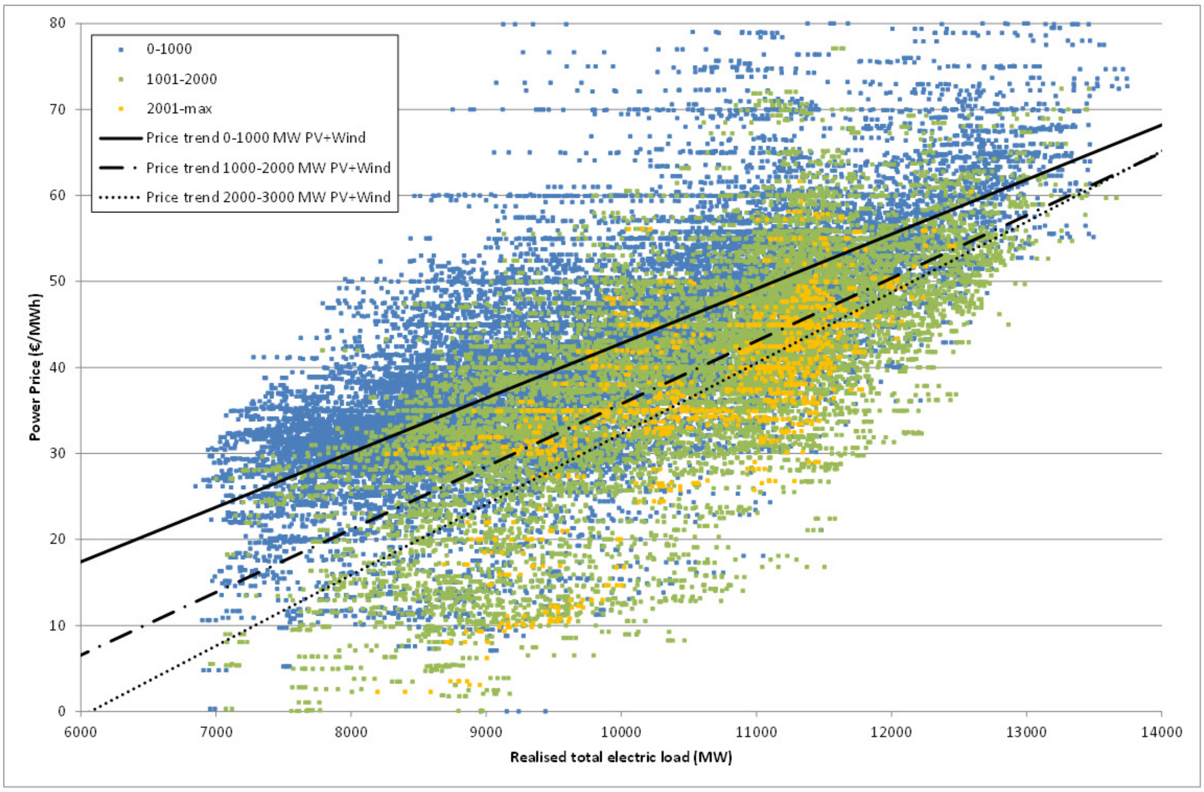

**Belgium**

As already explained, only a limited part of the electricity consumed in Belgium comes out of renewable energy sources. The share of intermittent renewable energy, being wind and solar power, was only 8 % in 2014.

Correlation between spot market prices in Belgium (Belpex Day-Ahead Market) and the total load in Belgium (electricity consumption) is shown in the graph below (black lines). The correlation is clear, but is not as strong as in Germany or Denmark. Low share of (intermittent) renewable energy in combination with the high share of power generation out of natural gas, explain why the correlation is less strong than in Germany and Denmark.

[49] Source: own calculation

**Correlation between power price, electric load and RES (wind + solar) feed-in power in Belgium** [50]




However, as central-European markets are getting more and more interconnected and as the share of intermittent renewable energy will rise in the future, it can be expected that the trends that are observed in Germany will also be applicable to Belgium. Price estimates for the forthcoming years could therefore be based on the correlations and trends observed in Germany.

Based on this assumption, a model can be built calculating the impact of actual demand and actual intermittent renewable energy generation on power prices. In order to include German correlations and trends, actual demand is expressed relative to the annual minimum and maximum load, and actual intermittent renewable energy generation is expressed relative to the average load.

In order to calculate actual prices and price duration curves, not only the impact of actual demand and actual intermittent renewable energy generation on the prices had to be known, but also a reference point for the power price has to be given. As explained before, this reference could be the levelized cost of electricity in a (theoretical) situation when electricity demand is at its maximum and intermittent renewable energy generation is at zero. It is assumed that gas-fired power plants will be the reference technology for power generation in such a situation, at least for Belgium.

Below, the calculation of the levelized cost of electricity for gas fired power plants in Belgium is shown, based on techno-economic assumptions (investment cost, O&M cost, lifetime, efficiency,…) from (VGB PowerTech e.V., 2015) and market assumptions (natural gas price, CO2 emission allowance cost, annual operating hours,…) from (Kost, et al., November 2013). For the market assumptions, low, mid and high scenarios are presented for 2030 and 2050, as done earlier for the natural gas prices in 2030 and 2050.

[50] Source: own calculation

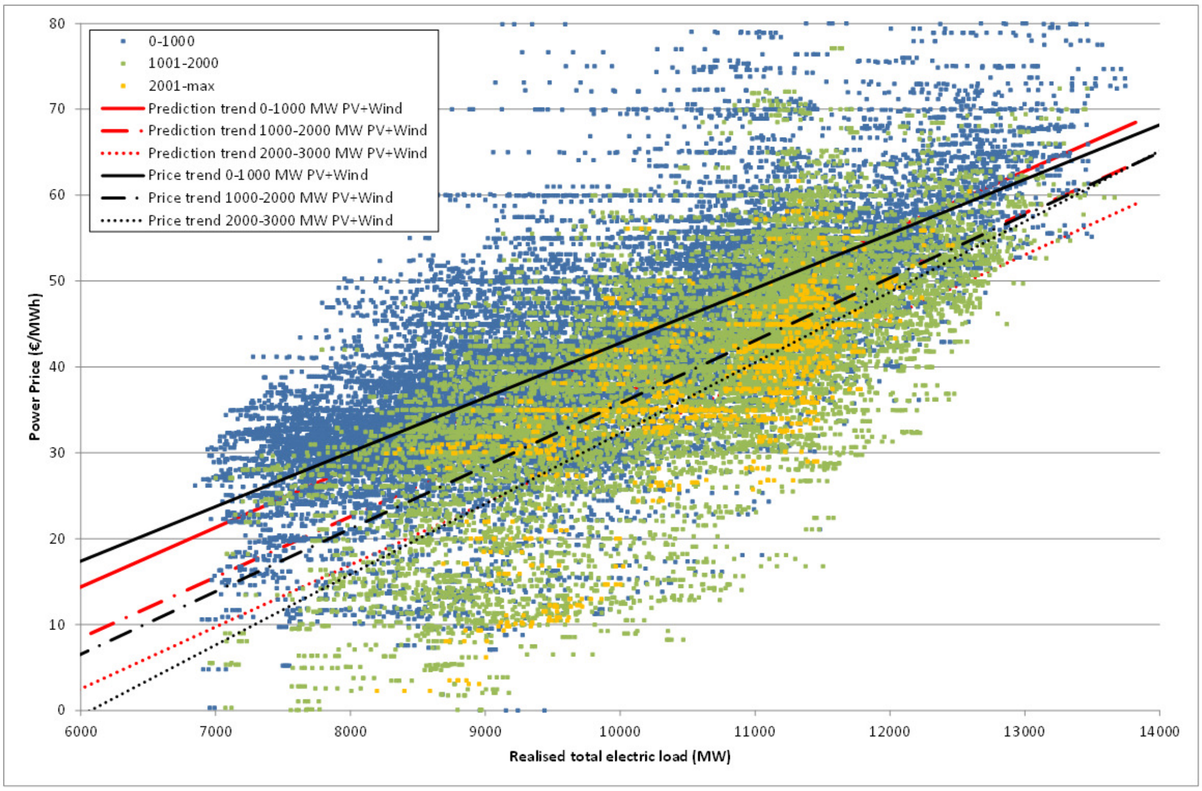
**Main assumptions for the estimation of a reference power prices in Belgium for 2030 and 2050**

| | 2015 | 2030 low | 2030 mid | 2030 high | 2050 low | 2050 mid | 2050 high | *Source* |
|---|---|---|---|---|---|---|---|---|
| Natural gas price (€/MWh LHV) | 25 | 28,7 | 32,5 | 36,3 | 42,3 | 47 | 51,7 | *Fraunhofer* |
| Natural gas grid costs (€/MWh LHV) | 1 | 1 | 1 | 1 | 1 | 1 | 1 | *Own estimate* |
| Efficiency of CCGT | 60% | 62% | 62% | 62% | 62% | 62% | 62% | *VGB Powertech* |
| CO2 emission allowances cost (€/ton) | 5 | 28 | 35 | 42 | 40 | 47,5 | 55 | *Fraunhofer* |
| Total variable cost of electricty generation (€/MWh) | 45 | 57 | 65 | 74 | 83 | 93 | 103 | *Calculation* |
| | | | | | | | | |
| Investment cost CCGT (€/MW) | 800000 | 800000 | 800000 | 800000 | 800000 | 800000 | 800000 | *VGB Powertech* |
| Lifetime CCGT (years) | 25 | 25 | 25 | 25 | 25 | 25 | 25 | *VGB Powertech* |
| Annual number of equivalent full load operating hours (h) | 3600 | 3600 | 3100 | 2600 | 3100 | 2600 | 2100 | *Fraunhofer* |
| Total capex for electricity generation (€/MWh) | 20 | 20 | 24 | 28 | 24 | 28 | 35 | *Calculation* |
| | | | | | | | | |
| Annual Operations and Maintenance costs (% of CAPEX) | 2,5% | 2,5% | 2,5% | 2,5% | 2,5% | 2,5% | 2,5% | *VGB Powertech* |
| Total opex for electricity generation (€/MWh) | 6 | 6 | 6 | 8 | 6 | 8 | 10 | *Calculation* |
| | | | | | | | | |
| **Levelised cost of electricity generation (€/MWh)** | **71** | **83** | **95** | **110** | **113** | **129** | **147** | *Calculation* |
| *Relative to 2015* | | *117%* | *135%* | *155%* | *159%* | *182%* | *208%* | *Calculation* |

Finally, in order to take into account random variations of power prices, a random noise with a normal distribution (Gauss) and an average of 0 is added to the calculated price.

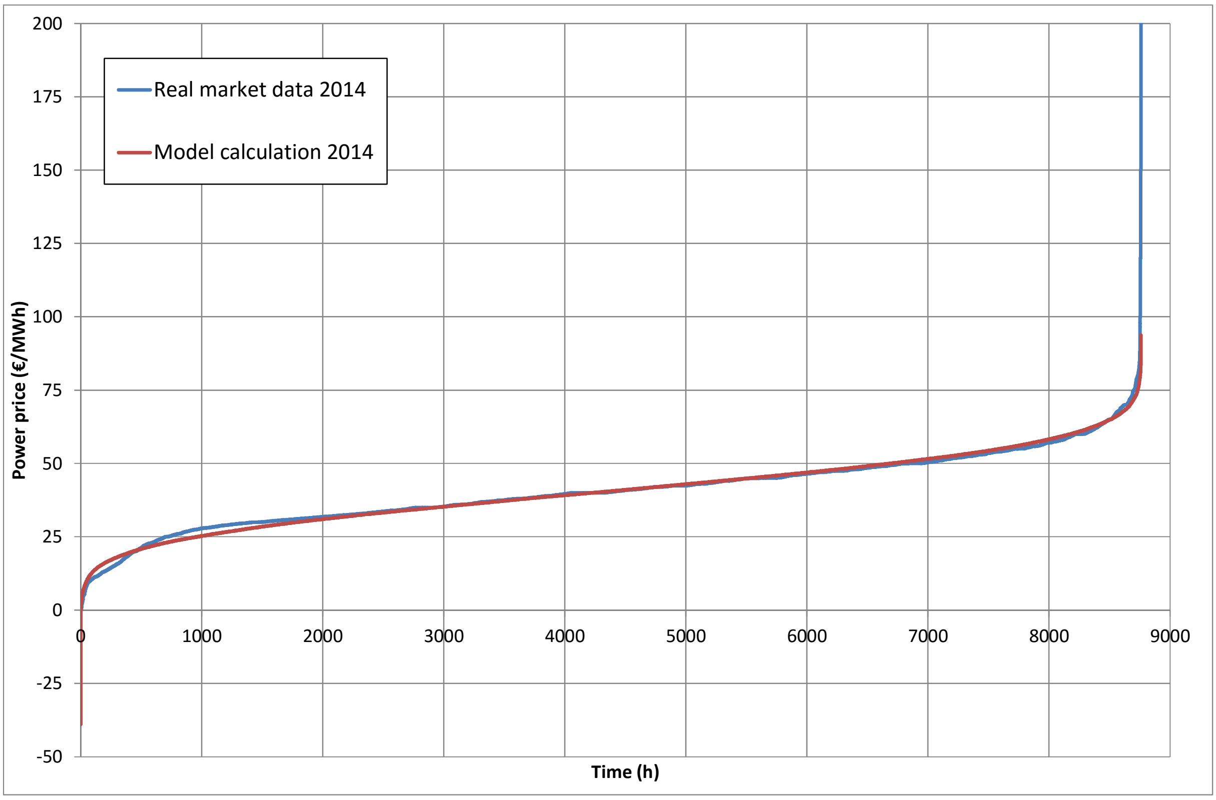
In order to validate the calculation model, price trends as a function of actual demand and actual intermittent renewable energy generation are calculated for the year 2014, and compared to real time values. Besides, also the price duration curve for Belgium in 2014 is calculated and compared to real Belpex DAM market data. Graphs showing these comparisons are shown below.

**Estimated future correlation between power price, electric load and RES (wind + solar) feed-in power in Belgium** [51]




[51] Source: own calculation

**Comparison of modelled price duration curve for Belgium in 2014 with real market data**




It can be concluded that the model generates results that are quite close to the real values. Where the calculated price duration curve is almost identical the one observed in reality, still some deviations are observed for the price trends (red curves compared to black curves), but as explained previously, these difference are expected to decrease in the future.

**Estimated price duration curves for Belgium for 2030 and 2050**

The same model can be used to calculate power prices and price duration curves for Belgium for 2030 and 2050.

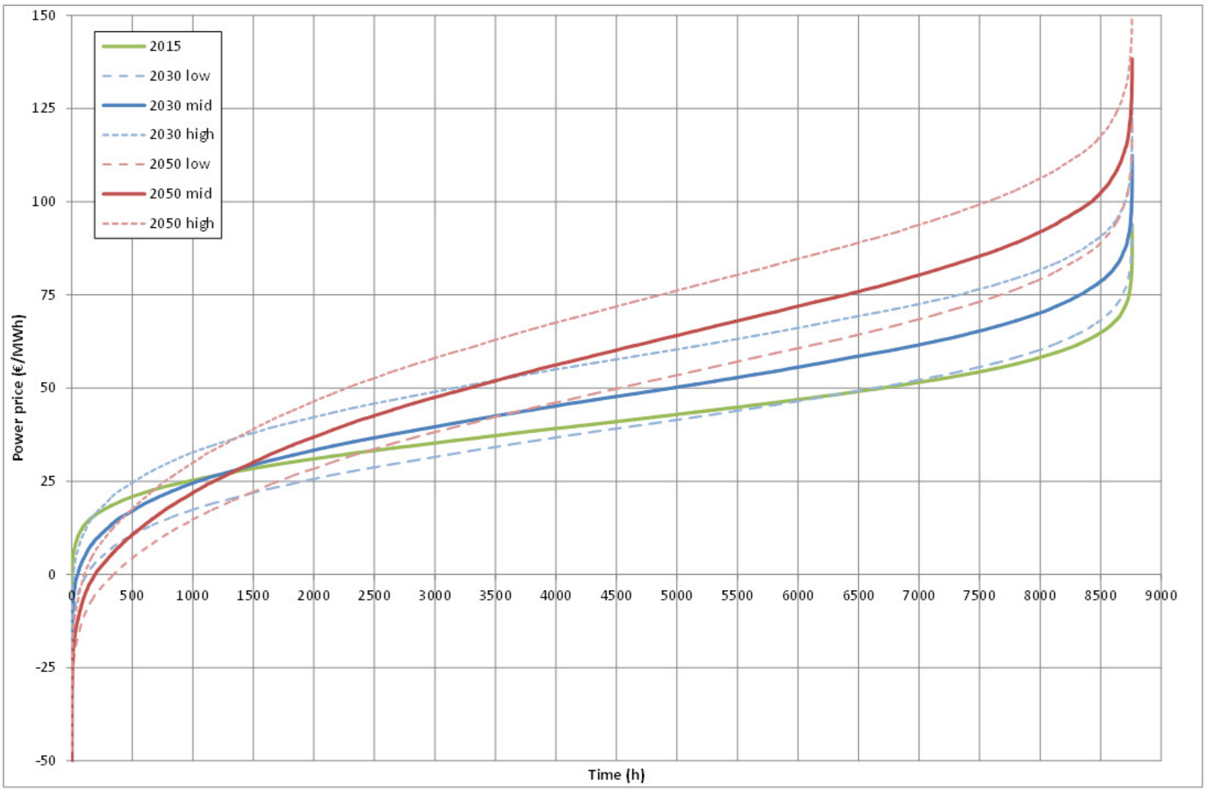
Therefore, the assumptions mentioned above for the installed capacities of intermittent renewable energy in Belgium in 2030 and 2050, the total power demand in Belgium in 2030 and 2050, and the levelized cost of electricity (CCGT) in Belgium for 2030 and 2050 are used. For installed capacity of intermittent renewables and total power demand in Belgium, only the – in our opinion – most likely scenario is used. For the levelized cost however, a low, mid and high case are considered. The table below summarises the assumptions.

**Main assumptions for price duration curve calculation in Belgium for 2030 and 2050**

| | 2015 | 2030 | | | 2050 | | |
|---|---|---|---|---|---|---|---|
| | | low | mid | high | low | mid | high |
| Total annual electricity consumption (TWh) | 88,3 | 90,8 | | | 121,4 | | |
| Minimum load (MW) | 6848 | 7140 | | | 10627 | | |
| Maximum load (MW) | 13821 | 14113 | | | 17600 | | |
| Average load (MW) | 10076 | 10368 | | | 13854 | | |
| On shore wind installed capacity (MW) | 1123 | 4678 | | | 7213 | | |
| Off shore wind installed capacity (MW) | 712 | 3522 | | | 7687 | | |
| PV sun installed capacity (MW) | 2818 | 4800 | | | 10000 | | |
| Levelised cost of electricity generation (€/MWh) | 71 | 83 | 95 | 110 | 113 | 129 | 147 |

Using these assumptions, the model gives the price duration curves shown in the graph below as an output.

**Modelled price duration curve calculation in Belgium for 2030 and 2050** [52]




As shown in the curves, the average electricity prices in Belgium tend to go up in the near future. On the other hand, the number of hours with (very) low prices also increases. The table below gives some numbers illustrating these trends.

[52] Source: own calculation

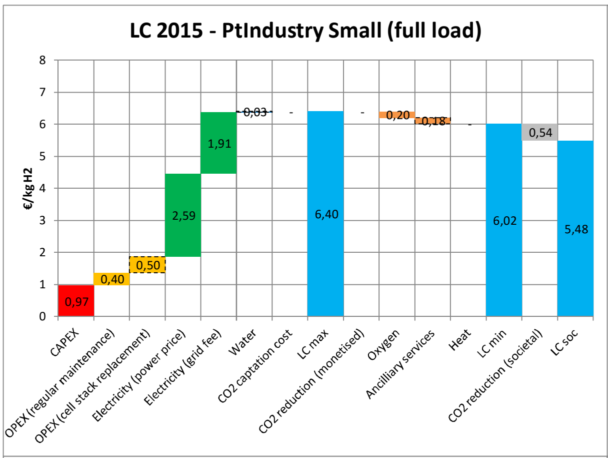
**Illustrative values from the price duration curve calculation in Belgium for 2030 and 2050**

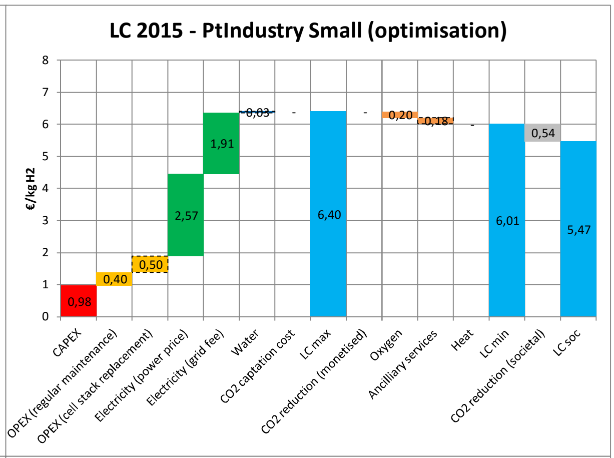
| | 2015 | 2030 | | | 2050 | | |
|---|---|---|---|---|---|---|---|
| | | low | mid | high | low | mid | high |
| Natural gas price (€/MWh LHV) | 25 | 28,7 | 32,5 | 36,3 | 42,3 | 47 | 51,7 |
| Natural gas price (€/MWh HHV) | 22,6 | 25,9 | 29,3 | 32,8 | 38,2 | 42,4 | 46,7 |
| | | | | | | | |
| CO2 emission allowances cost (€/ton) | 5 | 28 | 35 | 42 | 40 | 47,5 | 55 |
| | | | | | | | |
| Levelised cost of electricity generation (€/MWh) | 71 | 83 | 95 | 110 | 113 | 129 | 147 |
| | | | | | | | |
| **Baseload power price (8760h/year) (€/Mwh)** | **41** | **38** | **46** | **56** | **47** | **57** | **68** |
| **Partload power price (6570h/year) (€/Mwh)** | **35** | **31** | **39** | **48** | **37** | **46** | **57** |
| **Partload power price (4380h/year) (€/Mwh)** | **30** | **25** | **32** | **41** | **27** | **35** | **45** |
| | | | | | | | |

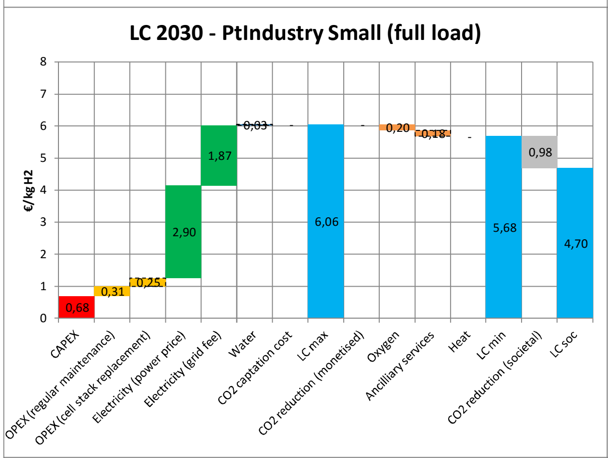
The table shows that for baseload power an increase is expected from 41 €/MWh in 2015 to 46 €/MWh in 2030 and 57 €/MWh in 2050. For half load, if the 4380 hours with lowest price can be considered, the increase is less significant (30 € in 2015, 32 € in 2030 and 35 € in 2050).

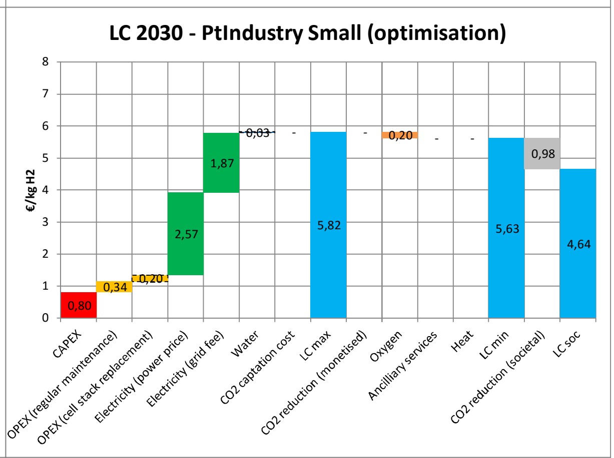
When interpreting the results, it should be taken into account that the calculation model does not include the future construction of large scale storage infrastructure, such a pumped hydro plant. However, it is found that the slope of the price duration curve is rather moderate in 2015, but gets more and steeper in 2030 and 2050. Steeper slopes indicate that there is a growing market, or even demand, for (large scale) storage facilities of electricity. In this respect, Power-to-Gas can certainly play its role.

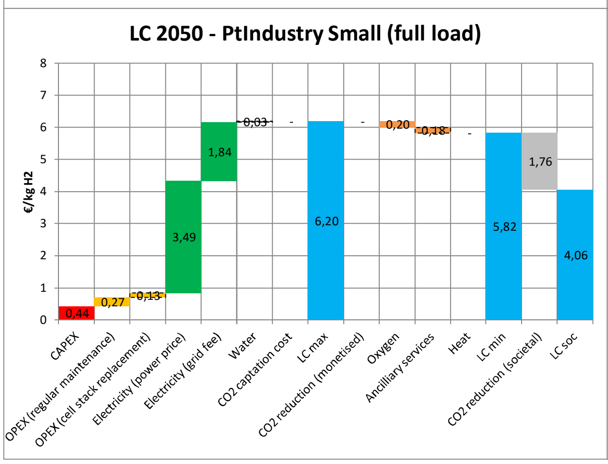
# ANNEX 10: DETAILED RESULTS CASE 1: POWER-TO-INDUSTRY - SMALL SCALE

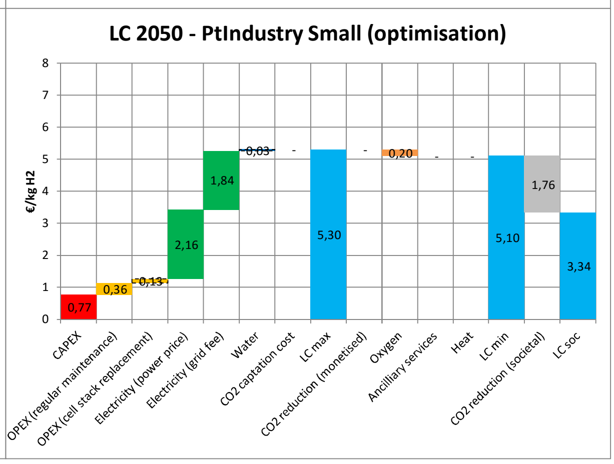


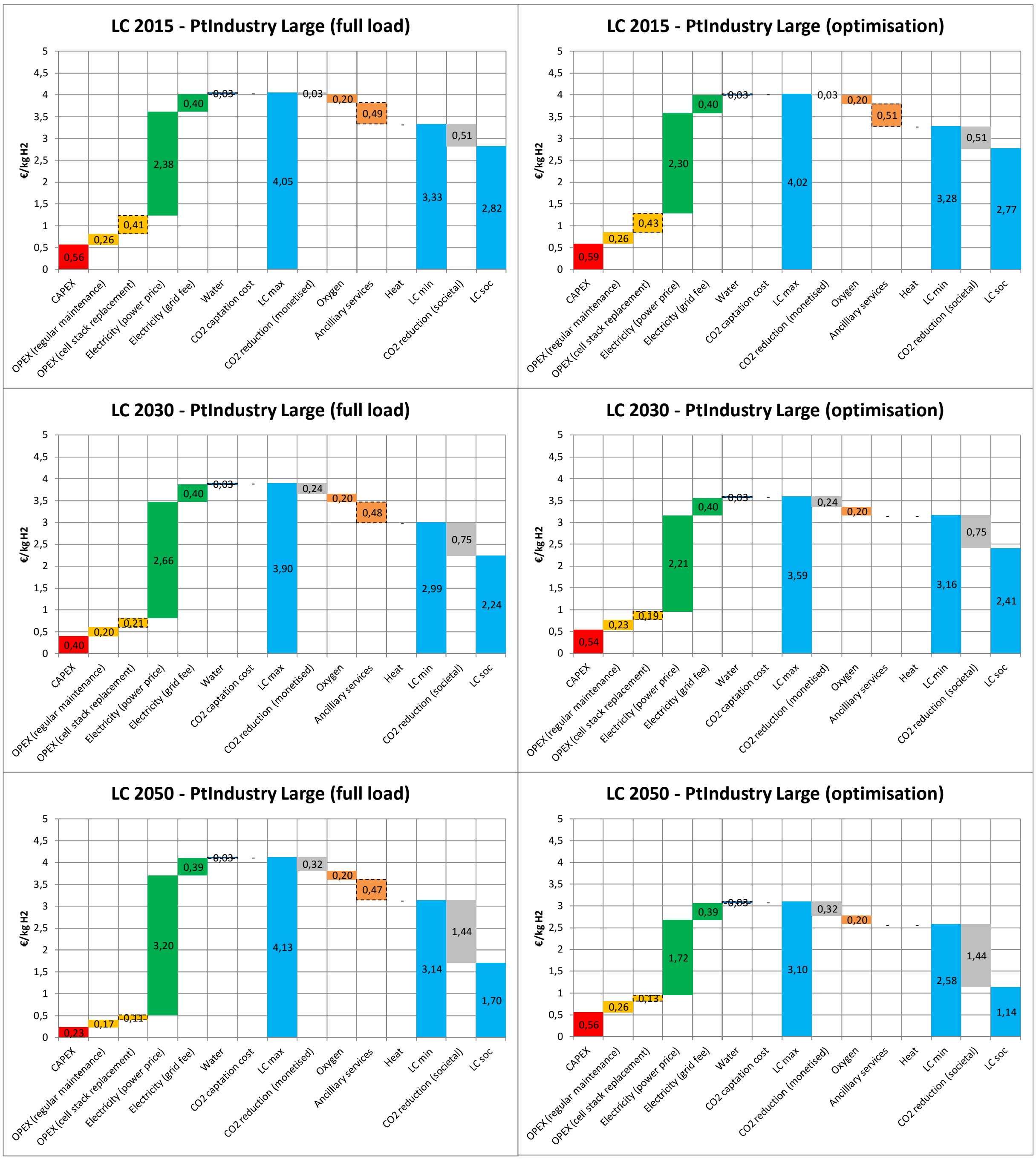



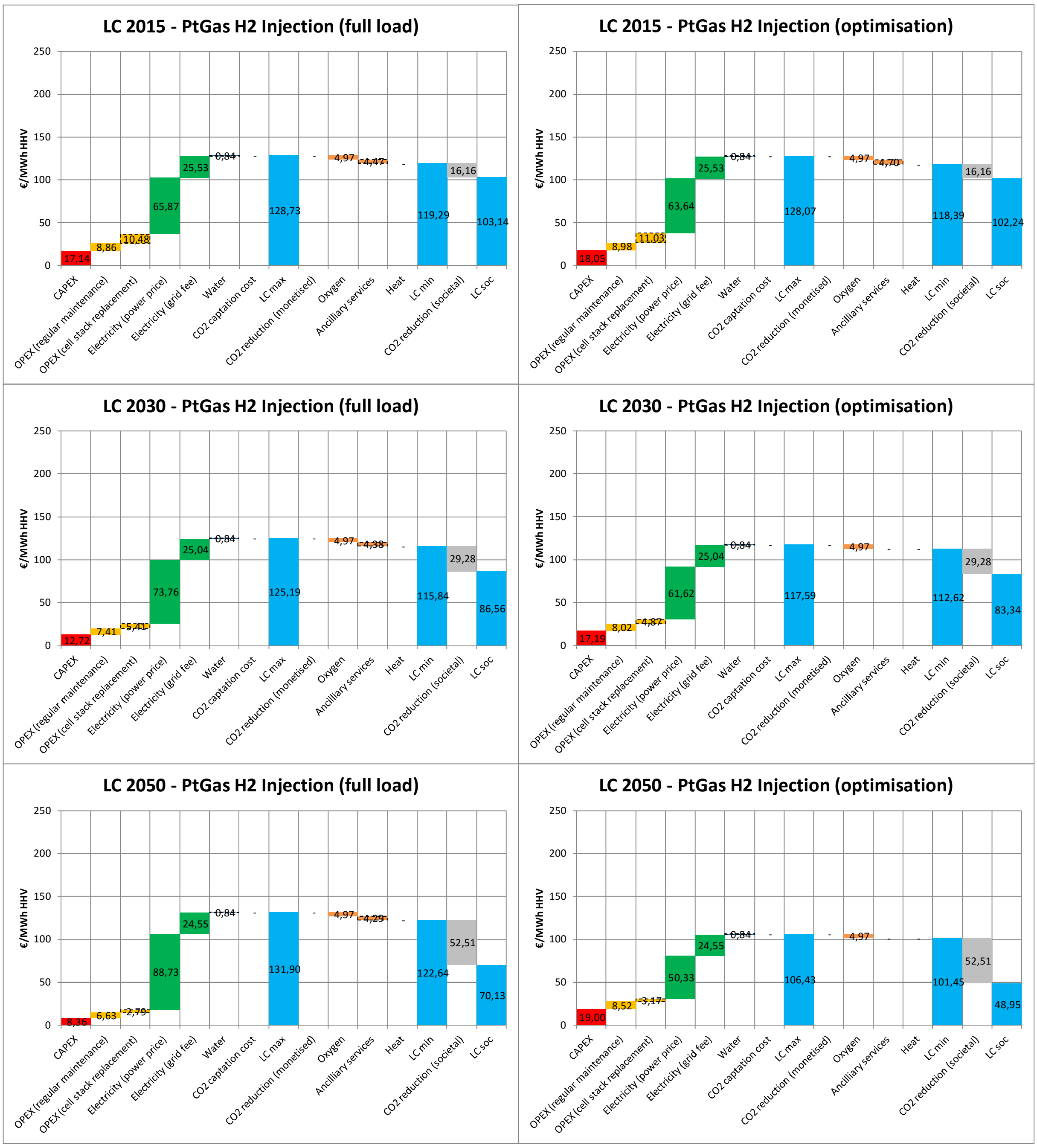

| | ***Baseload power price (€/MWh)*** | ***Optimised # operating hours*** | ***Power price during optimised OH (€/MWh)*** |
|---|---|---|---|
| ***2015*** | 40,71 | 8412 | 40,37 |
| ***2030*** | 46,48 | 7053 | 41,21 |
| ***2050*** | 57,02 | 4249 | 35,32 |

# ANNEX 11: DETAILED RESULTS CASE 2: POWER-TO-INDUSTRY - LARGE SCALE



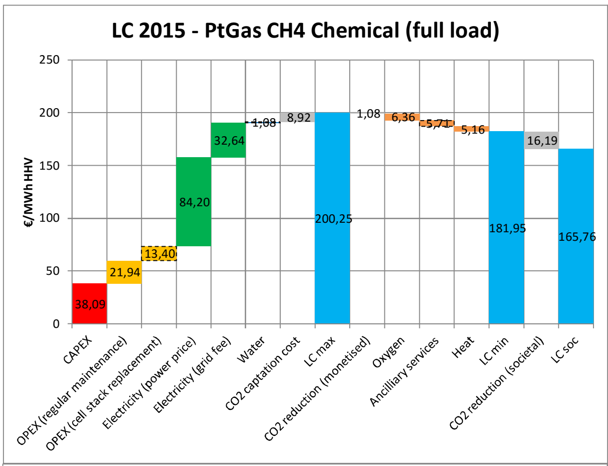

| | *Baseload power price (€/MWh)* | *Optimised # operating hours* | *Power price during optimised OH (€/MWh)* |
|---|---|---|---|
| ***2015*** | 40,71 | 8072 | 39,32 |
| ***2030*** | 46,48 | 6203 | 38,56 |
| ***2050*** | 57,02 | 3484 | 30,77 |

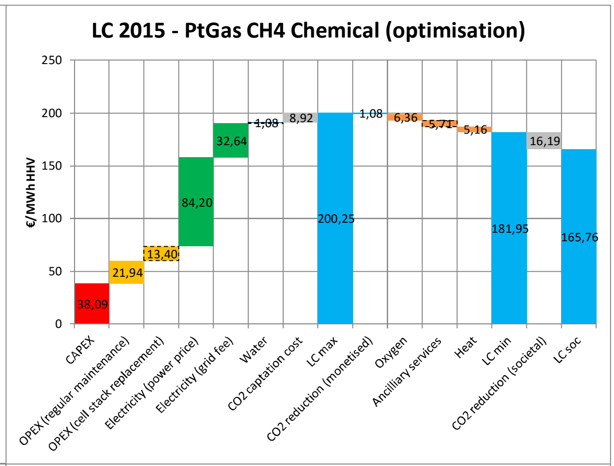
## ANNEX 12: DETAILED RESULTS CASE 3: POWER-TO-GAS - DIRECT INJECTION OF HYDROGEN

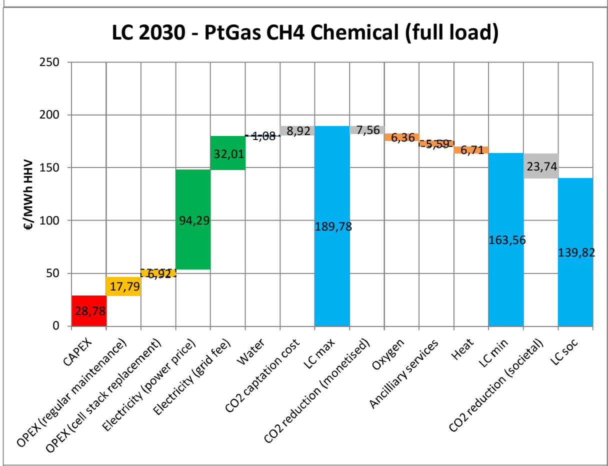


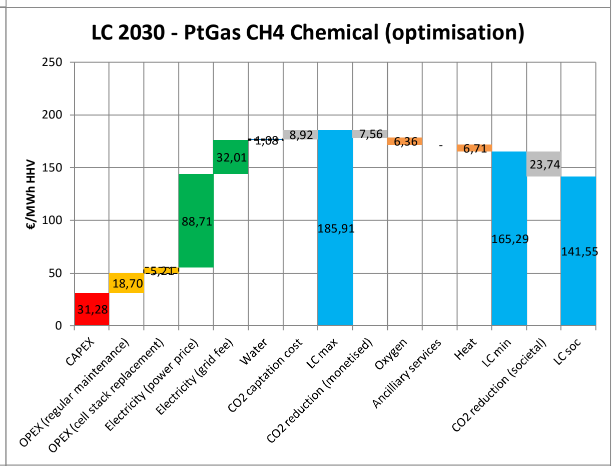

| | *Baseload power price (€/MWh)* | *Optimised # operating hours* | *Power price during optimised OH (€/MWh)* |
|---|---|---|---|
| ***2015*** | 40,71 | 8072 | 39,32 |
| ***2030*** | 46,48 | 6288 | 38,82 |
| ***2050*** | 57,02 | 3739 | 32,35 |

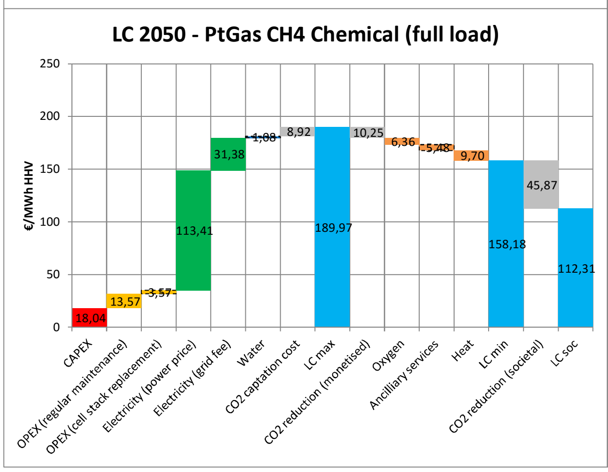
## ANNEX 13: DETAILED RESULTS CASE 4: POWER-TO-GAS - INJECTION OF SNG

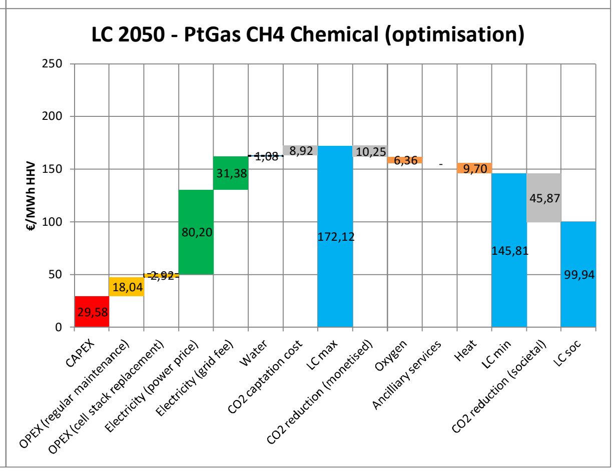


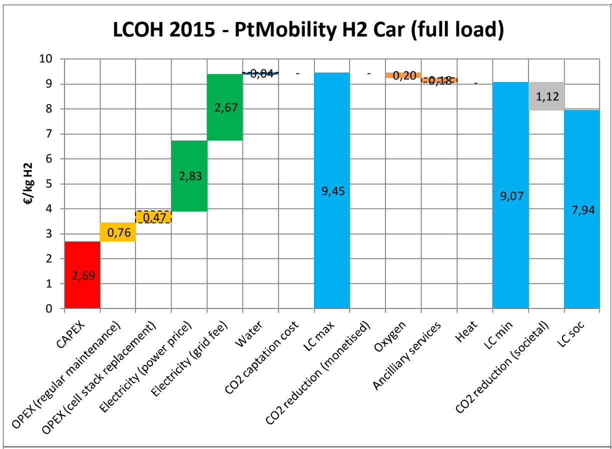



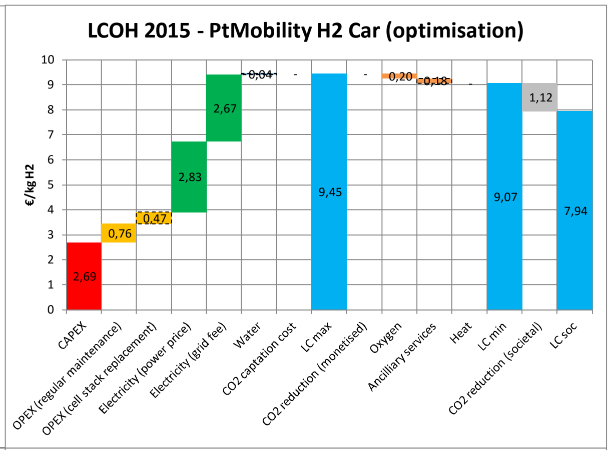



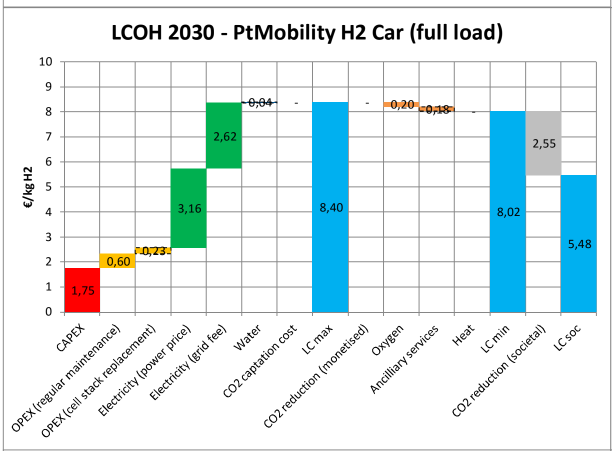



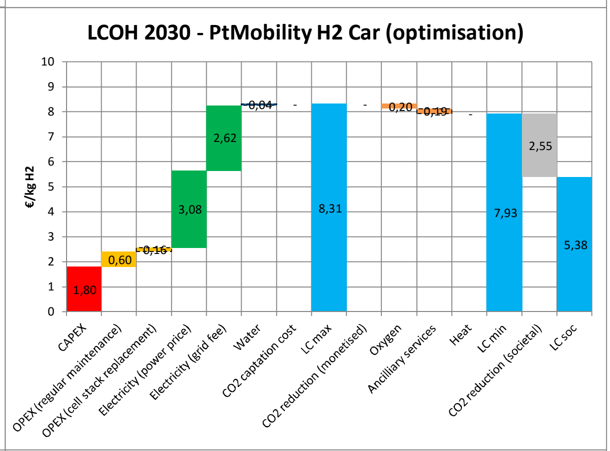

| | ***Baseload power price (€/MWh)*** | ***Optimised # operating hours*** | ***Power price during optimised OH (€/MWh)*** |
|---|---|---|---|
| ***2015*** | 40,71 | 8497 | 40,71 |
| ***2030*** | 46,48 | 7817 | 43,73 |
| ***2050*** | 57,02 | 5183 | 40,32 |

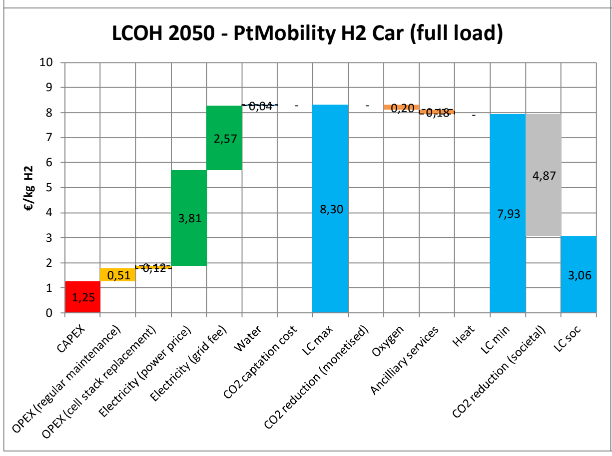
# ANNEX 14: DETAILED RESULTS CASE 5: POWER-TO-MOBILITY - HRS FOR CARS

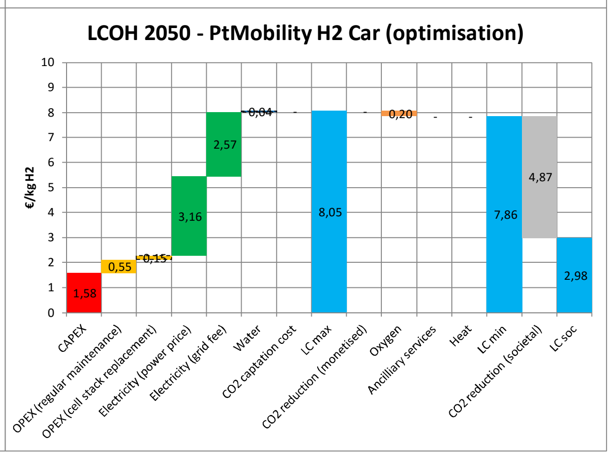


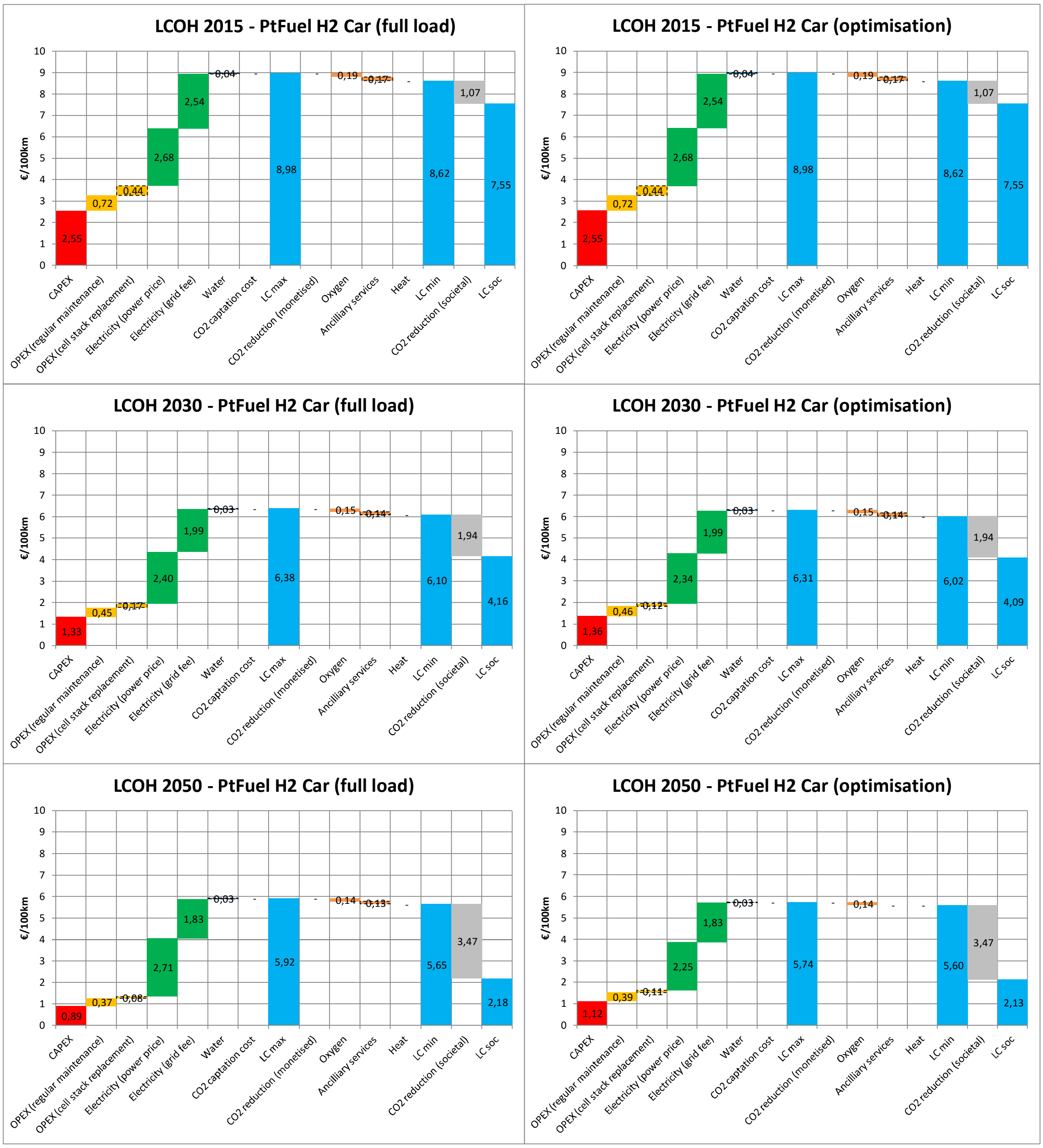



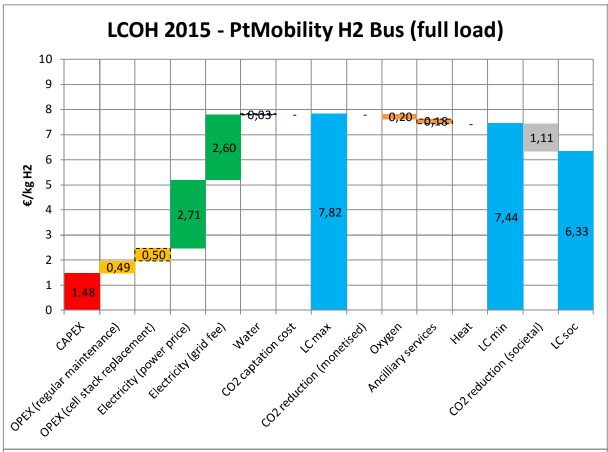



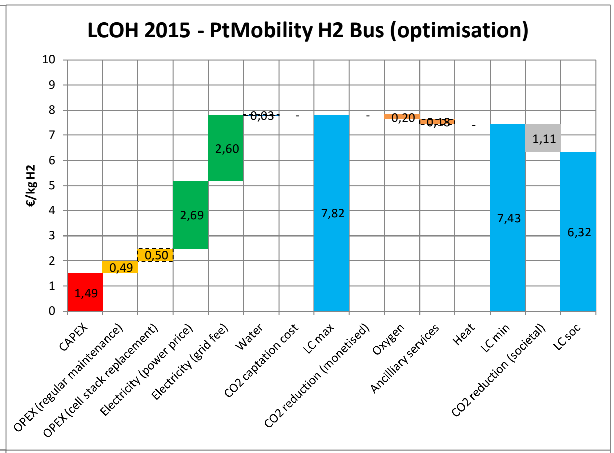



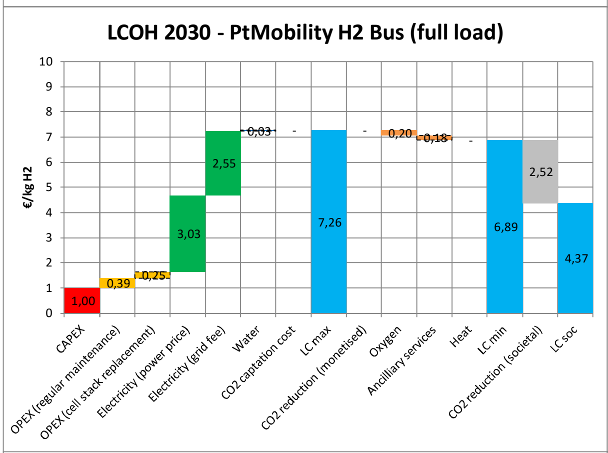


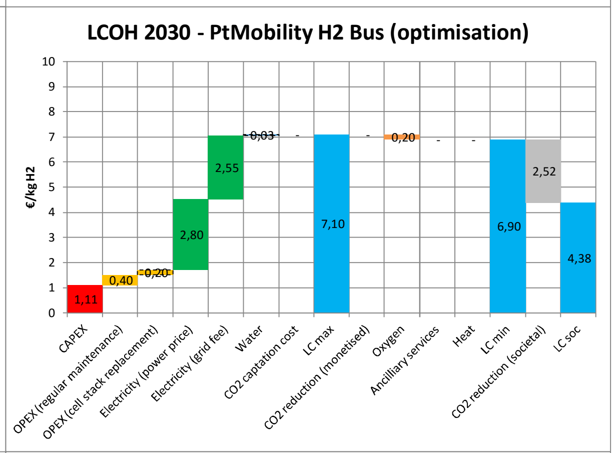

| | *Baseload power price (€/MWh)* | *Optimised # operating hours* | *Power price during optimised OH (€/MWh)* |
|---|---|---|---|
| ***2015*** | 40,71 | 8497 | 40,71 |
| ***2030*** | 46,48 | 8242 | 45,30 |
| ***2050*** | 57,02 | 6628 | 47,37 |

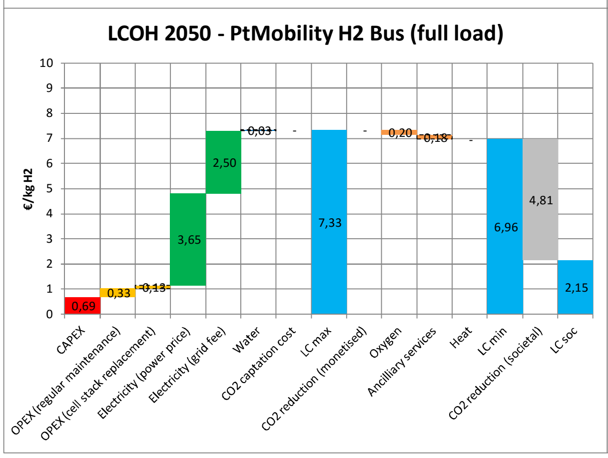
## ANNEX 15: DETAILED RESULTS CASE 6: POWER-TO-MOBILITY - HRS FOR BUSES

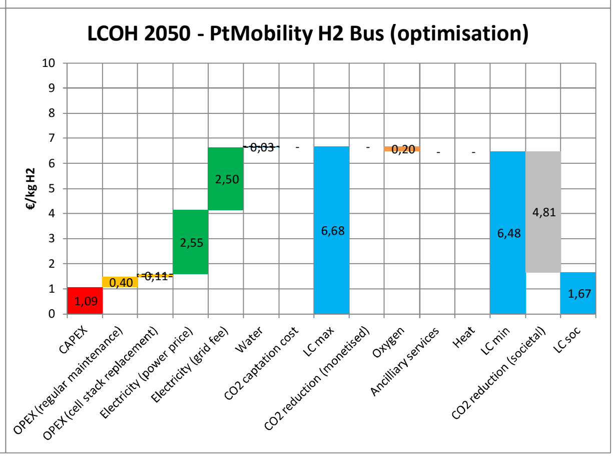


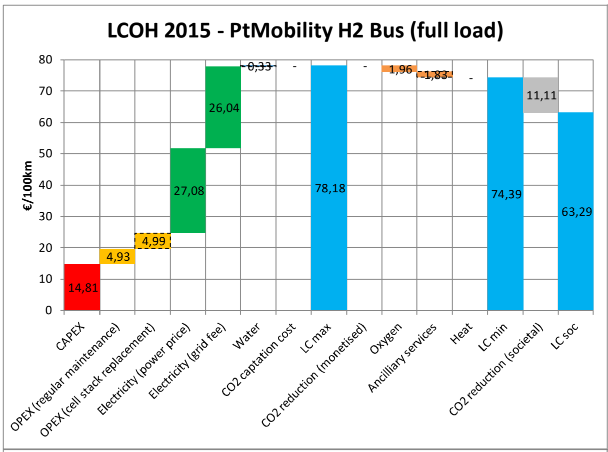



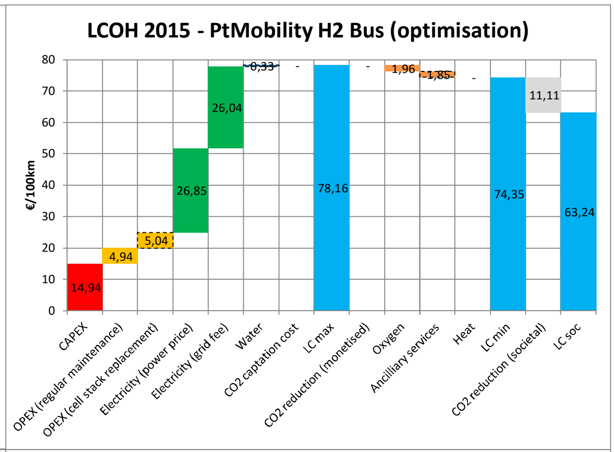



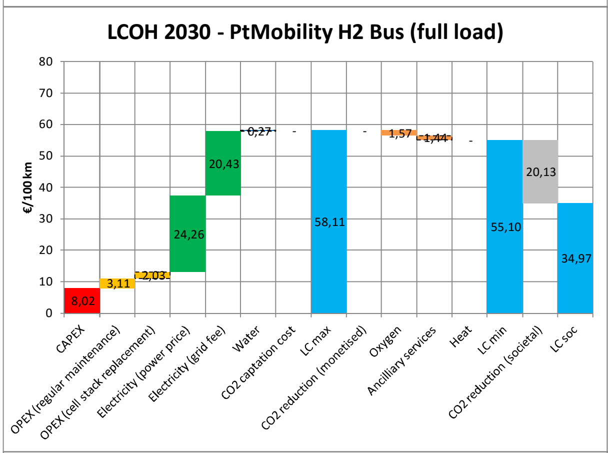



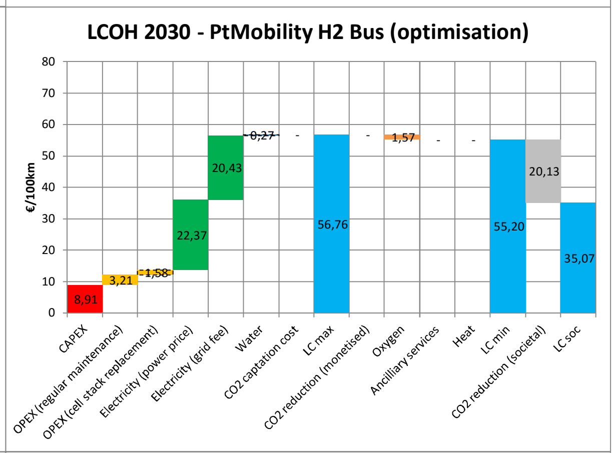



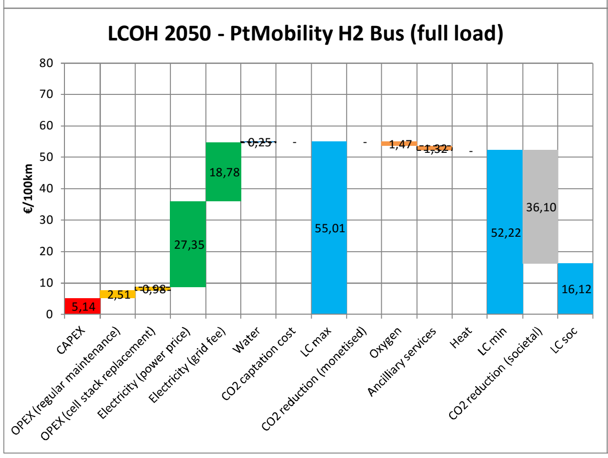



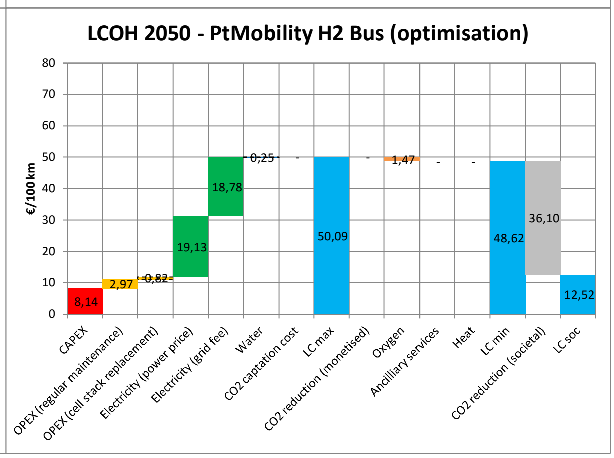


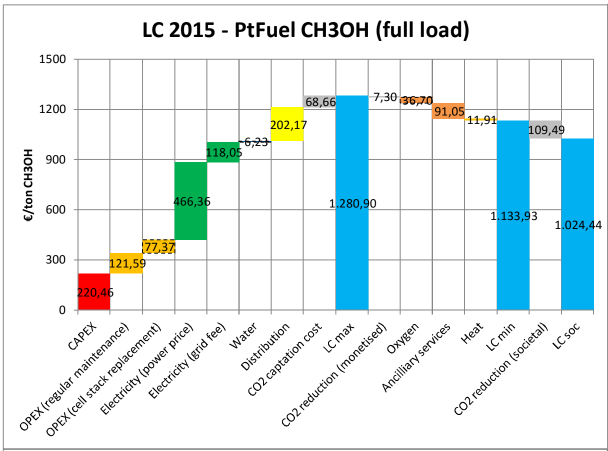



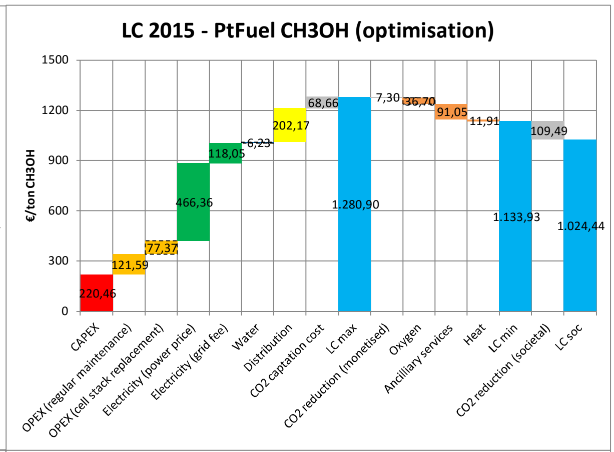



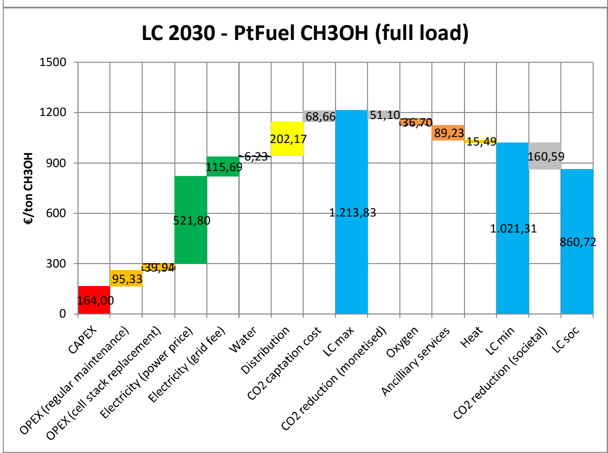



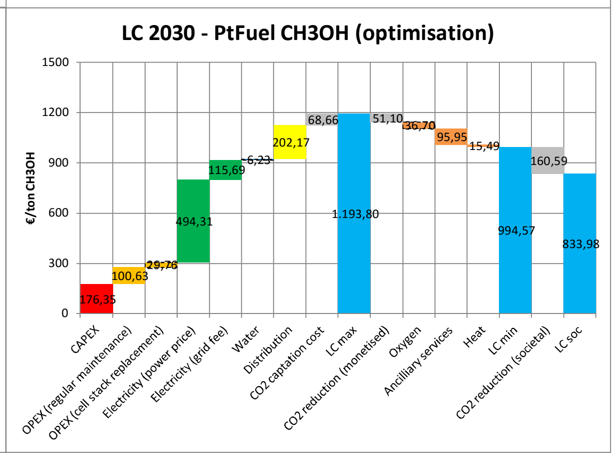

| | ***Baseload power price (€/MWh)*** | ***Optimised # operating hours*** | ***Power price during optimised OH (€/MWh)*** |
|---|---|---|---|
| ***2015*** | 40,71 | 8412 | 40,37 |
| ***2030*** | 46,48 | 7563 | 42,86 |
| ***2050*** | 57,02 | 5098 | 39,88 |

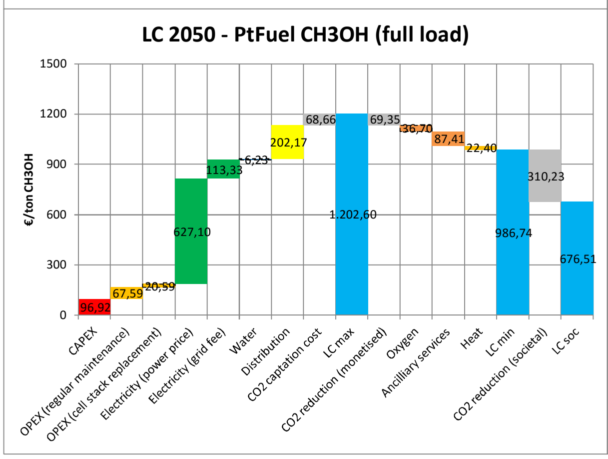
# ANNEX 16: DETAILED RESULTS CASE 7: POWER-TO-FUEL - METHANOL AS A FUEL

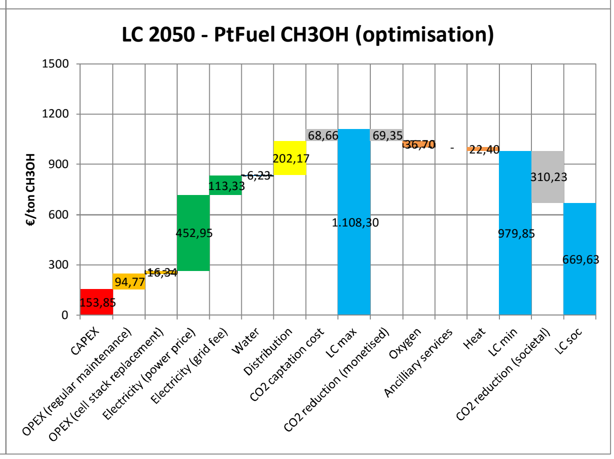


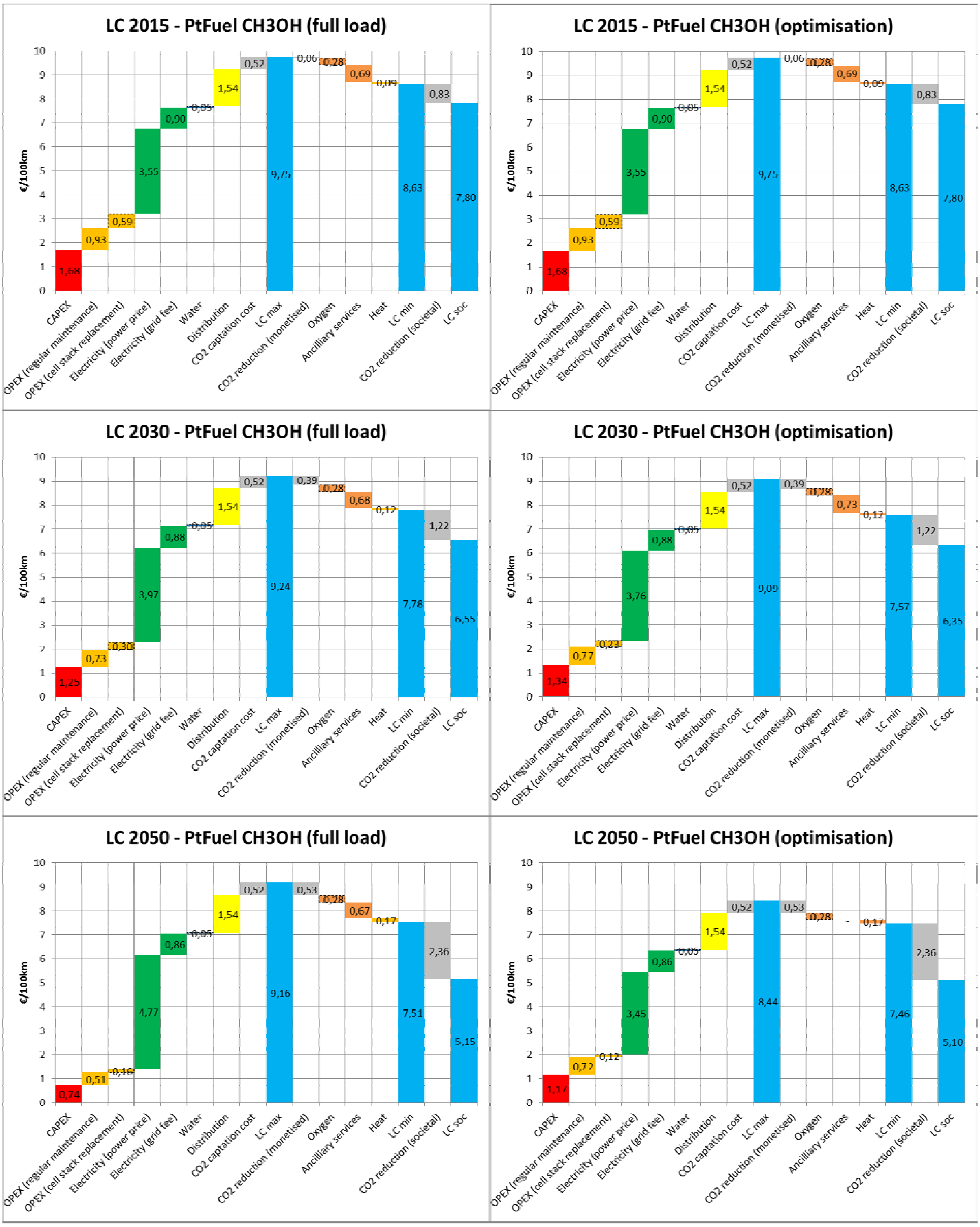



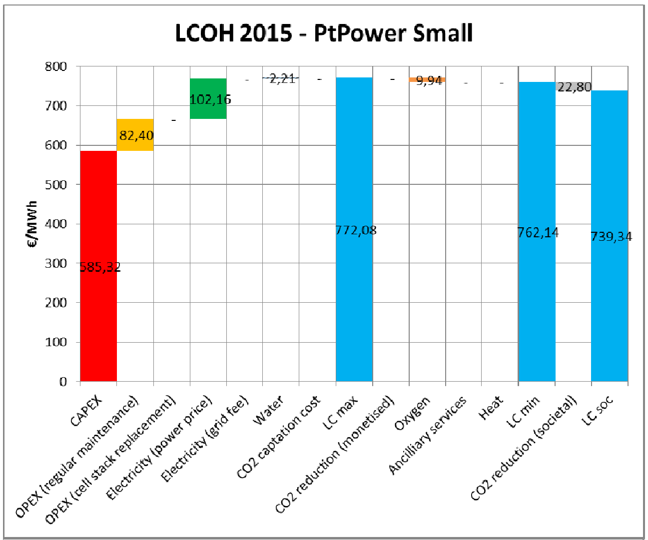



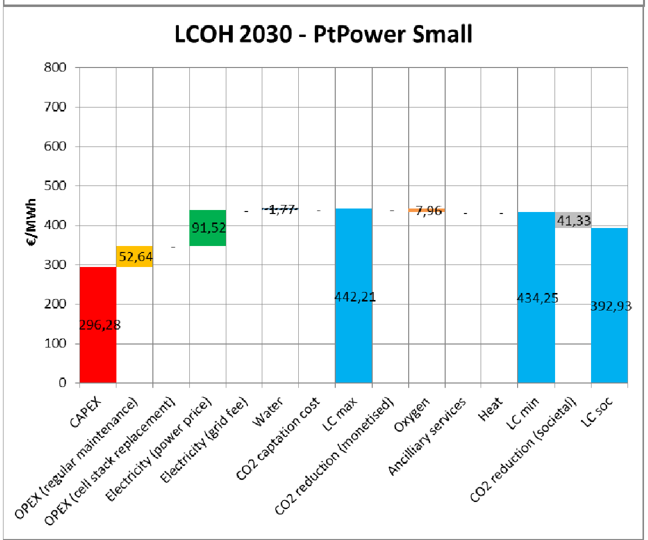



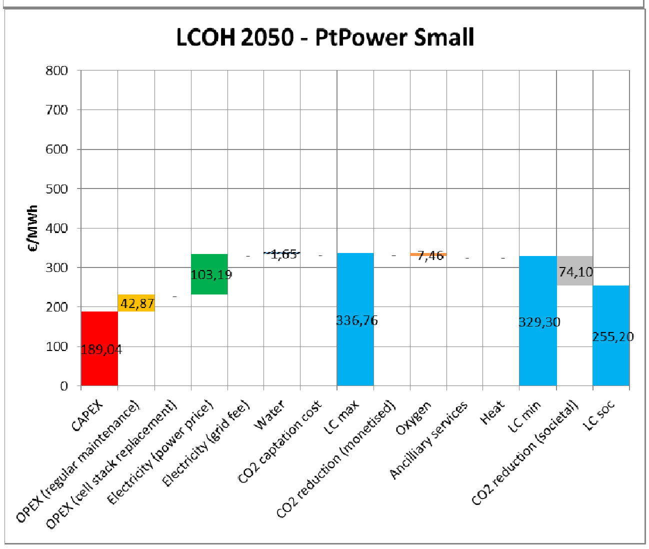



| | *Baseload power price (€/MWh)* | *Optimised # operating hours* | *Power price during optimised OH (€/MWh)* |
|---|---|---|---|
| ***2015*** | 40,71 | 8497 | 40,71 |
| ***2030*** | 46,48 | 7902 | 44,03 |
| ***2050*** | 57,02 | 5353 | 41,18 |

# ANNEX 17: DETAILED RESULTS CASE 8: POWER-TO-POWER - HYDROGEN ENERGY STORAGE SMALL SCALE



## ANNEX 18: DETAILED RESULTS CASE 9: POWER-TO-INDUSTRY - METHANOL

**Case specific assumptions**

- Electrical power input of the electrolyser: 50 MW
- Annual operating hours of the electrolyser: 8497 (baseload operation @ 97% availability)
- Annual hydrogen production: +/- 85.000.000 Nm³ at low pressure (20 bar)
- Type of electrolyser: large scale PEM
- No storage
- No compression
- Civil works cost: 1.000.000 €
- Connection cost to the public power grid: 1.000.000 € (limited, as connection of the industrial plant already exists)
- Power price: according to price duration curves (mid scenario for 2030 and 2050) for Belgium as mentioned before (commodity) + 10% (supplier's margin) + 11,33 €/MWh (grid costs taxes and levies, as calculated for a 70/36 kV connected customer (direct connection to HS transformer), with an annual off take of 500 GWh)
- Methanol sales price: 400 €/ton in 2015; 460 €/ton in 2030 and 576 €/ton in 2050
- $CO_2$ captation and purification cost: 50 €/ton
- The avoided emission of $CO_2$ amounts 59.553 ton per year. This is the captured amount of $CO_2$ (56.019 ton) plus the avoided emission of a natural gas fired boiler with 90% efficiency (for generating the heat that is replaced by heat recovery from the methanolisation reaction). Per ton of generated methanol, the avoided emission of $CO_2$ equals 1.37 ton.

**Results for economic feasibility**

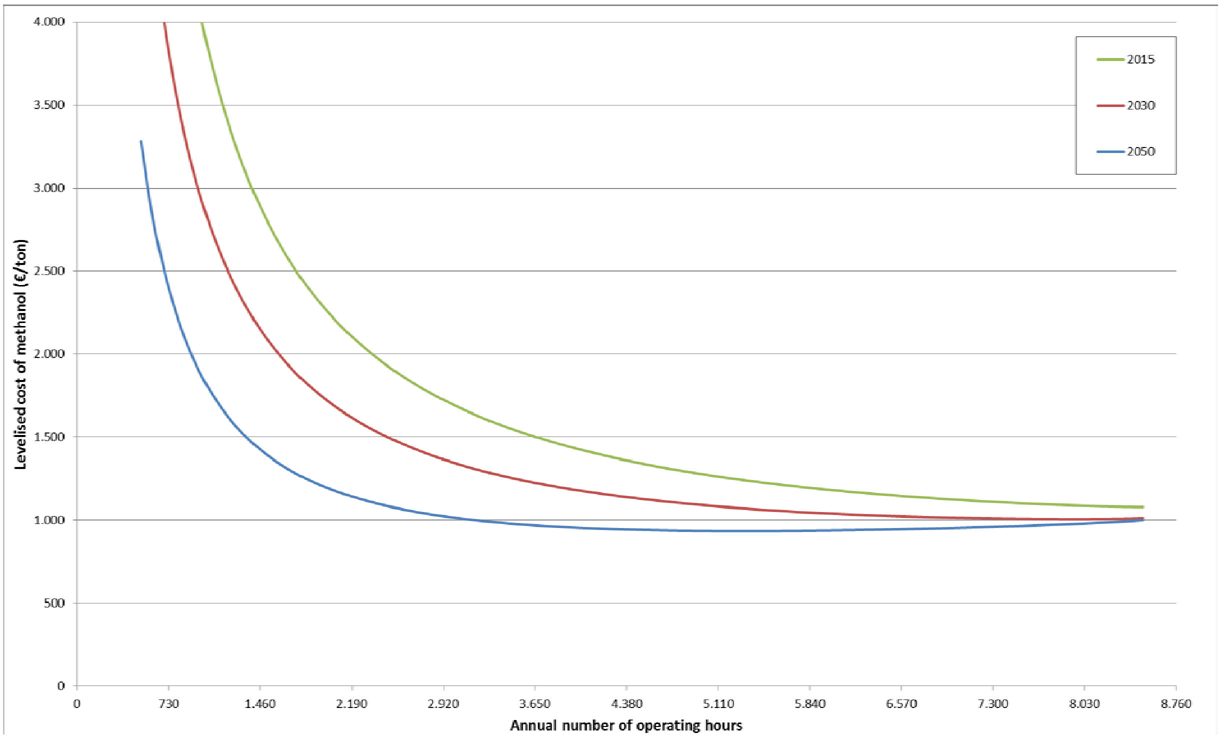
The operational result (EBITDA) equals -18,7 million euro in 2015, improving to a (still negative) value of –16,1 million euro in 2030 and -13,9 million euro in 2050. NPV equals -296 million euro in 2015, -244 million euro in 2030 and -188 million euro in 2050. The ratio of the NPV over the total CAPEX even decreases from -2,64 in 2015 towards -2,86 in 2030 and -3,66 in 2050.

**Tipping points**

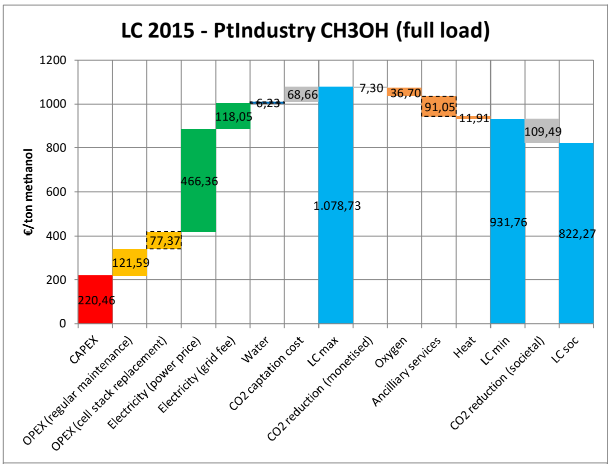
| | 2015 | | 2030 | | 2050 | |
|---|---|---|---|---|---|---|
| | Requirement | Actual value | Requirement | Expected value | Requirement | Expected value |
| Power price (all-in) | < -21,8 €/MWh | 56,1 €/MWh | < -1,3 €/MWh | 62,5 €/MWh | < 25,8 €/MWh | 74,1 €/MWh |
| Selling price of methanol | > 1211 €/ton | 400 €/ton | > 1110 €/ton | 460 €/ton | > 1059 €/ton | 576 €/ton |
| CO2 captation and filtration cost | < -541€/ton | 50 €/ton | < -424 €/ton | 50 €/ton | < -302 €/ton | 50 €/ton |

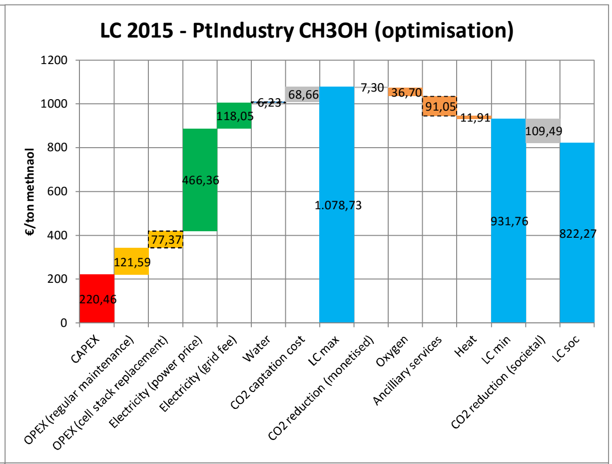
**Optimisation of the operating hours**

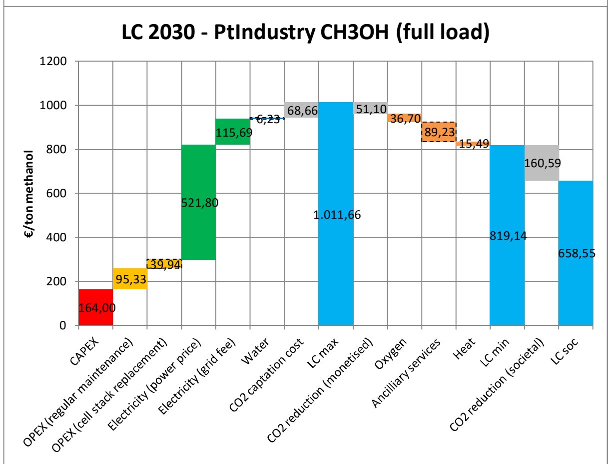
The number of operating hours minimising the levelized cost, equals approximately 7900 hours in 2030 and 5350 hours in 2050.

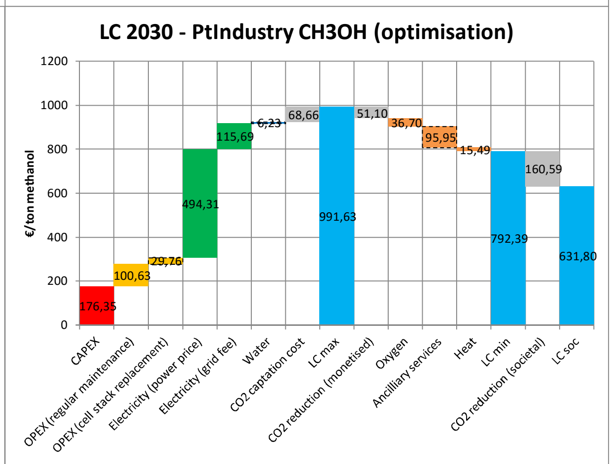


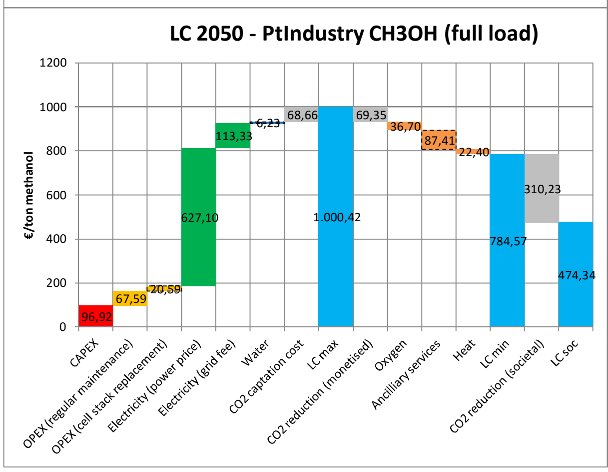
## Sensitivity Analysis

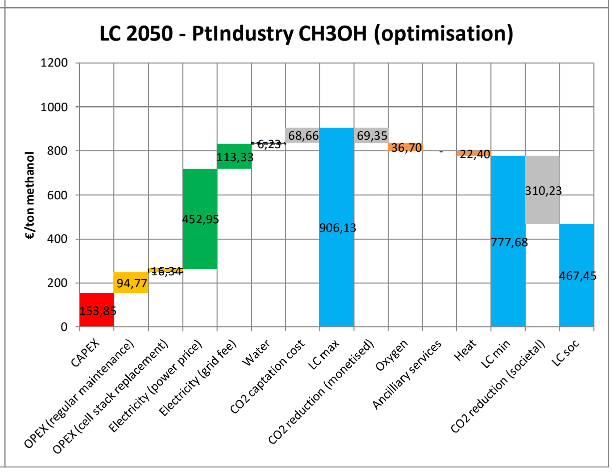



| | ***Baseload power price (€/MWh)*** | ***Optimised # operating hours*** | ***Power price during optimised OH (€/MWh)*** |
|---|---|---|---|
| ***2015*** | 40,71 | 8497 | 40,71 |
| ***2030*** | 46,48 | 7902 | 44,03 |
| ***2050*** | 57,02 | 5353 | 41,18 |

## ANNEX 19: DETAILED RESULTS CASE 10: POWER-TO-GAS - INJECTION OF SNG WITH BIOLOGICAL METHANATION

### Case specific assumptions

- Electrical power input of the electrolyser: 5 MW
- Annual operating hours of the electrolyser: 8497 (baseload operation @ 97% availability)
- Annual hydrogen production: +/- 8.500.000 Nm³ at low pressure (20 bar)
- Type of electrolyser: large scale PEM
- No storage
- Compression towards 70 bar, one compressor, one stage, compressor capacity equal to the electrolyser production capacity (1000 Nm³/h), specific investment cost 370 €/Nm³/h in 2015, decreasing later on)
- Civil works cost: 250.000 €
- Connection cost to the public power grid: 350.000 €
- Connection cost to the public natural gas grid: 1.000.000 € (gas injection facility, including measurement and safeties)
- Power price: according to price duration curves (mid scenario for 2030 and 2050) for Belgium as mentioned before (commodity) + 10% (supplier's margin) + 25,34 €/MWh (grid costs taxes and levies, as calculated for customer connected to 36kV distribution grid, with an annual offtake of 40 GWh)
- Value of generated methane per MWh HHV equal to natural gas price per MWh HHV: 22,6 €/MWh in 2015; 29,4 €/MWh in 2030 and 42,4 €/MWh in 2050
- The avoided emission of $CO_2$ amounts 5.085 ton per year. This is the captured amount of $CO_2$ (4.201 ton) plus the avoided emission of a natural gas fired boiler with 90% efficiency (for generating the heat that is replaced by heat recovery from the (exothermal) methanation reaction). Per MWh of generated methane, the avoided emission of $CO_2$ equals 216 kg.

### Results for economic feasibility

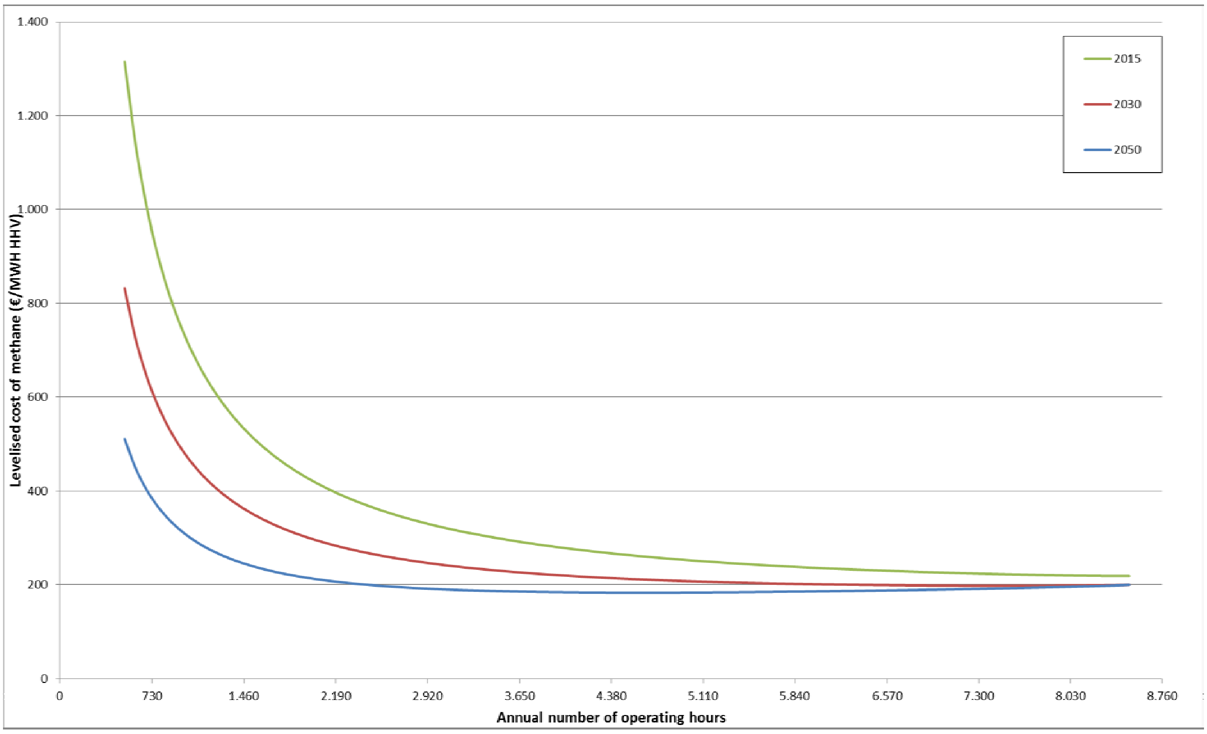
The operational result (EBITDA) equals -3,64 million euro in 2015, improving to a (still negative) value of -3,44 million euro in 2030 and -3,45 million euro in 2050. NPV equals -51 million euro in 2015, -458 million euro in 2030 and -42 million euro in 2050. The ratio of the NPV over the total CAPEX even decreases from -4,26 in 2015 towards -5,66 in 2030 and -8,68 in 2050.

### Tipping points (full load)

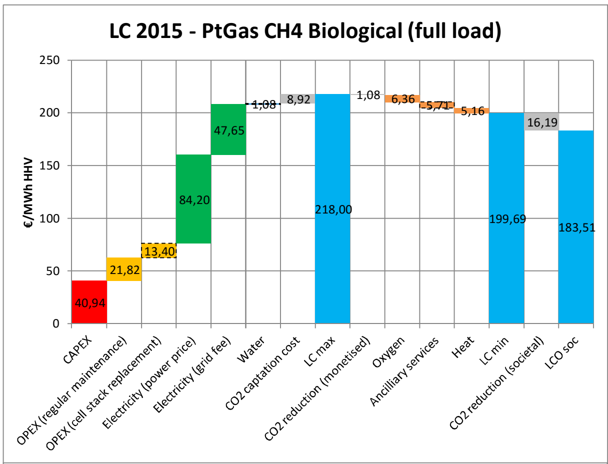
| | 2015 | | 2030 | | 2050 | |
|---|---|---|---|---|---|---|
| | Requirement | Actual value | Requirement | Expected value | Requirement | Expected value |
| Power price (all-in) | < -42,5 €/MWh | 70,1 €/MWh | < -21,3 €/MWh | 76,5 €/MWh | < -2,0 €/MWh | 88,1 €/MWh |
| Natural gas price | > 234,3 €/MWh | 22,6 €/MWh | > 209,6 €/MWh | 29,4 €/MWh | > 205,3 €/MWh | 42,4 €/MWh |
| CO2 captation and filtration cost | < -1137€/ton | 50 €/ton | < -961 €/ton | 50 €/ton | < -863€/ton | 50 €/ton |

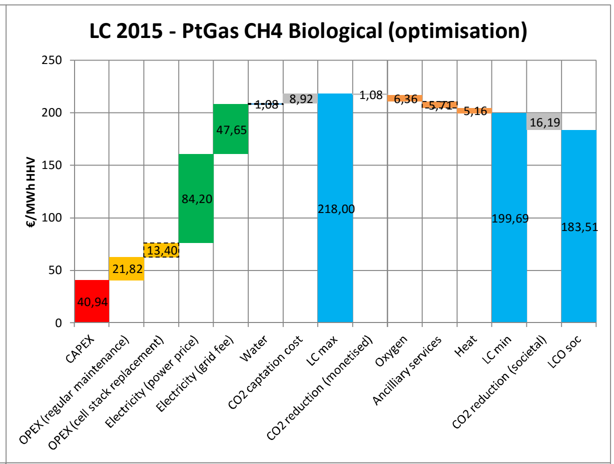
**Optimisation of the operating hours**

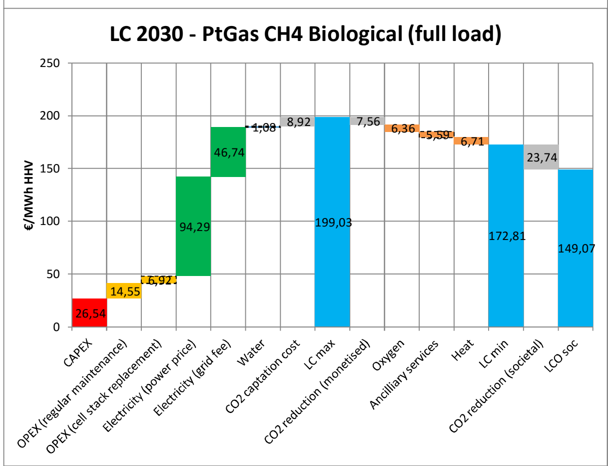
The number of operating hours minimising the levelized cost, equals approximately 7560 hours in 2030 and 4590 hours in 2050.

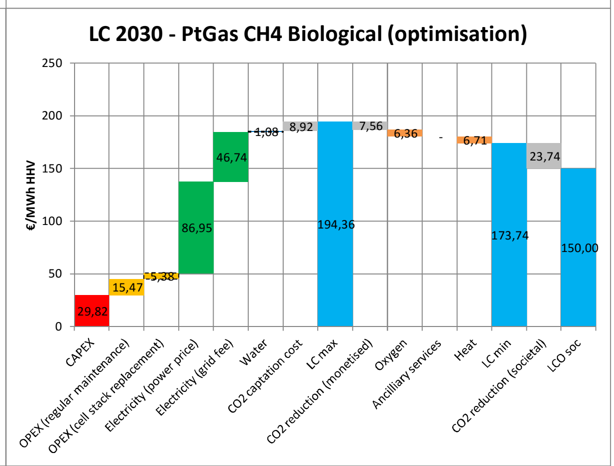


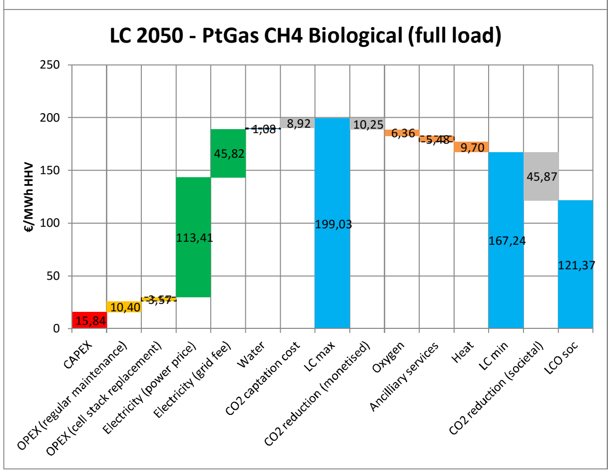
## Sensitivity analysis

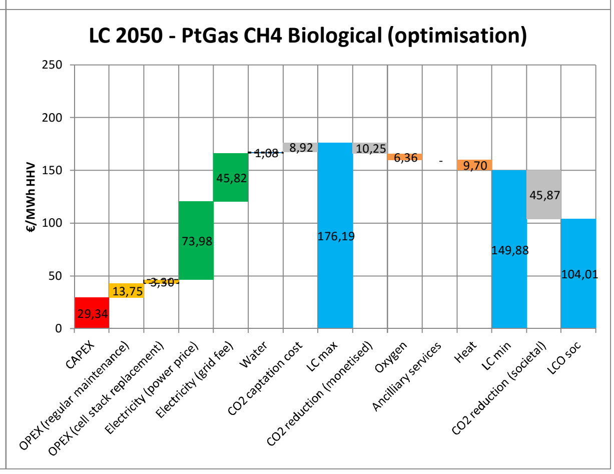



| | ***Baseload power price (€/MWh)*** | ***Optimised # operating hours*** | ***Power price during optimised OH (€/MWh)*** |
|---|---|---|---|
| ***2015*** | 40,71 | 8497 | 40,71 |
| ***2030*** | 46,48 | 7563 | 42,86 |
| ***2050*** | 57,02 | 4588 | 37,20 |

## ANNEX 20: DETAILED RESULTS CASE 10: POWER-TO-POWER - HYDROGEN LARGE SCALE ENERGY STORAGE

**Case specific assumptions**

- Electrical power input of the electrolyser: 400.000 kW
- Type of electrolyser: large scale PEM
- Electrical power output of the fuel cell: 80.000 kW
- Storage: 100.000 kg of hydrogen, at 200 bar, at a cost of 200 €/kg (in 2015)
- Compression: multiple compressors, one stage, total capacity equal to the electrolyser output capacity (+/- 80.000 Nm³/h)
- Power production profile: calculated profile for all intermittent renewable energy production (photovoltaics, onshore and offshore wind) installed in Belgium, based on typical profiles for the different production types
- Power demand: calculated profile for total power demand in Belgium minus the power generation by 'must-run' power plants, such as nuclear power plants, cogeneration plants, non-intermittent renewable power plants (such as biogas, sewage gas and landfill gas plants, biomass plants,…) and spinning reserve. Installed capacity of must-run plants is estimated to be 6800 MW in 2015 (incl. 5800 MW nuclear), decreasing to 4000 MW in 2030 and 2050 (after phase-out of nuclear)
- Annual equivalent full load hours of the electrolyser: 976 in 2015 (which is in line with the current number of equivalent full load hours of the pumped hydro plant in Coo); 542 in 2030 and 837 in 2050 (calculation based on capacities and profiles mentioned above)
- Annual hydrogen production: +/- 70.000.000 Nm³ at low pressure (20 bar)
- Civil works cost: 20.000.000 €
- Connection cost to the public power grid: 8.000.000 € (bidirectional connection to high voltage grid)
- Power price:
    - Value of consumed electricity: weighted average price during the hours with excess, according to pricing calculations (mid scenario for 2030 and 2050) for Belgium as mentioned before (commodity), without any supplier margin or grid costs
    - Value of generated electricity: weighted average price during the hours with shortage, according to pricing calculations (mid scenario for 2030 and 2050) for Belgium as mentioned before (commodity), without any supplier margin or grid costs
- The avoided emission of $CO_2$ amounts approximately 39.000 ton per year in 2015, 28.000 ton in 2030 and 47.000 ton in 2050. This equals the avoided emission of electric power generation with the average Belgian production park (assuming an emission factor of 285 kg/MWh of electricity).

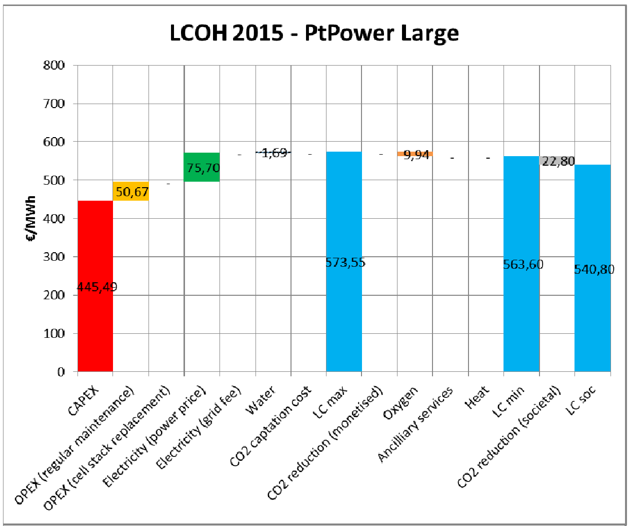
**Economic feasibility**

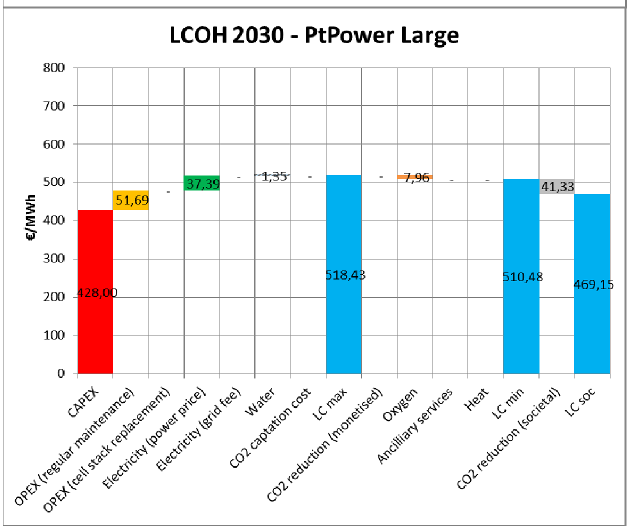
The operational result (EBITDA) equals -11,7 million € in 2015, improving to a (still negative) value of -4 million € in 2030 and -850.000 € in 2050. NPV equals -894 million euro in 2015, -566 million euro in 2030 and -368 million euro in 2050. The ratio of the NPV over the total CAPEX stays relatively constant (with little increase), from -1,16 in 2015 towards -1,08 in 2030 and -1,03 in 2050.

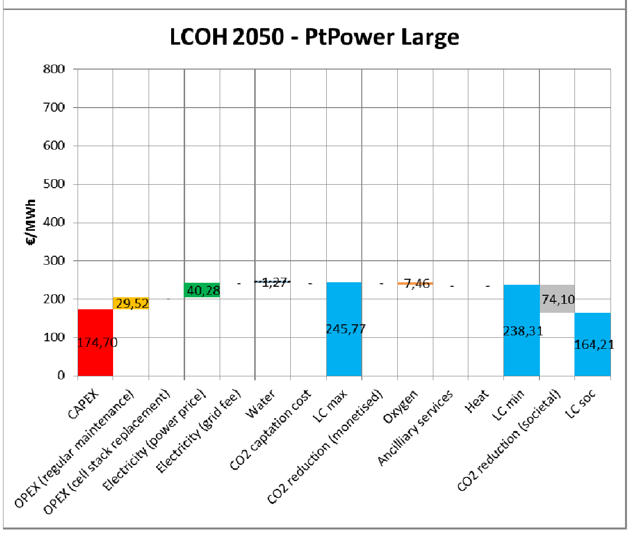
### Tipping points

| | 2015 | | 2030 | | 2050 | |
|---|---|---|---|---|---|---|
| | Requirement | Actual value | Requirement | Expected value | Requirement | Expected value |
| Consumed power price | < -224 €/MWh | 26,8 €/MWh | < -272 €/MWh | 16,9 €/MWh | < -103 €/MWh | 19,8 €/MWh |
| Generated power price | > 750 €/MWh | 43,5 €/MWh | > 688 €/MWh | 49,4 €/MWh | > 315 €/MWh | 65,9 €/MWh |

### Sensitivity analysis



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