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STUDY ON EARLY BUSINESS CASES FOR H2 IN ENERGY STORAGE AND MORE BROADLY POWER TO H2 APPLICATIONS

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1. EXECUTIVE SUMMARY

It is generally accepted that energy storage is slated to become a key component of power systems in decades to come, as the share of intermittent renewables continues to rise. Within the portfolio of storage technologies, hydrogen is widely recognised as a promising option for storing large quantities of renewable electricity over longer periods. For that reason, in an energy future where renewables (RES) are a dominant power source, opportunities for Power-to-Hydrogen in the long-term appear to be generally acknowledged.

The key challenge today is to identify concrete short-term investment opportunities, based on sound economics and robust business cases. Initial business cases will likely be based on producing green hydrogen and supplying it to industry and mobility ("Power-to-Hydrogen" and "Hydrogen-to-X"). Business cases based on storing and re-electrifying large quantities of renewables ("Power-to-Power") are expected to be niche applications in the short-term.

The focus of this study is to identify these early business cases and to assess their potential replicability within the EU from now until 2025. An essential part and innovative approach of this study is the detailed analysis of the power sector including its transmission grid constraints. This is of key importance for hydrogen business cases, for at least two reasons. First, because electricity grids represent a potential source of revenues via the provision of balancing services[1] given that electrolysers are flexible loads, i.e. can adapt their consumption. Second, because the running costs of hydrogen production are mainly determined by the price of electricity and this price may vary depending on local grid bottlenecks and RES curtailment. Already today, low-cost curtailed renewable electricity is available in various locations across Europe, thus representing an opportunity for electrolyser operators to significantly cut their input costs.

In this study, we identify particular sub-national locations where low-cost electricity is available based on electricity market and transmission grid models with an hourly time resolution. It is important to note that these locations are not representative at country-level but represent the best starting point for building a bankable business case.

[1] Balancing services are procured by the grid operator to maintain a real-time balance between supply and demand.

1.1. Key conclusions of the study

1.1.1. Power-to-Hydrogen is bankable today

The key conclusion of this study is that **Power-to-Hydrogen is bankable already today**. By 2025, **an estimated cumulative electrolyser capacity of 2.8 GW** could be installed in Europe based on sound economics, **representing a market value of €4.2 bn**. Even today, the aggregate amount of profitable business cases would amount to 1.4 GW and €2.6 bn, if all cases were realised.

In general, a total (baseload) electricity price of 40-50 €/MWh or lower is required to build a profitable business case. This price consists of the total cost of supplying electricity to the electrolyser including grid fees, taxes & levies.

An effective way to achieve profitability is to **stack up several revenue streams** from a variety of market applications. **In locations with access to discounted electricity prices** through valorization of local curtailed renewable electricity, the **most bankable business cases identified** in the short- and medium-term involve **mobility and industry as primary applications**, such as regional hydrogen mobility[2] deployment, refineries and cooking oil production, **complemented by gas grid injection**. The payback time of the best located business cases varies from 3 to 11 years depending on the primary application, conditional on a gas grid injection tariff of 90€/MWh LHV.

Only the refinery business case is not identified as profitable in 2017. An investment cost reduction of 10% (e.g. through investment subsides) would be required to bring the refinery business case at breakeven already today.

In general, business cases that are purely based on primary applications (i.e. selling the molecule to industry or mobility) can be profitable but have a longer payback time than business cases that stack up multiple revenue streams. Revenues from **providing frequency services to the power system (frequency containment and/or restoration reserves) will significantly improve bankability and cut payback times.** They represent a small share of the total revenues (between 10 and 30%) but have a sizeable and positive impact on net margin (+40% to +80%) as the extra cost needed to offer grid services remains relatively low. On payback time, it allows a reduction of 30 to 50%, from 4-11 years down to 3-8 years.

[2] Irrespective of the final consumer (buses, cars, forklifts…), as we study the delivery of H_2 to an HRS.

Weighted Average Cost of Capital (WACC) on CAPEX: 5% Project lifetime: 20 years	Semi-Centralised production for mobility (Albi, France)		Food industry (Trige, Denmark)		Refinery (Lubeck, Germany)	
	2017	2025	2017	2025	2017	2025
Primary market H2 volume (t/year)	270	950	900	900	3 230	3 230
Average total electricity price for prim. market (€/MWh)	44	45	38	47	17	26
Net margin without grid services (k€/MW/year)	**39**	**71**	**228**	**248**	**-146**	**30**
Net margin with grid services (k€/MW/year)	**159**	**256**	**373**	**393**	**-13**	**195**
Share of grid services in net margin (%)	**75%**	**72%**	**39%**	**37%**	**-**	**85%**
Payback time without grid services (years)	11.0	9.0	4.6	3.7	-	8.4
Payback time with grid services (years)	8.0	4.5	3.4	2.7	-	3.5
Key risk factors	• Taxes & Grid fees • H2 price • Size of fleets • Injection tariff • Grid services revenues		• H2 price • Taxes & Grid fees • Grid services revenues		• Taxes & Grid fees • Grid services revenues • Carbon price	

Source: Hinicio

Table 1: Profitability results of the three best short-term business cases

1.1.2. Power-to-Hydrogen and renewables will reinforce each other

Given the cost structure of electrolysers, **the access to low-cost electricity is key factor of profitability.** Accessing curtailed renewable electricity at discounted price would be very effective in that regard, as well as system-beneficial. A value corresponding to 40% of the market price (60% price discount) in times of oversupply and at the specific location of oversupply has been assumed throughout this study.[3] This is contrary to prevailing beliefs that excess renewables will be free, which is at the same time overly optimistic for the electrolyser operator and strongly unfavorable for the RES generator. This study demonstrates that **Power-to-Hydrogen can be an attractive downstream market for RES generators** in a context where the added cost of intermittency will be increasingly borne by the producers themselves, e.g. if priority dispatch is indeed phased out. Local price signals could be based on a **legal and pricing framework between the RES and the hydrogen sector, which would be mutually beneficial** as it would allow improving financial predictability on the RES generators side while at the same time contribute to **making Power-to-Green-Hydrogen an economic reality.**

Partial exemptions from grid fees, electricity taxes or levies for electrolyser operators, justified on the grounds that these provide benefits to the electricity grid, will also help improve the economics of Power-to-Hydrogen. Such partial exemptions are already in place today in the four studied countries (France, Germany, Great Britain, Denmark), but not across the whole European Union.

[3] In the current regulatory framework, such local price signals are not foreseen.

1.1.3. Gas grid injection is instrumental to de-risk mobility business cases

Strong synergies exist between Power-to-Hydrogen for mobility, gas grid injection and grid services, representing a **short-to-mid-term de-risking instrument through the valley of death of mobility**. As a matter of fact, gas grid injection can boost cash flows at low marginal cost towards breakeven during the ramp-up phase of mobility applications, when the risk of expected demand not materializing remains high ("valley of death"). Injection also allows for continuous electrolyser operation that helps to secure revenues from providing grid services, which generally require that the electrolyser is running.

1.2. Summary of findings

1.2.1. Identification of high-potential areas for Power-To-Hydrogen business cases (Section 3)

Five power systems are selected for in-depth modelling, namely **Germany, France, Denmark, Great Britain and Sardinia,** following a multi-criteria selection process including power system criteria (RES share, grid congestion management costs), power market criteria (wholesale market price as well as its volatility, existence of and access to flexibility markets), hydrogen market criteria and natural gas system criteria.

A detailed power system modelling of these 5 selected territories including their expected grid reinforcements allows to identify potential constraints at transmission grid level caused either by over-injection of RES in the network or by high local peak demand (e.g. during cold winter periods**).** For each power system, the area that would potentially offer the biggest opportunities for Power-to-Hydrogen applications is selected. The selection is motivated by a high amount of local RES curtailment that could enable electrolyser operators to purchase electricity at a lower cost than the system price when there is curtailment. In certain areas of Northern Germany, up to 40% of local RES production is curtailed due to grid constraints. **Each area selected can be viewed as the place offering the most attractive power-system environment for the development of Power-to-Hydrogen systems in each of the 5 countries under scrutiny.** The characteristics of the selected areas are displayed in Table 2.

Country	Area name	Area type	RES curtailment (% of production) and frequency[4] (% of the year) 2017	2025
Germany	Herrenwyk (near Lübeck)	Rural	428 GWh (34%), 59% of hours/year	475 GWh (40%), 43% of hours/year

[4] Frequency refers to the hours of the year when partial curtailment occurs, i.e. when at least 1% of the local production is curtailed.

France	Albi (near Toulouse)	Semi-urban	24 GWh (12%), 9% of hours/year	72 GWh (20%), 15% of hours/year
Denmark	Trige (near Aarhus)	Rural	89 GWh (2.5%), 5% of hours/year	442 GWh (13%), 23% of hours/year
Great Britain	Tongland (South-Western Scotland)	Semi-urban	71 GWh (20%), 34% of hours/year	117 GWh (20%), 35% of hours/year
Sardinia	Sarroch (South of Sardinia)	Semi-urban	0	1.4 GWh (0.2%), 0.1% of hours/year

Table 2: Recommended areas for an electrolyser installation and RES curtailment in that area

1.2.2. Hydrogen technology cost and performance (Section 4)

A comprehensive cost and performance data of all technologies involved in Power-to-Hydrogen systems (production, logistics, etc.) is elaborated and agreed upon with the contribution of key industry experts for the years 2017 and 2025. An overview of input parameters for ALK and PEM electrolysers is given in Table 3.

		ALK						PEM					
		2017 @ P atm			2025 @ 15 bar			2017 @ 30 bar			2025 @ 60 bar		
Nominal Power	UNITS	1 MW	5 MW	20 MW	1 MW	5 MW	20 MW	1 MW	5 MW	20 MW	1 MW	5 MW	20 MW
Minimum power	% Pnom	15%			10%			5%			0%		
Peak power – for 10 min	% Pnom	100%			100%			160%			200%		
Pressure output	Bar	0 bar			15 bar			30 bar			60 bar		
Power consumption @ P nom	kWhe/kg	58	52	51	55	50	49	63	61	58	54	53	52
Water consumption	L/kg	15 L/kg											
Lifetime – System	Years	20 years											
Lifetime – Stack @ full charge	hr	80 000 h			90 000 h			40 000 h			50 000 h		
Degradation – System	%/1000 h	0,13%/ 1000 h			0,11%/ 1000 h			0,25%/ 1000 h			0,20%/ 1000 h		
Availability	%/year	>98%											
CAPEX – Total system Equipment	€/kW	1200	830	750	900	600	480	1500	1300	1200	1000	900	700
OPEX – Electrolyser system	%CAPEX	4%	3%	2%	4%	3%	2%	4%	3%	2%	4%	3%	2%
CAPEX – Stack replacement	€/kW	420	415	338	315	300	216	525	455	420	300	270	210

Table 3: Summary of electrolyser selected cost and performance data

1.2.3. Monetization of potential value streams (Section 5)

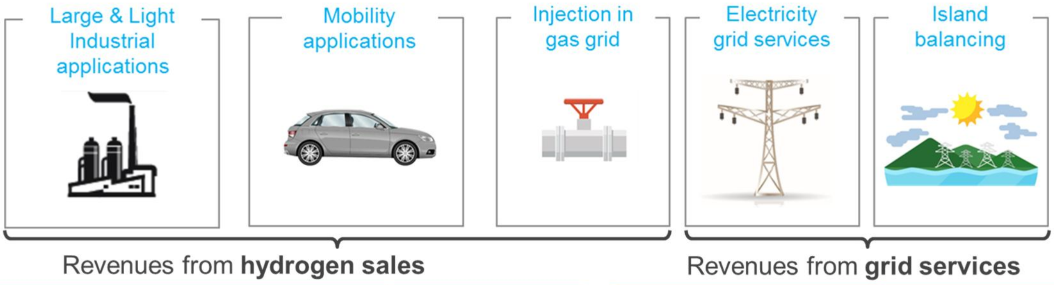
Power-to-Hydrogen system can access several value streams, which can range from selling hydrogen to industry and transport applications, to providing electricity grid services and injecting hydrogen into the gas grid.

Figure 1 should be understood as an overview of revenues of a 1MW 'baseload'[5] hydrogen plant, serving one sole revenue stream: i.e. either industry, mobility or injection into the gas grid or providing system services. The various value streams can be classified into two categories:

[5] 1MW PEM electrolyser based on power efficiency of 60 kWh/kg operating 90% of the year.

- On the one hand, “primary value streams”, namely industry and mobility, where the highest volumes of hydrogen can be committed and contracted with customers, and hence where a bankable business case can be found.
- On the other hand, “secondary value streams” (gas grid injection and grid services) that are insufficient to drive a business case on its own, but that can be opportunities to stack additional revenues on top of a primary value stream at very low marginal cost, thus increasing profitability of the plant.

The potential revenues from primary applications are at least one order of magnitude higher than those of the secondary ones.



PtoH application	Potential revenues [k€/MW/year]
Refineries, without carbon penalty	237 – 512
Refineries, with carbon penalty*	792 – 1068
Light industry market (delivery by trailer)	499 – 1235
Mobility (delivery to the HRS)	526 – 920
Hydrogen injection into gas grid based on national biomethane injection tariff[1]	171 – 350*

PtoH application	Potential revenues [k€/MW/year]
Balancing services	2 -17
Frequency control services	70 - 224
Distribution grid services	< 1

Primary value streams
Secondary value streams
(combinable with primary applications for little extra cost)

Source: Hinicio

*Carbon penalty of 470€/tCO_2 is based on German law of emission intensity reduction requirement on conventional fuel production (§37c BImSchG), if H_2 was recongnised in the carbon intensity calculation.
[1]Biomethane injection tariff can vary significantly depending on injection capacity and feedstock. The study considers a realistic lower revenue for hydrogen gas grid injection.

Figure 1: Overview of potential value streams

A Power-to-Hydrogen system is primarily (and quite obviously) a hydrogen production unit. Therefore, its very existence has to be justified by the presence of a final “high value” consumer (industry or mobility) willing to use the hydrogen produced. Successful business cases will therefore be built upon primary applications representing the bulk of the revenues for the operator and complemented by secondary value streams boosting profitability. While combining value streams, the study also takes into account operational constraints. For example, the same hydrogen cannot both be used to be injected into the grid and to be sold to industry. Another example, while offering system services, hydrogen production might be deferred. This can only be done if a hydrogen buffer storage is foreseen to continue serving the industrial primary revenue source.

1.2.4. Definition and evaluation of business cases (Section 6)

Three case studies are selected for an in-depth evaluation: a case of **semi-centralised production for mobility application** is studied for **France** (Albi), a **cooking oil industry case** for **Denmark** (Trige) and an **oil refinery case** for **Germany** (Herrenwyk).

“On-site” production for Mobility also offers viable business case opportunities, however these have been addressed by numerous previous studies such as NewBusFuel report [123] and Power-train for Europe study [80]. Moreover, the business case of on-site production of hydrogen for a hydrogen refuelling station (HRS) is similar to that of “on-site” production for light industry, i.e. the HRS being comparable to an industrial site. Results from light industry can therefore be extrapolated for the “on-site” mobility business case. For these reasons, “on-site” production for mobility is not one of the three business cases selected for detailed analysis.

The value propositions of the three business cases are as follows:

Business case	Description	Primary application	Secondary applications
Semi-centralised production for mobility application	Electrolyser (MW-scale) designed to supply a regional network of HRS via trailers	Mobility	· Frequency grid services · Gas grid injection
Food-oil industry	On-site electrolyser for light industry client	Light industry (cooking oil)	
Oil refinery	On-site electrolyser for large-industry client	Large industry (refinery)	

Table 4: Selected business cases

Typically, electrolysers are sized to address 100% of the primary hydrogen market needs (mobility or industry). In this study, the business cases are also stretched to analyse the impact of oversizing electrolysers up to 200% of the primary hydrogen market.

Capacity oversizing leads to higher CAPEX and triggers two important effects: i) economies of scale ensures the CAPEX / $MW_{installed}$ will drop both for the installation that will serve the primary market and for the over-sized installation; ii) the extra capacity can produce and sell H_2 to inject into the gas grid, offering additional opportunities for the electrolyser to provide grid services. The business cases analyses determine whether this oversizing increases the profitability or not.

The evaluation shows that **profitable business cases can be built already today** for all three applications with net margins of up to 1.5 €/kg today and up to 1.9 €/kg in 2025, i.e. H_2 production costs are below the H_2 selling price by these amounts. **Secondary value streams can represent up to 85% of this margin, and enable a business case to become profitable in many occasions,** meaning that once an electrolyser has been deployed, the extra cost required to provide electricity grid services is relatively low compared to the potential revenues. **Combining primary and secondary revenue streams thus is an effective way of boosting the profitability of a Power-to-Hydrogen system.**

WACC on CAPEX: 5% Project lifetime: 20 years	SC mobility (Albi, France)		Light industry (Trige, Denmark)		Large industry (Lubeck, Germany)	
	2017	2025	2017	2025	2017	2025
Primary market H2 volume (t/year)	270	950	900	900	3 230	3 230
Average total electricity price for prim. market (€/MWh)	44	45	38	47	17	26
Nominal system size (MW)	2 MW	12 MW	6 MW	6 MW	40 MW	40 MW
CAPEX (k€/MW)	3 660	1 900	1 760	1 400	1 480	960
H_2 cost (€/kgH2)	6.7	4.1	3.5	3.4	2.4	2.3
H_2 price (€/kgH2)	7.0	6.0	5.0	5.0	1.8	2.6
Net margin per kg_{H2} (€/kgH2)	**0.3**	**1.9**	**1.5**	**1.6**	**-0.6**	**0.3**
Share of grid services in net margin (%)	**75%**	**72%**	**39%**	**37%**	**-**	**85%**
Net margin w/o grid services (k€/MW/year)	**39**	**71**	**228**	**248**	**-146**	**30**
Net margin w/ grid services (k€/MW/year)	**159**	**256**	**373**	**393**	**-13**	**195**
Payback time w/o grid services (year)	**11.0**	**9.0**	**4.6**	**3.7**	**-**	**8.4**
Payback time w/ grid services (year)	**8.0**	**4.5**	**3.4**	**2.7**	**-**	**3.5**
Key risk factors	• Taxes & Grid fees • H2 price • Size of fleets • Injection tariff • FCR value		• H2 price • Taxes & Grid fees • FCR value		• Taxes & Grid fees • FCR value • Carbon price	

Source: Hinicio

Table 5: Summary of the three business cases profitability

All in all, the profitability of a Power-to-Hydrogen project serving one primary market can be characterised via 3 key parameters:

- **The maximum hydrogen sales price at the point of production** (i.e. just downstream of the electrolyser system, at 15-30 bar), to make abstraction of the different client supply strategies, the distances to the end customers and their respective willingness to pay.
- The **total electricity price** which includes full or reduced grid fees, taxes, levies (depending on exemption framework) as well as the cost for guarantees of origin that are needed to certify that grid electricity is green. Revenues from providing grid services such as a participation to the frequency containment or restoration reserves (FCR / FRR) can be considered as a reduction of the electricity price.
- The **system size to address a hydrogen primary market**. It influences the project CAPEX per MW installed through economies of scale.

Figure 2 combines these three parameters to create a **simple and easy-to-use tool to approach roughly the profitability of a Power-to-Hydrogen project**. It can help project developers to identify the boundary conditions for a Power-to-Hydrogen project to be profitable. For example, a 1 MW mobility project in 2017 with a target hydrogen sales price (electrolyser output) of 5 €/kg would require a total electricity price of 35 €/MWh or lower to achieve profitability. Should the primary market demand increase to allow the installation of a 5MW electrolyser, H_2 sales price could drop to about 4 €/kg (moving along the horizontal axis); or, alternatively, the acceptable electricity price could increase to ~52€/MWh to achieve the 5 €/kg sales price target (moving along the diagonal 5€/kg curve).

The total electricity cost of 35 €/MWh in the example above can be found in France, Germany and Denmark in locations with available curtailed and discounted electricity. If the project is providing grid services at 15 €/MWh, the wholesale electricity price threshold can be raised to 50 €/MWh. Figure 3 shows that profitable business cases can be found in all four regions.

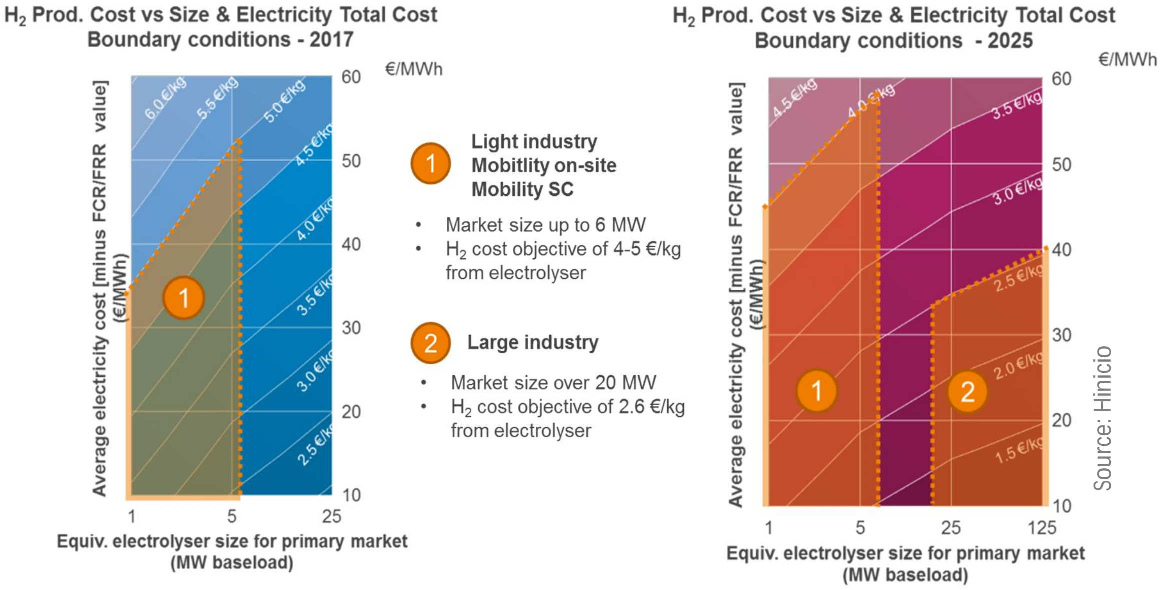


Figure 2: H_2 production cost vs electrolyser size vs total electricity cost boundary conditions in 2017 and 2025

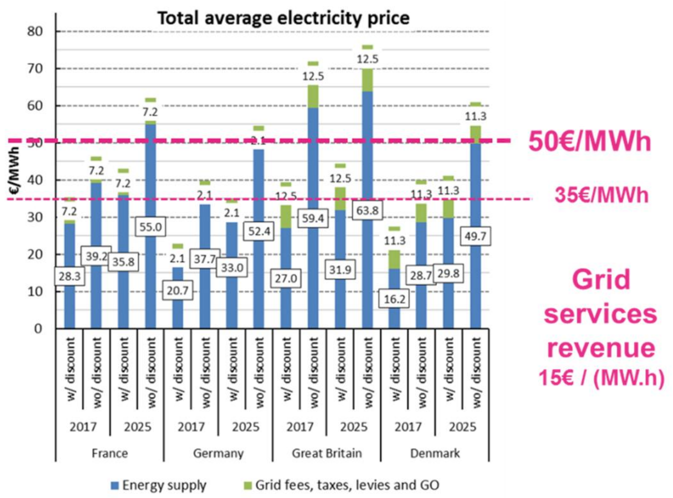


Figure 3: Total average electricity price structure per country assuming a 1MW electrolyser operating 8760 h/y

Based on this analysis, the three studied business cases can be extrapolated within the five countries assessed; the replication potential in these five countries is estimated at **a cumulated 1.1 GW by 2025. At European level, the total addressable market by 2025 is estimated at a cumulated 2.8 GW of electrolysis, representing a total market value of €4.2 bn.** For 2017, the aggregate amount of profitable business cases would amount to 1.4 GW and €2.6 bn, if all were realised.

1.2.5. Policy options and regulatory recommendations (Section 7)

Several regulatory recommendations can be drawn that directly affect the profitability of Power-To-Hydrogen applications:

- Inflating electricity prices with costs that are unrelated to the electricity supply will reduce the profitability of Power-to-Hydrogen solutions. **Partial exemptions** from grid fees, taxes or levies **exist already** today in the studied EU member states, **provided that electrolysers operate in a system-beneficial mode**. This represents an effective way of supporting the uptake of Power-to-Hydrogen solutions. A more consistent and stable regulation framework should be put in place to ensure a level playing field across countries and a more favorable investment environment.
- Curtailed RES electricity is a significant phenomenon in a large number of EU member states today, with Germany being at the forefront with **4 TWh of curtailed RES** electricity in 2015, corresponding to 2.5% of total RES production. **A clear regulatory framework on how to access this electricity should be provided** to facilitate the uptake of bilateral contracts between RES operators and potential consumers, thus reducing curtailment.
- European guidelines for **grid balancing services** should be developed to facilitate a standardisation among the EU member states and allow Power-to-Hydrogen solutions to be part of country's local frequency reserves. Focus is to be put on the definition of **accessibility** to these services **of both load and generation on the one hand, and to asymmetric provision of reserves**[6] on the other hand.
- Combining gas grid injection with mobility as primary market is a short-to-mid-term de-risking instrument through the valley of death of mobility. We recommend the European Commission and the EU member states **setting up a consistent regulatory framework allowing to leverage those strong synergies,** including standardizing hydrogen injection limits and setting sound levels of injection tariffs throughout Europe.
- Power-to-Hydrogen electrolysers can provide gas with low- or even zero-carbon footprint. This represents a new type of product that should be recognised and be made traceable, for example via certificates. A complementary measure is to aim for a **level playing field for the injection of low- or zero-carbon gas into the gas grid** - **be it bio-methane or green hydrogen.**

[6] Asymmetric reserves dissociate upward and downward frequency regulations, which forecast revenues respectively for reducing the load (increasing the generation) and increasing the load (decreasing generation).

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GLOSSARY

Abbreviation	Full Name
aCAPEX	Annualised Capital Expenditures
ALK	Alkaline
BF	Blast Furnace
CAPEX	Capital Expenditures
CWE	Central-West Europe
DE	Germany
DK	Denmark
DRI	Direct Reduction Iron
DSO	Distribution System Operator
EFR	Enhanced Frequency Response
ETS	Emission Trading Scheme
EU-4	Denmark + France + Germany + Great Britain
EU-24	28 Member countries of the European Union excluding EU-4
FCR	Frequency Containment Reserve
FFR	Firm Frequency Response
FIT	Feed-in Tariff
FQD	Fuel Quality Directive
FR	France
FRR	Frequency Restauration Reserve
GB	Great Britain
GHG	Greenhouse Gas
GoO	Guarantee of Origin
HHV	High Heating Value
IT	Italy
LCOH	Levelized cost of hydrogen
LHV	Low Heating Value
OPEX	Operating Expences
PEM	Polymer Electrolyte Membrane
RED	Renewable Energy Directive
RES	Renewable Energy Source
RR	Replacement Reserve
SARD	Sardinia
SMR	Steam Methane Reforming
TSO	Transmission System Operator
WACC	Weighted Average Cost of Capital

2. OVERVIEW AND APPROACH

The goal of this study is to identify bankable business cases for Power-to-Hydrogen applications in Europe in the short- (2017) and medium-term (2025).

To this end, we follow methodology that we define as “hour-glass approach”, because the steps follow the logic of an hourglass. The process is illustrated in Figure 4.

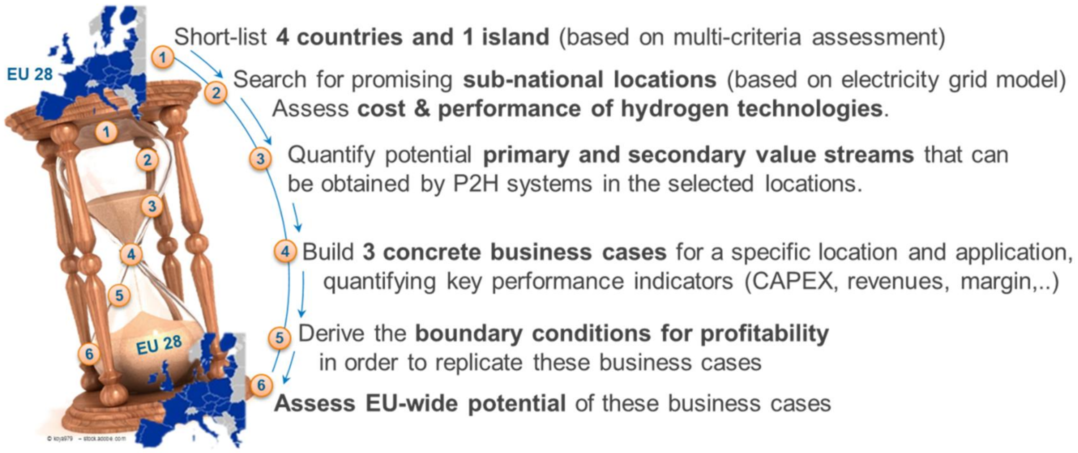


Figure 4: Approach to identify short and medium-term opportunities for Power-to-Hydrogen applications in Europe

- **From EU-28 to 3 business cases**
  1) Starting from the EU-28, **four countries and one island are short-listed based on a multi-criteria approach**, considering criteria from the power system, power markets, hydrogen applications and the natural gas grid.
  2) For the 5 short-listed regions, a detailed power market and power grid model is built to **identify the most promising sub-national locations for Power-to-Hydrogen applications**, driven by the presence of low electricity prices and of curtailed renewable electricity due to grid congestion (see **section 3**). Moreover, the **cost and performance of hydrogen technologies** is assessed through expert interviews and based on existing knowledge of the consultants (see **section 4**).
  3) For the five identified sub-national locations, the **obtainable revenues from different value streams are quantified and compared to the required costs**. This includes ‘classical’ value streams such as selling hydrogen to mobility or industry but also streams where value is generated by providing flexibility to the electricity grid or injecting hydrogen into the natural gas grid. These value streams are combined (stacked) whenever economically reasonable and technically feasible. The overall objective of **section 5** is to **rank the most promising Power-to-Hydrogen applications** and select the techno-economically most interesting ones that **could potentially lead to bankable business cases.**

- **Assessment of 3 business cases**
  4) Finally, **three concrete business cases are built based on combining the most interesting Power-to-Hydrogen applications** that were determined in the previous steps. These are studied in 3 different sub-national locations identified through extensive electricity grid modelling. Within the scope of this analysis is the quantification of key performance indicators such as CAPEX, OPEX, annual revenues as well as profit margins. Details can be found in **section 6**.
- **From 3 business cases to EU-28 market potential**
  5) For the profitable business cases, the **boundary conditions for profitability are derived**, i.e. the conditions that are necessary to replicate the business in other locations. This includes a view on the necessary regulatory and financing frameworks (see **section 6.5**).
  6) Using the boundary conditions, a **replicability analysis** is carried out to **determine the total EU-28 potential** of the three bankable business cases (see **section 6.6**). Finally, **recommendations** on the current regulatory and financing frameworks are given to provide an overview of necessary changes **towards enabling conditions for Power-to-Hydrogen applications** (see **section 7**).

3. IDENTIFICATION OF THE HIGHEST POTENTIAL REGIONS FOR BANKABLE BUSINESS CASES (EU, 2017-25)

Key findings

Based on a multi-criteria analysis reflecting the market potential for the various power-to-H2 applications identified, five locations have been pre-selected for this study: **Germany, Great Britain, France, Denmark and Sardinia.**

For these five systems, a detailed modelling of the national power system is carried out. This section provides 2 deliverables for each location and each time horizon (2017 & 2025):

- **Hourly market prices of electricity** from which H2 production cost from an electrolyser can be derived later in this study;
- **Identification of the areas** which are the most likely to offer access to electricity at lower cost (due to local RES curtailment) and / or where grid services could offer the largest remuneration. The most interesting subnational locations are given in Table 6. They correspond to locations with maximum RES curtailment that may lead to access to electricity at a lower price than the wholesale electricity price.

Country	Selected location
Germany	Herrenwyk (near Lübeck)
France	Albi (near Toulouse)
Denmark	Trige (near Aarhus)
Great Britain	Inverarnan (South-Western Scotland)
Sardinia	Sarlux (South of Sardinia)

Table 6: Subnational locations identified as high-potential areas

3.1. Load & generation modelling of selected locations

3.1.1. Load and generation modelling methodology

Due to the significant level of interconnections of the selected countries, a larger geographical scope has been modelled to estimate hourly electricity prices. The geographical scope is depicted in Figure 5. The 5 locations, the rest of Central Western Europe and Italy are modelled in a detailed way. The Nordics (Norway and Sweden) are modelled in an aggregated way to capture the seasonal storage potential of hydro reservoirs, mostly in Norway. Finally, the other countries are taken into account by predefined import and export flows, based on historical data.

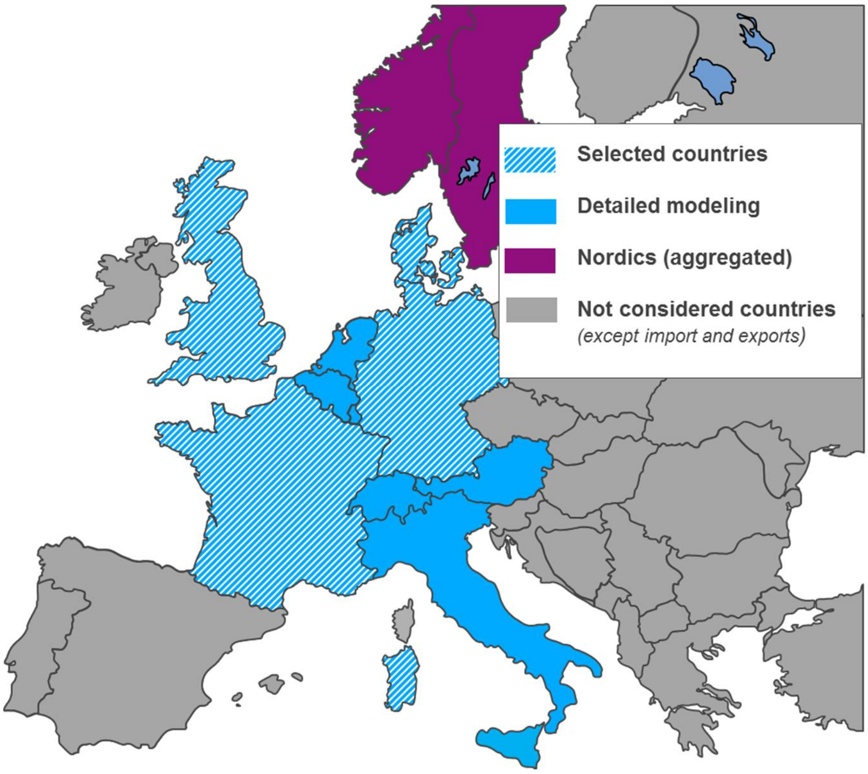


Figure 5: Geographical scope of the load and generation modelling.

The power prices are driven by many factors. The most important drivers are the fuel prices, the demand, the CO_2 prices and the capacity mix (i.e. the share of nuclear, coal, natural gas, hydro and renewable assets). Table 7 summarizes the assumptions used in the power price simulations with respect to those drivers. Fuel, CO_2 prices and power demand are based on the World Energy Outlook 2015 from the International Energy Agency (IEA). The scenarios for electricity production from renewables and nuclear are aligned with national and European policy targets (e.g. the nuclear phase-out in Germany, nuclear lifetime extensions in Belgium and the national renewable energy action plans). The numerical values regarding CO2 prices, power demand and RES share are presented in Tables 8, 9, and 10. For the nuclear and other power plants capacities, the energy mixes of each country are presented in Annex 1.1.

Driver	Source
Fuel and CO2 Prices	IEA world Energy Outlook (2015) [68]
Power Demand	IEA world Energy Outlook (2015) [68]
RES & Nuclear	Aligned with National and European Law and targets
Existing Fleet of Power Plants	In house Market Intelligence.

Table 7: Power Price Scenario

CO2 Prices (€/tCO2)	EU-ETS	Great Britain
2017	12.7	28.8
2025	28.1	42.8

Table 8: CO2 Price Scenario – EU-ETS and UK CO2 Price

Power Demand (TWh)	France	Germany	Great Britain	Denmark	Sardinia
2017	478.9	519.6	340.4	34.7	11.2
2025	495.3	537.5	352.1	34.9	11.6

Table 9: Power Demand per Country

RES Share (%)	France	Germany	Great Britain	Denmark	Sardinia
2017	21%	34%	29%	44%	43%
2025	31%	50%	42%	61%	61%

Table 10: RES Share per Country

Figure 6 presents the fuel prices, more specifically coal ARA (i.e. the price for coal delivered at ports of Antwerp, Rotterdam or Amsterdam), TTF natural gas (i.e. the reference price for gas traded in the Netherlands), and finally the evolution of the BRENT oil price. The IEA expects substantial price increases for all fuels between 2017 and 2025. Table 11 indicates in fact +26% for coal, about +14% for natural gas and close to +13% for oil. This will translate into an increase in power prices in this study, as shown in the next section.

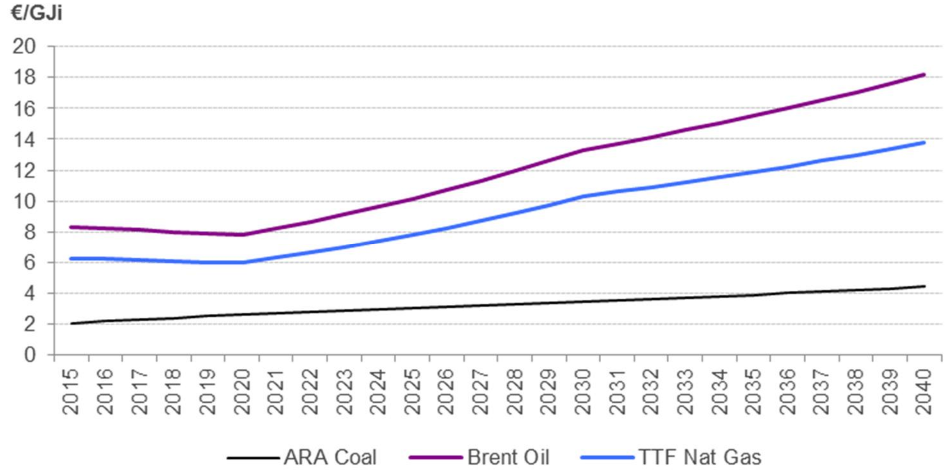


Figure 6: Fuel Price Evolution (based on WEO 2015, IEA)

	ARA Coal	TTF NatGas	Brent Oil
2015	2.1	6.3	8.3
Delta $^{2015}/_{2017}$ (%)	+10.5%	-2.1%	-2.6%
2017	2.3	6.2	8.1
Delta $^{2017}/_{2025}$ (%)	+26.0%	+14.3%	+12.8%
2025	3.0	7.8	10.2

Table 11: Evolution of fuel prices including relative increase between time steps

Finally, the power prices are simulated using a detailed model of the power sector. The hourly prices result from a supply and demand equilibrium in each hour. A key assumption is that market behaves in perfect competition. This implies that the price equals the production costs of the most expensive plant that is needed to meet the demand (marginal pricing). The price varies over time due to the fact that the demand for power changes from hour to hour and that electricity is not easily storable. Typically, lower prices can be observed during the night, when demand is low. In addition, the supply of power also differs from hour to hour, especially due to the increased penetration of non-dispatchable renewable energy resources. Figure 7 schematically presents the simulation of the power prices. At the left side of the picture, the various drivers of the power prices are summarized. Some drivers are global, e.g. fuel prices are typically driven by worldwide events, whereas other drivers are rather European or national (e.g. renewable and nuclear policies). Those drivers are used in Plexos simulation tool, leading to hourly power prices and an hourly dispatch of the plants.

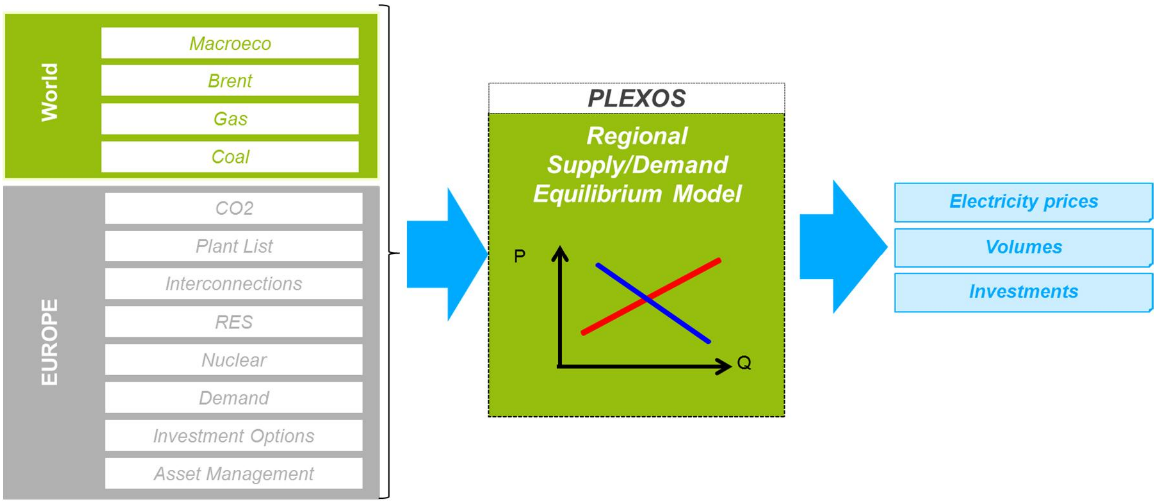


Figure 7: Simulation of Power Prices

3.1.2. Results: Mean wholesale electricity prices

Electricity costs are a big share in the hydrogen production costs because they represent the variable fuel cost for the electrolyser. Favourable locations would therefore be indicated by low wholesale electricity prices. Wholesale electricity price duration curves are presented in Annex 1.2 for each country, both for 2017 and 2025.

As shown in Figure 8, the low wholesale prices nowadays in Denmark and Germany increase towards 2025. Part of this increase can be explained by inflation. The cumulative inflation between 2017 and 2025 is 16%. The remainder of the increase is chiefly due to a surge in the fuel prices (mostly natural gas +14% and coal +26%), a higher CO_2 price (+122% between 2017 and 2025) and the decommissioning of the German nuclear fleet, as explained in the previous Section. Denmark's prices in 2025 reach about the same level as prices in France or Germany. This can be explained by an enforcement of cross border trade due to more interconnection capacity leading to price convergence. Furthermore, additional interconnection capacity is developed between Great Britain and the rest of Europe. Likewise, this tends to lower the spread in prices between Great Britain and the rest of Europe. The spread shrinks from about 24 €/MWh to 13 €/MWh as one can see in Figure 8.

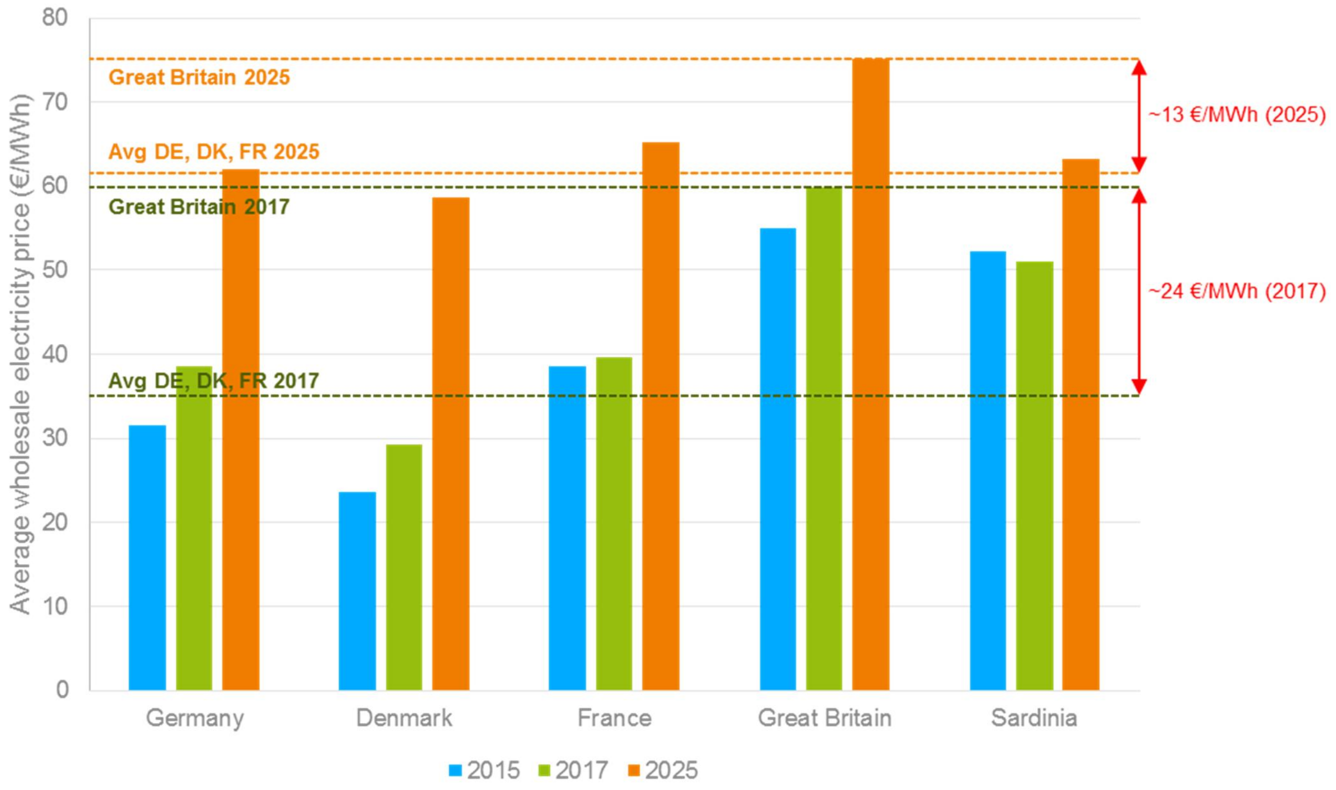


Figure 8: Spread between power prices in Europe and Great Britain shrinks in 2025

Especially in Great Britain, annual wholesale baseload prices are higher compared to continental prices. This is due to the CO_2 floor price in the UK. The CO_2 price in the UK in 2025 is equal to €43/t compared to € 28/t in the rest of Europe.

In Sardinia, the annual wholesale price in 2017 is higher than in Continental Europe because it has, like Great Britain, few interconnections with continental countries. In 2025, the presence of zero-price hours in the electricity duration curve (cf. Annex 1.2) reduces the average wholesale electricity price in the country, aligning Sardinia with the other countries in 2025.

(€/MWh)	France	Germany	Great Britain	Denmark	Sardinia
2015	38.5	31.6	55.0	23.7	52.3
2017	39.6	38.5	59.9	29.3	51.0
2025	65.2	62.1	75.2	58.7	63.2

Table 12: Mean Wholesale Electricity Prices (nominal)

3.2. Identification of favourable areas within a given location

3.2.1. Power system modelling methodology

To identify the areas presenting the largest opportunities for Power-to-Hydrogen technologies in Europe from a power system perspective, the power systems of the selected countries have been modelled using the SCANNER software (developed by Tractebel) for the time horizons 2017 and 2025. This modelling has been performed in two steps:

- **Model design:**
  - Modelling of the transmission grid: description the main equipment (transformers and lines) characteristics (GIS coordinates, capacities in MW, length etc…);
  - Modelling of the load demand and input exchange flows between countries (peak demand, hourly profile and location on the grid);
  - Modelling of the generation capacity (installed capacity, location on the grid, production cost etc…).
- **Model Calibration:**
  - Through simulation, ensuring results are consistent with today data available on national production per fuel type (Wind, PV etc…).

As an indication, Table 13 shows the number of nodes (connecting points for injection & load consumption) and power plants considered for each national power systems model.

Country	France	Germany	Great Britain	Denmark	Sardinia
# Nodes	1360	815	1988	311	67
# Power plants	1953	1994	388	1170	42

Table 13: Size indicators of the SCANNER models built per country

Transmission grid modelling

The grid models (substations, lines and transformers) are built using today official data published by TSO as well as ENTSO-E Ten Year Network Development Plan [41], which describes the transmission grid reinforcements (220 and 380 kV) planned for the next ten years in Europe.

- For **France** and **Germany**, a grid model is built based on power system maps published by ENTSO-E.
- For **Great Britain**, yearly grid models made available for each year between 2015 and 2025 are extracted directly from NationalGrid publications [89].
- For **Denmark**: a grid model at horizon 2020 is published by Energinet.dk [34].
- For **Sardinia**: a grid model is built based on power system maps published by ENTSO-E [39] and Terna [120].

Load and exchanges modelling

The **load** is modelled in SCANNER as the product of an hourly load profile and a geographical load repartition.

- **Timely load profile** is derived from historical data published by TSOs taking into account annual load forecast of the selected IEA scenarios.
- The **geographical distribution** of the load is obtained from TSOs publication.
  - For **France**, RTE [106].
  - For **Germany**, regional 2013 loads are published at the national level by Föderal Erneuerbar [51].
  - For **Denmark**, Energinet.dk presents a load repartition per node in its 2020 grid model [34].
  - For **Great Britain**, National Grid publishes load repartition for each year between 2015 and 2025 in its grid model [89].
  - For **Sardinia**, due to lack of data available, the load is assumed proportional to the population per city [129].

The **input power flows exchanges** are built based on historical data taking into account official evolution forecasts (reinforcement of interconnections etc…).

Generation modelling

Generators are dispatched according to the following rules for each country.

- **Thermal power plants:**
  - Existing and projected thermal power plants and CHP are located based on official data.
- **Hydro storage power plants:**
  - Based on official power plants locations
- **Renewable power plants:**
  - Distributed generation (PV & CHP): Set proportionally to geographical load distribution, except for Great Britain where government publications are available for CHP [15].
  - Wind farms: Set according to an online database of onshore and offshore wind farms in the world [122]. Especially for offshore wind farms, the extra production is localised based on projects.

3.2.2. Results: Grid constraints & curtailment of renewables

3.2.2.1. KEY RESULTS

From a power sector perspective, opportunities for flexibility and electricity storage (incl. electrolysers) generally arise from grid constraints. There are two main causes of grid congestion:

- Local net injection into the grid (RES generation) is greater than downward lines capacity (overproduction)
- Local net consumption is greater than upward lines capacity (overconsumption)

The first situation will likely result into curtailment of generation, unless demand can be increased, e.g. through an electrolyser. Overproduction is the main reason of congestion in Europe today. The second situation (overconsumption) could either result into a call for reducing demand or re-dispatch (i.e. the grid operator ordering to fire up costly back-up generation units). Such situations are rare - they might for instance occur during a very cold winter, causing augmented electricity consumption for heating. An electrolyser can in principle contribute to solving both issues. Yet, considering that it would be an *additional* load, it would not contribute to solve already *existing* situations of overconsumption. In fact, electrolyser consumption would tend to add to the over-consumption problem. For this reason, **areas with overproduction are generally more promising than areas with underproduction from the perspective of an electrolyser operator.**

To identify areas with potential opportunities for electrolysers from a power system perspective, it is necessary to move from a pure market view towards a view integrating grid constraints as discussed in section 3.2.1, where the grid benefit for an electrolyser can be observed. Notice however that, if electrolysers' flexibility may benefit to the grid, it will not prevent the construction of new transmission corridors since its impact is only limited: while new HVDC lines allow extra transmission capacities of ~1GW, electrolysers' flexibility is some orders of magnitude lower, in the range of ~1MW.

Simulations with the SCANNER tool underline that the grid-related curtailment is not negligible but also not massive *at national level* (see Table 14). Annual curtailment is below 2% of total RES generation for the studied locations - one notable exception being Denmark, linked to the strong increase of RES there.

Curtailment figures can massively increase, if we zoom into the geographical level of nodes, i.e. at the level of high or medium voltage transformers.

GWh (% RES national production)	Germany	France	Great Britain	Denmark	Sardinia
2017	2124 (1.8%)	104 (0.3%)	660 (1.1%)	2242 (14.6%)	0 (0.0%)
2025	1702 (0.9%)	464 (0.6%)	2108 (2.1%)	2801 (13.4%)	8 (0.1%)

Table 14: Annual curtailment per country (absolute and share in total RES generation)

It is worth noting that already today RES curtailment is significant in Germany. For 2015, the German regulator *Bundesnetzagentur* reported roughly 4.7 TWh of curtailment, up from 1.6 TWh in 2014. This strong increase was partly due to the increase in installed capacity (+3,500 MW onshore wind power, i.e. the 2nd highest deployment in history) but also due to the exceptionally good weather conditions: 2015 was the best wind year since two decades with onshore wind having a capacity factor of 23% (compared to 17% in 2014). For the simulations, an average wind year was assumed (17-18% load factor for onshore wind), which explains the lower curtailment figures compared to 2015.

The SCANNER modelling results generally indicate that overproduction and overconsumption occur in different parts of a country, i.e. it will not be possible to capture both value streams. Recommendable areas for an electrolyser installation are therefore driven by the locations where the highest volume and frequency of **overproduction** occurs. The most promising areas per country for a storage mean and the associated RES curtailment figures are summarised in Table 15.

For France and Great Britain, the indicated potentials can be increased if one accepts as green input electricity for the electrolyser the energy that would result from an extra production of nuclear power plants. In that case, the marginal overproduction cost becomes the marginal cost of nuclear electricity instead of zero as for RES. Table 16 presents the average full load hour equivalents of nuclear power plants in the different countries as well as the energy that can be obtained if the power plants production is extended to 8000h/y. Denmark and Sardinia, as well as Germany for 2025, are not represented in this table because they do not produce electricity from nuclear in the considered scenarios.

Country	Area name	Area type	RES curtailment (% of production) and frequency[7] (% of the year)	
			2017	2025
Germany	Herrenwyk (near Lübeck)	Rural	428 GWh (34%), 59% of hours/year	475 GWh (40%), 43% of hours/year
France	Albi (near Toulouse)	Semi-urban	24 GWh (12%), 9% of hours/year	72 GWh (20%), 15% of hours/year
Denmark	Trige (near Aarhus)	Rural	89 GWh (2.5%), 5% of hours/year	442 GWh (13%), 23% of hours/year
Great Britain	Inverarnan (South-Western Scotland)	Industrial	71 GWh (20%), 34% of hours/year	117 GWh (20%), 35% of hours/year
Sardinia	Sarlux (South of Sardinia)	Industrial	0	1.4 GWh (0.2%), 0.1% of hours/year

Table 15: Recommended areas for an electrolyser installation and RES curtailment in the area

	Germany 2017	France 2017	France 2025	Great Britain 2017	Great Britain 2025
Full load hour (h)	7948	6697	6674	5793	5576
Energy potential (GWh)	522	82,233	70,410	19,613	21,542
Marginal cost (EUR2015 / MWh)	13.1	13.6	15.8	13.7	17.4

Table 16: Nuclear energy potential for low-cost and decarbonised electricity for electrolysers. Germany 2025, Denmark and Sardinia are not represented because not producing energy from nuclear.

Most selected areas in Table 15 show curtailment ratios well above 20%, which would be a significant share of the production of single RES installations. Curtailment frequency, i.e. the share of hours of the year where at least 1% of the production has to be curtailed, easily exceeds 20%. This means that curtailment occurs throughout the year, which is important to ensure that this (likely low-cost) electricity represents a sizeable and stable share of the total consumption of the electrolyser throughout the year.

[7] Frequency refers to the hours of the year when partial curtailment occurs, i.e. at least 1% of the production has to be curtailed.

Wind power drives the curtailment in all selected areas. This is due to the fact that most wind power installations are more distant from consumption centres than solar installations.

A notable exception is Sardinia where there is generally little curtailment across the whole island. RES curtailment would therefore be not a primary criterion for selecting a suitable area to sit an electrolyser.

3.2.2.2. ANALYSIS PER LOCATION

The location-specific analysis follows two main lines: a quantification of curtailment and an identification of the congested areas (grid constraints analysis). To this end, we first present curtailment figures at the national level and then discuss their spatial distribution within the countries. Only the detailed results for Germany, France and Denmark are presented here as they are involved in the location of the studied business cases. The results details for Great Britain and Sardinia are presented in a similar way in Annex 2.

The development of renewables is an important criterion for identifying promising electrolyser locations. In certain areas, the share of renewables can be high enough to cause grid congestion and, if impossible to solve, curtailment of renewables. As a flexible load, an electrolyser located in an area between RES farm and congested line could thus have access to low cost electricity during these curtailment periods where RES see their injection in the grid limited by congestions. It is important to note that curtailment does not necessarily occur at exactly the same location as congestion. There is a potentially wider area where it can be valuable to install an electrolyser. This is illustrated in Figure 9.

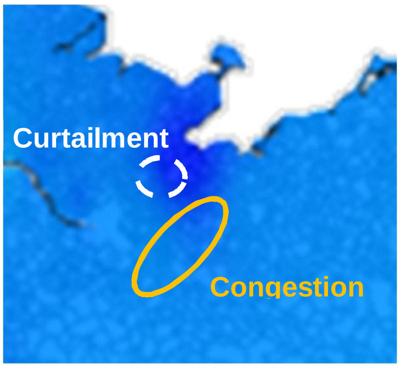


Figure 9: Curtailment vs. congestion area

3.2.2.2.1. Germany

Recommended location for electrolyser installation:

Herrenwyk (Lübeck area, Northern Germany) due to highest curtailment of onshore wind in the country and close proximity to a refinery.

RES curtailment analysis

GWh (% RES national production)	Germany	France	Great Britain	Denmark	Sardinia
2017	**2124 (1.8%)**	104 (0.3%)	660 (1.1%)	2242 (14.6%)	0 (0.0%)
2025	**1702 (0.9%)**	464 (0.6%)	2108 (2.1%)	2801 (13.4%)	8 (0.1%)

Table 17: Annual expected curtailment per country, focus on Germany

In **Germany**, curtailment is expected to be around 2 TWh for both 2017 and 2025. This amount corresponds to a significant share in total RES production, 1.4% and 0.9% respectively. Despite the build-up of new RES plants, curtailment can be kept at a constant level. This indicates that the planned grid reinforcements, especially first North-South HVDC lines, are an effective option to limit curtailment increase.

It is worth noting that already today RES curtailment is significant in Germany. For 2015, the German regulator *Bundesnetzagentur* reported roughly 4.7 TWh of curtailment, up from 1.6 TWh in 2014. This strong increase was partly due to the increase in installed capacity (+3,500 MW onshore wind power, i.e. the 2nd highest deployment in history) but also due to the exceptionally good weather conditions: 2015 was the best wind year since two decades with onshore wind having a capacity factor of 23% (compared to 17% in 2014). For the simulations, an average wind year was assumed (17-18% load factor for onshore wind), which explains the lower curtailment figures compared to 2015.

Geographical maps with bar charts are used to illustrate the spatial distribution of curtailment and the RES technology curtailed. Higher bars indicate more curtailment. It is worth noting that there is a dedicated bar scale for each country to ensure good readability and to cope with the fact that curtailment varies significantly from country to country in absolute terms. However, the scale is the same for both studied periods (2017 and 2025).

Areas with high curtailment are highlighted. For those areas, we present additional charts to illustrate the temporal distribution of curtailment for this specific area.

Figure 10 shows the geographical distribution of curtailment in Germany, indicating that curtailment is and will remain concentrated to areas in Northern Germany, affecting mainly onshore wind (WON) and to a lesser extent offshore wind (WOF). A rural area with a particularly high curtailment is Herrenwyk in the proximity of Lübeck.

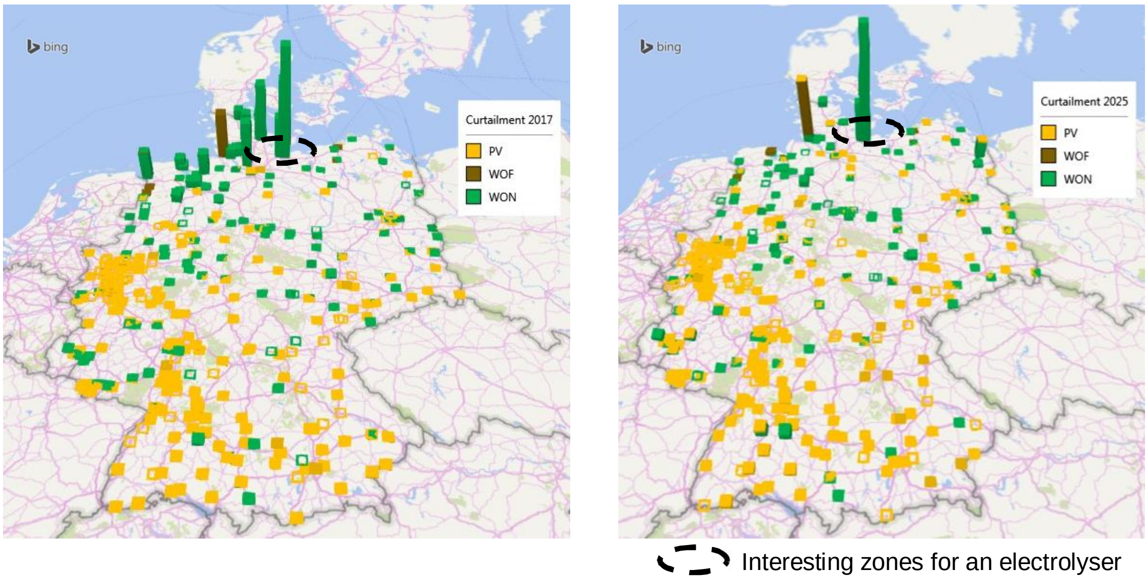


Figure 10: Annual curtailment per renewable technology in Germany (maximum bar height: 475 GWh)

The temporal representation of curtailment in this area is illustrated in Figure 11. It is a two-dimensional representation of the hour of the day (x-axis) vs. the day of the year (left y-axis), in which curtailment occurs. Darker values represent stronger curtailment, on a relative scale (right y-axis), that was normalized to the installed RES capacity in that node (value 1 should be read as 100% of the nominal RES capacity curtailed)

Figure 11 indicates that curtailment occurs throughout the year but is stronger in the winter season and in late evening. In total, partial curtailment (>1% of production) occurs in almost 60% of the hours in 2017 and in almost 40% of the hours in 2025. During these periods, winds speeds are typically higher than in summer or during the day.

Overall, in this specific node, curtailment amounts to **428 GWh in 2017** and **475 GWh in 2025** as indicated in Figure 12, at an installed capacity of 247 MW and 357 MW respectively. **Up to 40% of the annual production** would therefore be excess electricity.

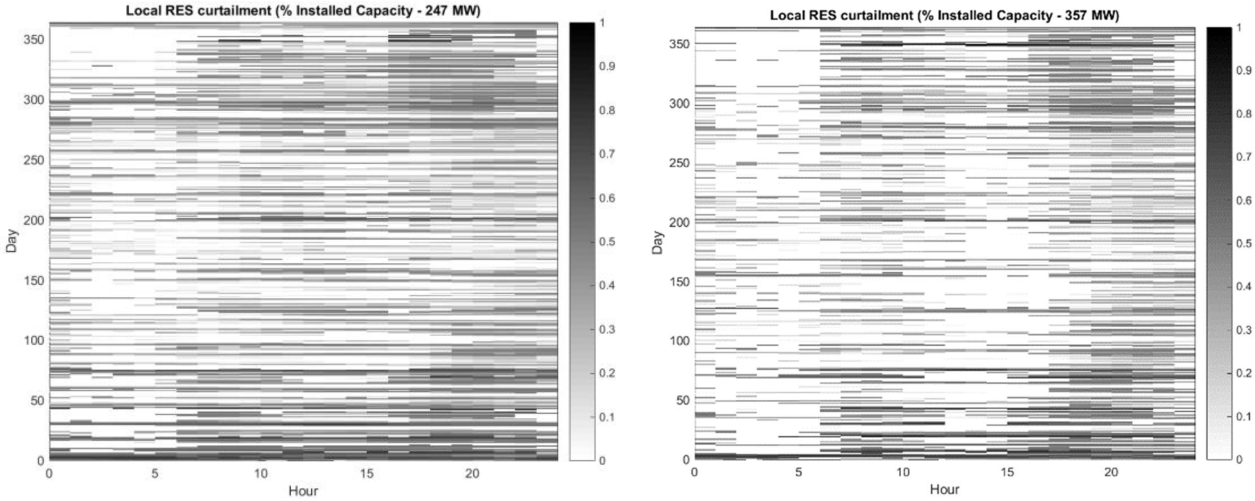


Figure 11: Temporal distribution of curtailment in the area of Herrenwyk (Germany)

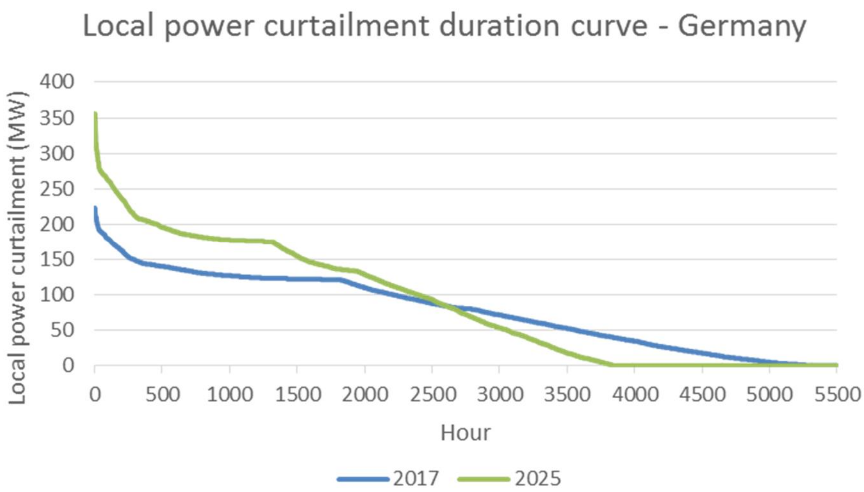


Figure 12: Power curtailment duration curve at Herrenwyk, Germany

For the grid constraints analysis, geographical maps of the nodal marginal generation costs are used to illustrate. Nodal marginal costs refer to the cost of increasing the consumption by one MWh at the geographical level of nodes (transformer HV/MV). If marginal costs differ significantly between neighbouring locations, it indicates that the line connecting these two nodes is congested.

Grid constraints analysis

The Table 18 presents the most important projects (interconnections and North-South corridor) expected to be achieved between 2017 and 2024 included [41]. They represent the main grid differences between the two models 2017 and 2025.

Major Project		Line capacity (GW)	Commissioning year
Interconnection with Norway (Nordlink)		1.4	2017
Interconnection with Denmark	Kriegers Flak CGS	0.4	2018
	Audorf-Kasso	0.7	2020
	Niebull-Endrup	0.5	2022
Interconnection with Belgium (ALEGrO)		1.0	2019
Interconnection with the Netherlands (Doetinchem-Niederrhein)		1.5	2020
North-South HVDC Corridor (Osterath-Phillipsburg)		2.0	2021

Table 18: Major grid reinforcements in Germany between 2017 and 2024

In 2017, a significant North-South split of nodal marginal costs can be observed (see Figure 13, left part). This split is related to the distribution of low-marginal cost production units: due to the more attractive wind speeds, most wind power capacity is deployed in the North, especially close to the coast. At the same time, demand centres are mostly located West and South close to industrial areas or densely populated urban areas.

The situation is similar in 2025 (see Figure 13, right part): very low nodal marginal costs can be observed close to the coast, driven by the high concentration of low-marginal cost producers there. However, the cost level is more homogenous in general, with the exception of areas close to the French and Swiss border in the South-West of Germany, indicating congested *interconnectors* in this area.

In 2017, congested transmission lines can be identified across the North-South corridor, especially downward the area of Herrenwyk confirming the widely recognized challenge of transporting wind production from the North towards the consumption centres in the South. Interestingly, congestion decreases from 2017 to 2025, showing that the transmission line extensions projected by the German TSOs would be effective if realized in the planned time-frame.

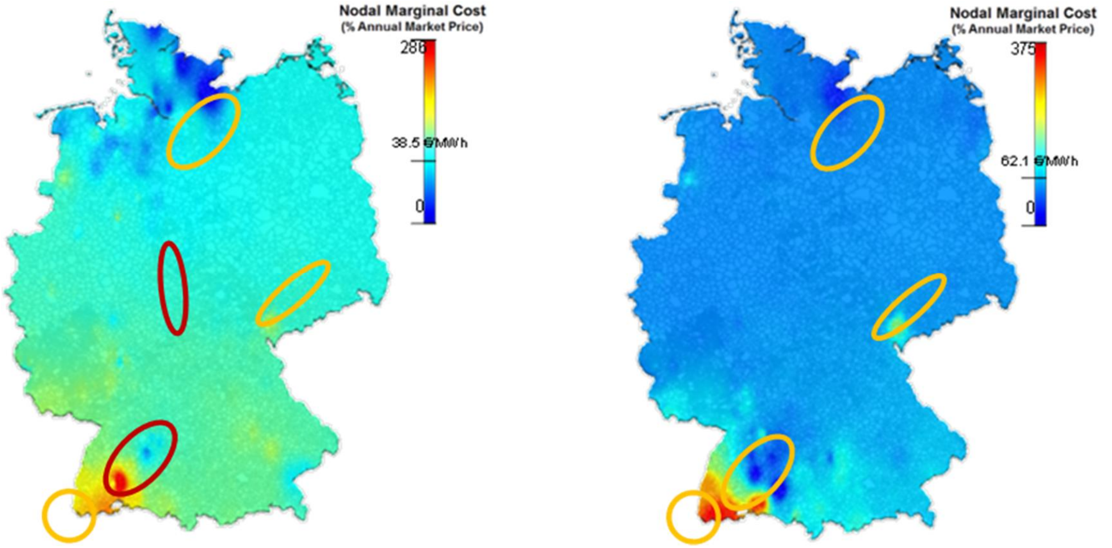


Figure 13: Nodal marginal costs and grid constraints thermal map of Germany (2017 - left, 2025 - right)

3.2.2.2.2. France

Recommended location for electrolyser installation:

Albi (Occitanie region) due to highest curtailment of onshore wind in the country.

RES curtailment analysis

GWh (% RES national production)	Germany	France	Great Britain	Denmark	Sardinia
2017	2124 (1.8%)	**104 (0.3%)**	660 (1.1%)	2242 (14.6%)	0 (0.0%)
2025	1702 (0.9%)	**464 (0.6%)**	2108 (2.1%)	2801 (13.4%)	8 (0.1%)

Table 19: Annual expected curtailment per country, focus on France

In **France**, curtailment volumes amount to roughly 230 GWh in 2017 and 630 GWh in 2025, corresponding to 0.5% and 0.7% of total RES production respectively. These values are lower than the German ones, both in absolute in relative terms. Neither the French regulator (CRE) nor the French TSO (RTE) have published curtailment figures in recent years, which can be interpreted as an implicit confirmation that curtailment of renewables currently is not an issue in the French electricity transmission grid.

The geographical representation in Figure 14 confirms that curtailment is rather limited in 2017 and increases slightly towards 2025. The most curtailed RES technology is onshore wind (WON). A high curtailment area can be identified in Albi, a semi-rural area in the proximity of Toulouse.

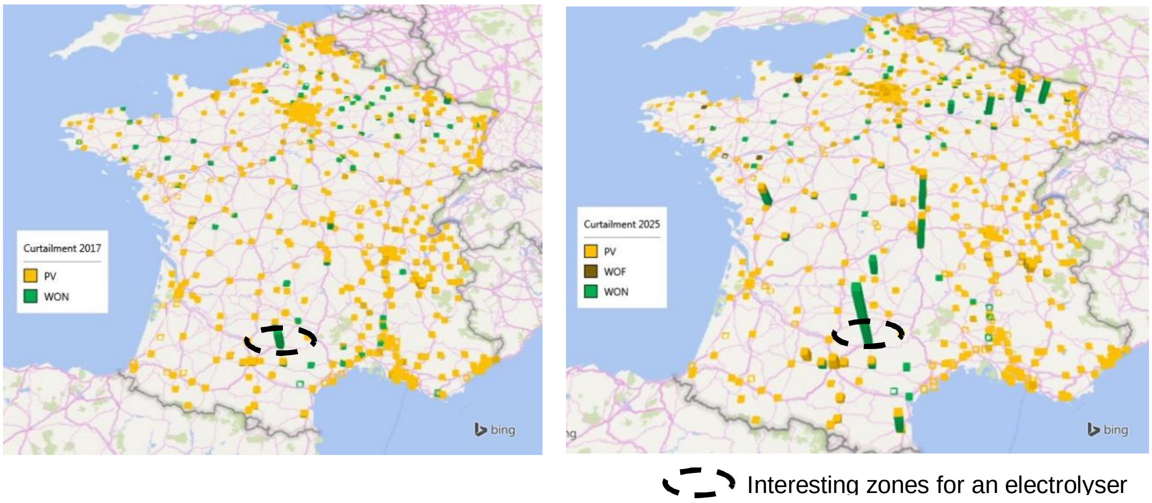


Figure 14: Annual curtailment per renewable technology in France (maximum bar height: 72 GWh)

The temporal representation of this area (see Figure 15) shows that curtailment does not occur equally across a year or across a day. Curtailment is generally low during winter when power demand in France is high due to electricity being used for heating. Spring and autumn appear to be periods of stronger curtailment, driven by a combination of strong winds and lower electricity demand (compared to the winter season). In total, partial curtailment (>1% of production) occurs for less than 9% of the total local RES generation and less than 13% of the hours.

Overall, in this specific node, curtailment amounts to 24 GWh in 2017 and 72 GWh in 2025 as emphasized in Figure 16, at an installed capacity of 111 MW and 196 MW respectively. Up to 15% of the annual production would therefore be excess electricity.

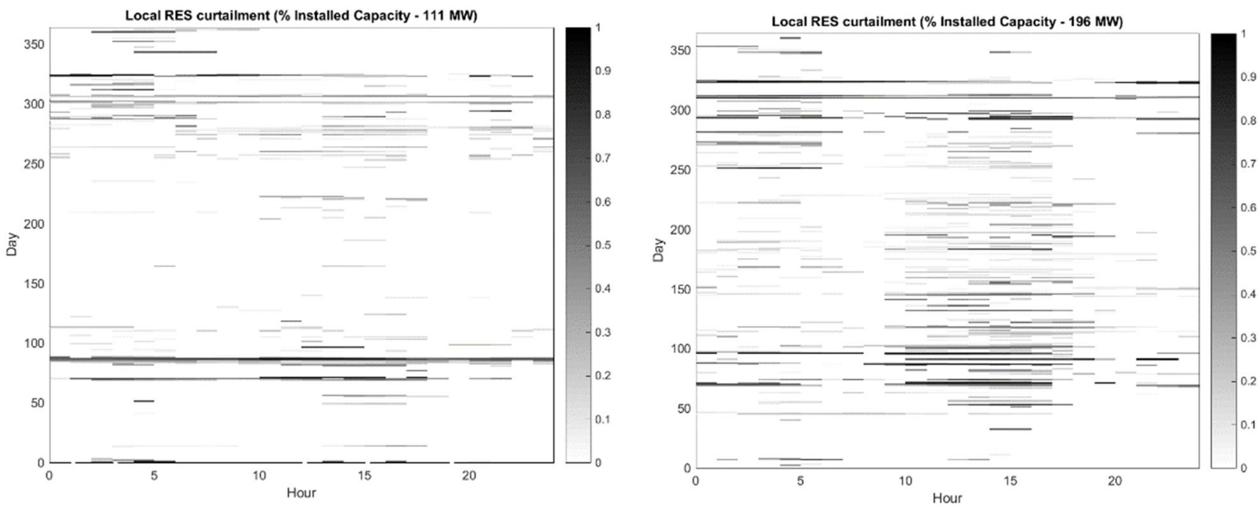


Figure 15: Temporal distribution of curtailment in the area of Albi (France)

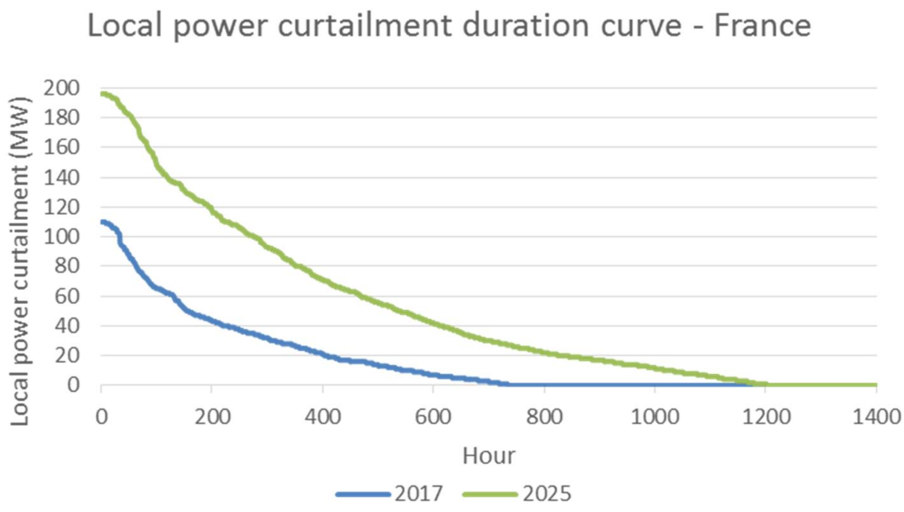


Figure 16: Power curtailment duration curve at Albi, France

Grid constraints analysis

The Table 20 presents the most important confirmed interconnection projects expected to be commissioned between 2017 and 2024 included [41]. They constitute the main grid differences between the two models 2017 and 2025.

Major Project		Line capacity (GW)	Commissioning year
Interconnections with Great Britain	ElecLink	1.0	2018
	Aquind	2.0	2019
	IFA2	1.0	2020
	GridLink	1.5	2021
	FAB	1.4	2021
Interconnection with Italy (Grande Île – Piossasco)		1.0	2019

Table 20: Major grid reinforcements in France between 2017 and 2024

The French power system shows similar average marginal costs as the German one, highlighting the good interconnection between these countries and the well-functioning of the EU internal market. As shown in Figure 17, the 2017 cost levels are lower in the Eastern part of France (Champagne-Ardenne and Lorrain regions) as well as in the South-Eastern part (Rhône-Alpes region). This can be explained by the density of low-marginal cost producers in these regions. The former two regions feature a high concentration of wind power, while the latter has a large number of hydro power stations.

Towards 2025, the cost structure appears to be less homogenous than in 2017 but the pattern of low marginal costs being observed in the three above-mentioned regions prevails. In 2025, cost peaks can be observed towards the border to Germany and Switzerland, indicating congested *interconnectors* in this area.

As explained, congested lines can be identified by stark differentials of marginal costs between neighbouring nodes. As such, they appear when moving out of the zones with low marginal costs, i.e. when moving out of the Rhône-Alpes region or when moving out of the Champagne-Ardenne region. Congestion also occurs on the French-Belgian border.

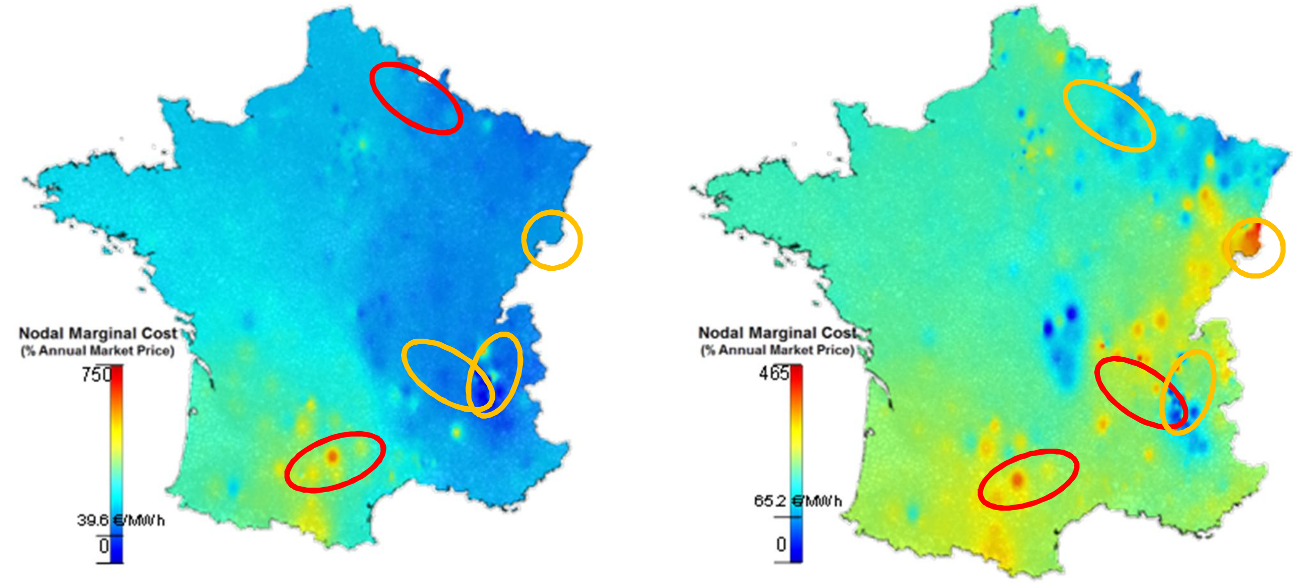


Figure 17: Nodal marginal costs and grid constraints thermal map of France (2017, 2025)

3.2.2.2.3. Denmark

Recommended location for electrolyser installation: Trige (Midtjylland region – Aarhus municipality), because of the highest offshore wind curtailment value.

RES curtailment analysis

GWh (% RES national production)	France	Germany	Great Britain	Denmark	Sardinia
2017	104 (0.3%)	2124 (1.8%)	660 (1.1%)	**2242 (14.6%)**	0 (0.0%)
2025	464 (0.6%)	1702 (0.9%)	2108 (2.1%)	**2801 (13.4%)**	8 (0.1%)

Table 21: Annual expected curtailment per country, focus on Denmark

For **Denmark**, curtailment values are significantly higher than in other areas, mainly due to the combination of a high RES and a high CHP share. In fact, wind power alone can peak at 140% of the Danish load. In absolute terms, annual curtailment volumes are in the range of 2.2 and 2.8 TWh, which is comparable to the German values in absolute terms but corresponds to up to 15% of Danish RES production. Interestingly, neither the Danish TSO nor the regulator report noteworthy curtailment figures today [9]. This is likely related to the specificity of the Danish subsidy system, namely *economic* curtailment. Onshore wind operators receive a fixed feed-in premium, which encourages them to reduce their production when spot market prices drop below their inverse feed-in premium (i.e. a payment they receive on top of the spot market price). In that case, curtailment is voluntary and based on market price signals (hence: economic curtailment), avoiding grid-related curtailment. Another likely reason for the negligible curtailment volume reported today is the flexible use of Power-To-Heat (i.e. the use of electricity to generate heat) to absorb excess RES production.

In Denmark, curtailed renewable production is mainly located in Denmark West[8] for both time horizons as indicated in Figure 18, and more precisely in the Nordjylland region (in the North) for wind onshore, and in Midtjylland (central region) for wind offshore. In numbers, curtailment of wind onshore represents 63% of the curtailed energy in 2017 and 61% in 2025; and wind offshore 34% and 34%, respectively.

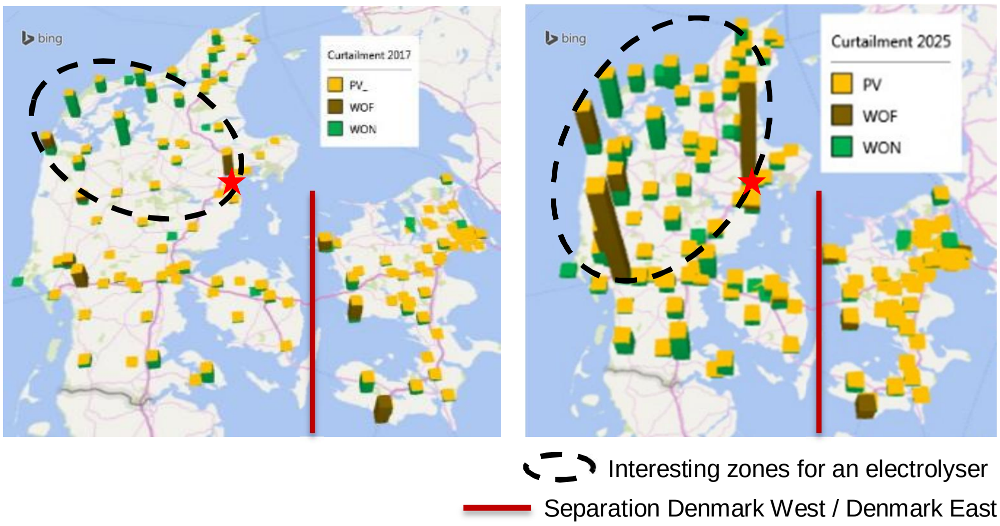


Figure 18: Annual curtailment per renewable technology in Denmark (maximum bar height: 442 GWh)

Figure 19 shows the temporal curtailment profile of the Anholt offshore wind farm (marked by a ★ in Figure 18). A similar curtailment pattern as in Germany can be observed in terms of inter-seasonal variation, i.e. there is more curtailment in winter than in summer. In 2017, this leads to a total curtailment of 89 GWh (2.5% of annual production) as shown in Figure 20, while in 2025 curtailment amounts to 442 GWh (13% of annual production) for a 409 MW power plant (curtailment over 400 hour/year in 2017 and 2000 hour/year in 2025).

[8] Denmark West and Denmark East refer here to the two asynchronous grids of Denmark, that are separated geographically as indicated in Figure 18.

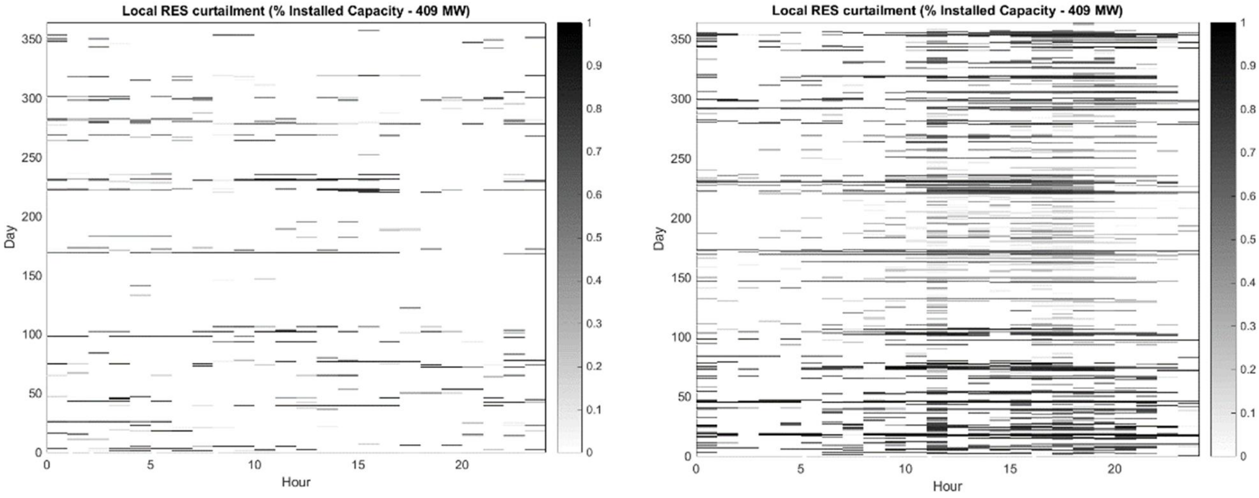


Figure 19: Temporal distribution of curtailment in the area Nordjylland (Denmark West)

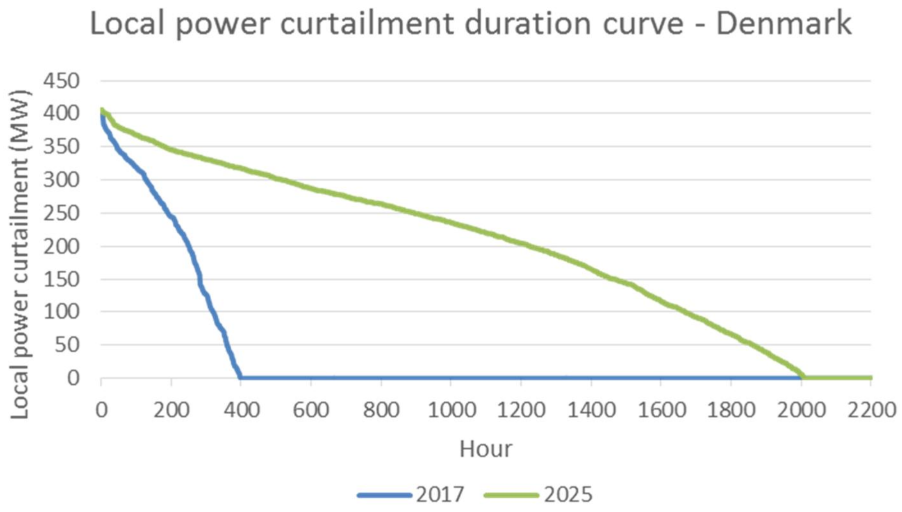


Figure 20: Power curtailment duration curve at Anholt offshore wind farm, Denmark

Grid constraints analysis

The most important confirmed interconnection project expected with Denmark between 2017 and 2024 included [41] are presented in Table 22

Major Project		Line capacity (GW)	Commissioning year
Interconnections with Germany	Kriegers Flak CGS	0.4	2018
	Audorf-Kasso	0.7	2020
	Niebull-Endrup	0.5	2022
Interconnection with the Netherlands (Cobra)		0.7	2019
Interconnection with Great Britain (Viking Link)		1.4	2022

Table 22: Major grid reinforcements in Denmark between 2017 and 2024

In Denmark, a noteworthy difference of annual marginal cost exists between Denmark West and Denmark East for both 2017 and 2025. This can be explained by the presence of important wind curtailment in Denmark West as presented in Figure 18, while the concentration of load is more important in Denmark East (40 % of Danish load is located in Denmark East, while the region represents only 22% of the surface of Denmark).

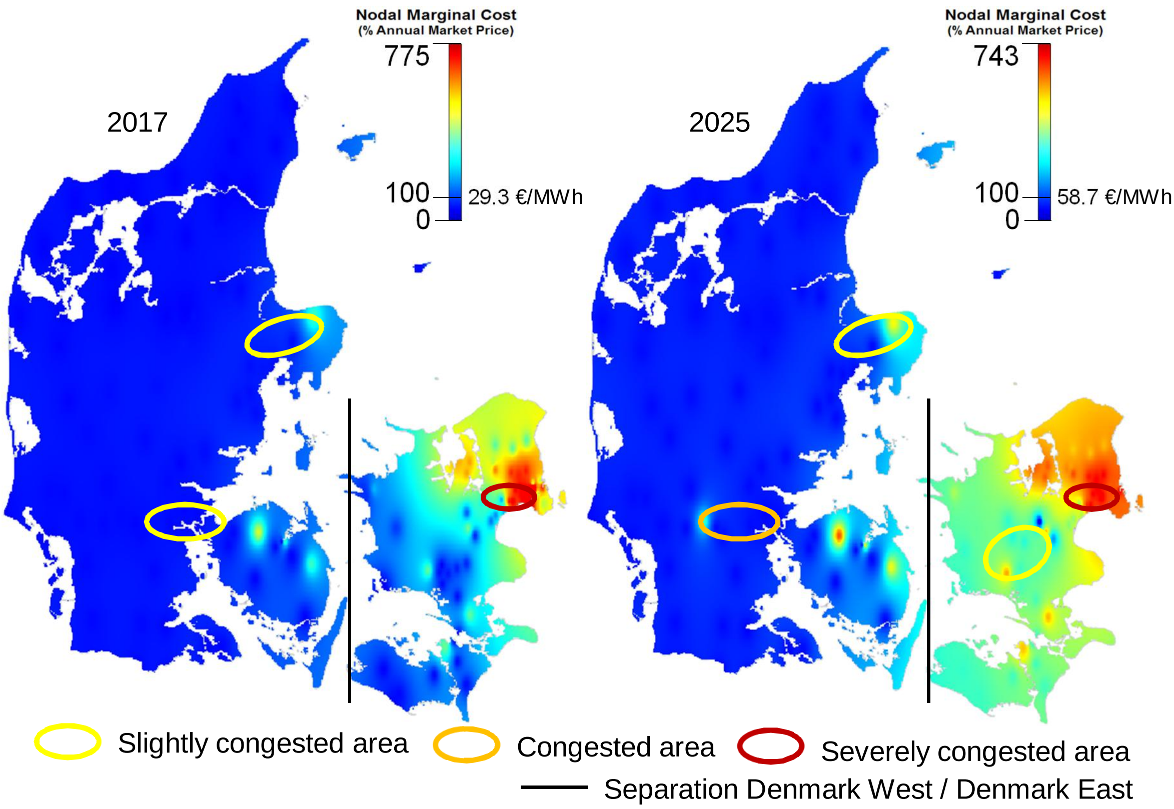


Figure 21: Nodal marginal costs and grid constraint thermal map of Denmark

Near Copenhagen, where this load is even more concentrated, the presence of thermal power plants (coal, gas and biomass) induces a higher marginal cost than in the rest of Denmark East with the existence of congestions between Hovedstaden and Sjælland regions. The same explanation stands for the thermal power plants in Denmark West for which the annual marginal cost is higher than in the rest of the region.

3.2.3. Identification of potential grid services

Potentially interesting grid services for electrolysers can be grouped into two categories: (1) traditional grid services and (2) new grid services. The first group is dominated by load-frequency control services (including balancing services), as envisioned decades ago when interconnected electricity systems began to emerge. Primary and secondary reserves belong to this group. A detailed description of its purpose and functionality in the European framework is given in the next section. The second group is currently emerging in the context of the energy transition: with an increasing share of fluctuating renewable energy sources in electricity production, some grid operators see a need to define new types of grid services that are able to react faster.

3.2.3.1. LOAD-FREQUENCY CONTROL GRID SERVICES

Load-frequency control is a major grid service and an interesting possible value stream for an electrolyser. It is activated by the grid operator in order to keep the system frequency stable and can be supplied by pre-qualified, grid-connected plants. Unlike wholesale electricity markets, ancillary services for load-frequency control vary significantly from one EU member state to another – in terms of product definition, procurement rules, technical requirements and remuneration.

In 2012, the EU Agency for the Cooperation of Energy Regulators (ACER) introduced a new taxonomy within its Framework Guidelines on Electricity Balancing [1]. These Guidelines are seen as a first step to standardise products across Europe. Following them, three major products can be distinguished: (1) Frequency Containment Reserve (FCR), (2) Frequency Restoration Reserve (FRR) and (3) Restoration Reserve (RR). The total market size for load-frequency services is closely correlated to the size of the power sector of a country. For Germany, roughly 5 GW of services are procured, representing 6% of its peak demand. The highest-value service FCR covers 800 MW (1%), while FRR and RR cover roughly 2.5% of peak demand each.

A graphical overview of the activation sequence is given in Figure 22. FCR is activated within max. 30 seconds (during the frequency containment regulation process) to contain frequency changes caused by a disturbance. It is followed by the activation of FRR to restore the frequency to 50 Hz and later replaced by the slower RR so that FCR resources are disengaged and again available to tackle potential new disturbances.

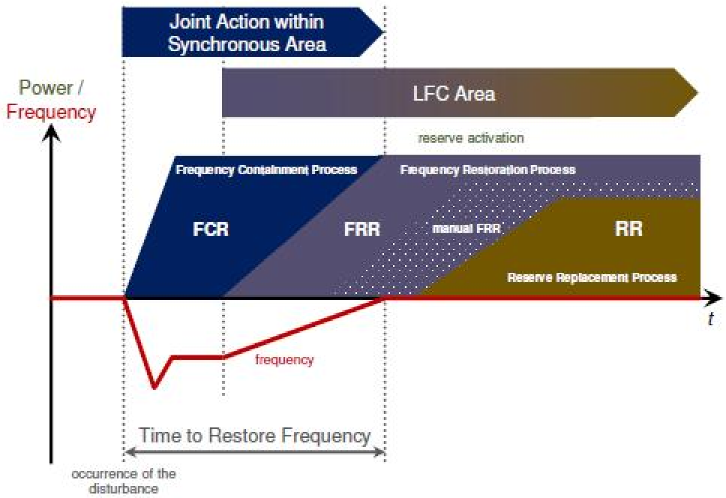


Figure 22: Activation order of load-frequency services (source: [1])

FCR activation is a joint action within a synchronous area, for example Continental Europe spreading from Portugal to Poland and from Denmark West to Greece. Consequently, technical requirements for FCR are quite homogenous already, which greatly facilitates joint procurement across the border. In fact, FCR is already procured jointly via one trading platform for Germany, Belgium, the Netherlands, Switzerland and Austria. It is planned that France and Denmark (West) will also join in a later stage [31]. Technical requirements for FRR and RR are not standardized yet, nor are there common procurement schemes across multiple countries.

A more detailed overview of the regulatory context in the five selected countries is given in section 5.4, where we also quantify historical revenues for plant operators in these ancillary services markets. Table 23 provides a summary of the favourable and unfavourable conditions of these services from the perspective of an electrolyser operator.

Grid service	Favourable conditions	Unfavourable conditions
Frequency Containment Reserve (FCR)	Joint action across synchronous area à harmonized technical requirements Minimum bid size ≤1 MW Activation time (≤30sec)	Typically, a **symmetrical** product (i.e. joint procurement of upward and downward regulation) Not all countries allow load / storage
Frequency Restoration Reserve (FRR)	Typically **asymmetrical** product (i.e. separate procurement of upward and downward regulation)	Fragmented regulation across EU
Replacement Reserve (RR) – Balancing services	Typically **asymmetrical** product	Fragmented regulation across EU Low technical requirements à high number of potential suppliers/competitors

Table 23: Load-frequency grid services - favourable vs. unfavourable conditions

3.2.3.2. NEW GRID SERVICES

The first European country to implement a new type of grid service related to the uptake of fluctuating renewables is Great Britain. This service is named "Enhanced Frequency Response" (EFR) and is defined by the British TSO National Grid as a service that achieves 100% active power output at 1 second (or less) of registering a frequency deviation. This is fundamentally different to the currently fastest responding grid service in continental Europe, which is FCR and requires a full activation within 30 seconds. The first auction for this service was held in July 2016. A full overview of the British grid services and its historical revenues (incl. an analysis of the outcome of the first auction) is given in Annex 4.5.

At this stage, no other European country has introduced a similar service.

4. H_2 TECHNOLOGIES COSTS & PERFORMANCES

Key findings

A comprehensive cost and performance data of all technologies involved in Power-to-Hydrogen systems (production, logistics, etc.) is elaborated and agreed upon with the contribution of key industry experts. An overview of the costs and performance of all technological components is made for the year 2017 and the year 2025. The input parameters for ALK and PEM electrolysers are summarized on Table 24.

4.1. Cost and performance detailed results

This section details the cost and performance data on the hydrogen technologies for 2017 and 2025, to be used as input parameters in the Business Cases that will be elaborated as part of section 6. The data presented in this section results of a literature review, interviews conducted with key hydrogen stakeholders and Hinicio internal database which has been agreed by key industry experts.

The production plant is decomposed in sub-systems which will be described in the following sub-sections. Each important parameter will be discussed both in quantitative and qualitative ways. The sub-systems of the production plant include the following elements:

- Hydrogen production;
- Hydrogen conditioning;
- Hydrogen injection skid (for injection into the gas grid)
- Hydrogen logistics and storage (including storage at the client's site, which is usually considered as part of the logistical chain in the conventional merchant market)

The installations within the final client's facilities (e.g. Hydrogen Refuelling Station, etc.) are outside the perimeter of the business cases.

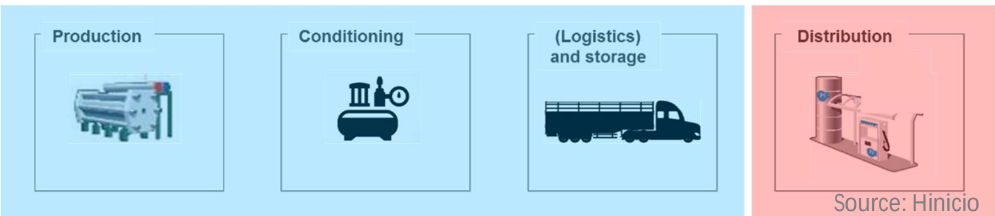


Figure 23: Production plant system boundary

The detailed methodology of this section is described in Annex 3.

4.1.1. Electrolyser systems

4.1.1.1. ELECTROLYSER SYSTEM BOUNDARY

Figure 24 shows the electrolyser system boundary which includes the stacks and all auxiliary sub-systems (gas purification, water management, cooling system, system control, power supply) that are required to operate the electrolyser.

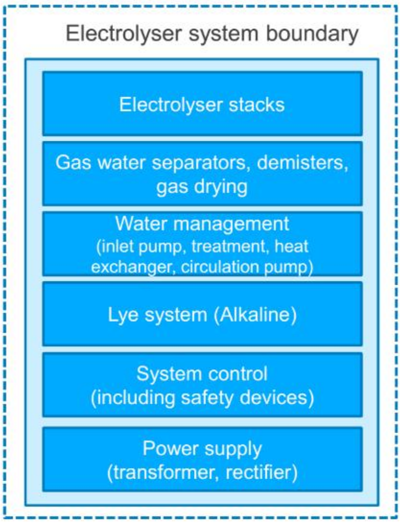


Figure 24: Electrolyser system boundary

The following table summarises the selected value for this study. The parameters will be described in the following sub-sections:

- Load range and dynamic operations
- Output pressure, power consumption and lifetime
- CAPEX and OPEX

		ALK						PEM					
		2017 @ P atm			2025 @ 15 bar			2017 @ 30 bar			2025 @ 60 bar		
Nominal Power	UNITS	1 MW	5 MW	20 MW	1 MW	5 MW	20 MW	1 MW	5 MW	20 MW	1 MW	5 MW	20 MW
Minimum power	% Pnom	15%			10%			5%			0%		
Peak power – for 10 min	% Pnom	100%			100%			160%			200%		
Pressure output	Bar	0 bar			15 bar			30 bar			60 bar		
Power consumption @ P nom	kWhe/kg	58	52	51	55	50	49	63	61	58	54	53	52
Water consumption	L/kg	15 L/kg											
Lifetime – System	Years	20 years											
Lifetime – Stack @ full charge	hr	80 000 h			90 000 h			40 000 h			50 000 h		
Degradation – System	%/1000 h	0,13%/ 1000 h			0,11%/ 1000 h			0,25%/ 1000 h			0,20%/ 1000 h		
Availability	%/year	>98%											
CAPEX – Total system Equipment	€/kW	1200	830	750	900	600	480	1500	1300	1200	1000	900	700
OPEX – Electrolyser system	%CAPEX	4%	3%	2%	4%	3%	2%	4%	3%	2%	4%	3%	2%
CAPEX – Stack replacement	€/kW	420	415	338	315	300	216	525	455	420	300	270	210

Table 24: Summary of electrolyser (ALK and PEM) selected cost and performance data

4.1.1.2. LOAD RANGE AND DYNAMIC OPERATIONS

ALK and PEM electrolyser technologies have different dynamic performance which can provide specific electrical grid services. In general, ALK electrolysis offers less flexibility compared to PEM, in terms of load range and response time. However, when operated adequately, this flexibility may be sufficient to address slow grid services such as Frequency Restoration Reserve (FRR) and Replacement Reserves (RR).

State of the art PEM electrolysers are already technically capable of supplying frequency reserve. Therefore, they are considered suitable for wider range of grid services. PEM electrolysers can be maintained in stand-by mode with minimal electricity consumption, and are able to operate for a short time (typically 10 minutes) at much higher capacity than nominal load, a specific capability that can be taken advantage of for provision of primary reserve services. Additional costs are needed for the cooling system and power supply.

2017	ALK	PEM
Load range	15-100% nom. load	0-160% nom. load
Start-up	1 - 10 minutes	1 sec - 5 minutes
Ramp-up	0,2 - 20 % /s	100% /s
Ramp-down	0,2 - 20 % /s	100% /s
Shut down	1 - 10 minutes	Seconds

Table 25: Dynamic operation comparison

4.1.1.3. OUTPUT PRESSURE, POWER CONSUMPTION AND LIFETIME

Letting the pressure build up inside the stack is more energy efficient than mechanical compression and can significantly simplify the downstream process by avoiding an additional compression system. Higher pressure operation induces mechanical stress on the membranes which has an impact on system efficiency and stack replacement rate. PEM electrolysers are better suited than ALK electrolysers for operation under pressure due to smaller cell surfaces resulting from operation at higher current densities, as well as simpler mechanical integration, thanks to the use of a solid material electrolyte.

Manufacturers have different design strategies for addressing specific applications. Therefore, the values of the parameters selected for the study are collected data averages.

For simplicity reasons, it is assumed that ALK electrolyser can provide atmospheric pressure and 15 bar output pressure in 2017 and 2025 respectively. PEM electrolyser can provide 30 and 60 bar output pressure in 2017 and 2025 respectively.

The shown power consumption considers the electrolyser additional power needed at the selected output pressures. The PEM electrolyser high output pressure explains the higher power consumption compared to ALK electrolyser.

		ALK						PEM					
		2017 @ P atm			2025 @ 15 bar			2017 @ 30 bar			2025 @ 60 bar		
Nominal Power	UNITS	1 MW	5 MW	20 MW	1 MW	5 MW	20 MW	1 MW	5 MW	20 MW	1 MW	5 MW	20 MW
Pressure output	Bar		0 bar			15 bar			30 bar			60 bar	
Power consumption @ P nom	kWhe/kg	58	52	51	55	50	49	63	61	58	54	53	52

Table 26: Projection of electrolysers pressures and power consumptions

Electrolyser systems are generally designed for **20 years lifetime** and aims for **more than 98% availability rate**.

Some components will degrade, which will affect the overall performance of the stack. Stack degradation is expressed in number of hours of continuous operation before stack replacement. Stack replacement is generally planned when energy efficiency drops to 90% of its nominal initial value. Stack degradation over time is still not fully predictable especially when operated in variable modes. State of the art MW-scale PEM only have an history of 10 000 operating hours.

		ALK		PEM	
		2017 @ P atm	2025 @ 15 bar	2017 @ 30 bar	2025 @ 60 bar
Lifetime – System	Years	20 years			
Lifetime – Stack @ full charge	hr	80 000 h	90 000 h	40 000 h	50 000 h
Degradation – System	%/1000 h	0,13%/ 1000 h	0,11%/ 1000 h	0,25%/ 1000 h	0,20%/ 1000 h
Availability	%/year	>98%			

Table 27: Electrolyser durability and lifetime projection

4.1.1.4. CAPEX AND OPEX

ALK electrolysers offer interesting cost/capacity ratio for H_2 production. Even though ALK is cheaper than PEM, cost spread in small size electrolyser is limited due to ALK difficulty to scale down sub-systems cost (e.g. electrolyte management).

		ALK						PEM					
		2017 @ P atm			2025 @ 15 bar			2017 @ 30 bar			2025 @ 60 bar		
Nominal Power	UNITS	1 MW	5 MW	20 MW	1 MW	5 MW	20 MW	1 MW	5 MW	20 MW	1 MW	5 MW	20 MW
CAPEX – Total system Equipment	€/kW	1200	830	750	900	630	600	1500	1300	1200	1000	750	700
OPEX – Electrolyser system	%CAPEX	4%	3%	2%	4%	3%	2%	4%	3%	2%	4%	3%	2%
Stack replacement cost	€/kW	420	380	338	315	270	216	525	470	420	300	250	210

Table 28: Electrolyser CAPEX and OPEX projection

Overall, system cost optimisation can be seen up to 5 MW electrolyser system. Over a certain production plant size, the cost saving is reduced as all building blocks have to be replicated. For example, a 40 MW production plant will be a multiple of 10 MW electrolyser containers, leading to only marginal economies of scale on construction costs.

According to data collected, cost reduction in 2025 is expected to be faster on PEM than ALK due to ALK's technology maturity and potential evolution of PEM.

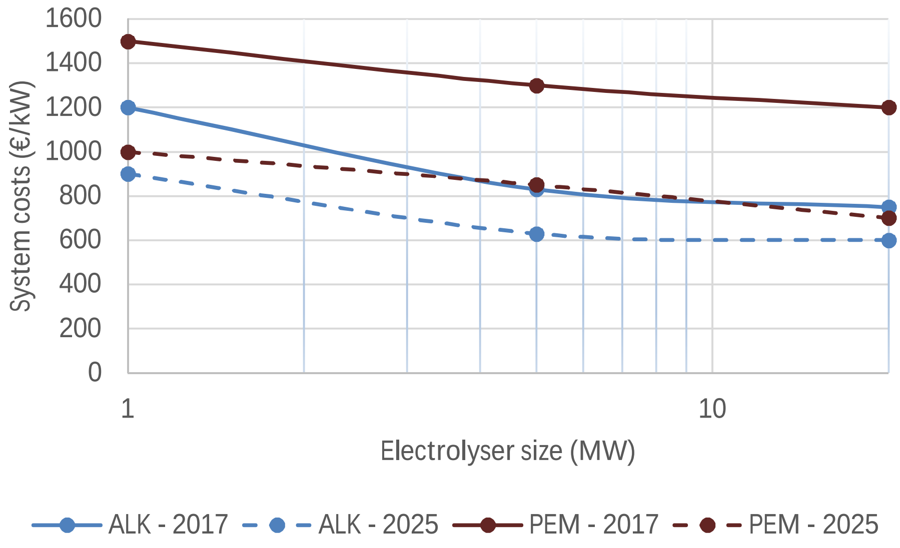


Figure 25: Electrolyser system CAPEX extrapolation

Electrolyser system OPEX includes the maintenance, spare parts and replacement of the auxiliary components (pumps, filters…). This excludes electricity, water consumptions and stacks replacement which will be considered later. The following table summarizes the compiled data based on full load.

	Full load	Fixed part	Variable part
1 MW	4% of CAPEX	$^1/_3$	$^2/_3$
5 MW	3% of CAPEX		
20 MW	2% of CAPEX		

Table 29: Electrolyser system OPEX

To take in to account the usage rate, the electrolyser system OPEX is divided into 1/3 fixed and 2/3 variable costs. The variable costs are proportional of the electrolyser operating time.

Stack replacement cost takes a considerable part of the system operation. Stack replacement is needed when efficiency reaches below 90% of its initial value. As pointed out by the respondents, the stack replacement cost will get cheaper over time to account for stack cost reduction.

As seen in the following graph, ALK and PEM stack replacement cost should tend toward the same values by 2025.

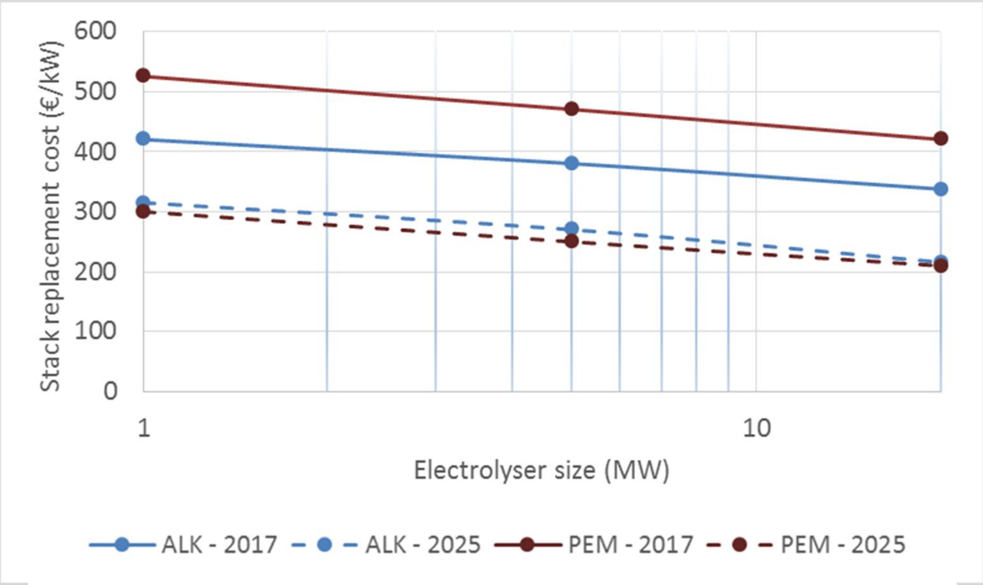


Figure 26: Stack replacement costs extrapolation

4.1.2. Filling centres and compressor skids

The term **filling centre** designates the physical infrastructure needed to fill gas bundles and/or tube-trailers. In other word, it is the physical interface with the hydrogen logistical system. This includes the compressors skids, piping and filling equipment. It excludes the fixed or mobile storage components and civil work as they will be described specifically in section 4.1.3.

Hydrogen trailer filling centres typically have a filling capacity of 100 to 200 kg/h and serve customers within a radius of 200 to 400 km. Smaller filling centres (<100 kg/h) filling only a few trailers per day (20 kg/h = 1 trailer/day) require new design concepts (e.g. with higher degrees of automation and standalone operation capacity rather than a full-size centre) to be economically viable.

A compressor skid is often needed with on-site production in order to pressurize the hydrogen for the on-site storage or for feeding the application process. The compressor skid includes the compressors and the auxiliary components such as cooling and control systems.

A model based approach is used to estimate filling centre and compressor cost and power consumption data. The cost and performance models are detailed in Annex 3.

4.1.2.1. POWER CONSUMPTION

Power consumption is estimated from **adiabatic compression model** with an **efficiency of 50%**. This efficiency considers the efficiency of electrical power transformation and auxiliary systems such as the cooling circuit.

	Pressure input	Pressure output	Number of stages	Power consumption
2017	P atm	200 barg	4	5.0 kWh e/kg
		500 barg	5	6.3 kWh e/kg
	30 barg	200 barg	2	1.7 kWh e/kg
		500 barg	3	2.7 kWh e/kg
2025	15 barg	200 barg	2	2.4 kWh e/kg
		500 barg	3	3.5 kWh e/kg
	60 barg	200 barg	1	1.1 kWh e/kg
		500 barg	2	2.0 kWh e/kg

Table 30: Estimated power consumption of compressor skid

4.1.2.2. CAPEX AND OPEX

The cost of compressor and filling centre is based on a cost model detailed in Annex 3.1. The cost model depends on the compressor capacity, the pressure input and output. The following tables are the results from this cost model.

Filling centre

k€ CAPEX		Estimated value	k€ CAPEX		Estimated value
Patm → 200 bar	20 kg/h	687	30 bar → 200 bar	20 kg/h	467
	100 kg/h	1986		100 kg/h	1351
	400 kg/h	4959		400 kg/h	3373
15 bar → 200 bar	20 kg/h	498	60 bar → 200 bar	20 kg/h	441
	100 kg/h	1441		100 kg/h	1276
	400 kg/h	3597		400 kg/h	3185

k€ CAPEX		Estimated value	k€ CAPEX		Estimated value
Patm → 500 bar	20 kg/h	910	30 bar → 500 bar	20 kg/h	562
	100 kg/h	2631		100 kg/h	1626
	400 kg/h	6569		400 kg/h	4061
15 bar → 500 bar	20 kg/h	572	60 bar → 500 bar	20 kg/h	493
	100 kg/h	1654		100 kg/h	1426
	400 kg/h	4129		400 kg/h	3561

Table 31: Estimated cost for filling centre based on the cost function

Compressor skids

k€ CAPEX		Estimated value
Patm → 60 bar	20 kg/h	265
	100 kg/h	766
	400 kg/h	1912
15 bar → 60 bar	20 kg/h	182
	100 kg/h	528
	400 kg/h	1318

k€ CAPEX		Estimated value
30 bar→ 60 bar	20 kg/h	144
	100 kg/h	418
	400 kg/h	1043

Table 32: Estimated cost for compressor skid based on the cost function

4.1.3. Storage systems

Gas distribution is done in two ways: **bump filling** and **even exchange**. Each approach requires specific type of storage systems.

Bump filling: The gas supplier unloads its tube-trailer into the client's on-site stationary storage by pressure difference. This approach allows the gas supplier to fill multiple clients with one tube-trailer. This practice is relatively common in Germany, for example.

Even exchange: The gas supplier swap empty bundles or tube-trailers for full ones at the client's location. This approach optimizes the useful transported hydrogen. In this case, the storage is mobile and is transported between the production site to the client. The client is billed for the consumed gas (measured by weight difference of the mobile storage) and for the mobile storage renting.

4.1.3.1. STATIONARY STORAGE SYSTEMS

This study will focus on steel stationary storage as they are widely used in the industry and are the most cost effective when compared to composite storage. Composite storage is preferred when available surface is limited and/or high pressure is needed (over 400 bar).

Two types of designs are used for stationary storage of hydrogen: (i) large welded steel tanks having a water capacity of 50 m^3 and a service pressure of 50 bar and (ii) assemblies (bundles) of steel cylinders allowing storage at up to 200 bar. Welded tanks are typically used in Germany with bump filling. The low stationary storage pressure allows higher gas transfer from tube-trailer. Data shows similar costs between tanks and bundles. This can be explained because tanks may be simpler to make but require more steel/volume and bundles may be smaller but are more complex to assemble. At the end, cost remain the same. The technology of steel pressure vessels is mature and no cost evolution is forecasted: same values are considered for 2017 and 2025.

*CAPEX €/kg	2017	2025
50 bar (tank)	470	470
200 bar (bundle)	470	470
350 bar (bundle)	470	470

Table 33: Fixed steel storage cost projection

*Unit in total hydrogen capacity (not effective hydrogen capacity which depends on the downstream application)

Stationary pressure vessels in steel have a lifetime of 30-40 years, but require maintenance and inspection every 10 to 15 years. This represents an annual OPEX of 2% of the initial storage investment.

4.1.3.2. MOBILE STORAGE SYSTEM

Hydrogen distribution in the light industry market is typically done by large bundles and tube-trailers. The following table summarize the differences in volume and capacity.

	Large bundles	Tube-trailers
Pressure	200 to 500 bar	
Volume	0.8 to 3 m^3	13 to 33 m^3
Capacity	12.5 to 100 kg H_2	200 to 1000 kg H_2
Lifetime	20-30 years	
Periodic maintenance and inspection	10-15 years	

Table 34: Comparison between large bundles and tube-trailers

Similar to stationary storage, 200 bar large bundles have the same costs. Steel storage is a mature technology and cost should remain the same in 2025.

Standard tube-trailers are constituted of 200 bar steel cylinders and have a capacity of 400 kg of H_2. Their cost is approximately 200 000 € including the pressure valves and the chassis. That number is not expected to change by 2025.

Development of 500 bar tube-trailers with a capacity of 1000 kg of H_2 is underway. They use composite cylinders (type 4) and still face technological obstacles such as durability. However, they could be commercially available by 2025. This new trailer can optimize the supply chain by allowing more hydrogen supplied per delivery and reducing compression needs at the HRS.

	Large bundles		Tube trailers	
***CAPEX €/kg**	**2017**	**2025**	**2017**	**2025**
200 bar	470	470	500	500
500 bar	815	590	830	605

Table 35: Large bundle and tube-trailer storage cost projection

*Unit in total hydrogen capacity (not effective hydrogen capacity which depends on the downstream application)

Mobile storage has a lifetime of 20-30 years, but requires maintenance and inspection every 10 to 15 years. This represents an annual OPEX of 4% of the initial storage investment.

4.1.4. Hydrogen injection interface for the gas grid

Hydrogen direct injection into the gas network is still under demonstration. Similar to the biomethane sector, the injection interface requirements vary from country to country (injection point and pressure, cost sharing…). This will be further developed in sections 5 and 0.

For this study, the following cost data will be used based on the interview with industry players, the literature, and actual feedback from current projects

Transport network	2017	2025
Pressure	60 bar	
Injection station	700 k€	560 k€
OPEX [% CAPEX]	8%	
Lifetime [years]	35 years	

Distribution network	2017	2025
Pressure	10 bar	
Injection station	600 k€	480 k€
OPEX [% CAPEX]	8%	
Lifetime [years]	35 years	

H2 connection piping	300 k€/km
H2 connection piping equipment	200 k€
OPEX [% CAPEX]	2%

Figure 27: H_2 injection data [32]

4.1.5. Fuel cell system for re-electrification

Re-electrification is the use of hydrogen to create electrical power. This conversion is performed inside a fuel cell where the H_2 molecule is combined with the oxygen from air. The produced electricity can serve multiple grid services, such as:

- Frequency response reserve (FRR)
- Replacement Reserves (RR)
- Backup system

Based on re-electrification performance (power, response time and energy stored), the system can address specific grid services. The following table summarize the cost and performance of a fuel cell system.

	Data range	Selected
Unit size [MW]	Up to 1 MW scalable	
Power range [% Pnom]	0-100% nom. power	
Efficiency rate [%LHV]	45-55%	50%
Dynamic response	± 2 – 10 %/s	5%/s
Lifetime [years]	15-20 years	20 years
Stack lifetime [hr]	10 000 – 20 000	15 000
CAPEX [€/kW]	1600 – 3000	2000
OPEX [%CAPEX]	4-5%	4%
Stack replacement cost	40-50%	50%

Figure 28: Fuel cell system data

4.1.6. Hydrogen facility costs other than equipment costs

The previous sub-sections detailed the cost and performance of the major equipment (electrolyser, compressors, storage…). This sub-section presents the additional costs needed to complete the project. The hydrogen production facility costs are divided into investment (CAPEX) and operational expenditure (OPEX).

The remaining facility CAPEX, including studies, civil work, grid connection, installation, typically represents 70-80% of the equipment costs. The remaining facility OPEX represents 4% of non-equipment costs.

The facility costs estimation is detailed in Annex 3.2.

Cost	
CAPEX – Electrolyser system	
CAPEX – Filling centre or compressor skids	
CAPEX – Buffer and client storage	
CAPEX – Transport costs	
CAPEX – Distributed Control System and Energy Management Unit	
CAPEX – Engineering studies, permitting and insurance	
CAPEX – Civil work, building, infrastructure, fencing, safety	
CAPEX – Grid connection	
CAPEX – Installation, commissioning and start up	

Equipment costs

Other costs typically represents 70-80% of equipment costs

Figure 29: Hydrogen facility investment costs description

5. MONETIZATION OF VALUE STREAMS THAT CAN BE CAPTURED BY H2

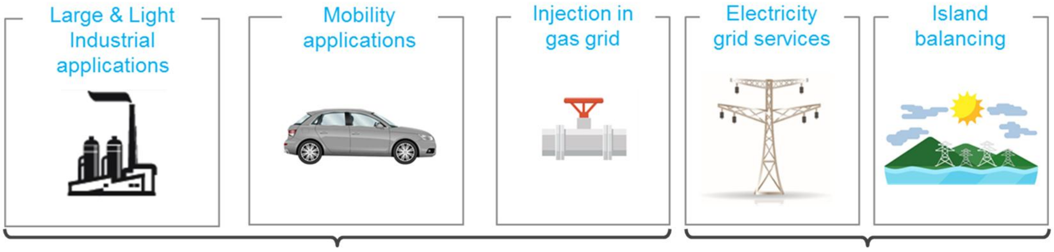
The aim of this section is to capture and quantify value streams *individually*. Suitable combinations of individual value streams will be built in section 6, forming the basis for a business case.

Based on experience and confirmed by this study, the **greatest part of the revenues will always come from selling the molecule to hydrogen consumers**, i.e. to either mobility or industry clients. Industry and mobility will therefore be considered as “primary value streams”. Extra layers of revenues can then be stacked up, either from gas grid injection, re-electrification or electrical grid services. Those will be considered as “secondary value streams”.

The output of this section will be the price ranges for industry and mobility applications corresponding to successful business cases for the relating downstream applications. Those price ranges indicate the “willingness to pay” of end-consumers. Both hydrogen sellers and buyers have been interviewed to ensure that those price ranges will not be biased, neither on the low nor on the high side. The data communicated during these interviews have been crossed-checked with HINICIO’s internal database to ensure consistency.

Key findings

The following table summarizes the various revenue streams that a 1MW electrolyser could capture when operating only for one specific application with a utilization rate of 90%.



Revenues from **hydrogen sales**

PtoH application	Potential revenues [k€/MW/year]
Refineries, without carbon penalty	237 – 512
Refineries, with carbon penalty*	792 – 1068
Light industry market (delivery by trailer)	499 – 1235
Mobility (delivery to the HRS)	526 – 920
Hydrogen injection into gas grid based on national biomethane injection tariff[1]	171 – 350*

Revenues from **grid services**

PtoH application	Potential revenues [k€/MW/year]
Balancing services	2 -17
Frequency control services	70 - 224
Distribution grid services	< 1

Primary value streams
Secondary value streams
(combinable with primary applications for little extra cost)

Source: Hinicio

*Carbon penalty of 470€/tCO$_2$ is based on German law of emission intensity reduction requirement on conventional fuel production (§37c BImSchG), if H$_2$ was recongnised in the carbon intensity calculation.
[1]Biomethane injection tariff can vary significantly depending on injection capacity and feedstock. The study considers a realistic lower revenue for hydrogen gas grid injection.

Figure 30: Overview of potential value streams

The value streams can be separated into primary and secondary value streams based on the volume of hydrogen committed and revenues captured. The primary value streams, namely industry and mobility applications, generates the highest potential revenues. The potential revenues from primary applications are at least one order of magnitude higher than those of the secondary ones. The secondary value streams, namely hydrogen injection and electrical grid services, constitute opportunities to stack additional layers of revenues for electrolyser operators next to a primary application.

5.1. H_2 for industrial applications

Industrial applications are the most common use of hydrogen. They are divided into large and light industry, based on their hydrogen consumption volume. Typically, large industry, such as refineries, chemical plants and potentially steel manufacture, consumes very large quantity of hydrogen (over 10 000Nm^3/h). Hydrogen supply is done by on-site production by SMR or supplied via pipeline. Light industry is typically supplied by truck in or (smaller) on-site SMR, if volume is sufficient.

5.1.1. Large industry: Refineries

Hydrogen is mainly used in refineries for desulphurisation of crude oil. European refineries are expected to use more hydrogen because of restrictive fuel quality regulation and lower crude oil quality. Power-to-Hydrogen could be an opportunity to supply this increasing hydrogen need in the short-to-mid-term if favourable regulation to lower carbon intensity of produced fuel can be put in place. The emergence of a business case in large industries such as refineries can lead to large volume deployment of electrolysers.

Figure 31 shows a map of European refineries. The size of a circle represents the capacity in barrels per day (BpD).

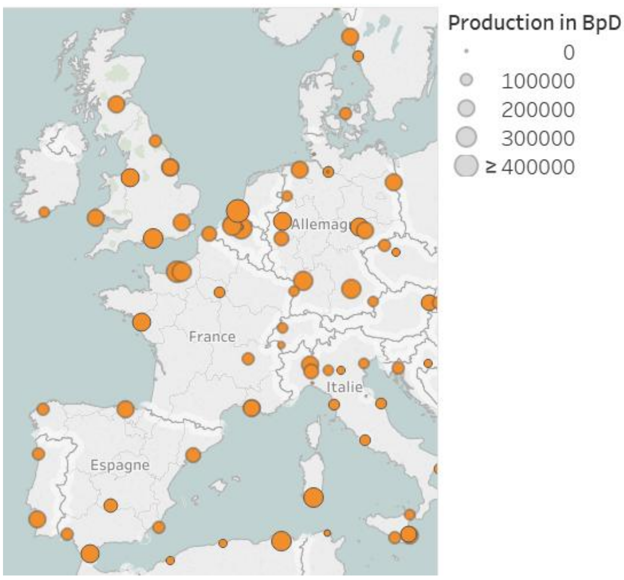


Figure 31: Map of refineries in Western Europe

Value stream

The value streams are calculated considering the marginal production cost of hydrogen in an existing refinery SMR or pipeline, in comparison of using electrolysis. It is assumed that the refinery would be owner and operator of the electrolyser in order to be able to take advantage of all the value streams.

Power-to-Hydrogen for refineries brings the following value streams:

- **Hydrogen** is the main product of electrolysis of water. The value stream of hydrogen from Power-to-Hydrogen for a refinery is estimated based on the production cost using conventional technology or based on the source of supply SMR or pipeline.
- **Oxygen** is a by-product of electrolysis of water and has (potential) value in a refinery. Value stream of oxygen is estimated based on production cost using conventional technology or on the cost of supply from a gas supplier.
- Generating hydrogen using electrolysis has the potential to reduce GHG footprint of the refinery. The potential cost saving by **reducing $CO_{2\,eq}$ emissions** is calculated based on the typical emissions of hydrogen production using conventional technology and on selected CO_2 price scenarios.
- Introducing an electrolyser in a refinery brings an extra **degree of freedom for real time optimization**. An estimate is made of the possible cost saving.

Table 36 summarises the Power-to-Hydrogen value stream available from refineries application. The range of production cost of hydrogen have been calculated considering spare capacity available on onsite SMR, capacity increase by onsite SMR and capacity increase by 3rd party supplier (pipeline). Spare capacity available on onsite SMR have been found to be the cheapest way to produce hydrogen, however, it would depend on the capacity rate of each SMR. The production cost of oxygen appears to be not significant as compared to the hydrogen production cost. The cost saving of CO_2 reduction are based on the forecasted price of carbon for 2025 in EU and UK.

Details on the methodology and calculations are described in Annex 4.1.1.

	DE	FR	UK	DK
Production cost of hydrogen [€/t H_2]	1350-2670	1394-2720	1226-2677	1626-2987
Production cost of oxygen [€/t H_2]	160 – 640	160 – 640	160 – 640	160 – 640
Cost saving of Carbon Dioxide reduction [€/t H_2]	289	289	440	289
TOTAL VALUE [€/t H2]	**1800-3600**	**1840-3650**	**1830-3760**	**2075-3920**

Table 36: Hydrogen value stream overview of a typical hydrogen refinery in the selected regions

Real time optimisation using an extra degree of freedom by means of the electrolyser has a potential of an additional production cost saving, which can be as high as 305 €/t H2.

Revision of RED II and FQD opportunity

The Fuel Quality Directive (FQD) requires the Life cycle analysis (LCA) carbon intensity of fuels to be reduced by 6% compared to 2010. While any actions within a refinery cannot be considered for meeting this requirement, due to the fact that emissions associated to fossil fuels are quantified using a pre-set default value, actions to reduce certain defined upstream emissions, such as flaring and venting in exploration, are considered in the calculation of the achieved reduction of carbon intensity. It was at some point contemplated to include the emissions from the production of hydrogen in refineries in the group of defined “upstream emissions”. This would have opened a new market for green hydrogen, considering in particular the implementation measures taken by Member States, such as Germany, where a carbon penalty of 470 €/tCO_2 is foreseen for fuel suppliers failing to meet the emissions intensity reduction requirement (Federal Emission Protection Law - §37c BImSchG). This penalty would correspond to an increase of green hydrogen value 4230 €/tH_2. However, possible consideration of hydrogen production as a source of “upstream emissions” was abandoned and there is therefore currently no specific “regulatory value” in reducing the emissions related to hydrogen production in refineries. This perspective may nonetheless reappear through the revision of the European **Fuel Quality Directive** (FQD) and **Renewable Energy Directive** (RED II) which has been initiated for defining the requirements which will be applicable beyond 2020.

For the period 2017-2020, limited value should be captured for hydrogen. Beyond 2020, there is still a possible opportunity, but this is to be clarified in RED2 – Winter Package.

5.1.2. Large industry: Steel manufactures

EU is the second largest producer of steel in the world after China. It produces over 177 million tons of steel a year, accounting 11% of global production. Mainstream steel manufacturing is energy and carbon intensive as it uses coal or natural gas both for heating the iron ore and as a reducing agent through CO. As shown in the table below, carbon price has a great impact on steel cost, higher than concrete and aluminium. Even though EU ETS price dropped, R&D efforts are underway to develop new alternative low carbon processes. Hydrogen is identified as a possible alternative to substitute the fossil fuel and reduce the carbon footprint of steel.

	Emission factor [kg CO_2 eq./unit]	Average price [€/unit]	Impact of CO_2 price at 30€/t	Impact of CO_2 price at 50€/t	Impact of CO_2 price at 100€/t
1 ton concrete	866	80 €/ton	32%	54%	108%
1 ton steel	3190	200 €/ton	48%	80%	160%
1 ton aluminium	9830	1 500 €/ton	20%	33%	66%
1 ton ammonia 33,5%	1966	310 €/ton	19%	32%	63%

Table 37: Impact of CO_2 price on products average price [18]

5.1.2.1. STEELMAKING PROCESSES

There are two main ways to produce crude steel from iron ore:

- With a **blast furnace**, established process, using mainly (coal derived) coke as source of energy and reducing agent (mainly CO), producing hot metal (a liquid iron smelt), converted (together with scrap) to crude steel in a Basic Oxygen Furnace (BOF) as a standard route. Today, Blast Furnace is the most common process used in Europe. In 2009, there were about 41 blast furnace plants in Europe [27]. However, this process is considered very pollutant as it uses coke as feedstock.
- Through different **direct reduction iron** process uses mainly natural gas as source of energy and reducing agent (CO or syngas from NG reforming), producing "Direct Reduced Iron", converted with additional scrap input to steel in an electric arc furnace (EAF). The process uses less fuel and generates less GHG emissions compared to Blast Furnace. This process is widely used in Middle East and South America where natural gas price is very cheap and can compete with coal. Today, there is only one DRI plant in Europe (ArcelorMittal Hamburg).

5.1.2.2. USE OF HYDROGEN FOR STEEL WITH LOW CARBON EMISSION

Hydrogen can be used in both processes as a reducing gas in total or partial substitution of the CO to reduce carbon intensity of steel.

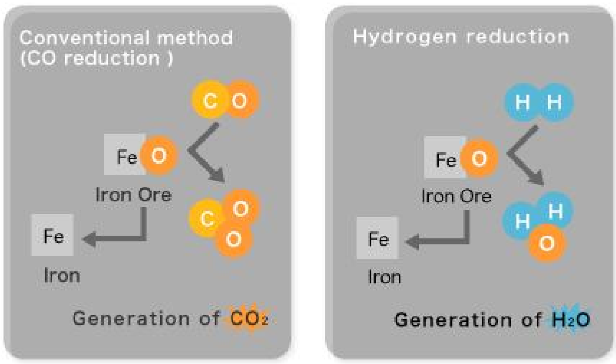


Figure 32: Comparison of iron reduction process with CO and H2 [72]

Hydrogen in Blast Furnace

As Blast Furnace is the most common process in Europe, it can be interesting to convert existing plant for hydrogen. However, hydrogen injection at significant scale in a blast furnace is unlikely to be viable for the following reasons:

- A considerable part of the hydrogen injected would leave the blast furnace with the off-gas, limiting the environmental and economic benefit;
- The change of composition of the off-gas mixture would likely require an adaption of the downstream processes (power plant, burners…);
- Due to the simultaneous injection of air, injection of hydrogen raises considerable safety issues.

There are currently no European projects experimenting hydrogen usage in blast furnaces.

Hydrogen in Direct Reduction Iron process

On the other hand, the injection of hydrogen in a gas based direct reduction process raises less technical issues in principle.

There is currently two European projects experimenting hydrogen usage in DRI process:

- **H2future**, a FCHJU supported project launched by Verbund, Voestalpine and Siemens in 2016, will focus on grid balancing services in order to provide affordable hydrogen for the current use in steel making processes. The demonstration 6MW plant will be installed at Voestalpine steel plant in Linz, Austria. Voestalpine foresee green H2 use in DRI after 2035.
- **HYBRIT**, a national Swedish project launched by the consortium SSAB, LKAB and Vattenfall in April 2016, will analyse the prefeasibility of using green hydrogen to decarbonize crude steel in Sweden. Large scale demonstration plant trials are expected in 2025-2035 horizon using DRI process.

A full-scale pilot plant implementing DRI with 100% H_2 was constructed in Trinidad and Tobago (CIRCORED project). However, operation was discontinued. The more likely approach in the future would be to use a mixture of natural gas and hydrogen. Implementation of such a solution would nonetheless require further process development work ("Carbon Direct Avoidance" concept, CDA).

Based on experts, hydrogen consumption is approximately 650 Nm^3 H_2/tDRI (figure for CIRCORED process) for 100% H_2 operation.

So far, this is the most promising use of hydrogen in steel manufacturing. This would need a full-scale conversion of the existing plants. Clear signals are needed for a market transition.

5.1.2.3. MAIN DRIVERS FOR STEEL WITH LOW CARBON EMISSION

There are two potential main drivers for steel with low-carbon emission:

- A **functioning carbon market**, increasing the price of steel with a high carbon intensity makes steel with low carbon emission more competitive: this requires either a worldwide carbon market or ETS with a border carbon adjustment to be able to allocate higher production costs due to CO_2 avoidance to the final users of steel products. Under such conditions, European players would be in a good position to implement their technical know-how for the competitive supply of steel with low carbon emissions, or
- End-user's **willingness to purchase steel with low-carbon emissions** (for a higher steel price); Higher market value of products made from steel with low carbon emissions could help support the implementation of lower-carbon processes.

Operation of natural gas based DRI processes in Europe and even more substituting part of the needed gas by electrolytic hydrogen will necessarily increase production costs compared to the blast furnace route. Making this profitable for the producer will require a certain level of CO_2 cost combined with an increase of end-product market value (to be determined).

The Wuppertal Institute study [50] compared economically both technologies, coke based blast furnace and hydrogen based DRI. The study suggests that marketability of hydrogen based DRI can be reached with the combined conditions of a carbon price at 34 €/tCO_2, electricity price between 33-88 €/MWh, coke price of 235 €/t and gas price of 8.3 €/GJ. These conditions are expected to be met after 2030.

5.1.2.4. ALTERNATIVES SOLUTIONS FOR STEEL WITH LOW CARBON EMISSIONS

There are other possible solutions for strongly decreasing emissions in steel manufacturing:

- CCU: Utilization of captured CO_2 from carbon based steelmaking processes to produce e.g. synthetic fuels from a low carbon primary energy sources
- CCS: Storage of CO_2 in underground repositories (politically not viable in most parts of Europe)
- Possibly future new process developments, e.g. iron ore electrolysis (ULCOS process); up to now did not go beyond early development stages - (large scale) feasibility unclear.

5.1.3. Large industry: Chemical industry

Similar to refineries, the chemical industry already uses hydrogen in their main processes, mainly for ammonia and methanol production. This hydrogen is typically supplied via on-site SMR of natural gas or via pipeline. Power-to-Hydrogen brings an opportunity to lower the carbon footprint of these chemical product.

Ammonia synthesis combines hydrogen and nitrogen at high pressure (150 to 250 bar) and high temperature (>350^{o}C) to produce ammonia. This is known as the Haber-Bosch process. Europe produces about 21 million tonnes of ammonia in 17 countries through 42 plants which is mainly used for production of fertilizers.

Methanol synthesis uses hydrogen, carbon monoxide and carbon dioxide to produce methanol. Methanol is used to create other chemicals and fuel blend for transportation. Low carbon methanol can be obtained with other alternative source such as biogas which would compete against green hydrogen based methanol synthesis.

The hydrogen supply to the chemical plant is typically done though onsite SMR or pipeline. The main drivers for chemical industry to transition to a decarbonised hydrogen production are:

- A **functioning carbon market**
- End-user's **willingness to purchase low-carbon chemicals** (for a higher price)

The chemical industry is only subject to the EU ETS scheme and has limited specific carbon intensity targets such as refineries.

5.1.4. Light industry hydrogen market

This section will focus on sub-segments where on-site production has the most potential, namely glass production, hydrogenation of fat and heat treatment. Electronics is also analyzed because hydrogen purity and supply reliability requirements make it a very favorable ground for local production.

Table 38 gives an overview of the different hydrogen applications in light industry. Details of the applications can be found in the Annex 4.2.1.

Light industry	Cooking oil and fat	Glass	Electronic	Metallurgy
EU market size (billion Nm^3/year)	0,41	0,07	0,33	0,32
Plant capacity range (expressed in MW of electrolyser)	30kW to 3MW	250 to 600 kW	Up to 2 MW	100kW to 4 MW
Hydrogen supply capacity need	10-50 Nm^3/h	300-700 t/d	500 Nm^3/h	20-1000 Nm^3/h

Table 38: Overview of the light industry hydrogen market

Light industry hydrogen gas price

In the merchant market, the selling price will vary a lot from one location to the other, depending on the volume purchased (which itself depends on the sector), the proximity to a hydrogen source, the level of competition amongst gas companies in the regions, etc. Additionally, there is limited public data available on hydrogen market price in a specific region as transactions systematically take place over the counter.

Therefore, estimating the value stream in a generic way for the light industry hydrogen market is a challenging task. Light industry hydrogen price largely depends on multiple factors, such as:

- Gas related factors
  - Hydrogen production (process, volume, quality)
  - Hydrogen distribution (format, transport, accessibility)
- Customer related factors
  - Bulk package deal (possible purchase of other gas next to hydrogen)
  - Agreement duration
  - Additional services (training, reliability, guarantee)
  - Negotiation and customer relation
- Location related factors
  - Industrial density
  - Distance to hydrogen sources
  - Competitive environment (number of gas suppliers present in the area)

Gathering data through interviews with clients across 5 regions is not efficient. Therefore, two approaches were used to estimate light industry hydrogen gas price. The approaches methodology and calculation are described in Annex 4.2.1.

- **Price-based**: Price extrapolation from literature and field data collection;
- **Cost-based**: Price extrapolation from a theoretical economic model.

Both approaches gives an interesting point of view of the light industry market. However, both have limitation as they only try to reflect local and specific realities. The ideal situation would be to have real inputs from the local pricing. For the purpose of this study, the selected value stream is based on the most conservative value between both approaches. This ensures to capture the theoretical value and local competitive environment.

		Selected region	Closest filling center	Distance (one-way)	Cost-based	Price-based	Value used within the study
2017 / 2025	DE	Lubeck	Stade	80 km	7.8 €/kg	3.8 €/kg	**3.8 €/kg**
	FR	Albi	Boussens	150 km	8.0 €/kg	10.2 €/kg	**8.0 €/kg**
	UK	Tongland	Greenock	200 km	8.4 €/kg	6.6 €/kg	**6.6 €/kg**
	DK	Trige	Stade (DE)	390 km	10.0 €/kg	9.4 €/kg	**9.4 €/kg**
	IT-SARD*	NA	NA	NA	NA	NA	**NA**

Table 39: Light industry hydrogen market evaluation based on cost and price approaches in the selected regions (Hinicio)

Table 39 summarise the cost and price-based approaches value stream estimation in the selected regions. It appears that **Denmark and France are high potential regions for Power-to-Hydrogen** for light industry, largely due to distance from any filling centre and the low competitive environment and high price of trucked in hydrogen. Germany and United Kingdom generate lower value for Power-to-Hydrogen mainly due to the high industrial density and the resulting strong competitive environment. Sardinia is excluded from light industry application as it has a limited or inexistent light industry hydrogen market.

5.2. H_2 for mobility application

The hydrogen mobility application is an emerging market that will require additional hydrogen production infrastructure. The value stream generated from this application depends on the end-user acceptable price. The study assumes the acceptable price will enable the mobility end user not to pay more than the current fuel price on a cost / km basis.

Based on the end-user acceptance price, the costs and profit margin of the HRS operator are deducted to calculate the price at which the hydrogen needs to be supplied to the HRS. Calculation of HRS acceptable price of hydrogen supply is further explained in the Annex 4.3.1. Tax on hydrogen fuel is assumed absent in the short term to promote low and zero emission mobility.

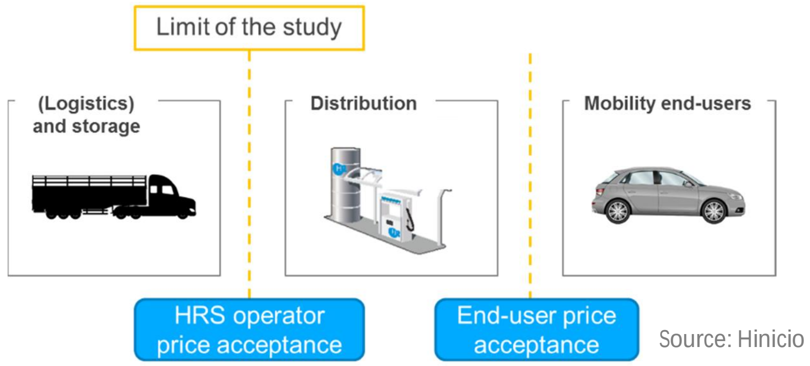


Figure 33: Relation between end-user and HRS operator price acceptance

Table 40 summarises the HRS operator price acceptance for each mobility application based on reference boundary conditions such as:

- Typical fleet consumption (daily, weekly, monthly, annually);
- Operational constraints impacting electrolyser operation and storage;
- Typical requirements (typical consumption pattern, typical space constraints, etc.);
- Acceptable hydrogen fuel price ranges.

The HRS operator price acceptance usually ranges between 4 - 7 €/kg depending of the mobility application.

The hydrogen price for mobility applications has been covered intensively by other studies such as the FCHJU's Electrolyser study [30], Power-trains for Europe study [80] and the Fuel cell Electric buses study [107].

Example of mobility applications	Forklift	Urban bus	Captive fleet of FCEV range-extenders
Users	B2B: Private operator (e.g. distribution centre)	B2B: Bus operator	B2B: Private operator (e.g. distribution or postal company, car-sharing schemes)
Hydrogen supply	Trailer delivery, semi-centralized or on-site production	On-site production	Trailer delivery, semi-centralized or on-site production
Utilization rate	2 to 3 shifts per day 330 days per year	250 km/day/bus 307 day per year	100 km/day/vehicle 330 days per year
Typical fleet size (considered in this study)	50 forklifts: 50 kg/day 200 forklifts: 200 kg/day	10 buses: 250 kg/day 20 buses: 500 kg/day	50 FCEV range-ext.: 50 kg/day 100 FCEV range-ext.: 100 kg/day
H2 consumption (average)	33 tons per year (200 forklifts)	154 tons per year (200 buses)	16,5 tons per year (50 FCEV)
Delivery pressure	350 bar	350 bar	350 bar
On-site production – Storage backup	Dedicated 24h autonomy of storage (120 kg H_2)	Dedicated 24h autonomy of storage (500 kg H_2)	Dedicated 24h autonomy of storage (50 kg H_2)
Refuelling schedule	Whole day depending of needs 2 to 3 refuelling per day (1 per shift) 330 days per year	1 refuelling per day at night 307 day per year	Whole day depending of needs 330 days per year
Acceptable hydrogen fuel price to end-users (at the pump)	11-12 €/kg	6-7 €/kg	9-10 €/kg
Acceptable hydrogen fuel price delivered to station (selling price for the Power-to-Hydrogen system operator)	**6 – 7 €/kg H_2**	**4 – 5 €/kg H_2** [9]	**5 – 7 €/kg H_2** [10]

Table 40: Example of mobility business cases

[9] Calculated based on H_2 station CAPEX: 1,4 M€; OPEX: 4% of CAPEX; Power consumption: 3 kWh/kg; Electricity price: 100€/MWh; Lifetime: 10 years
[10] Calculated based on H_2 station CAPEX: 300 k€; OPEX: 4% of CAPEX; Power consumption: 3 kWh/kg; Electricity price: 100€/MWh; Lifetime: 10 years

5.3. H_2 for injection into gas grid

Gas grid injection is foreseen as a promising pathway for large scale seasonal storage of excess renewable electricity. Generally, the rationale behind hydrogen injection into the gas grid, at the systemic level, relies on the idea that it does not require any new investment in infrastructure as the existing natural gas grid can be used both as a storage and as a transport medium. It can therefore be applied to store and transport large quantities of excess renewables, which sometimes occur on a seasonal basis, over very long distances, without having to build new connectors. The most commonly used example is Germany, where large quantities of excess wind in the North cannot currently be transported towards the consumption centres of the South because of congested lines and must be curtailed as a result. Battery storage cannot really be the solution given the scale of the problem in size and in time, and the construction of new lines is extremely challenging in terms of public acceptance. Gas grid injection is often presented as a potential solution to that problems.

This argument is probably true from a theoretical standpoint but should however be moderated in some way because of the following practical and economic limitations (under current market and regulatory conditions). First, the maximum volume of hydrogen that can be directly injected into the natural gas grid is currently limited by regulation. Technical limits also exist as several components or end-users of the natural gas system (CCGT plants, etc.) have a low tolerance or no tolerance at all in terms of hydrogen content. That is not a show blocker and can often be solved but adaptation costs should be considered. The production of synthetic natural gas via methanation is a way to avoid such limitations in terms of injection volume. However, it adds significant costs components to the equation, making it even more challenging economically (which is the reason, this study on short-term business cases will only focus on direct injection).

In fact, the economic equation is currently quite challenging for power-to-gas. Without any kind of support, the hydrogen injected is competing with the natural gas that is flowing through the pipeline. No business case can be found in the short-to-mid-term under those conditions and specific instruments must be introduced. This will be accurately quantitated in section 6.

Two instruments can be envisaged:

- A **feed-in tariff** (or injection tariff) for green hydrogen, similar in principle to what already exists in several countries for biomethane. No such framework currently exists for green and/or low carbon hydrogen in Europe.
- A **carbon price** that would apply (among others) on natural gas that would mechanically reduce the cost gap between the two gases.

In the short-to-midterm, the creation of green hydrogen injection tariffs, largely inspired by the existing framework on biomethane (where it exists), seems to be the most probable option. However, renewable or low carbon origin of hydrogen would need to be recognised prior to the creation of the support scheme. CertifHy project managed to create a widely acceptable definition for green hydrogen and design a robust Guarantees of Origin scheme. [14]

This section will present the local conditions impacting feasibility (regulation, in particular in regards to maximum injection limit) and potential income (such as existing feed-in tariffs for bio-methane) in the different countries.

In some countries, strict specifications were applied due to the use of gas for specific applications where the H_2 content is strongly limited (e.g. 0.1%vol in the UK).

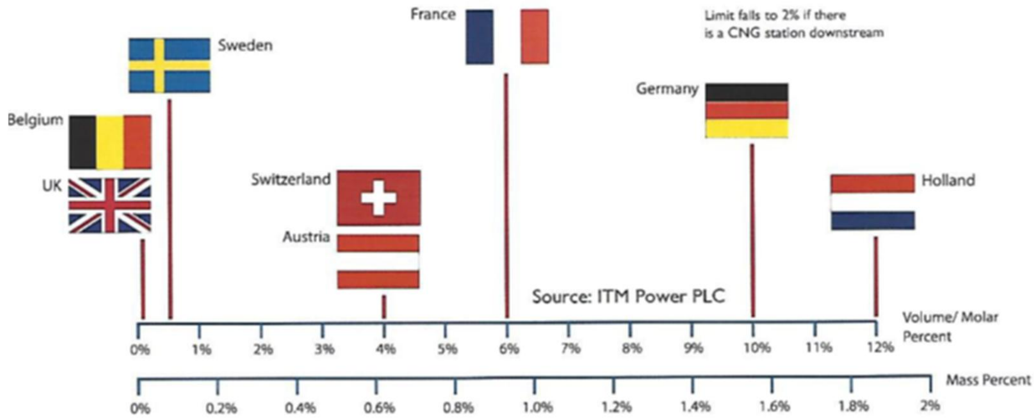


Figure 34: Hydrogen injection limit in national gas networks [71]

The European Committee for Standardisation (CEN), in cooperation with the European Association for the Streamlining of Energy Exchange (EASEE-gas), is working toward a harmonised standard for gas quality in the EU. Due to the type II vessels for CNG vehicles, 2%vol hydrogen tolerance in the gas mix is the current basis for discussion.

Demonstration projects are underway to identify the technical and economic impact of hydrogen injection in the gas grid. Most current demonstration projects follow national biomethane injection guidelines.

Current biomethane injection is supported directly or indirectly by tariff schemes. Table 41 summarizes the situation in the four countries under assessment (Sardinia does not have any natural gas network) in regards to hydrogen limit in gas mix and existing biomethane injection tariff. All supporting details are presented in the following sub-sections

	Germany	**France**	**UK**	**Denmark**
Hydrogen limit	9.9%vol <2%vol in some conditions	6%vol	0.1%vol	Not defined
Biomethane injection tariff	32.3 €/MWh	45-140€/MWh (2015)	50.5 €/MWh (2016)	67.5 €/MWh
Hydrogen equivalence	**1.3 €/kg**	**1.8-5.5 €/kg**	**2.0 €/kg**	**2.6 €/kg**

Table 41: Summary of regional hydrogen injection opportunities

It is assumed that tariffs will decrease as a carbon price/tax emerges. A carbon price would increase the European natural gas wholesale price, allowing higher trading value for low carbon gas such as biomethane and green hydrogen. Table 42 shows the European wholesale market price of natural gas. GHG emission factor of natural gas based on combustion is equal to 0.18 tons CO_2/MWh_{HHV}.[11] Based on NG and carbon price projection in 2025 (see section 3.1.1), the following table shows the impact of carbon price on natural gas wholesale market price in the selected regions.

A carbon price of 100 €/tCO_2 would increase by 129% the natural gas wholesale price. This is equivalent of a hydrogen injection value of 1.8 €/kg.

Natural gas	Emission factor [t CO_2 eq./MWh]	Wholesale price (2025)	DE / FR / DK (2025)	UK (2025)	Impact of CO_2 price at 100€/t
1 MWh_{HHV}	0.18	28 €/MWh	+5.1 €/MWh (15%)	+7.7 €/MWh (22%)	+18€ (39%)
Hydrogen equivalence		**1.1 €/kg H_2**	**1.3 €/kg H_2**	**1.4 €/kg H_2**	**1.8 €/kg H_2**

Table 42: Impact of carbon price on natural gas wholesale price and hydrogen injection value

5.4. H_2 to deliver electrical grid services

For this section, only continental locations are considered.[12] The Sardinian case will be studied separately in section 5.5 to include considerations on the re-electrification value stream. A full techno-economic assessment of all competing technologies for these services (e.g. stationary batteries, V2G…) is outside the scope of this study.

To evaluate the value a water electrolyser could potentially capture from grid services, three types of grid services are considered:

- Balancing & congestion management (transmission grid – national level)
- Frequency containment reserves for stability (transmission grid – includes enhanced frequency reserve service type)
- Distribution grid services: as such services are not as mature as services at the transmission level, value for distribution grid will be assessed from a systemic standpoint estimating distribution grid CAPEX and OPEX that can be avoided thanks to an electrolyser flexibility (load shifting activation).

Various configurations combining 3 dimensions have been examined:

- **Locations:** 1 location (identified in section 3) per country
- **Time horizon**: 2017 / 2025
- For the balancing service, 3 levels of **remuneration of** the electrolyser for its **flexibility activation**: 1, 15 & 40€/MWh

[11] ADEME Base Carbone database

[12] It is important to note that we do take into consideration the power flows between continental areas and islands.

For each type of grid service and each configuration, an annual potential revenue per MW of installed electrolyser capacity (€/MW/yr) is quantified.

5.4.1. Key results

The assessment of the potential value that a water electrolyser could capture from delivering grid services, allowed to derive the following conclusions:

Table 43 emphasises the benefits that can be expected for a 1 MW electrolyser in each country for each of the value stream detailed in section 5.4.2. At this stage it is important to note that values presented in this section do not take into account potential conflicts of usages with primary value streams (industrial& mobility).

Grid Service	Expected benefits for a 1MW PEM electrolyser (k€ / MW / year)							
	France		Germany		Great Britain		Denmark	
	2017	2025	2017	2025	2017	2025	2017	2025
Balancing (15€/MWh)	10.5	11.2	9.8	10.8	2.1	1.9	3.0	11.3
Frequency	158.5 – 162.8		167.0 – 223.9		70.0 – 123.0		133.3 – 164.8	
Distribution	< 1							

Table 43: Expected benefits from supplying grid services with a 1MW PEM[13] electrolyser.

Based on Table 43, revenues from supplying frequency services appear to be the highest (with one to two orders of magnitude difference) and the best location, for both 2017 and 2025 appear to be North Germany. Therefore the technology that should be chosen is the one allowing to supply frequency services. This requires fast reaction times (full activation within <30s), i.e. the PEM technology.

It is important to note that frequency service revenues are historical ones. It should not be taken for granted that future auctions for load-frequency grid services will clear at the same price level, because these services represent a rather small market. The highest-value service, Frequency Containment, typically amounts to ~1% of peak demand, e.g. 800 MW in Germany. New entry-players with a volume of 5-10 MW may therefore easily change the price levels of an auction.

For balancing, activation frequency decreases with increasing flexibility price, with revenues peaking in a flexibility price range around 15€/MWh, depending on the country.

However, a major step forward to facilitate the participation of electrolysers (PEM or Alkaline) in Frequency Containment Reserves (FCR, the most valuable service) would be an asymmetrical product definition, i.e. allowing to offer unequal upward and downward capacity (MW). This applies to all countries with the exception of Denmark. Lower-quality frequency services do instead foresee asymmetrical products.

[13] The PEM electrolyser technology is selected to cope with the variability requirements of the frequency services in terms of time of activation.

In the context of section 6, we will then proceed with an assessment of the economic gap between the potential value of an electrolyser and its cost. It goes without saying that extra cost originating from a variable operation mode (e.g. compressor size, buffer storage size) as well as the compatibility and complementary with other value streams (most importantly with serving an industry or mobility client) will be considered.

5.4.2. Detailed results

5.4.2.1. VALUE TO BE CAPTURED FROM BALANCING SERVICES

5.4.2.1.1. Methodology selected to assess the value to be captured thank to an electrolyser's flexibility

If hydrogen production targets are set for the electrolyser over time periods (for instance, for each week) while maintaining a spare capacity, this could allow an electrolyser to provide load shifting (flexibility) for balancing services. It could thus adapt its consumption to renewable production variation.

Load shifting activation brought by the electrolyser can be either in advance or in delay as illustrated in Figure 35.

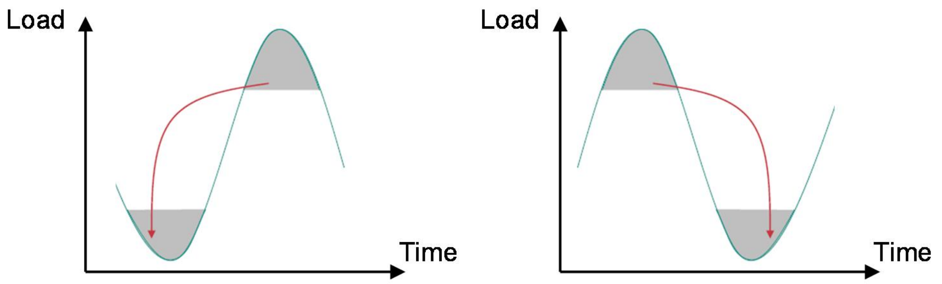


Figure 35: Flexibility principle scheme, in advance (left) and in delay (right)

Important parameters to describe load shifting service are the following:

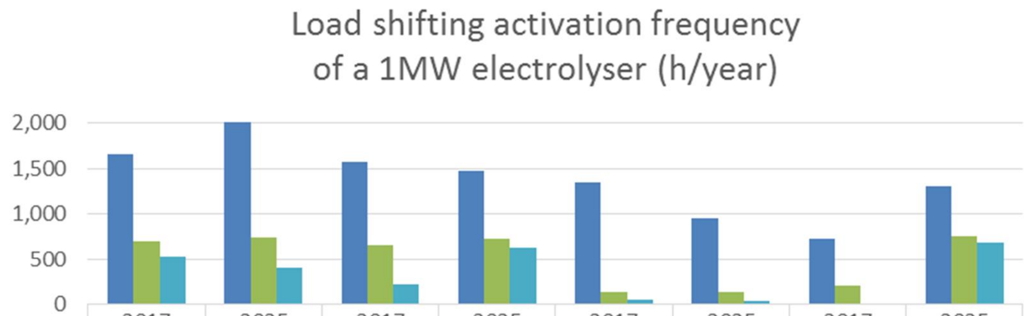
- Maximum time shift allowed in hours (to determine how long the electrolyser can decrease or increase its power consumption without disturbing its H_2 production plan).
- The times length allowed to recover the consumption shifted, which depends on the production target. For the present simulations, we assume that the electrolyser can shift its load within a time window of [+2; -2] hours.
- The rebound rate, i.e. the ratio of the energies absorbed and reinjected by the flexible asset. As only load shifting is considered here for electrolysers, this rebound rate is 100%.

This analysis is performed through simulations of an hourly national dispatch of the generation units taking into account grid constraints, simulating the presence of electrolysers at the desired places. SCANNER is used to run those simulations.

5.4.2.1.2. Results

The potential value that can be obtained from balancing services with an electrolyser is here assessed with an electrolyser of 1 MW (be it PEM or Alkaline type) able to shift its load on demand by maximum 2 hours, in advance as in delay.

Figure 36 presents the expected activation frequency of this electrolyser over the two considered periods (complete year 2017 or 2025, with a 1h time step) for different activation prices[14] (1 / 15 / 40 €/MWh) when placed, for each country, at the location presented in section 3.2. Naturally, the higher the activation price, the lower the activation frequency. This is more or less sensitive in the different countries due to the generation price of the neighbouring units: the more the flexibility brought by the electrolyser allows preventing running more expensive units in its vicinity to supply the load (and hence cope with the renewables variability), the more attractive.



	2017 France	2025 France	2017 Germany	2025 Germany	2017 Great Britain	2025 Great Britain	2017 Denmark	2025 Denmark
1 €/MWh	1,657	2,240	1,570	1,474	1,348	954	733	1,301
15 €/MWh	700	744	655	722	139	129	200	752
40 €/MWh	526	407	222	623	45	38	0	686

Figure 36: Load shifting frequency activation for balancing services with a 1 MW electrolyser with 3 activation costs

Figure 37 emphasizes the revenues that can be expected from those flexibility activations, in k€ over the overall year. From the three analysed activation prices, the highest gains appear to be with the highest activation price:

- In 2017: in France, then Germany;
- In 2025: in Denmark, then Germany and France.

Looking at the same results per country:

- France and Germany look the most attractive when considering for both time horizons.
- Great Britain presents much lower revenues for those two considered years.

[14] Activation price refers here to the compensation price that can be delivered to the electrolyser operator for its flexibility.

- Denmark appears attractive in 2025 but not in 2017. This is due to the difference of number with curtailment between 2017 and 2025 presented in section 3.2.2.2 (400 hours in 2017 compared with 2000 hours in 2025).

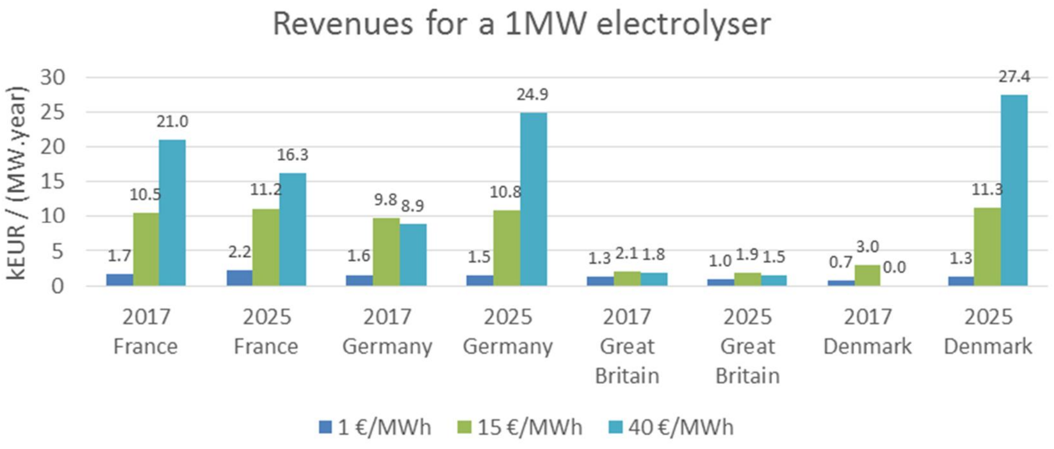


Figure 37: Balancing services expected annual revenues for a 1 MW electrolyser with 3 activation costs

Those numbers should be handled with care if one wants to scale up the number of flexibility sources in the same grid zone, for instance because competition is increasing in the concerned area. Indeed, as the flexibility needs are not necessarily sufficient to require all units to shift their loads at the same time, the marginal revenues that can be expected from grid services decrease with the number of electrolysers. As an example, Figure 38 shows, with an increasing number of electrolysers offering flexibility – this decrease of full-activation of the electrolyser (and hence the decrease of marginal revenue with competition) for Denmark in 2017, with an activation price of 15€/MWh.

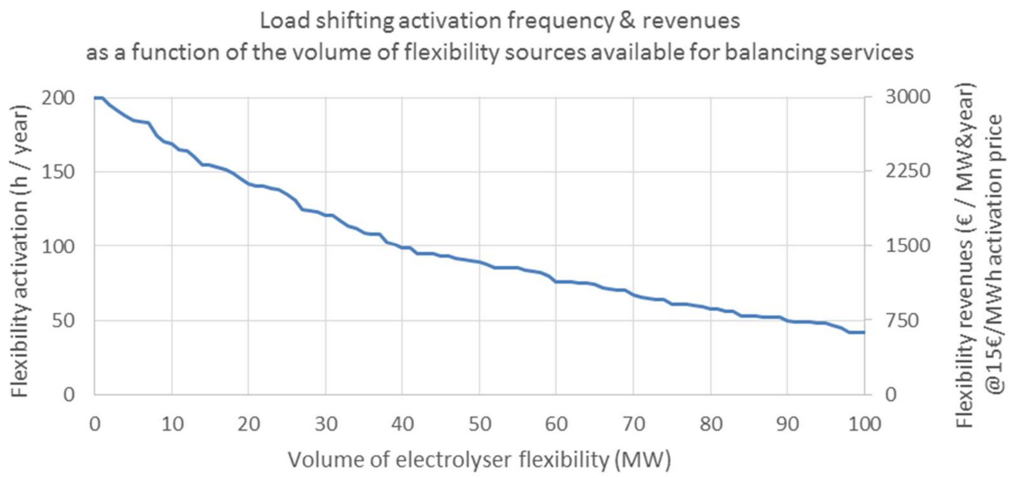


Figure 38: Load shifting activation frequency and revenues for an increasing volume of electrolysers' flexibility until 100 MW, for Denmark 2017 with a 15 €/MWh activation price.

5.4.2.2. VALUE TO BE CAPTURED FOR LOAD FREQUENCY CONTROL

Ancillary services for Load-Frequency Control greatly differ across EU member states, both in terms of regulation and remuneration. The present analysis focuses on Frequency Containment Reserve (FCR) and Frequency Restoration Reserve (FRR) as defined by the EU regulatory body ACER. These services were previously known as primary and secondary reserves in most countries. The assessment of the regulatory framework is presented in details in Annex 4.5 for each of the selected locations, based on [95] and [39]. Other complementary national sources are used when necessary. Table 44 presents a summary of these national regulations.

	DE		FR		DK-West	GB		SARD	
	FCR	FRR	FCR	FRR	Primary Regulation (FCR)	FFR (FCR)	EFR (FRR)	FCR	FRR
Can be provided by loads	✓	✓	✓	✓	✓	✓	✓	✗	✗
Symmetric / Asymmetric Reserve	Sym.	Asym.	Sym.	Sym.	Asym.	Sym.	Sym.		
Minimum bid size (MW)	1 MW	5 MW	< 1 MW	< 1 MW	1 MW	10 MW	1 MW		
Maximum time for activation	30 s	5 min	30 s	15 min	30 s	30 s	1 s		
Suitable for PEM	✓	✓	✓	✓	✓	✓	✓		
Suitable for ALK	✗	✓	✗	✓	✗	✗	✗		
Capacity price (k€/MW /y)	167.0	4.1 - 19.0	160.8	160.8	12.8 - 152.0	58.0 - 64.0	70.0-123.0		
Activation price (€/MWh)	0	1103-1217	26.48	26.48	0	0	0		

Table 44: Value to be captured for load frequency control

In Sardinia, the national regulation currently foresees no possibility for flexible loads to participate in frequency reserves.

For the other countries, the participation into the Frequency Containment type of Reserve (FCR) is the one leading to the highest capacity remuneration (i.e. remuneration for participating in the reserve, compared with the activation price remunerating only on request). For units in Germany, France and Denmark West, one can obtain annual revenues above k€150/MW by offering these services to the respective grid operator. Given the high requirements in terms of availability and reactivity, it is however uncommon to offer a unit's full nameplate capacity to the grid operator but rather a fraction of it.

Great Britain's new Enhanced Frequency Response (EFR) also offers a fairly high annual remuneration. However, technical requirements for EFT are higher than those for FCR in continental Europe, i.e. the activation time is just one second instead of 30 seconds.

PEM electrolysers can offer both FCR and FRR, while Alkaline eletrolysers are unlikely to comply with the activation time of less than 30s required for FCR.

5.4.2.3. VALUE TO BE CAPTURED FROM DISTRIBUTION GRID SERVICES

Installing an electrolyser in the distribution grid brings some flexibility to this grid by allowing turning on or off the electrolyser while it is normally (not) used. This flexibility can be of interest to delay investments of the distribution grid and earn money on the long term, leading to a negotiable remuneration for the electrolyser flexibility.

To assess those earnings, the Smart Sizing tool developed by Tractebel is used to model two types of typical distribution networks, corresponding to those that can be identified in the subnational locations identified in section 3.2: a rural one for Denmark and Great Britain, and a semi-urban one for France, Germany and Sardinia.

Results of the handled simulations are provided in Annex 4.6. The key results indicate that the earnings linked to the flexibility of the electrolyser are pretty low because the networks need to be reinforced to install the electrolyser while the added value of its flexibility lies in postponing reinforcement investments. Computations of the value to be captured in those localities lead to a **potential below 1 k€/MW /y** (annualised over the lifetime of the electrolyser)[15].

5.5. H_2 for re-electrification in islands

In the specific case of Sardinia, the potential revenue streams of electricity storage through hydrogen (i.e. electrolysis plus re-electrification) are also estimated. As noted earlier, a full techno-economic assessment of all competing technologies (e.g. stationary batteries, V2G…) is outside of the scope of this study.

The same configurations as in section 5.4 are considered:

- **Technology for re-electrification:** 1 technology of fuel cell / 1 technology of gas turbine
- **Time horizon**: 2017 / 2025
- For the balancing service, 3 levels of **remuneration of** the electrolyser for its **flexibility activation**: 1, 15 & 40€/MWh

2 potential revenues are assessed:

- Balancing & congestion management, with and without the ability to re-electrify hydrogen
- Load frequency control

Given the limited size of an island grid, we perform a combined analysis at transmission and distribution level. The above-mentioned services therefore refer to both transmission and distribution.

5.5.1. Key results

Through the assessment of the potential value that hydrogen storage could capture from delivering grid services on islands, following conclusions can be delivered.

[15] Another study [28] emphasizes flexibility revenues in distribution of up to 30-90k€/MW/y, though without considering the potential reinforcements for the electrolyser to install.

For Sardinia, the recommended location (see section 3.2.2) is the closest position near an existing refinery, because no transmission grid constraint was identified for the whole island. In general, Sardinia is not a typical island, given its good level of interconnection to the Italian mainland (see section 5.5.3).

Table 45 compares the revenues that can be expected from balancing grid services, both in the cases with and without re-electrification of hydrogen.

Grid Service	Expected benefits for a 1MW electrolyser in Sardinia (k€ / MW / year)			
	With re-elec.		Without re-elec.	
	2017	2025	2017	2025
Balancing	1.8	16.6	6.4	6.0
Frequency	-			
Distribution	< 1			

Table 45: Expected benefits from supplying grid services with a 1MW electrolyser in Sardinia. The case without re-electrification considers an activation price of 15€/MWh for the balancing services.

The regulatory framework does not foresee availability compensations for frequency control in Sardinia. From this table, re-electrification is interesting in 2025 but not yet in 2017.

The best electrolyser technology to consider is the one achieving balancing services with the highest conversion efficiency, i.e. alkaline.

From Table 45, the grid service presenting the biggest opportunity for an electrolyser is the balancing service, without re-electrification in 2017 but with the latter in 2025. For islands that have smaller power systems or that have less interconnections than Sardinia, revenues from re-electrification can be more important as peak units are more frequently solicited along the year. However, this is generally not sufficient to make profitable the use of hydrogen as storage system for autonomous systems based on decentralised generation.

As revenues from frequency services are considered relatively low compared to other grid services, it is not necessary to select the technology with the fastest reaction times but the one leading to the highest process efficiency, i.e. the alkaline electrolyser.

The Italian system currently lacks a remuneration framework for availability in grid services. It is purely based on activation payments. This differs from most other EU member states. In line with the recommendation for other countries, another important aspect would be to facilitate the participation of flexible load such as electrolysers in frequency services. This requires organising a separate procurement for upward and downward regulation of these services.

5.5.2. Detailed results

We only present the results for the balancing services (with and without re-electrification) here, since there is no capacity payment for frequency containment in Sardinia. Details on the current regulation for frequency reserve participation are presented in Annex 4.5. For distribution flexibility services, the results presented in section 5.4.2.3 are valid for Sardinia as well. Detailed computations can be found in Annex 4.6.

5.5.2.1. VALUE TO BE CAPTURED FROM BALANCING SERVICES

The value that can be captured from balancing services in Sardinia is assessed here for an electrolyser combined with a fuel cell for re-electrification in Sardinia considering hydrogen as an electricity storage application.

Figure 39 shows the costs, revenues and benefits that can be obtained for this storage facility for Sardinia in 2017 and 2025. The difference of benefits between the two scenarios is due to the number of operating hours of the electrolyser over the year: 90 hours in 2017 versus 742 hours in 2025. This low number of operating hours is due to the processes efficiencies that induce important losses of energy (only 22% of the energy used to produce hydrogen is delivered back into electricity[16]) while the price variation is limited over the year as indicated in the price duration curves presented in Figure 40.

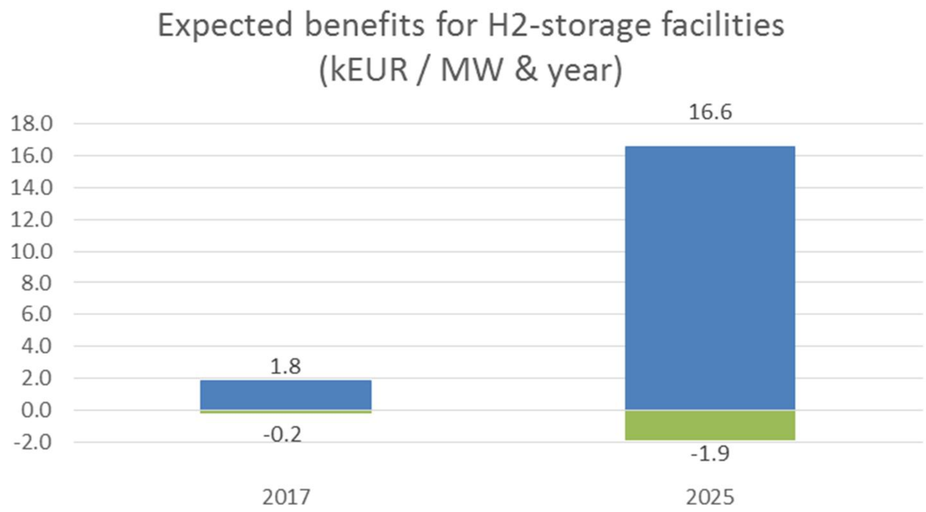
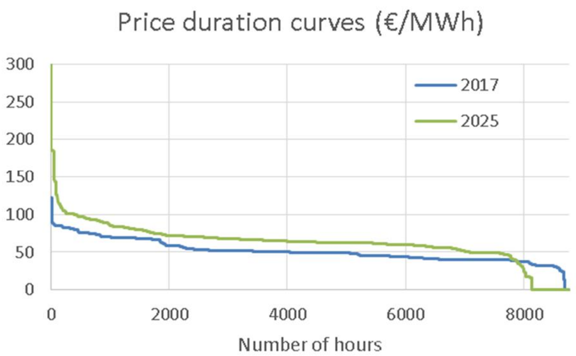


Figure 39: Annual expected benefits from an H2-storage facility of 1 MW in Sardinia.
The indicated top values are the benefits related to the combination of the electrolysis costs (negative green bars) and the fuel cell revenues (cumulated blue and green bars).



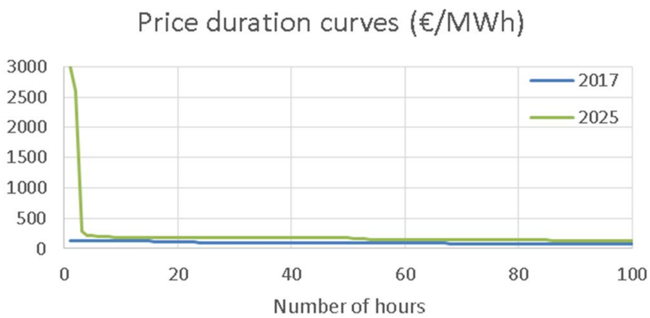


Figure 40: Price duration curves for Sardinia 2017 and 2025.
The second chart is a zoom of the first 100 hours.

[16] The efficiencies considered here are 57% for the electrolyser and 38% for the fuel cell. They correspond to mid-life operation of facilities with 63% and 42% efficiencies, respectively; assuming a linear decrease in efficiency of both processes from 100% to 80% at their end of life.

To compare those revenues with the ones that can be obtained without re-electrification for the same case in Sardinia, Figure 41 emphasises that the potential savings from supplying balancing services with flexibility are of about 6 k€/(MW.year) for different activation prices. This indicates that the re-electrification of hydrogen is only attractive in 2025.

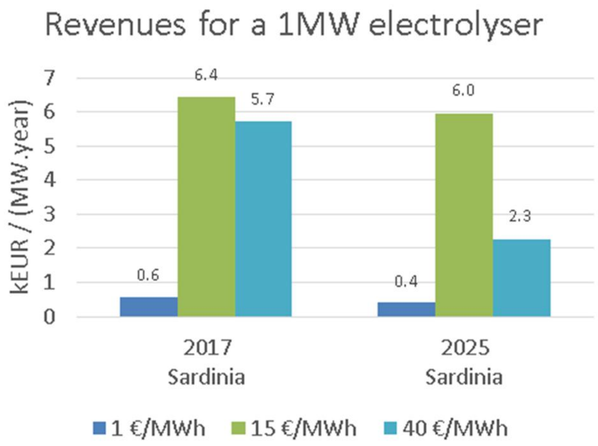


Figure 41: Balancing services expected annual revenues for a 1 MW electrolyser in Sardinia, for 3 activation costs

5.5.3. Potential applicability of results to other islands

It has to be noted that Sardinia is not a typical island, given its large area and its good interconnection to the Italian mainland. This has two main consequences: First, load and intermittent generation can balance over larger areas, resulting into flatter profiles and hence a lower need for electricity storage. Second, access to the Italian mainland implies access to electricity generation from large, centralized power stations. Their variable costs are lower than the cost of diesel generators that supply electricity in isolated systems.

The results shown in the previous sections can therefore not be applied to smaller non-interconnected islands or networks.

In isolated, smaller systems, the competitive threshold would be a diesel generator, with variable costs of up to €200/MWh. Still, this does not automatically imply that hydrogen-based electricity storage is cost-competitive to conventional solutions. The seasonality of solar PV is still very strong in latitudes of islands of the Mediterranean Sea. As a result, 100% renewable electricity system solely based on solar and hydrogen would be more expensive than €200/MWh.

Hydrogen can play a role in hybrid systems (diesel, solar, hydrogen) or in overseas islands that belong to European countries and where there is less seasonality of solar. In this case, the main competitor is batteries.

6. DEFINITION & EVALUATION OF SHORT-TERM BUSINESS CASES

Key findings

In **section 6.1**, three case studies are selected for an in-depth evaluation, each based on a different primary value stream supplied by an electrolyser in the MW range and focusing on another country to consider variations both in terms of geography but also in terms of political traction for hydrogen. The three cases are:

- **Semi-centralised production for mobility applications** is studied in Albi (**France**);
- **Cooking oil industry case** is studied in Trige (**Denmark**);
- **Oil refinery case** is studied in Herrenwyk (**Germany**).

The three case studies are assessed in depth in **section 6.2.** It appears that profitable business cases can be built already today. **Combining primary and secondary revenue streams thus is an effective way of boosting the profitability of a Power-to-Hydrogen system. Secondary value streams can represent up to 78% of this margin, and enable a business case to become profitable in many occasions,** meaning that once an electrolyser has been deployed, the extra cost required to provide electricity grid services is relatively low compared to the potential revenues. Hydrogen injection into gas grid allows the system to operate longer, taking advantage of low electricity price and enabling more revenue generation from electrical grid services.

WACC on CAPEX: 5% Project lifetime: 20 years	SC mobility (Albi, France)		Light industry (Trige, Denmark)		Large industry (Lubeck, Germany)	
	2017	2025	2017	2025	2017	2025
Nominal system size (MW)	2 MW	12 MW	6 MW	6 MW	40 MW	40 MW
CAPEX (k€/MW)	3 660	1 900	1 760	1 400	1 480	960
H_2 cost (€/kgH2)	6.7	4.1	3.5	3.4	2.4	2.3
H_2 price (€/kgH2)	7.0	6.0	5.0	5.0	1.8	2.6
Net margin per kg_{H2} (€/kgH2)	**0.3**	**1.9**	**1.5**	**1.6**	**-0.6**	**0.3**
Share of secondary value streams in total revenues (%)	**11%**	**21%**	**16%**	**15%**	**60%**	**28%**
Share of secondary value streams in net margin (%)	**68%**	**54%**	**36%**	**34%**	**–**	**78%**
Net margin w/o grid services (k€/MW/year)	**39**	**71**	**228**	**248**	**-146**	**30**
Net margin w/ grid services (k€/MW/year)	**159**	**256**	**373**	**393**	**-13**	**195**
Payback time w/o grid services (year)	**11.0**	**9.0**	**4.6**	**3.7**	**–**	**8.4**
Payback time w/ grid services (year)	**8.0**	**4.5**	**3.4**	**2.7**	**–**	**3.5**
Key risk factors	• Taxes & Grid fees • H2 price • Size of fleets • Injection tariff • FCR value		• H2 price • Taxes & Grid fees • FCR value		• Taxes & Grid fees • FCR value • Carbon price	

Source: Hinicio

Table 46: Summary of the three business cases profitability

The **semi-centralised production for mobility business case** shows that an equivalent of hydrogen market size over 2MW is profitable today if the hydrogen price is sold higher than 7€/kg to the HRS operators. Profitability is boosted by the grid services provision which represents up to 68% of total net margin today. Th payback time reaches 8 years in 2017. The business case profitability is improved in 2025 due to scale effect and equipment cost reduction. Hydrogen injection into gas grid application can help mitigate risk of lower than expected mobility demand by ensuring operation costs breakeven.

The **refinery business case** shows a near profitable scenario in 2017. Subside on demonstration project today could prepare large scale electrolysers technology and make the business case profitable. It is expected that Power-to-Hydrogen will be profitable in 2025 following the carbon price increase and the equipment cost reduction. Green hydrogen from Power-to-Hydrogen would be competitive against SMR based production. The payback time is 3.5 years.

The **light industry business case** shows the best payback time of all analysed cases, reaching below 4 years. This is largely due to high selling hydrogen price, large demand leading to large system size and lower system costs. Grid services contribution on net margin is limited as the primary application is the most lucrative.

In **section 6.3**, contracts defined between the different stakeholders (electrolyser operator, electricity and gas grid operators, and public authorities) are presented. In particular, electricity contracts are assumed to allow purchasing electricity from the **electricity** market **at the wholesale price, or at a lower price when** purchasing it directly from a **renewable** producer in the vicinity who would see his production **curtailed** otherwise. This is considered together with **(partial) exemptions on grid fees, taxes and levies** defined by the national regulatory authorities. **This is often needed to achieve businesses profitability. Legislative confidence is therefore required to ensure that the existing exemptions will not be removed in the medium-term.**

In **section 6.4**, benefits not yet captured by the national or European regulations are quantified: (i) **green hydrogen promotes green vehicles deployment** despite diesel fleets replacement, reducing the EU transport CO_2 emissions; (ii) achieving **electrolysis process from green electricity** instead of from natural gas (through SMR) can reduce EU industry CO_2 emissions; (iii) **making use of curtailed renewables** can allow reducing the investments in new RES farms to achieve the same decarbonisation targets. Valuation of these benefits leads to **~0.5 €/kgH2 for the two first** (mainly driven by CO_2 mitigation costs depending on decarbonisation targets) **and above 1 €/kgH2 for the last one** (though depending strongly on the business case and on the presence of curtailed renewable electricity in the vicinity).

In **section 6.5**, key factors determining the business case profitability are quantified, being: the **system size** (influencing project CAPEX and equipment OPEX, must fit the primary application), the **total electricity cost** (impacting directly the hydrogen production final cost) and the **targeted or acceptable hydrogen price for the final consumer**.

In **section 6.6**, extrapolation of the three business cases is made from the three specific locations to EU-28. The assessed replication potential emphasizes a **cumulated 1100 MW electrolysis potential by 2025 in the five treated countries**, **and** a total addressable potential of **2.8 GW** (representing a total market value of €4.2bn) **for EU-28 in 2025.**

6.1. Business cases definition

6.1.1. Overview of potential primary markets & associated business cases

Based on results from previous sections, the business cases are built by combining primary and secondary value streams on selected time frames (2017 and 2025) and selected locations where grid constraints allow a broad access to lower electricity cost for the electrolyser.

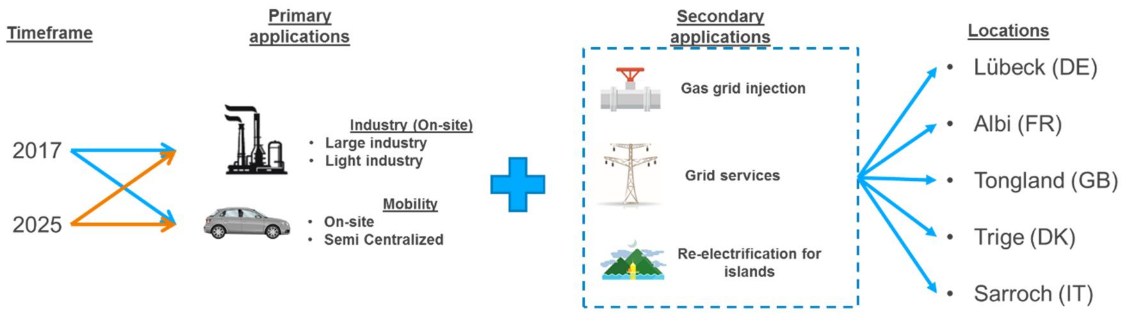


Figure 42: Business cases combinations

Mobility applications can be supplied through both on-site production or through delivery from a near-by production unit, "semi-centralised" production designating the configuration where a local production unit is used to supply a cluster of stations by truck delivery on a regional level with a maximum of 50 km radius. As presented in section 5, there are many hydrogen mobility end-users (captive fleets, buses, forklifts…) that may have different hydrogen price objectives.

Light industry applications can vary widely in terms of gas supply chain, industrial customer requirements and the location environment, as presented in section 5.1.4,. Light industry end-users could be oil and fat, flat glass, electronics and metallurgy. This study focuses only on applications where the consumption is high enough to justify on-site production already today.

Large industry applications are processes consuming a large amount of hydrogen, such as refineries, and possibly ammonia plants, steel mills in the future. They can only be supplied through on-site production or via a hydrogen pipeline. Carbon pricing could significantly increase the cost of hydrogen produced by steam methane reforming (SMR), increasing the competitiveness of hydrogen produced by electrolysis from renewable electricity. However, current regulations on carbon emissions (EU ETS or carbon tax) are not expected to impact the large industry hydrogen supply in the short term (up to 2020). Refineries are potentially an exception as fuels are subject to specific targets on carbon intensity through Fuel Quality Directive and renewable share through Renewable Energy Directive by the EU. **As these targets and the eligible means for achieving them are currently under revision, this could open a new market for green hydrogen after 2020.**

#	Primary applications	Description from WP3	Market size	Production mode	Horizon	Regions	Comments
1	Light industry	General case (250 Nm3/h) Oil and fat Glass Electronics Metallurgy	500 kg/d (2017 / 2025)	On-site	2017 2025	DE, FR GB, DK	• Light industry can have very diverse needs in hydrogen. A general case is needed. • Equivalent of 1 MW is selected. • Sardinia is not considered as there is no merchant market
2	Mobility	Forklifts Buses Captive fleet Carsharing	250 kg/d (2017) 1250 kg/d (2025)	On-site	2017 2025	DE, FR GB, DK, SARD	• On-site mobility requires large volume of consumption and HRS capacity. Therefore, a bus application is selected
4	Large industry	Refinery Steel Ammonia	9900 kg/d (2025)	On-site	2017 2025	DE, FR GB, DK	• 20 MW scale project will most likely be completed by 2020-2025 • Possibility of fuels specific carbon price/tax only after 2020
	Large industry	Refinery, Steel, Ammonia		Semi-centralised	2017 2025	DE, FR GB, DK	• Excluded: volumes too large for off-site production
	Light industry	Oil and fat, Glass, Electronics, Metallurgy		Semi-centralised	2017 2025	DE, FR GB, DK	• Excluded: the semi-centralised model is mainly justified for addressing the needs of multiple users within a relatively small area.
3	Mobility	Forklifts Buses FCEV	1000 kg/d (2017) 2000 kg/d (2025)	Semi-centralized	2017 2025	DE, FR GB, DK, SARD	• FCEV deployment will require an array of HRS which is coherent with the semi-centralized mobility philosophy.

Table 47: Summary of business cases selection

Due to the large number of potential markets and configurations, primary market reference cases were created to compare the business cases between them and are summarised in the Table 48. In total, over 80 scenarios were analysed by combining the primary market, supply chain (on-site vs semi-centralised), time frame (2017/2025) and regions. (see Table 47) A preliminary analysis is performed on the reference cases in order to shortlist only 3 business cases for detailed analysis. The profitability is defined by the net margin expressed in k€ per MW of electrolyser capacity per year (k€/MW/year). This facilitates comparison of business cases addressing different levels of consumption. The result of this preliminary analysis is detailed in section 6.1.4.

#	Primary applications	H_2 consumption	Information from WP3	Comments
1	Light industry – On-site	~250 Nm³/h	Oil and fat : 10-50 Nm³/h / batch Glass: 60 – 150 Nm³/h Electronics: ~500 Nm³/h Metallurgy: 20 - 1000 Nm³/h	General case of 1 MW
2	Mobility – On-site	250 kg/d (2017)	10 buses (2017)	Size consistent with current H_2 bus projects
		1250 kg/d (2025)	50 buses (2025)	
3	Mobility – Semi centralised	1000 kg/d (2017)	5 HRS 200kg/d (2017)	Size consistent with current HRS deployment
		2000 kg/d (2025)	10 HRS 200kg/d (2025)	
4	Large industry – Refinery On-site	9900 kg/d (2025)	General case: 6 t/h additional H_2 needs	6 t/h → 7% of additional H_2 needs

Table 48: Primary applications reference scenarios for preliminary analysis

6.1.2. Electricity cost structure

The electricity cost plays a key role in defining the profitability and viability of a business case. The hourly electricity cost that is used for the business cases analyses is composed of:

- Hourly local electricity price;
- Grid fees;
- Taxes and levies (T&L);
- Guarantee of origins (GoO) certifying the green electricity use.

These parameters, which vary from country to country, are described in the following subsections.

6.1.2.1. HOURLY LOCAL ELECTRICITY PRICE

The local hourly electricity price is derived from the hourly *wholesale* electricity price obtained with PLEXOS in section 3.1.1, by discounting it when curtailment is present locally. The price discount amounts to 60% for the present study, leading to a purchase of electricity at 40% of the hourly wholesale price in that condition. This represents a conservative scenario compared with studies where curtailed electricity is available at a price of zero. Though, regulatory changes are required to access this discounted electricity.

The derivation of the local electricity price duration curve from the country price duration curve is presented in Figure 43 for an illustrative example (Germany 2017). Figure 44 presents the local price duration curves for the five locations identified in section 3.2 (DE: Lübeck – FR: Albi – GB: Tongland – DK: Trige – IT: Sarlux) with a zoom on the usable electricity cost range.

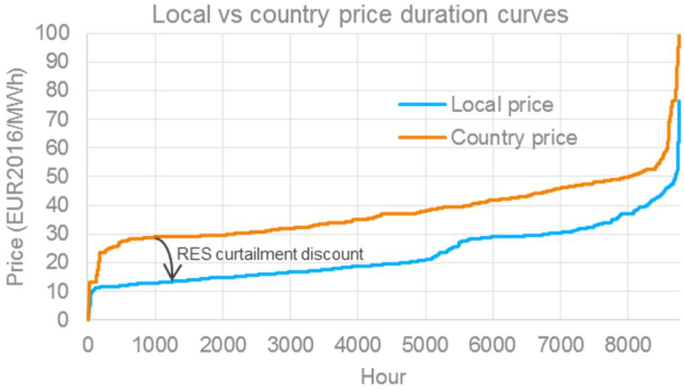


Figure 43: Local electricity price duration curve principle

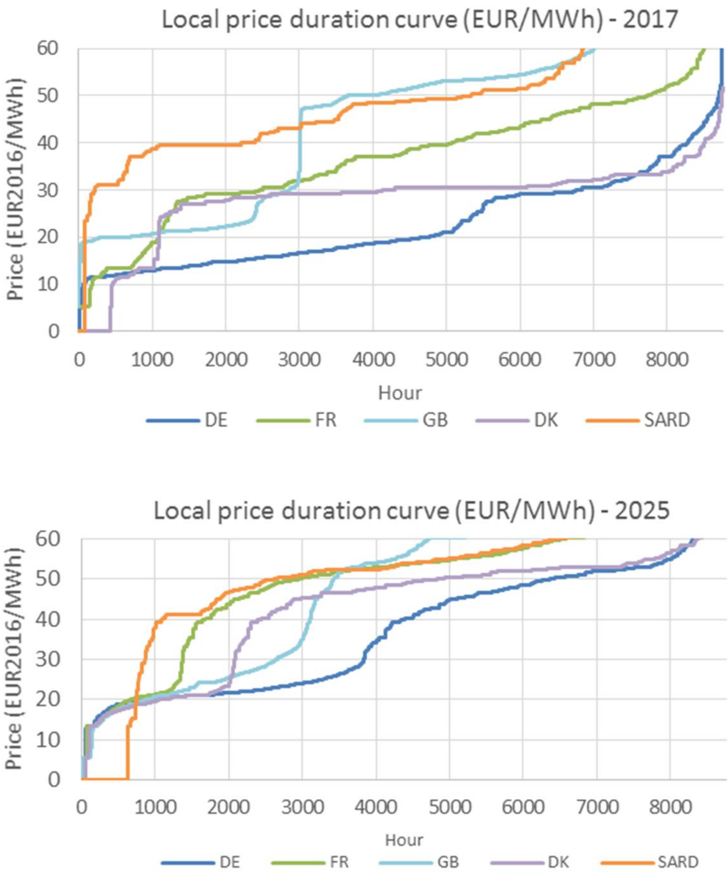


Figure 44: Local price duration curves for the 5 selected locations
(DE: Lübeck – FR: Albi – GB: Tongland – DK: Trige – IT: Sarlux)

As those price duration curves are obtained from local RES curtailment, the geographical perimeters in which they are valid are restricted to the five aforementioned specific locations. Other price duration curves can be obtained similarly where curtailment is present in the country (cf. section 3.2.2.2 Figure 10, 14 and 18, and Annex 2, according to their identified RES curtailment profiles.

6.1.2.2. GRID FEES

Grid fees are costs charged for connecting the electrolyser to the electricity grid. The cost structures that are used vary from country to country, but are generally composed of a fixed tariff for the connection plus additional fees proportional to the electricity consumed. The costs are computed based on latest publications from local TSOs, which references are provided hereunder. Those costs are applied for 2017 and are assumed identical for 2025.

- **Germany**: Tennet's grid tariffs [119];
- **France**: RTE's TURPE tariffs [106];
- **Great Britain:** National Grid's statement of use of system charges [90];
- **Denmark**, Energinet.dk's grid tariffs [35][92];
- **Sardinia**, CEPS average grid connection tariff in Italy (no details available from TSO publications) [12].

These grid fees can vary depending on the size and operation time of the electrolyser, as illustrated in Figure 45 and Figure 46:

- Constant price in time and in volume (for Denmark and Sardinia): the price is defined whatever the hour of consumption in the day, without reduction for electro-intensive consumers.
- Price-dependant on the volume consumed (for France and Germany): a price reduction is applicable for electro-intensive users if they consume more than a fixed amount of electricity (50GWh/y for France, 10GWh/y in Germany [21]).
- Price-dependant on the hour of the day (for France and Great Britain): multi-period tariffs are defined, with varying grid fees depending on the periods of consumption.

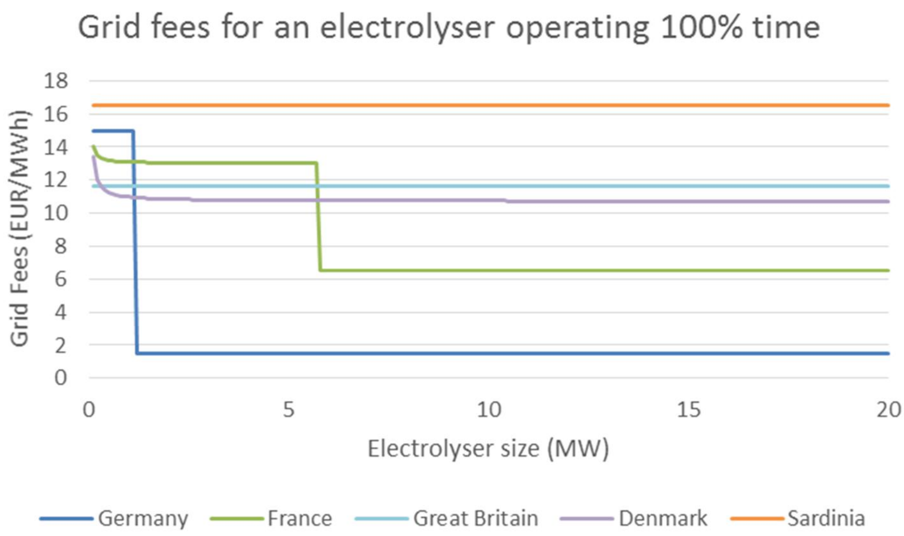


Figure 45: Grid fees variability with electrolyser size, for a 100% operation time

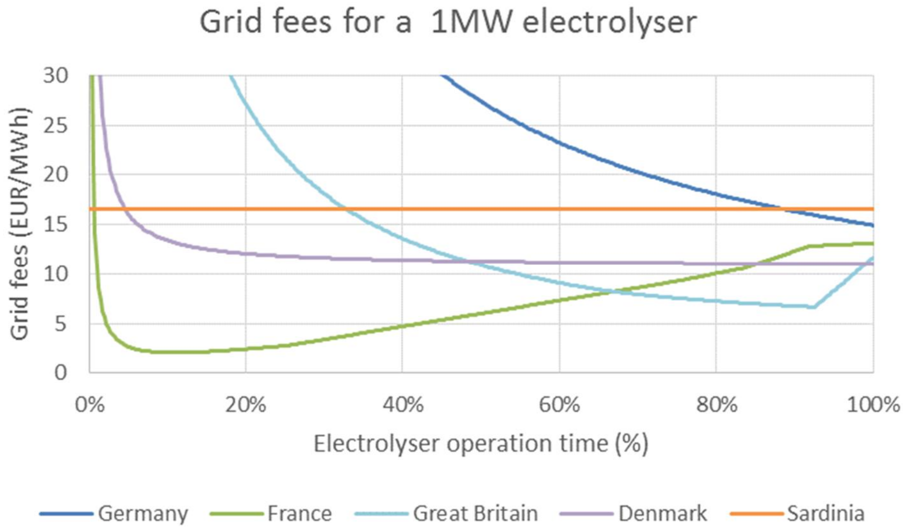


Figure 46: Grid fees variability with operation time, for a 1MW electrolyser

For **Germany**, the current regulatory framework (§118 of EnWG – "Energiewirtschaftsgesetz") actually foresees an **exemption of grid fees for 20 years for new Power-to-Hydrogen** or storage **installations**, provided that they operate in a system-beneficial mode, which the legislator defines as "not consuming during system peak load". [11].

6.1.2.3. TAXES AND LEVIES

In each country, a different taxes and levies scheme is applicable on the operation of green electrolysers. The taxes and levies that are considered in this study are listed in Table 49. For Sardinia, the average tax value for industrial consumers is taken from CEPS as for the grid fees [12].

Country	Tax on electricity use	Levy on electricity use
Germany	Stromsteuer [21]	EEG-Umlage [21]
France	CSPE [20][21]	-
Great Britain	-	Climate Change Levy [58]
Denmark	-	PSO Tariff [22]
Sardinia	Average tax and levies for industrial consumers [12]	

Table 49: Taxes and levies schemes considered on electricity for the 5 selected countries

The Table 50 presents a quantification of those schemes in equivalent €/MWh, with and without the (partial) exemption that electrolysers can benefit from. Those exemptions are detailed hereunder.

- **Germany**: Electrolysers are generally exempted from the tax on electricity use ("Stromsteuer"). For what regards the RES support levies ("EEG-Umlage"), the exemption is a case-by-case decision; being electricity-intensive, the study assumes that electrolysers are subject to the same special treatment as other electricity-intensive industries ("Besondere Ausgleichsregelung"), reducing the level of levies from 68.80 €/MWh to 1.7 €/MWh. [11]
- **France**: Electrolysers generally benefit from an exemption from the tax on electricity use ("Contribution au Service Public de l'Électricité", also called "Taxe Intérieure sur la Consommation Finale d'Électricité" [33]), to a minimum paid of 0.5% of the added value of the company depending on its electro-intensivity [85]. Historical values for electro-intensive consumers present an average tax on electricity use of 0.2 €/MWh in 2015. [13]
- **Great Britain**: Electro-intensive consumers get a 90% exemption from paying the Climate Change Levy if they sign a Climate Change Agreement, which electrolysers operators can do. [21] [42] [58]
- **Denmark**: The RES support levy ("Public Service Obligation" tariff) promotes projects linked to the integration of renewables or smart grids, which is the case for Power-to-Hydrogen electrolysers [37]. A demonstrator of 1MW ("HyBalance" project in Hobro) is exempted from paying the PSO tariff and is actually even financed by this levy scheme [65].

Taxes and levies (€/MWh)	Without exemption		With exemption		Reason for exemption
	Taxes	Levies	Taxes	Levies	
Germany	15.37	68.80	-	1.70	Electro-intensive consumer (levy exemption) in electrolysis sector (tax exemption) [11] [21]
France	22.50	-	~ 0.20 [13]	-	Electro-intensive consumer in electrolysis sector [21][85]
Great Britain	-	6.68	-	0.67	Electro-intensive consumer [58]
Denmark	-	24.00	-	-	Promoting RES integration [37]
Sardinia	10.70		10.70		No exemption identified

Table 50: Taxes and levies on electricity for the 5 selected countries, with and without exemption for a 1MW electrolyser

6.1.2.4. GUARANTEE OF GREEN ORIGIN

Guarantees of origins are 1MWh-certificates proving that 1MWh of electricity has been produced from renewable energy sources. They are valid for a period of 1 year and can be traded among all EU countries (+ Norway & Switzerland) [29].

Buying guarantees of origin from Nordics hydro can be achieved at the price of 0.4 €/MWh [94].

6.1.3. Operating constraints from value stacking

In section 5, the potential revenues of each secondary application were identified independently on the primary applications. The present section aims at identifying the interoperability between the primary and secondary value streams to determine what share of the revenues identified in section 5 can really be extracted, and what benefits they allow.

In particular, the electrolyser commitment to the secondary value streams is not permitted in permanence and is here analysed. Figure 47 emphasizes that operating for a secondary value stream can lead to a de-optimization, in terms of electricity cost (i.e. in hydrogen production cost), of the initial hydrogen production plan supplying the primary application.

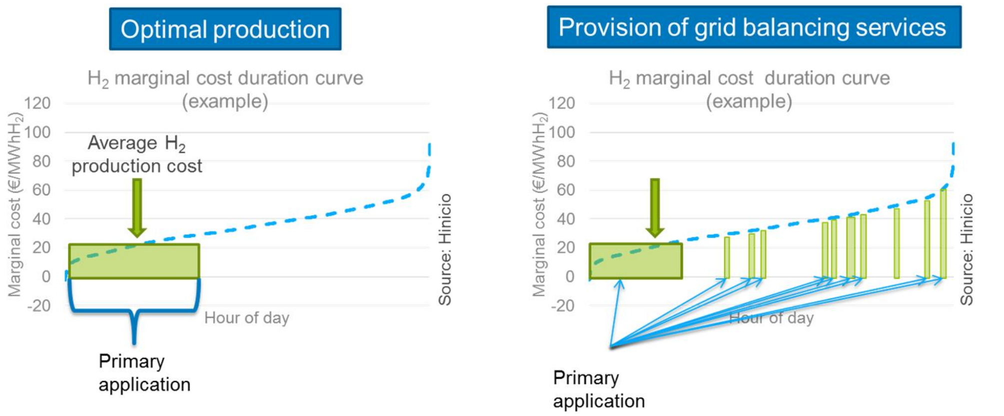


Figure 47: Impact of grid services on the production optimisation based on H_2 marginal production cost

6.1.3.1. DAILY SYSTEM OPERATION

Most H_2 consumers require daily supply. Typically, an electrolyser sized to meet a demand (100%) would operate continuously (24h/day) at full nominal load. There are no operation flexibility or optimisation available as the electrolyser is expected to run continuously.

Oversizing an electrolyser can be beneficial to secure the cheapest daily electricity price. For example, an electrolyser sized to cover twice the H_2 demand (200%) would operate only half day (12 hours). The system can optimise operation only during the 12 cheapest electricity hours. The study uses the daily price duration curves for production optimisation.

On-site H_2 buffer storage is sized on the production shift to ensure continuous supply to the customer.

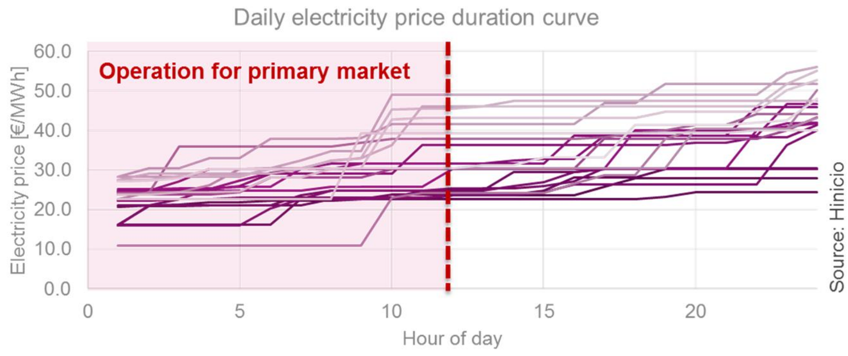


Figure 48: Daily electricity price duration curves

6.1.3.2. GAS GRID INJECTION

Gas grid injection allows to make use of spare, for generating extra revenue from the supply of energy to the gas grid together with the additional provision of grid services during this time.

If the revenue from gas grid injection is high enough, it could even in some cases be economically justified to oversize of the electrolyser with regards to the sole needs of the primary market.

Priority is given to satisfying daily demand from the primary market (e.g. industry or mobility). When there is remaining capacity, the electrolyser can be operate with a profit as long as the marginal cost of operation is lower than the corresponding revenue from gas grid injection. This will be the case when the electricity price is below a certain threshold.

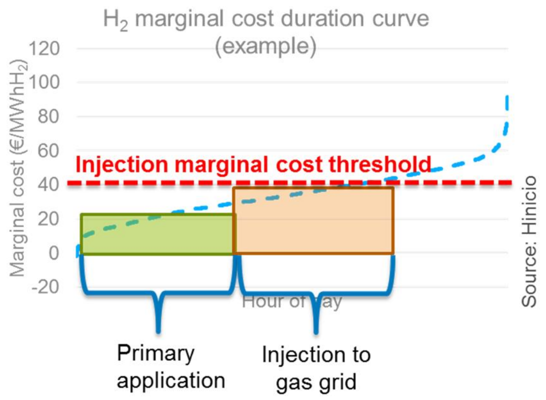


Figure 49: Injection threshold based on H_2 marginal production cost

6.1.3.3. ELECTRICITY GRID SERVICES: FREQUENCY

Based on the regulatory frameworks presented in Annex 4.5 for participation into the frequency containment or restauration reserves (summarised in section 5.4.2.2), the interoperability with the primary application hydrogen supply can be identified.

As requests for frequency regulations do not exceed 15 minutes, it is assumed that the extra/missing consumption for reaching the targeted hourly production can be recovered within the same hour, hence with no difference in electricity cost due to the displacement of the electric consumption.

Depending on the type of reserve participation that is allowed (either symmetric or asymmetric), revenues are computed differently, according to the schemes of principles presented in Figure 50:

- Participation into a symmetric reserve requires the possibility to vary the electrolyser consumption as upwards as downwards at any time. Hence, for ALK electrolysers, which cannot exceed its nominal power ($P_{max} = P_{nom}$), no revenues can be obtained unless the electrolyser is overdimensioned for that purpose.
- Participation into an asymmetric reserve requires the possibility to vary the electrolyser consumption either upwards or downwards. Depending on the electrolyser state (consuming electricity or not), revenues can thus vary but are non-zero values whatever the electrolyser is on or off.

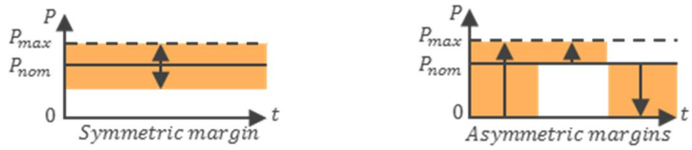


Figure 50: Symmetric and asymmetric frequency reserve participation principle schemes

As the participation to the frequency containment reserve and to the frequency restoration reserve cannot be contracted at the same time, the one selected in this study is the one maximising the profit margin that can be obtained. In most of the cases studied, this corresponds to considering the frequency containment reserve.

Revenues for frequency reserve participation vary thus with the electrolyser size, technology and operation time, but keep in the same ranges as those presented in section 5.4 (Table 43).

6.1.3.4. ELECTRICITY GRID SERVICES BALANCING

Compared with the revenues expected in section 5.4.2.1 for providing exclusively balancing service, interoperability with the supply of hydrogen for primary applications reduces the expectable potential.

The schematic principle of providing balancing services while focusing first on hydrogen supply is presented in Figure 51. It involves the following constraints:

- The electrolyser may be turned off for delaying its load consumption (to supply grid services) only if it was preliminarily switched on.
- The daily hydrogen supply target must be achieved whenever the electrolyser is providing grid services or not. Hence, the delayed consumption must be recovered within the day, at a higher electricity cost.
- The grid service is provided only if it induces benefits: the revenue linked to the activation of the load flexibility, called activation price, must at least cover the difference in price linked with the purchase of electricity at a higher cost.

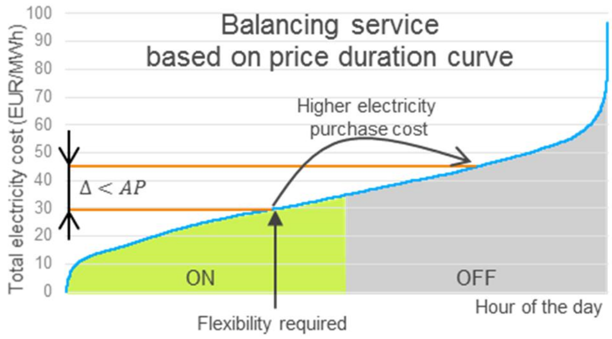


Figure 51: Balancing services principle scheme for service supply in addition to primary hydrogen supply

The Figure 52 emphasizes the expectable revenues for a 1MW electrolyser supplying grid services only (initial potential) or as extra to the primary hydrogen supply (effective potential), assuming an activation price of 15 €/MWh. Those revenues are significantly lower than those obtainable from gas grid injection or frequency services. For this reason, **the business cases** built in the present study **will not be based on balancing services**.

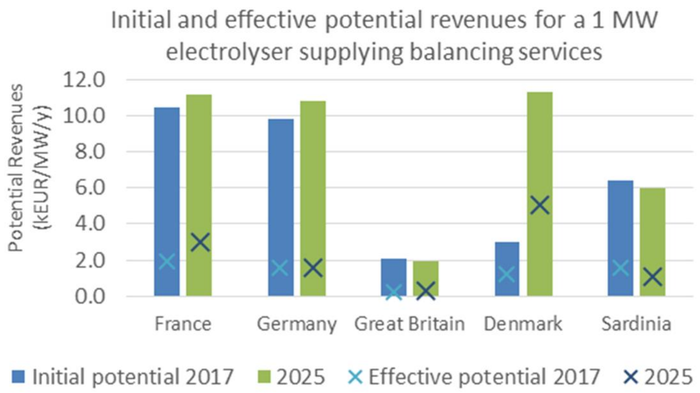


Figure 52: Expectable revenues for a 1MW electrolyser supplying balancing services, as exclusive activity (initial potential) or as extra to primary application hydrogen supply (effective potential)

6.1.3.5. ELECTRICITY GRID SERVICES: DISTRIBUTION

In section 5.4.2.3, the potential revenues from delaying investments in the distribution grid were identified to be relatively low, both in absolute value and in comparison with the other secondary value streams[17]. As a consequence, business cases are not built upon this secondary value stream. Potential revenues from providing distribution grid services are disregarded in the rest of this study.

[17] Another study [28] concludes that revenues of up to 30-90k€/MW/y can be expected as flexibility revenues in distribution grids, though without considering that integrating this flexibility induces an additional load in the system, which is the case for new electrolysers.

6.1.3.6. RE-ELECTRIFICATION BASED ON WHOLESALE PRICE ARBITRAGE

For the re-electrification value stream on an island (Sardinia), revenues are obtained from buying electricity at the cheapest cost while re-selling it at a higher price. The impact on this value steam of producing hydrogen as primary application is schematised in Figure 53: as the cheapest hours for purchasing electricity are used to minimize the production cost of hydrogen, the purchase of electricity for re-electrification must be done at a higher price, hence reducing the difference between the purchase and reselling prices.

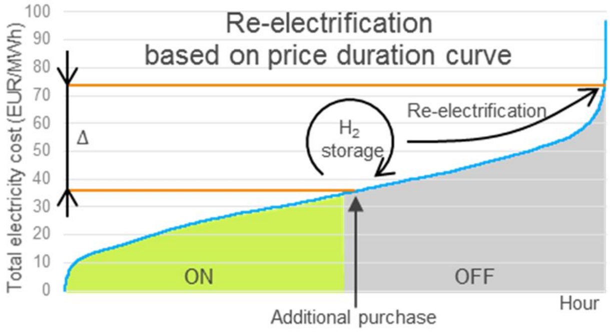


Figure 53: Re-electrification principle scheme for service supply in addition to primary hydrogen supply

Considering the cost of the extra installation needed to allow providing re-electrification services (i.e. a minima a storage tank and a fuel cell), the expectable revenues in Sardinia are too low to lead to a profitable situation. The Table 51 emphasizes this result considering the cost of the fuel cell to install for a 1MW system – presented in section 4.1.5 (Figure 28) – with the maximum revenues that were expected in section 5.5.2.1 (Figure 39). This conclusion is further reinforced when considering also the cost of the required H_2-storage tank or the reduction of expectable revenues due to the interoperability of this value stream with the primary hydrogen supply.

	2017	2025
Potential service revenues for a 1MW H2-storage facility	1.8 k€/MW/y	16.6 k€/MW/y
Cost of a 1MW fuel cell	- 104 k€/MW/y	- 104 k€/MW/y
Gross profit	**<< 0**	**<< 0**

Table 51: Non-profitability of the re-electrification value stream in Sardinia

As the re-electrification case in Sardinia appears to be non-profitable, no business case is based on that value stream in this study.

6.1.4. Preliminary classification of business cases

A preliminary analysis of the four reference scenarios described in section 6.1.1 is performed for the different locations with the discounted electricity price (i.e. renewable electricity subject to curtailment) presented in section 6.1.2.1. Positive or near positive business cases was found and are shown in the following table

Business Cases Preliminary ranking	2017					2025				
	DE	FR	GB	DK	IT	DE	FR	GB	DK	IT
Large industry – On-site	Near profitable	✖	✖	✖	✖	Near profitable	✖	✖	Profitable	✖
Light industry – On-site	✖	Profitable	✖	Profitable	✖	✖	Profitable	✖	Profitable	✖
Mobility – On-Site	✖	Profitable	✖	Profitable	✖	Profitable	Profitable	Profitable	Profitable	✖
Mobility – Semi-centralised	Near profitable	✖	✖	✖	✖	Profitable	Profitable	✖	Profitable	✖

Profitable
Near profitable

Table 52: Preliminary business case analysis

The **Large industry reference scenario** shows limited profitability in 2017 in absence of a carbon penalty increasing the cost of hydrogen production by SMR. However, in 2025, with the carbon penalty of 28 €/tCO_2 assumed at this date, a profitable business case is found in regions of Denmark and Germany, due to cheap average electricity price in Germany and to a relatively high value of asymmetric grid services (which is the type of grid services that can be provided by lower cost alkaline electrolyser technology) in Denmark.

For the **Light industry reference scenario,** conditions of profitability are found in regions of Denmark and France, both with the 2017 and 2025 assumptions, largely due to higher H_2 market prices (see section 5.1.4) and to lower average electricity price in comparison with the other regions.

The **Mobility "on-site" reference scenario,** is profitable in 2017 in Denmark and France. With the 2025 assumptions, the reference scenario is profitable in nearly all of the analysed locations. The size of captive mobility is an important factor of profitability.

The **Mobility "semi-centralised" reference scenario** is profitable for the studied regions of France, Denmark and Germany with the 2025 assumptions. In this operating model where hydrogen production for a cluster of fuelling stations and/or mobility applications is centralised at the local level, profitability is reached for sufficiently large hydrogen consumption through economies of scale compensating the added cost of logistics.

Based on this preliminary analysis, three business cases and regions were selected for the detailed analysis based on the preliminary results:

- **Semi-centralized** production for **Mobility** near **Albi, France**
- **On-site** production for **Light industry** near **Trige/Aarhus**, **Denmark**
- **On-site** production for **Large industry** (Refinery) near **Lübeck**, **Germany**

"On-site" production for Mobility also offers viable business case opportunities, however these have been addressed by numerous previous studies. Moreover, the business case of on-site production of hydrogen for a hydrogen refuelling station (HRS) is similar to that of "on-site" production for light industry, i.e. the HRS being comparable to an industrial site. Results from light industry can therefore be extrapolated for the "on-site" mobility business case. For these reasons, "on-site" production for mobility is not one of the three business cases selected for detailed analysis.

Primary applications	Geography (H_2 demand, infrastructure…)	Profitable	Political traction	Comments	Bcase Selection
Light industry On-site	DE, **DK**	FR, **DK**, GB	-	Highest H_2 merchant price	**DK**
Mobility On-site	DE, FR, DK, GB	FR, DK	DE, FR, DK, GB	Viable business case already well studied	-
Mobility Semi centralized	DE, **FR**, DK, GB	DE, **FR**, DK	DE, **FR**, DK, GB	High traction in H_2 fleet mobility in France	**FR**
Large industry Refinery On-site	**DE**	**DE**, DK	**DE**	Favorable policy on carbon penalty for refineries	**DE**

Table 53: Business cases selection for detailed analysis

6.2. Full technical specifications and bankability analysis of the business cases

6.2.1. Key findings

Bankable business cases already exist for Power-to-Hydrogen in Europe already today by complementing H_2 sales with the provision of flexibility services to the electricity grid. By 2025, the European market for Power-to-Hydrogen is estimated at a cumulative 3.1 GW, representing a market value of 4.7 B€.

Nonetheless, access to electricity at a discounted price and/or partial exemption from grid fees, taxes and levies is generally needed to achieve profitability. This condition is expected to be realized because Power-to-Hydrogen is a practical and profitable way to value excess renewable energy production which would otherwise be curtailed, thereby very significantly facilitating the integration of renewables in the energy mix.

Furthermore, strong synergies exist between Power-to-Hydrogen for mobility, gas grid injection and grid services:

- Combining Power-to-Hydrogen for mobility (and/or industry) and injection is more cost effective than stand-alone injection for the greening natural gas. Stand-alone injection may require a minimum Feed-in-tariff of 100 €/MWh. By combining with mobility and/or industry, Feed-in tariff can be reduced up to 20%.
- Combining gas grid injection with Power-to-Hydrogen for mobility (and/or industry) as primary markets, is a short-to-mid-term de-risking instrument through the valley of death of mobility and industry.

A consistent and stable regulation framework (grid fees, taxes, levies...) creating favourable conditions for investment in Power-to-Hydrogen facilities and ensuring a level playing should be put in place in order to allow the materialisation of the benefits of Power-to-Hydrogen for the energy system.

The Winter Package is a unique opportunity to create a market for Power-to-Hydrogen in refineries, which will be a game changer to unlock rapid Power-to-Hydrogen cost reductions with immediate spill-over effects on other Power-to-Hydrogen applications, including mobility. Additional advocacy efforts are urgently required.

6.2.2. Semi-centralised production for mobility applications in Albi (France)

6.2.2.1. CONTEXT

The region of Midi-Pyrénées-Languedoc-Roussillon is one of the first territories working on hydrogen in France. The region has been selected as a Hydrogen territory by the French ministry of environment in 2016. Their vision of H_2 for economic development is structured on 4 pillars:

- Airport and port applications
- Eco tourism
- Green H_2 production (electrolysis and biomethane reforming)
- Energy storage

Albi is located in South-West of France. The biggest nearby city is Toulouse at 75 km from Albi. The city is already hosting several mobility projects and hydrogen infrastructures (2 HRS). The region is home to the Alstom's hydrogen train development which could be deployed in the regional train line between Toulouse and Rodez. This hydrogen infrastructure and mobility deployment can scale up rapidly with local political and industrial support.

6.2.2.2. SCENARIO ANALYSED

The principle of semi-centralized H2 supply is to produce and distribute H_2 for a network of local consumers such as HRS. The production site is sized for a local demand on a city or regional scale (less than 50 km). Uncoupling the production and HRS allows flexibility of choosing the best location to take advantage of suitable land, discounted electricity and proximity of gas grid and road access.

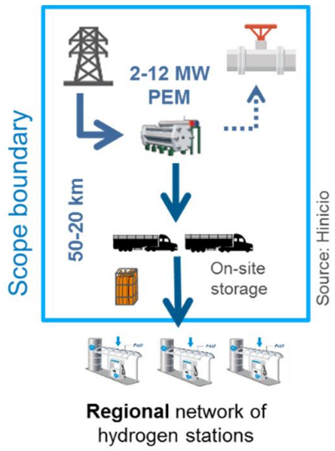


Figure 54: Mobility semi-centralised business case – Schema

This business case covers the whole H_2 value chain up to the HRS. The logistic of distribution and H_2 mobile storage (e.g. large bundles or tube-trailers) at HRS are covered in the business case. However, the investment and operation of HRS are excluded.

In order to prepare the local H_2 mobility ecosystem in Albi (FR), an ambitious mobility deployment is considered for the semi-centralised mobility business case which considers a mobility mix of FCEV, urban buses and regional trains reaching a H_2 demand of 740 kg/day[18] in 2017 and 2600 kg/day[19] in 2025. Mobility market size will be subject to sensitivity in later sections.

Produced hydrogen is distributed across a network of HRS in a 20 km radius which represents a city scale network.

HRS hydrogen price to mobility end-user is set at 9-10 €/kg. Considering a cost of operation for the HRS between 2-3 €/kg, H_2 price delivered and sold to the HRS must be under 6-7 €/kg. The target value is set for 2017 and 2025.

Electrolysers can be considered as electro-intensive in France and are eligible to partial exemption on grid fees and levies (CSPE). The mark-up on top of the wholesale electricity price through grid fees, taxes, levies and GO represents 13 €/MWh.

The gas grid injection tariff is set at 90 €/MWh_{LHV} on both 2017 and 2025, i.e. it is assumed that green hydrogen would receive the same tariff as bio-methane. A sensitivity analysis is performed to check the impact of not receiving this tariff.

Parameters	2017	2025
Daily and annual H2 demand	**740 kg/day 270 t/year**	**2600 kg/day 950 t/year**
H2 price to end-user (@700 bar)	9-10 €/kg	9-10 €/kg
H2 price to HRS (@200 bar)	**7 €/kg**	**6 €/kg**
HRS distance	20 km one-way (city scale)	
Nb. tube-trailers equivalent	7 trailers	21 trailers
Grid fees, taxes, levies and GO	**13 €/MWh** (incl. partial exemption because of electro-intensive status)	
Grid services value	**18 €/MW/h (symmetrical FCR)**	
Gas grid injection tariff	**90 €/MWh LHV**	

Table 54: Mobility semi-centralised business case – Main parameters and assumptions

6.2.2.3. REFERENCE CASE: SIZING & CAPEX

Figure 55 shows the resulting profitability based on different electrolyser size. Profitability is defined by the net margin expressed in k€ per MW of nominal electrolyser capacity per year (k€/MW/year). The net margin is calculated from the difference between revenues and total costs (annualised CAPEX and OPEX).

[18] 740 kg/day represents, for example, a mobility mix of 2 regional trains, 10 urban buses and 200 FCEV

[19] 2600 kg/day represents, for example, a mobility mix of 5 regional trains, 20 urban buses and 1100 FCEV

Net margin varies with sizing the electrolyser system over the primary application from 100 to 200%. Each curve represents a different value stream stacking configuration, starting from only the primary market (dash curve), then adding grid services (dotted curve) and finally adding gas grid injection (plain curve). 2017 and 2025 cases are represented in blue and red respectively.

The French symmetrical frequency containment reserve favours use of PEM technology, which is used in the reference case.

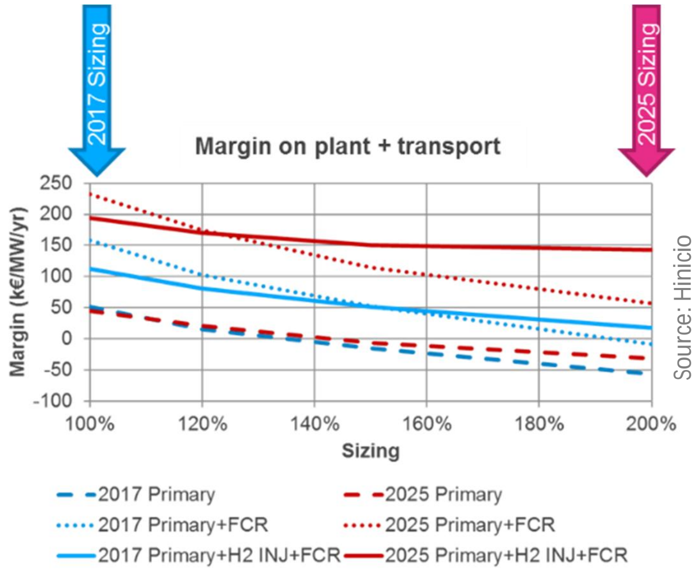


Figure 55: Mobility semi-centralised business case – Impact of sizing on margin

Serving only the primary application (supply of hydrogen for mobility in this case) through a unit sized just for this market (100% sizing) generates a positive net margin of 50 k€/MW/year for both the 2017 and 2025 scenarios. Adding provision of grid services to the value stream triples profitability.

Gas grid injection involves additional costs associated to additional production capacity and to the gas grid interconnection. With the assumption for 2017, the injection tariff is not high enough for injection to be profitable, with the margin continuously decreasing when the unit is increasingly oversized for this purpose. However, with the assumption of 2025, the net margin is rather flat with oversizing for injection, remaining above 150 k€/MW/yr. This, in practice, allows system oversizing at a limited cost for anticipating increasing needs, and reduces business case sensitivity to market sales.

Consequently, for the **2017 reference business case**, the electrolyser size considered is 100% of the mobility market, as oversizing reduces profitability. The corresponding PEM electrolyser size is 2 MW.

For the **2025 reference business case**, a sizing of 200% of the mobility market is considered. The corresponding PEM electrolyser size is 12 MW, of which 6 MW is dedicated to the mobility market.

Comparison of the breakdown of investment costs for 2017 and 2025 shows a 48% reduction of the specific cost (k€/MW) thanks to scale effect (2 à 12 MW) and technological progress (2017 à 2025).

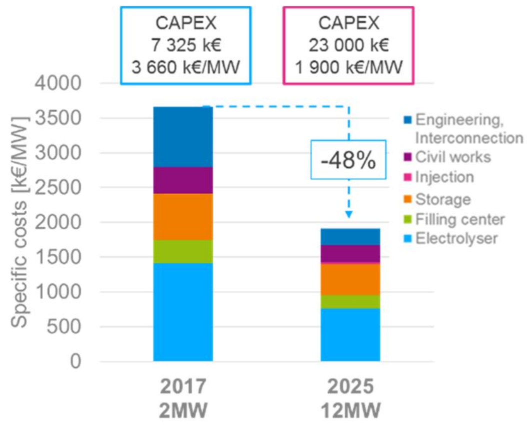


Figure 56: Mobility semi-centralised case – Investment breakdown

6.2.2.4. PROFITIABLITY ANALYSIS RESULTS

For each value stream (primary application, H_2 injection into gas grid and grid services), the normalised annual revenues, costs and net margin are shown in a cascade chart in k€/MW/year. The net margin is calculated from the difference between revenues and total costs (annualised CAPEX and OPEX).

2017 business case

As the electrolyser system is sized to meet 100% of H_2 demand, the operation time is maxed at 95%[20]. The average total electricity price[21] paid is 44 €/MWh. Levelized cost of hydrogen (LCOH) represents 6.7 €/kg, whereas selling price is set at 7.0 €/kg.

Selling H_2 to mobility market generates a revenue of 939 k€/MW/year, of which 95% is offset by the annualised CAPEX and OPEX. The business case remains positive with a 5% margin.

However, **adding grid services triples profitability** by generating additional revenues at low costs. The system payback time is fast tracked by 3 years with grid services revenues, reaching 8 years.

With the peak capacity of 160% of nominal power assumed for PEM electrolysers in 2017, it is considered in the analysis that these can respond within seconds to a call to increase or reduce power consumption by 60%. On the other hand, the peak power capability of ALK electrolysers is assumed not to exceed 100% of nominal capacity. Since symmetric adjustment capacity is required for providing FCR and FRR in France the revenue from grid services projected for ALK technology is very limited.

[20] Operation cap of 95% accounts for planned and unforeseen downtime.
[21] Total average electricity price includes discounted electricity, grid fees, taxes, levies and guarantees of origins RE

Results	2017
Primary market size	2 MW
Unit sizing	100%
Technology	PEM
Peak power	160% Pnom
Op. time and total elec. price (prim.)	95% @ 44 €/MWh
Levelized cost of H_2	6.7 €/kg
Net Margin	159 k€/MW/year
Payback time w/o grid services	11 years
Payback time w/ grid services	8 years

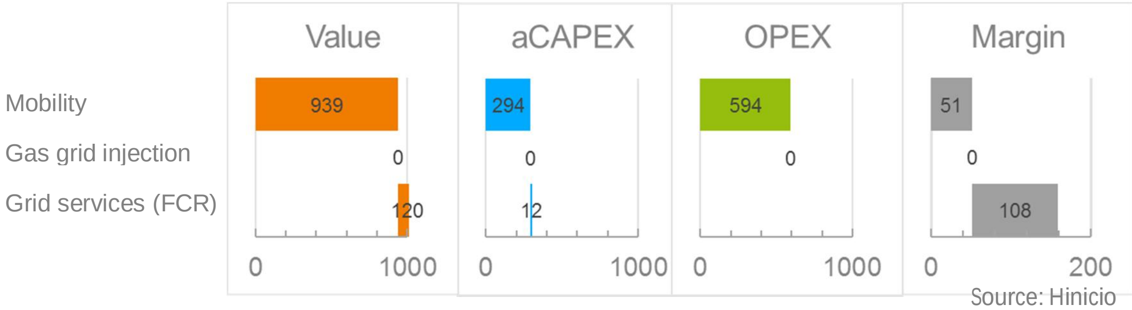


Figure 57: Mobility semi-centralised 2017 case – Financial breakdown

2025 business case

With an electrolyser system sized for being able to supply 200% of hydrogen demand for mobility, the load factor for the primary application is 48%. The average total cost of the electricity consumed is 50 €/MWh, resulting in a levelized cost of hydrogen (LCOH) of 4.1 €/kg, whereas the selling price is set at 6.0 €/kg.

Selling H_2 to the mobility market generates a revenue of 477 k€/MW/year, of which 75% is offset by the annualised CAPEX and OPEX. As a result, the net margin per MW is 25% higher than in the 2017 scenario. This is due to scale effects on the investment costs and improved stack performance.

Adding **gas grid injection increases the system's total operation time** to 90% of the time, as the marginal cost of production is lower than the revenue generated by gas grid injection about 95% of the time. The Average total cost of the electricity consumed for gas grid injection is 57 €/MWh[22]. **This additional operation time generates extra revenues from grid services, further boosting profitability**. In 2025, peak power performance of PEM electrolyser is projected to reach 200% of nominal power capacity, allowing the provision of reserve, complying with French symmetric FCR and FRR requirements for 100% of nominal power capacity. With these assumptions, the specific net margin is increased by 220% thanks to gas grid injection and grid services.

The system payback time reaches 4.5 years with grid services additional revenues.

[22] This is slightly higher than the cost of electricity for the primary application, as a result of allocation of the lowest cost electricity to H_2 production for the primary market.

Results	2025
Primary market size	6 MW
Unit sizing	200% w/ inj.
Technology	PEM
Peak power	200% Pnom
Op. time and total elec. price (prim.)	48% @ 50 €/MWh
Op. time and total elec. price (inj.)	42% @ 57 €/MWh
Levelized cost of H_2	4.1 €/kg
Net margin	256 k€/MW/year
Payback time w/o grid services	9 years
Payback time w/ grid services	4.5 years

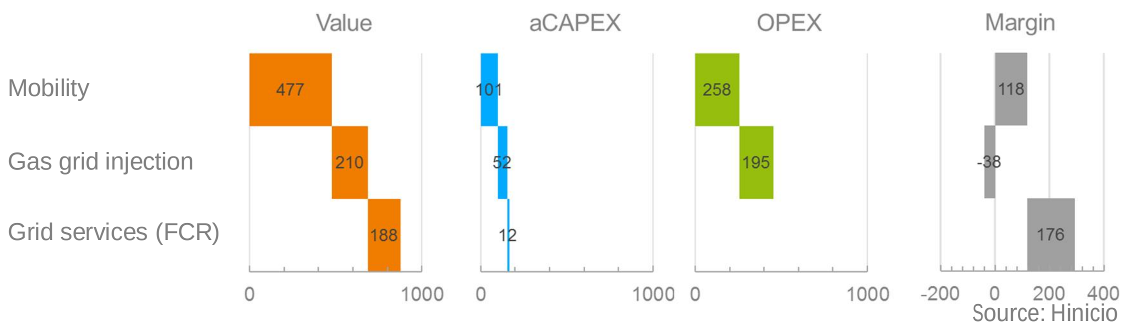


Figure 58: Mobility semi-centralised 2025 case – Financial breakdown

6.2.2.5. SENSITIVITY ANALYSIS

6.2.2.5.1. Sensitivity to the business model's input parameters

The following tornado charts show the impact of several parameters on profitability (net margin). The boundary condition is defined when net margin falls to zero. The business case parameters boundary conditions in Albi (FR) are summarised in a table at the end of this section.

2017 business case

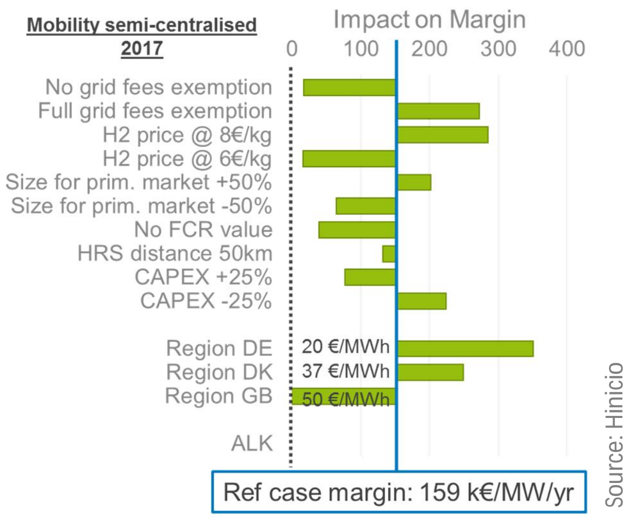


Figure 59: Mobility semi-centralised 2017 – Sensibility analysis

Main observations:

- The total electricity cost for which the net margin falls to zero (breakeven point) is 63 €/MWh. The granting of grid fees exemptions is critical for profitability. The net margin varies significantly when electricity cost assumptions of other regions are considered, with the total electricity cost being the lowest in the DE and DK locations.
- Increasing or reducing the H_2 selling price by 1€/kg on can double or eliminate profitability.
- Breakeven point can be achieved as from mobility markets of 90t/year which would require a 700 kW electrolyser. This represents the consumption of about 5-6 urban buses which can be reachable in the short term.
- Because of the small system size (2 MW), the specific cost is relatively high (>3500 k€/MW). Varying CAPEX of ±25% impacts the profitability by 50%.
- For this unit size, switching from PEM to ALK technology has no impact on the margin. The lower equipment cost compensates the lack of revenues from grid services.

2025 business case

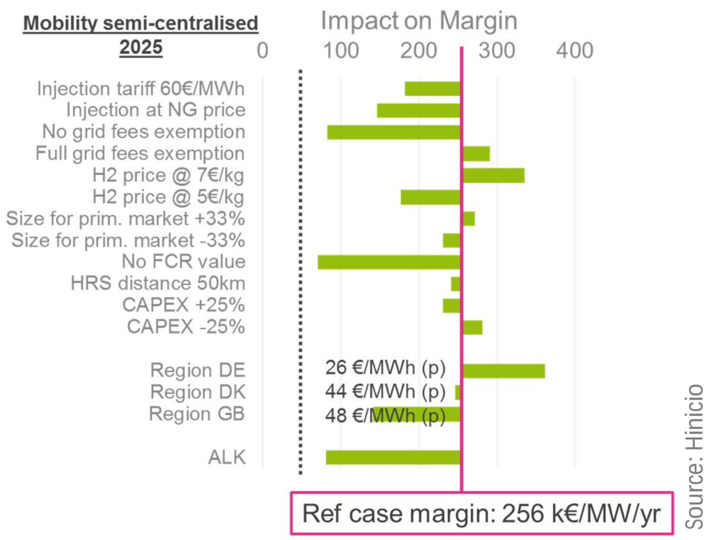


Figure 60: Mobility semi-centralised 2025 – Sensibility analysis

Main observations:

- The breakeven point for the total electricity price is 77 €/MWh. The net margin remains sensitive to grid fees exemption and to location considered for determination of the electricity cost.
- Increasing or reducing the H2 selling price by 1€/kg impacts the net margin by 100k€/MW/year.
- Breakeven point can be achieved as from mobility markets of 53 t/year which would require a 350 kW electrolyser .
- For the larger capacity considered in the scenario (12 MW), a change of CAPEX has a limited impact on the net margin, due to the lower weight of CAPEX costs.

- In 2025, switching to ALK technology strongly reduces the calculated margin due to the loss of revenue from grid services which cannot be provided with ALK technology, with limited offset from reduced equipment costs, the spread between ALK and PEM technologies being reduced at this time horizon.

Boundary conditions Albi, FR	2017	2025	Comments
Reference margin	159 k€/MW/yr	256 k€/MW/yr	
CAPEX	+50%	+155%	As project specific costs decreases over time (2017→2025) and on scale effect (2→12 MW), Bcase profitability increases.
Electricity price incl. Grid fees, taxes, levies and GO	63 €/MWh	77 €/MWh	
H_2 market price	5.8 €/kg	2.7€/kg	
Min. H_2 market size and Equiv. electrolyser. nom. size	90 t H_2/year (Equiv. 700 kW)	53 t H_2/year (Equiv. 350 kW)	
H_2 market ramp-up	-40% of expected market	-66% of expected market	
Grid services revenue	None	None	Grid services account for 2/3 of margin
Gas grid injection tariff	-	110 €/MWh LHV	

Source: Hinicio

Table 55: Mobility semi-centralised business case – Boundary conditions

6.2.2.5.2. Comparison with standalone injection business case

Green hydrogen injection into the gas grid is a solution to green natural gas networks. Similar to biomethane injection, stand-alone H_2 injection into the gas grid can be profitable with sufficient feed-in-tariff (FIT).

However, a lower FIT will be required for creating conditions of profitability if gas grid injection is performed as a secondary application using a Power-to-Hydrogen system primarily devoted to supplying hydrogen for mobility or industry applications (primary applications).

The FIT level in Figure 61 is calculated considering the gas grid injection related costs and revenues a payback time of 8 year. Payback time is defined by the period of time required to recoup the initial investment costs. It is calculated by dividing the investment costs with the annual gross margin, i.e. difference between revenues and operation costs.

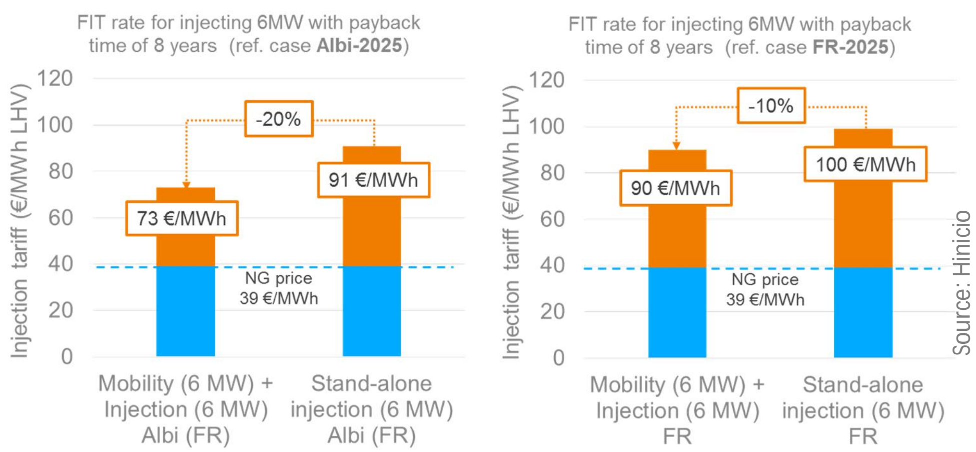


Figure 61: Gas grid injection Feed-in Tariff comparison with and without primary mobility application in 2025

For a 6 MW electrolyser capacity in Albi (FR) in 2025, a standalone injection project would require a FIT of 91 €/MWh$_{LHV}$ to reach a payback time of 8 years. When combining injection with a mobility project, the amount of costs that need to be covered by revenues from gas grid is smaller. Consequently, the value of the FIT needed to reach the same payback time drops to 73 €/MWh$_{LHV}$, i.e. a 20% reduction. This represents a carbon price of 165 €/tCO_2 over the natural gas price at 39 €/MWh.

The same comparison taking into account electricity costs in France without access to discounted electricity, yields a needed FIT of 100 €/MWh$_{LHV}$ for stand-alone injection and of 90 €/MWh$_{LHV}$ in installations supplying hydrogen to mobility application, i.e. a FIT reduction of 10%.

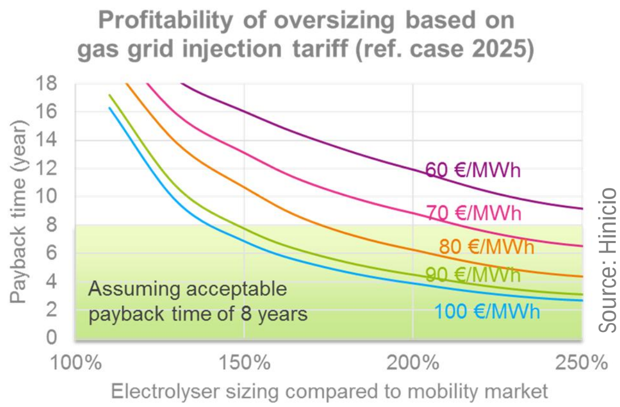


Figure 62: Profitability of oversizing based on gas grid injection tariff (ref. case: Albi-2025)

The higher the FIT, the lower the oversizing is needed to reach an acceptable payback time. For instance, in 2025, with a FIT of 70 €/MWh$_{LHV}$ a sizing of 150% is sufficient to reach a payback time of 8 years.

6.2.2.5.3. Gas grid injection is a de-risking instrument through the mobility application's "valley of death"

An important assumption in the profitability analysis above is that primary market demand is at 100% of the demand for which the PtH system is sized. However, for mobility applications, there is typically a ramp-up. Furthermore ramp-up could be slower than expected, adding a risk on the volumes to the H_2 producer. This phase is, typically, referred to as the "valley-of-death".

One way to mitigate the ramp-up risk is through secured take-or-pay contract with fleet operators. The risk is then transferred to the end-user. This is not ideal, as the fleet operator already bear other risks (technology performance, operation costs…), leading to a chicken-and-egg problem.

Gas grid injection can take part of the ramp-up risk by allowing exploitation of the spare capacity, generating extra revenues to help cover the operation costs.

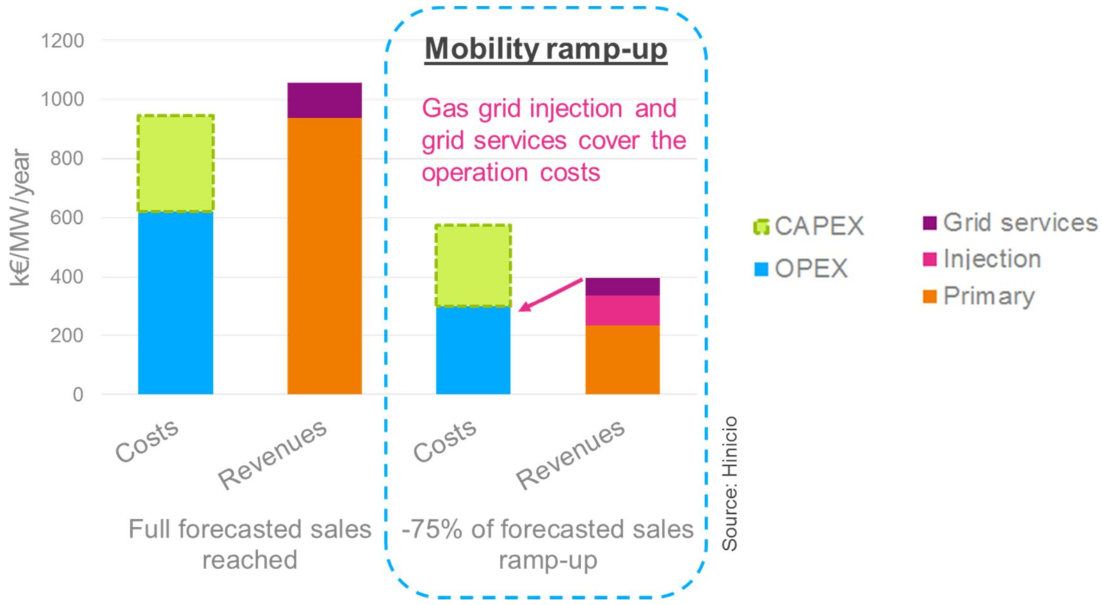


Figure 63: Gas grid injection revenues as de-risking tool for mobility ramp-up (ref. case Albi-2017)

Considering the semi-centralised mobility in Albi (FR) in 2017 and a FIT of 90 €/MWh$_{LHV}$[23], even with a mobility demand 75% under expectation, gas grid injection helps to cover the operation cost during the first year of mobility deployment. Combined with subsidies on investment, the project can reach the financial breakeven point earlier.

6.2.3. Light industry in Trige/Aarhus (Denmark)

6.2.3.1. CONTEXT

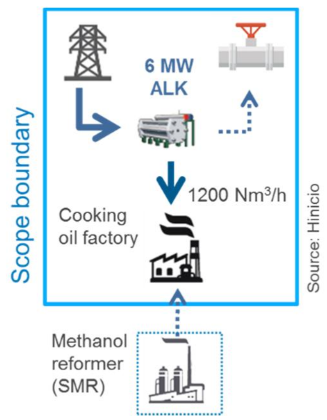


Figure 64: Light industry business case – Schema

H_2 merchant market price levels are higher in Denmark and France, than in Germany and Great Britain due to a lower number of filling centres and the larger travel distance (see section 5).

[23] Biomethane tariff in France range between 45 and 140 €/MWh$_{LHV}$ (see section 5)

There are no H_2 filling centres in Denmark. Therefore, H_2 merchant gas needs to be imported from Germany or produced on-site.

Only one site consuming significant quantities has been identified. It is a food-oil factory located in the port of Aarhus (15 km of Trige) supplied by an on-site methanol SMR with a capacity of 1200 Nm^3/h (900 t/year).

6.2.3.2. SCENARIO ANALYSED

The scenario considers the replacement of the on-site methanol reformer, assumed to be at end of lifetime, with an electrolyser unit. The electrolyser system needs to supply the current hydrogen demand of 900 t/year, which is not expected to change between 2017 and 2025. The target H_2 selling price is set to 5 €/kg for 2017 and 2025, the estimating market value for hydrogen produced in such quantities.

Aarhus is subject to DK-West electrical network regulations, exempting electrolysers from levies. The remaining added cost of grid fees, taxes, and the needed green electricity GOs on top of the wholesale electricity price represents 11 €/MWh. The DK-West FRR market allows for asymmetric provision of reserve. Based on historical price level, the remuneration considered for modulation of consumption upwards and downward is 17.36 €/MW/h and1.46 €/MW/h respectively.

The gas grid injection tariff is set at 90 €/MWh_{LHV} for both the 2017 and 2025 scenarios, i.e. it is assumed that green hydrogen would receive the same tariff as bio-methane. A sensitivity analysis is performed for checking the impact of not receiving this tariff.

Parameters	2017	2025
Annual H2 demand	900 t/year	
H2 price sold to industry	5 €/kg	
Grid fees, taxes, levies and GO (DK)	11 €/MWh	
Grid services value	17 €/MW/h (asymmetrical FRR)	
Gas grid injection tariff	90 €/MWh LHV	

Table 56: Light industry business case – Main parameters and assumptions

Light industry business case results can be extrapolated toward on-site production for mobility as the final client is the HRS instead of the light industry.

6.2.3.3. REFERENCE CASE: SIZING & CAPEX

Figure 65 shows the resulting profitability based on different electrolyser size. Profitability is defined by the net margin expressed in k€ per MW of nominal electrolyser capacity per year (k€/MW/year). The net margin is calculated from the difference between revenues and total costs (annualised CAPEX and OPEX).

Net margin varies with sizing the electrolyser system over the primary application from 100 to 200%. Each curve represents a different value stream stacking configuration, starting from only the primary market (dash curve), then adding grid services (dotted curve) and finally adding gas grid injection (plain curve). 2017 and 2025 cases are represented in blue and red respectively.

The Danish asymmetrical frequency reserve favours use of ALK technology, which is used in the reference case.

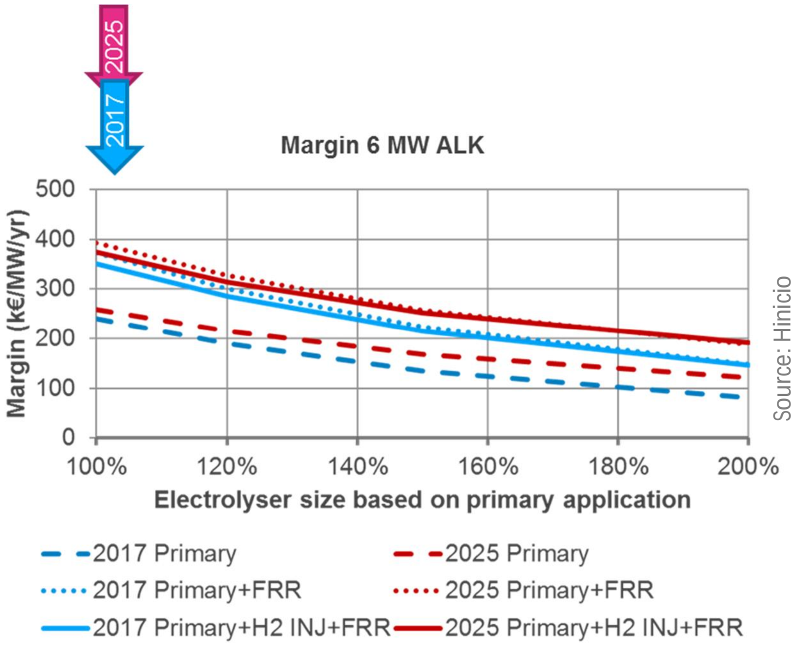


Figure 65: Light industry business case – Impact of sizing on margin

Serving only the light industry (primary) application generates a net margin of over 200 k€/MW/year, mainly due to the relative high H_2 selling price (5 €/kg). Adding grid services increase profitability by 60%. The 2025 profitability curves are slightly higher due to lower specific costs thanks to technological progress.

Gas grid injection involves additional costs associated to additional production capacity and to the gas grid interconnection. The assumed injection tariff is not high enough for injection to be profitable, with the margin continuously decreasing when the unit is increasingly oversized for this purpose.

The **2017 and 2025 reference business cases** will therefore consider a Power-to-Hydrogen system sized for 100% of the light industry H_2 demand. The corresponding ALK electrolyser nominal capacity is 6 MW.

Comparison of the breakdown of investment costs for 2017 and 2025 shows a 20% reduction of the specific cost (k€/MW) thanks to technological progress (2017 à 2025).

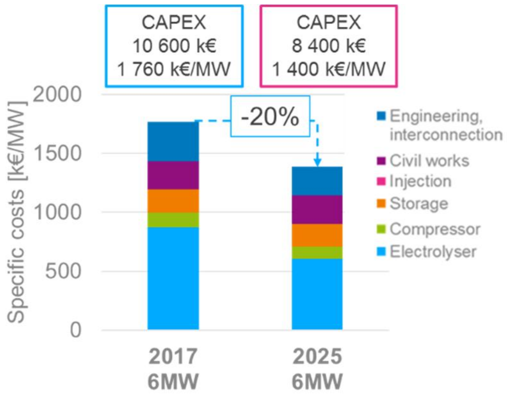


Figure 66: Light industry business case – Investment breakdown

6.2.3.4. PROFITIABLITY ANALYSIS RESULTS

2017 business case

As the electrolyser system is sized to meet 100% of H_2 demand, the operation time is maxed at 95%[24]. The average total electricity price[25] paid is 38 €/MWh. Levelized cost of hydrogen (LCOH) represents 3.5 €/kg, whereas selling price is set at 5 €/kg.

Selling H_2 to the identified light industry client generates a revenue of 784 k€/MW/year, of which 70% is offset by the annualised CAPEX and OPEX. The business case remains positive with a 30% margin.

Adding grid services enhance net margin by 55%. Danish FCR (DK-West) allows for asymmetric capacity. **Asymmetric grid services favours ALK electrolysers** as they are cheaper than PEM and can still make use of the whole electrolyser nominal capacity for grid services. The grid services contribution allows to fast track the system payback time to 3.4 years.

Results	2017
Primary market size	6 MW
Unit sizing	100%
Technology	ALK
Peak power	100%
Op. time and total elec. price (prim.)	95% @ 38 €/MWh
Levelized cost of H_2	3.5 €/kg
Net margin	373 k€/MW/year
Payback time w/o grid services	4.6 years
Payback time w/ grid services	3.4 years

[24] Operation cap of 95% accounts for planned and unforeseen downtime.
[25] Total average electricity price includes discounted electricity, grid fees, taxes, levies and guarantees of origins RE

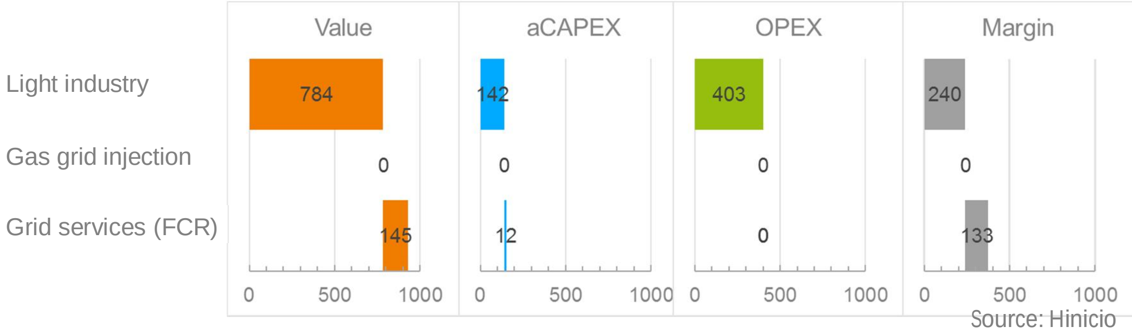


Figure 67: Light industry 2017 case – Financial breakdown

2025 business case

As the electrolyser system is sized to meet 100% of H_2 demand, the operation time is maxed at 95%[26]. The average total electricity price[27] paid is 47 €/MWh. Levelized cost of hydrogen (LCOH) represents 3.4 €/kg, whereas selling price is set at 5 €/kg.

Selling H_2 to the identified light industry client generates a revenue of 819 k€/MW/year, of which 68% is offset by the annualised CAPEX and OPEX. The business case remains positive with a 32% margin. Comparing to the 2017 reference case, the slight margin increase is mainly due to the system cost reduction over time.

Adding grid services enhance net margin by 51%. The grid services revenue and costs are the same as in 2017 because the system has the same size and operates the same amount of time (95%). The system payback time reaches 2.7 years with grid services contribution.

Results	2025
Primary market size	6 MW
Unit sizing	100%
Technology	ALK
Peak power	100%
Op. time and total elec. price (prim.)	95% @ 47 €/MWh
Levelized cost of H_2	3.4 €/kg
Net margin	393 k€/MW/year
Payback time w/o grid services	3.7 years
Payback time w/ grid services	2.7 years

[26] Operation cap of 95% accounts for planned and unforeseen downtime.
[27] Total average electricity price includes discounted electricity, grid fees, taxes, levies and guarantees of origins RE

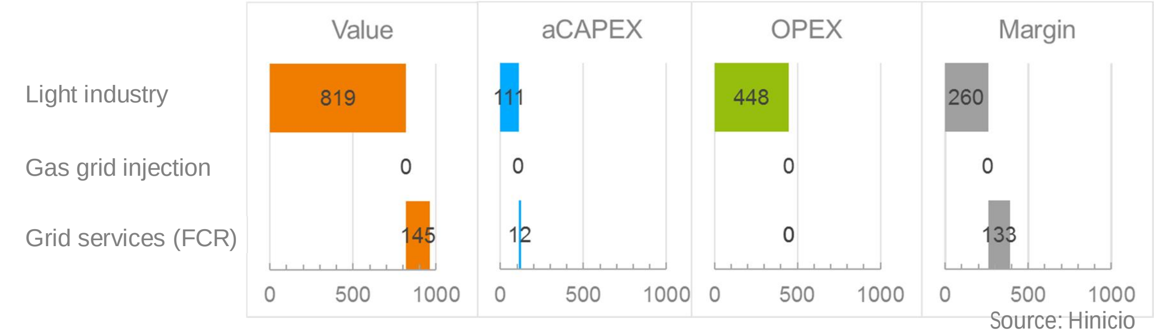


Figure 68: Light industry 2025 case – Financial breakdown

6.2.3.5. SENSITIVITY ANALYSIS

Both 2017 and 2025 reference cases have similar sensitivity results.

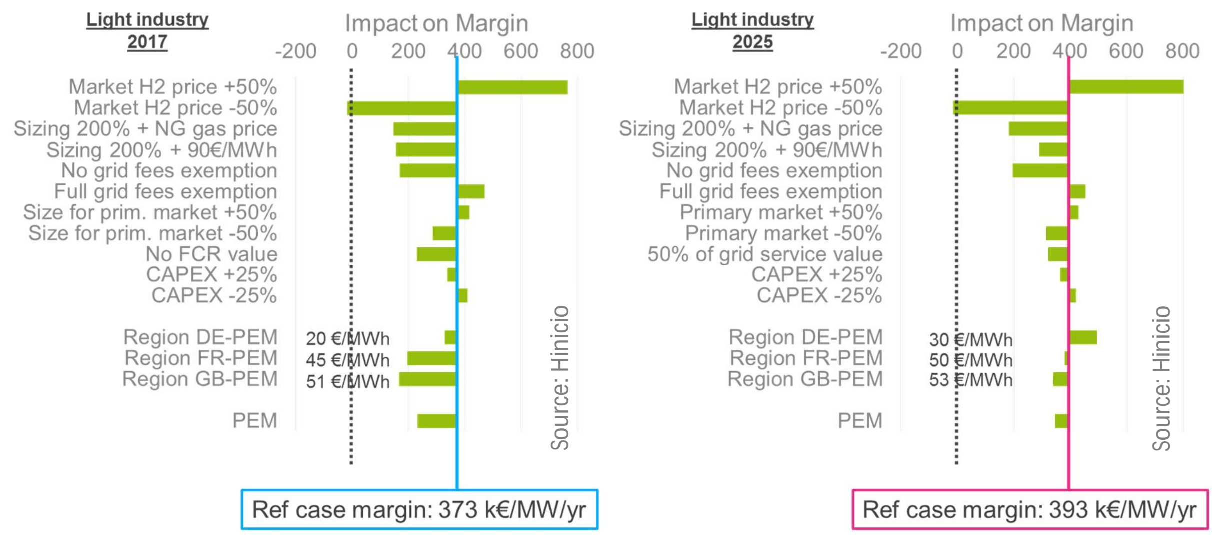


Figure 69: Light industry 2017 & 2025 – Sensibility analysis

Main observations:

- The parameter to which the net margin is the most sensitive is the hydrogen market price which can significantly alter profitability.
- Oversizing for gas grid injection is not profitable, even with a FIT of 90 €/MWh_{LHV}. Primary market contribution to the net margin is the most important and should be prioritized.
- The breakeven point for the total electricity cost is 80 €/MWh in 2017 and 93 €/MWh in 2025. Eligibility of grid fees exemption is important. Comparison with the other regions shows different profitability levels. DE has cheaper total electricity price and FR has similar total electricity price. However, results tend to be less profitable due to the impossibility to provide supply high value symmetrical grid services in those regions with ALK technology.
- For the larger capacity considered in the scenario (12 MW), a change of CAPEX has a limited impact on the net margin, due to the lower weight of CAPEX costs.

Boundary conditions Aarhus, DK	2017	2025	Comments
Reference margin	373 k€/MW/yr	393 k€/MW/yr	
CAPEX	+245%	+320%	
Electricity price incl. Grid fees, taxes, levies and GO	80 €/MWh	93 €/MWh	High elec. price tolerance due to high H_2 market price in DK
H_2 market price	2.6 €/kg	2.6 €/kg	With revenues from grid services
Min. H_2 market size and Equiv. electrolyser nom. size	145 t H_2/year (Equiv. 1 MW)	150 t H_2/year (Equiv. 1 MW)	DK: Grid services possible only >1 MW
Grid services revenue	None	None	Grid services account for 1/3 of margin

Source: Hinicio

Table 57: Light industry business case – Boundary conditions

6.2.4. Large industry in Lübeck (Germany)

6.2.4.1. CONTEXT

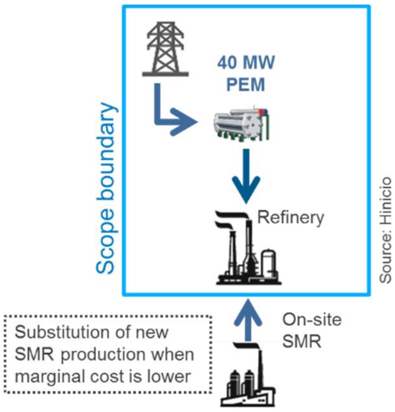


Figure 70: Large industry business case – Schema

In the selected area in Germany near Herrenwyk (close to Lübeck) in a range of 110 km there are four refineries which are still operational. [83]

- Tamoil Holborn Refinery in Hamburg
- H&R Ölwerke Schindler in Hamburg
- Nynas Refinery in Hamburg
- Heide Refinery in Hemmingstedt

The potential use of green hydrogen in these refineries was investigated based on an estimation of the hydrogen balance.

Hydrogen Balance	Unit	Tamoil	Nynas	Heide
Hydrogen Consumption for desulphurization	**kton**	**-35.5**	**-2.5**	**-12.5**
• Naphta	kton	-3.7	0.0	-2.3
• Diesel	kton	-19.2	-2.5	-10.2
• FCCU Feed	kton	-12.7	0.0	0.0
Hydrogen consumption hydrocracker	kton	0.0	0.0	**-36.0**
Hydrogen production Cat Reformer	**kton**	**19.2**	0.0	**18.6**
Hydrogen balance	**kton**	**-16.3**	**-2.5**	**-29.9**
	t/h	**-1.9**	**-0.3**	**-3.4**

Table 58: Hydrogen balance of refineries near Lübeck, Germany

Due to the presence of a hydrocracker, the hydrogen demand of the Heide refinery is expected to be the largest in the considered refineries. Hydrogen demand to close the hydrogen balance is estimated to be around 3.4 t/h (~30 000 t/year).

There is no indication of a nearby hydrogen pipeline and given the high hydrogen demand, the most likely scenario is that the hydrogen is produced onsite by SMR. The value of hydrogen is estimated at 1800 – 2250 €/t without carbon penalty.

Because of the large H_2 demand, the Heide refinery is selected for this scenario. Incidentally, the Heide refinery has shown interest in the past (2013) to produce green hydrogen using wind energy. [114] However, there is currently no regulation to encourage use of green H_2 in refineries or other large industries. There are three regulatory options that can be considered in the short-midterm:

- The current European **Fuel Quality Directive** (FQD) and **Renewable Energy Directive** (RED) do not allow accounting for emissions from hydrogen production in refineries to be considered in the carbon intensity calculation. However, revision of FQD and RED II could define new requirements which will be applicable beyond 2020. This is an opportunity for Power-to-Hydrogen when considering, in particular, the implementation measures taken by Member States, such as Germany, where a carbon penalty of 470 €/tCO_2 is foreseen for fuel suppliers failing to meet the emissions intensity reduction requirement (Federal Emission Protection Law - §37c BImSchG).
- Member States could impose a **carbon tax** on fossil energy use. As example, under the “Loi sur la transition énergétique” (Energy Transition Law), France will impose a carbon tax of 56 €/tCO_2 in 2020 and 100 €/tCO_2 in 2030.This tax is applied to the final fuel product.
- The last possibility could be a rise of carbon price under **EU ETS** which refineries and other large industries are subject to. Current carbon price remains quite low (approx. 6 €/tCO_2). However, EU ETS is currently under revision and market price level can be adjusted if sufficient measures are implemented (e.g. reducing free allocation quotas).

6.2.4.2. SCENARIO ANALYSED

Hydrogen demand increases generally in refineries due to lower input quality of crude oil and higher quality requirements on produced fuel. ESPRIT report expects an annual H_2 demand growth of 3.2%/year in EU refineries. [43]

The large industry scenario will focus on the ability of electrolyser to satisfy part of the refinery H_2 demand increase. The latter has a projected growth rate of 3%/year from 2017 to 2025. This represents a cumulated H_2 increase of approx. 7000 t/year by 2025 in a typical refinery. Half of the increasing demand is supplied by the on-site SMR which reaches maximum capacity. The electrolyser supplies the remaining half. This amount (3230 t/year) is referred as the scenario primary market.

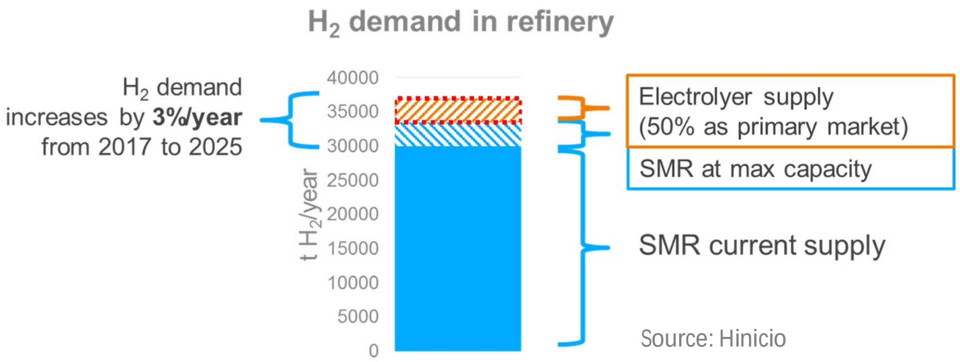


Figure 71: 2025 Scenario of Heide refinery H_2 demand growth

Based on the existing production costs, the market value for hydrogen is set at 1.8 €/kg in 2017 and at 2.6 €/kg, including carbon penalty of 80 €/tCO_2 in 2025. This value includes SMR marginal production costs, annualized SMR CAPEX costs and margin (0.25 €/kg).

Gas grid injection is not considered in this scenario. However, available electrolyser capacity will be used instead of the on-site SMR when the marginal cost of production of hydrogen from green electricity will be lower than the marginal cost of production of hydrogen from natural gas, i.e. 1.5 €/kg in 2017 and 2.4 €/kg in 2025 (including carbon penalty of 80 €/tCO_2).

A carbon penalty improves competitiveness of green hydrogen over hydrogen produced from natural gas.

No carbon penalty is considered in the 2017 scenario, based on the current regulatory situation.

The assumption of an 80 €/tCO_2 carbon penalty in 2025 is based on the hypothesis that the floor value for a carbon tax is foreseen in France for 2025 would apply also at European level and that the emissions reduction associated to the production of hydrogen in refineries will be considered for calculation of reduction of carbon intensity of fuels.

The electrolyser system is considered eligible for grid fees exemption specific to hydrogen energy projects (EnWG §118). Similarly, several exemptions from taxes and levies exist, as defined in section 6.1.2.3. The total mark-up on top of the wholesale electricity price through grid fees, taxes, levies and GO represents 1.7 €/MWh.

Parameters	2017	2025
Annual H2 demand	**3 230 t/year**	
Grid fees, taxes, levies and GO (DE)	**1.7 €/MWh** (EnWG §118)	
Grid services value	**19 €/MW/h (symmetrical FCR)**	
Carbon penalty	**0 €/tCO2**	**80 €/tCO2**
Value H2 from SMR incl. carbon penalty	**1.8 €/kg**	**2.6 €/kg**
Value of sub. H2 from SMR incl. carbon penalty	**1.5 €/kg**	**2.4 €/kg**

Table 59: Large industry business case – Main parameters and assumptions

6.2.4.3. REFERENCE CASE: SIZING & INVESTMENT BREAKDOWN

The figure below shows that for the case of a PEM unit sized to cover the primary market only (100% sizing), the net margin increases from 50 to 200 k€/MW/yr when the supply of hydrogen is combined with the provision of grid services (FCR)

Oversizing the electrolyser in order to be able to substitute hydrogen produced from natural gas by electrolytic hydrogen produced from green electricity when the of electricity is low is also beneficial from an economic standpoint. This shows that large scale electrolysis could compete with on-site SMR production if the context of a carbon penalty at a level currently foreseen by certain member states.

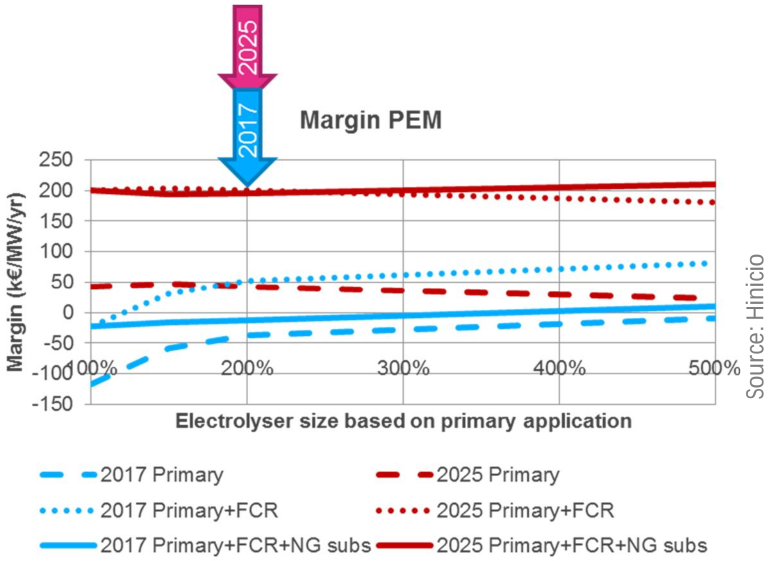


Figure 72: Large industry business case – Impact of sizing on margin

The **2017 and 2025 reference business cases** will consider an electrolyser sizing of 200% of the capacity needed to serve the refinery scenario primary market (3230 t/year), i.e. 40 MW. The choice of 200% is arbitrary, given that the impact of sizing on the margin is relatively constant (flat curve). The use of PEM is assumed in view of the provision of symmetric FCR.

Large project in the scale of tens of MW benefits from significant scale effect, allowing to reach a specific total CAPEX costs below 1000 k€/MW in 2025. Although units of this size have never yet been built, a 50% higher specific cost is assumed for 2017, extrapolating the cost functions developed for smaller size units.

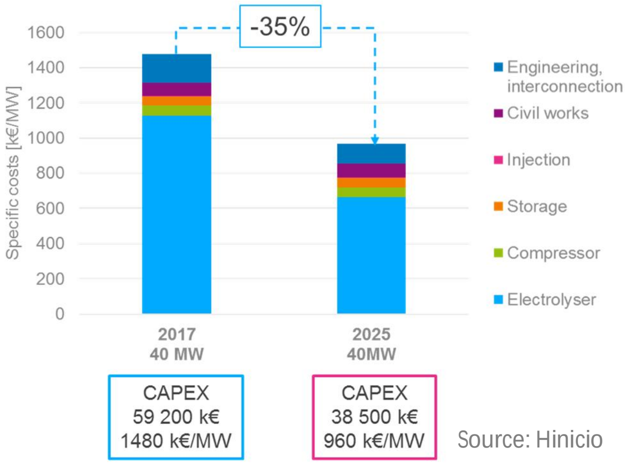


Figure 73: Large industry business case – Investment breakdown

The refinery market has the potential of triggering volume effects boosting the uptake of other Power-to-Hydrogen applications, in particular for mobility. Indeed, deploying units of tens or hundreds of MW would expectedly bring massive cost reductions for Power-to-Hydrogen technologies

6.2.4.4. PROFITIABLITY ANALYSIS RESULTS

2017 business case

With an electrolyser system sized for being able to supply 200% of hydrogen demand for refinery, the load factor for the primary application is 48%. The average total cost of the electricity consumed is 17 €/MWh, resulting in a levelized cost of hydrogen (LCOH) of 2.4 €/kg, whereas the selling price is set at 1.8 €/kg. Even with discounted electricity price, near full grid fees and levies exemption and grid services revenues, the business case is not profitable, with a net margin of -13 k€/MW/year.

Results	2017
Primary market size	20 MW
Unit sizing	200% w/ NG sub.
Technology	PEM
Peak power	200%
Op. time and total elec. price (prim.)	48% @ 17 €/MWh
Op. time and total elec. price (NG Sub.)	42% @ 21 €/MWh
Levellised cost of H_2	2.4 €/kg
Net margin	-13 k€/MW/year

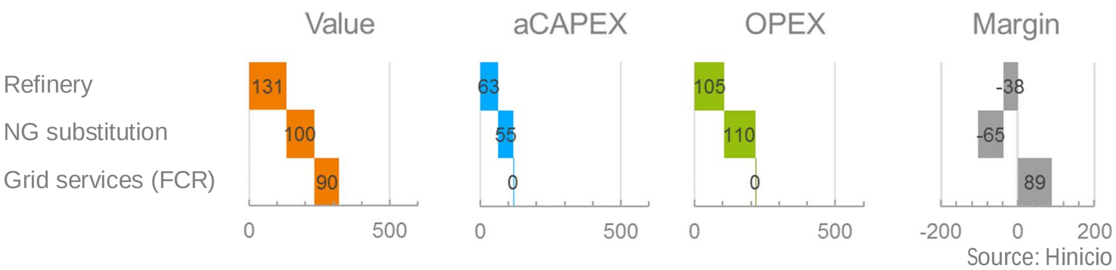


Figure 74: Large industry 2017 case – Financial breakdown

2025 business case

With an electrolyser system sized for being able to supply 200% of hydrogen demand for refinery, the load factor for the primary application is 48%. The average total cost of the electricity consumed is 26 €/MWh, resulting in a levelized cost of hydrogen (LCOH) of 2.3 €/kg, whereas the selling price is set at 2.6 €/kg including a carbon penalty of 80 €/tCO_2.

Selling H_2 to the mobility market generates a revenue of 213 k€/MW/year, of which 80% is offset by the annualised CAPEX and OPEX. The business case becomes profitable in 2025 for the following reasons:

- Implementation of a carbon penalty (raises the green hydrogen value)
- Project maturity (2017 à 2025)

Oversizing the system for natural gas substitution has a limited impact on net margin per MW, but increases the absolute margin. In 2025, the peak power capacity of PEM electrolyser is expected to reach 200% of nominal capacity, allowing to use 100% of the nominal power capacity for provision of symmetric FCR in accordance with the requirements of the German FCR market.

In this case, the revenues from **grid services exceed the annualized CAPEX costs, allowing commercialisation of green hydrogen at marginal production cost**. This can make green hydrogen competitive against "grey" hydrogen produced by SMR. The system payback time is fast tracked significantly by 5 years with grid services additional revenues, reaching 3.5 years.

Results	2025
Primary market size	20 MW
Unit sizing	200% w/ NG sub.
Technology	PEM
Peak power	200%
Op. time and total elec. price (prim.)	48% @ 26 €/MWh
Op. time and total elec. price (NG Sub.)	47% @ 34 €/MWh
Levellised cost of H_2	2.3 €/kg
Net margin	195 k€/MW/year
Payback time w/o grid services	8.4 years
Payback time w/ grid services	3.5 years

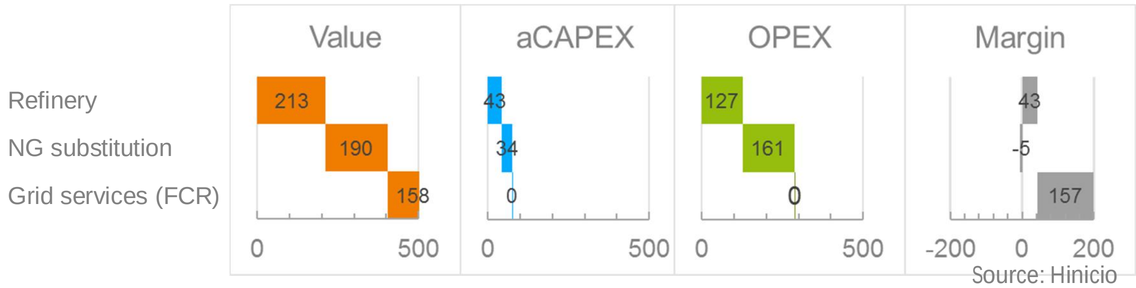


Figure 75: Large industry 2025 case – Financial breakdown

6.2.4.5. SENSITIVITY ANALYSIS

2017 business case

The business case would reach breakeven if the following can be achieved:

- **Investment subsidy** of at least 10%, representing 6 M€;
- Or **carbon penalty** of 10 €/CO_2.

This is considering the best location with the highest curtailment resources in Germany.

2025 business case

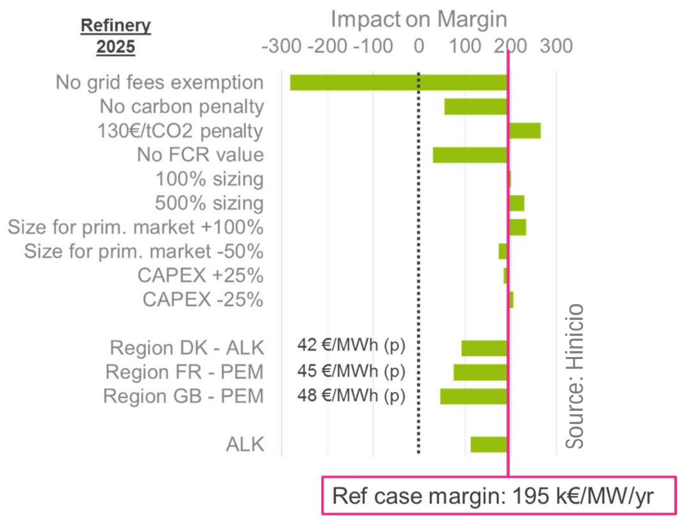


Figure 76: Large industry 2025 business case – Sensibility analysis

Main observations:

- The current reference scenario considers a best case where electricity is purchased at a low cost thanks to access to electricity at a discounted cost due to grid congestion, with nearly complete exemption from grid fees and levies. Without such conditions, the profitability deteriorates significantly. The breakeven point for the average total electricity cost is 53 €/MWh.
- In 2025 scenario, a carbon penalty is actually not required to achieve a positive net margin, however payback duration is significantly increased.
- The smallest market size that can preserve breakeven profitability in 2025 is 300 t/year, i.e. 2 MW system. The combination of cheap local electricity price in Lübeck, revenues from FCR and carbon penalty allows very cheap hydrogen production cost even on small system. However, large industry would typically require a much larger capacity before considering investing.
- ALK electrolyser inability to supply symmetric FCR is compensated by cheaper system costs and higher maturity in multi-MW scale. Even with lower profitability, ALK technology can still be suitable for large industry.

Boundary conditions Lubeck, DE	2017	2025	Comments
Reference margin	-13 k€/MW/yr	195 k€/MW/yr	
CAPEX	-10%	+250%	2017: 10% subsidy on investment for breakeven BCase
Electricity price incl. Grid fees, taxes, levies and GO	15 €/MWh	53 €/MWh	2017: Complete grid fees and levies exemption is required
H_2 market price	2.0 €/kg	0.3 €/kg	Selling H_2 is a secondary value stream. Grid services accounts for most of the gross margin
Min. H_2 market size and Equiv. electrolyser nom. size	8400 t H_2/year (Equiv. 30 MW)	300 t H_2/year (Equiv. 2 MW)	Electrolyser plant can be sized to cover any volume requirement from the refinery
Grid services revenue	+15% current price level	None	2017: Grid services would need to compensate loss from primary market and NG substitution 2025: Grid services account for 3/4 of gross margin
Carbon penalty	10 €/tCO_2	None	2025: LCOH is competitive against NG price

Source: Hinicio

Figure 77: Large industry business case – Boundary conditions

6.3. Contractual arrangements & de-risking

Contractual arrangements play an important role in defining the risk and hence the bankability of a project.

For all three cases, the interactions between the electrolyser operator and the different market players are presented in a way similar to Figure 78. Only considerations valid for the three business cases are discussed in this section, the others being treated in Annex 5.

- Electricity is purchased directly from the electricity market at the wholesale electricity price. In case of instantaneous local curtailment, electricity is directly purchased from the curtailed renewable power plant (in terms of location into the electricity grid, meaning a connection at the same transmission level substation as the generator), leading to a lower price than the wholesale electricity price. The counterparty of this contract depends on national regulation.
- Grid fees are charged by the electricity grid operator for connection to the network at a price defined with approval of the national regulatory authorities.

- Taxes and levies on the use of electricity are set by public authorities and/or national regulatory authorities. The situation greatly differs from one EU member state to another.
- Grid services (participation to frequency reserve) are provided to the TSO and lead to remuneration, either for availability or for effective use on request as presented in section 5.4.2.2.
- In the case of gas grid injection, H_2 is sold to the gas grid operator as green gas through a feed-in tariff.
- Hydrogen is certified as green by purchasing guarantees of green origin for the electricity that is purchased from the electricity grid ("grey mix"). This is done via the European GO market, which allows buying certificates from Alpine or Nordics hydro (storage) power plants, as mentioned in section 6.1.2.4. The price is not regulated but merely a result of supply and demand.

De-risking these contractual arrangements requires a long-term view, which greatly depends on national regulations as mentioned in Annex 5.

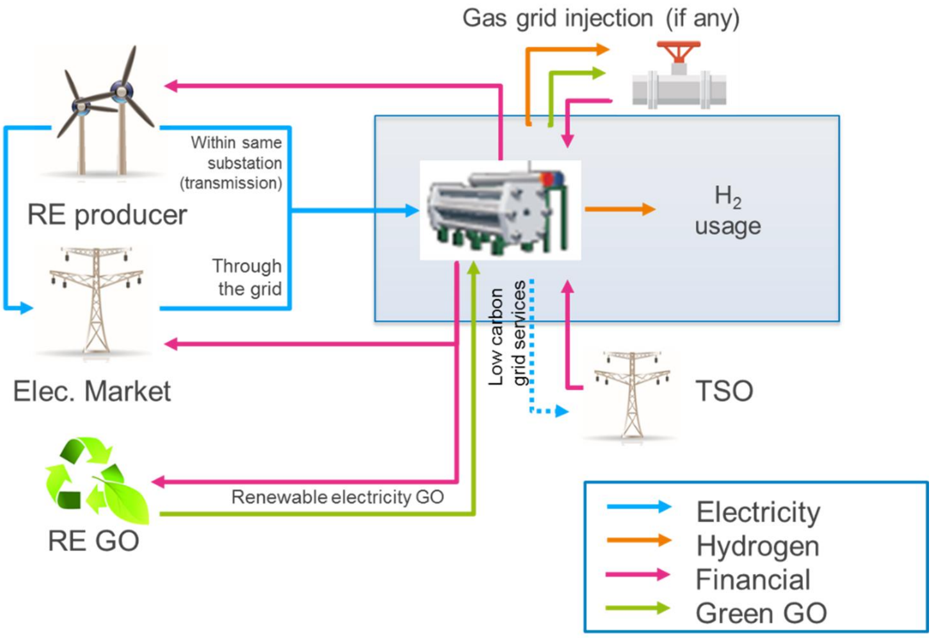


Figure 78: Interaction between the electrolyser operator and the other business stakeholders

6.3.1. Key contractual elements to enable de-risking

An essential element to de-risk projects and thus increase their bankability is to provide a long-term view on costs and revenues.

On the cost side, there is little long-term visibility. Being an electricity consumer, electrolysers can face a large number of fees, taxes and levies, unrelated to electricity supply costs. This group of components is sometimes referred to as the incontestable part of the electricity bill. Exemptions exist, but it is essential to offer legislative arrangements that these exemptions will not be removed abruptly. An effective way to provide this certainty is to offer exemptions for new installations for a period of >10 years, thus covering a large part of the lifetime of the asset. This is currently the case for grid fee exemptions in Germany.

On the revenue side, an important task of the project and business development phase will be to secure take-or-pay contracts for the supplied hydrogen. The volume risk can be further mitigated by offering feed-in tariffs for injecting hydrogen into the gas grid.

6.4. Societal benefits

The Power-to-Hydrogen applications considered in the present study lead to multiple benefits that are currently not fully captured by the national or European regulations:

- Using green electrolysis to feed hydrogen refuelling stations favours the deployment of greener vehicles fleets in Europe, by replacing a part of the current diesel or gasoline vehicles. Hence, CO_2 emissions will be reduced, which can contribute to the current EU 20/20/20 targets.
- Producing hydrogen from green electricity instead of from SMR, meaning from natural gas, can contribute to the aforementioned CO_2 emissions reduction.
- Setting new electrolysers close to curtailed renewable farms allows making use of green electricity that would be wasted otherwise. Compared with a random location of the electrolyser within the country, choosing a favourable location can then avoid requiring additional renewable power plants installation to better benefit from existing infrastructures.

The two first societal benefits amount roughly to 0.5 €/kg$_{H2}$ and are mainly driven by CO_2 mitigation costs (CO_2 emission price and processes efficiencies): they depend strongly on decarbonisation targets. The last one can lead to benefits above 1 €/kg$_{H2}$ but depends significantly on the business case considered and on its location in terms of presence of curtailed renewable electricity.

Those three societal benefits can serve as motivations for the regulatory recommendations proposed in section 7.

6.4.1. Avoidance of carbon emissions in mobility

The quantification of the societal benefit that can be expected with the semi-centralised business results from the valuation of the avoidance of CO_2 emissions from the diesel fleets reduction.

Table 60 presents the typical CO_2 savings of FCEV vis-a-vis diesel cars expected in 2017 and 2025, assuming an average distance covered of 20,000 km/y/car. The assumption taken on diesel cars consumptions corresponds, for 2017, to the existing upper limit on emissions for new cars sold from 2015 on; and for 2025, to the existing 2021 EU-target on average emissions on new cars sold [47]. For the replacing FCEV technology, an average consumption of 1kgH2/100km is taken (cf. Annex 4.3.4.1).

This valuation leads to earnings of 0.2 to 0.4 €/kg with the assumptions on CO_2 prices presented in section 3.1.1 (Table 8). Translated into €/MWh of electricity consumed by the electrolysis process (with the process efficiencies defined in Table 24, section 4.1.1.1), this means an expectable reduction on the total electricity price of 2.7-6.7 €/MWh.

		2017	2025
Replaced technology		New car sold 2015, 130 gCO_2/100km	New car sold 2021, 95 gCO_2/100 km
Typical CO_2 savings by new car		2.6 t_{CO2} /y /car (20,000 km /y /car)	1.9 t_{CO2} /y /car (20,000 km /y /car)
CO_2 Prices	**EU-ETS**	12.7 €/t_{CO2}	28.1 €/t_{CO2}
	GB	28.8 €/t_{CO2}	42.8 €/t_{CO2}
Societal value	**EU**	0.2 €/kg_{H2}, 2.7 €/MWh	0.3 €/kg_{H2}, 4.4 €/MWh
	GB	0.4 €/kg_{H2}, 6.1 €/MWh	0.4 €/kg_{H2}, 6.7 €/MWh

Table 60: Societal Benefit – CO_2 emissions avoidance in mobility

6.4.2. Avoidance of carbon emissions in industry

Given the legally binding renewable energy target by 2020, curtailed RES electricity will have to be compensated by deploying additional RES installations.

Applying the same CO_2 price for the refineries as for the semi-centralised mobility business case, one can estimate the savings in CO_2 emissions obtainable from replacing an SMR-based H_2 production plant by a green-electricity-based one.

SMR-based H_2 production is assumed, from Annex 4.1.1.4, to produce 72.4 g_{CO2}/MJ_{NG} with a fuel HHV of 142 MJ_{NG}/kg_{H2} and a process efficiency of 70% (MJ_{output}/MJ_{input}). Table 61 presents the societal benefits that can therefore be expected from using green-electrolysis instead of steam reforming to produce hydrogen.

Expectable earnings are between 0.1 and 0.3 €/kg_{H2} (1.6 to 5.3 €/MWh of electricity consumed) and are thus in the same order of magnitude as for mobility.

		2017	2025
Replaced technology		SMR H_2 production plant, 7.2 kg_{CO2}/kg_{H2}	
CO_2 Prices	**EU-ETS**	12.7 €/t_{CO2}	28.1 €/t_{CO2}
	GB	28.8 €/t_{CO2}	42.8 €/t_{CO2}
Societal value	**EU**	0.1 €/kg_{H2}, 1.6 €/MWh	0.2 €/kg_{H2}, 3.5 €/MWh
	GB	0.2 €/kg_{H2}, 3.6 €/MWh	0.3 €/kg_{H2}, 5.3 €/MWh

Table 61: Societal Benefit – CO_2 emissions avoidance in large industries

6.4.3. Avoidance of RES curtailment

By placing the electrolyser close to a curtailed renewable farm to benefit from curtailed electricity, the need of building new renewable farms can be reduced. Assuming an average LCOE of new wind farms of 50 €/MWh [70] and expecting this value to be further decreased down to 40 €/MWh by 2025, this societal benefit can be computed considering the amount and frequency of curtailment obtained from the simulations handled in section 3.2.2.

Depending on the electrolyser size and technology that are considered for the different business cases (6 MW PEM for semi-centralised mobility and light industry, 20 MW ALK for refineries) the avoidance of RES curtailment can lead to values higher than 1 €/kg$_{H2}$ but with a high dependence on the location within the country. Figure 79 shows those results with the different assumptions summarised in Table 62, for the 5 selected locations except Sardinia where nearly no curtailment was identified in section 3.2.2.

	Semi-centralised mobility and light industry		Large industry	
	2017	2025	2017	2025
Electrolyser size and technology	6 MW PEM		20 MW ALK	
Electrolyser efficiency (kWh/kg)	61	53	51	49
New Wind LCOE (€/MWh)	50	40	50	40

Table 62: RES curtailment avoidance assumptions for societal benefits computation

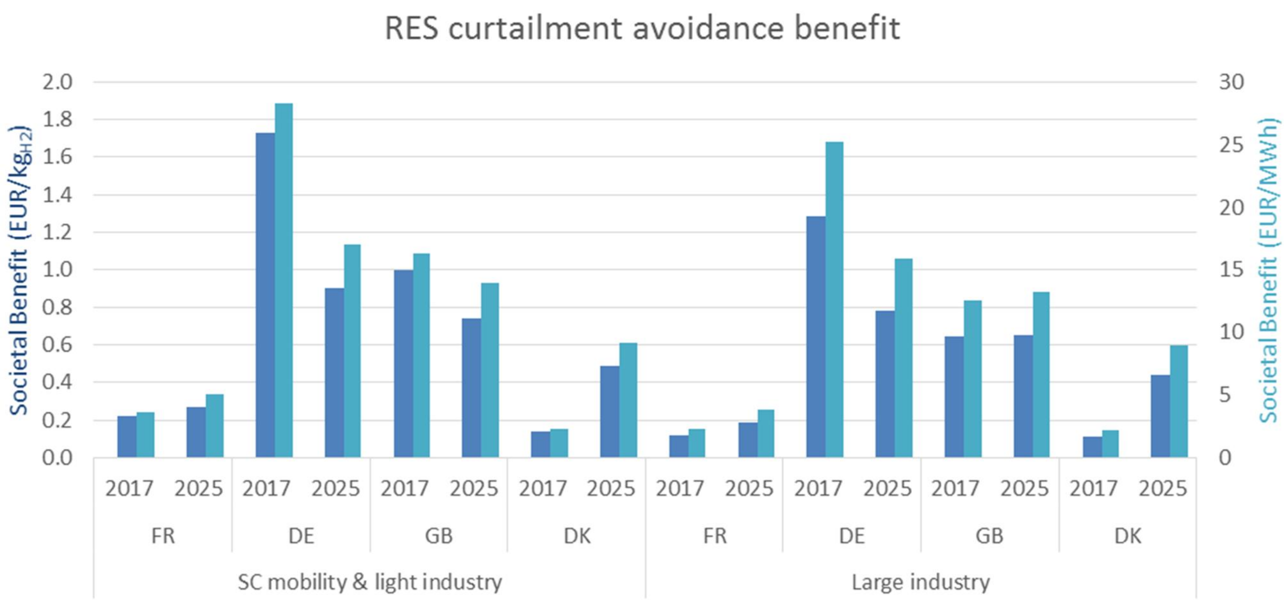


Figure 79: Societal Benefit – RES curtailment avoidance

6.5. Key conditions for profitability

This section proposes a simple approach for summarizing the key conditions for profitability based on the detailed analysis from section 3.2. Profitability of a project can be determined approximately based on 3 key parameters:

- **System size** influences the project CAPEX and equipment related OPEX. System size is selected to satisfy a specific primary application. This simple approach does not consider oversizing and gas grid injection options.
- **Total electricity cost** influences the resource related OPEX costs. The total electricity cost must include the wholesale or discounted electricity price, grid fees, taxes, levies and GO. Also, grid services generating a revenue proportional to the operating time (such as provision of FCR), hence offsetting the electricity cost, can be considered.
- **Targeted or acceptable hydrogen price for the primary market** influence the potential revenue the project can generate. The following figure shows examples of hydrogen value chains. In order to keep the same definition across the business cases, the target hydrogen price is defined for product just downstream of the H_2 production unit, i.e. electrolyser system.

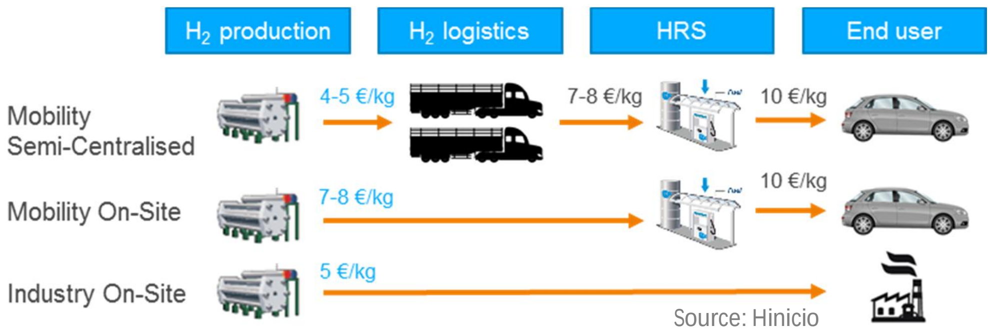


Figure 80: Example of hydrogen value chain and H_2 target price for primary market

Figure 81 *aggregates the three parameters discussed previously. Depending of the project size and location, it is possible to determine the profitability of a project. Each orange surface represents the boundary conditions for profitable business case. For instance, a 5 MW mobility project in 2017 with a target hydrogen production price (electrolyser output) of 4.5 €/kg can afford total electricity price of 44 €/MWh or cheaper. The total electricity price graph shows that most regions can achieve profitability as the electricity price is cheaper.*

The available total electricity price in different regions provided in section 6.6.3.1 (Figure 84) can be used to estimate project profitability in certain regions.

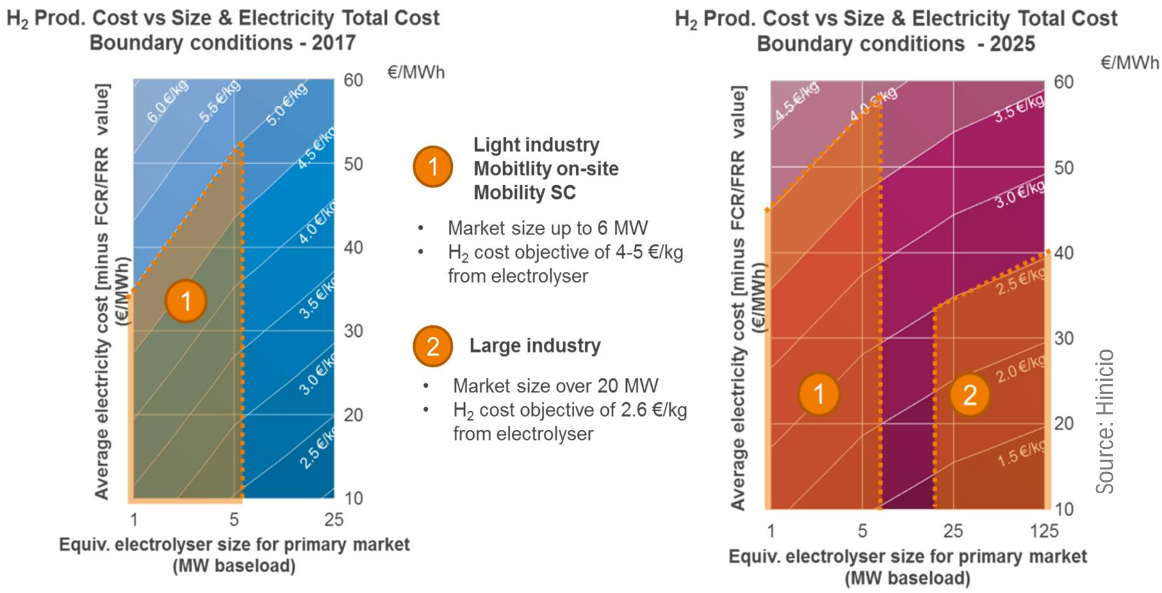


Figure 81: H_2 production cost vs electrolyser size vs total electricity cost boundary conditions in 2017 and 2025

The following sub-sections propose to extrapolate the boundary conditions for each primary application scenario to generate profitable business cases in 2017. The total electricity cost threshold can be compared to the Figure 84 to identify suitable locations.

6.5.1. Mobility business case extrapolation

Onsite production for mobility can benefit of higher acceptable hydrogen production cost as it does not need to transport gas, leading to a high total electricity cost threshold. Most EU regions can achieve the 65 €/MWh total electricity cost with grid services provision.

On the other hand, semi-centralised production for mobility requires high volume to compensate the low acceptable hydrogen production cost (4-5 €/kg). Short term business cases can be found in Germany and Denmark even at 1 MW electrolyser equivalent of hydrogen demand.

Mobility applications	OnSite	Semi Centralised Low volume	Semi Centralised High volume
Electrolyser size to fulfil full H2 demand onsite	1 MW	1 MW	6 MW
H2 acceptable production cost at electrolyser	7-8 €/kg	4-5 €/kg	
Total electricity cost threshold	~65 €/MWh	20-35 €/MWh	35-50 €/MWh
Regions where profitable business cases can be found	France, Germany, Great Britain, Denmark	Germany, Denmark	France, Germany, Great Britain, Denmark

Table 63: Mobility industry – Example of total electricity cost threshold estimation based on business case extrapolation (2017)

6.5.2. Light industry business case extrapolation

When considering an acceptable hydrogen production cost of 5€/kg for light industry, the total electricity cost threshold varies between 30-50 €/MWh depending on light industry's hydrogen volume requirement. A small hydrogen market volume leads to high system cost and would require a low total electricity cost threshold. Based on Figure 84, most light industry application business cases can be found in France, Germany and Denmark.

Light industry applications	Cooking oil and fat	Glass making	Electronics	Metallurgy
Electrolyser size to satisfy full H2 demand onsite	30 kW to 3 MW	250 to 600 kW	Up to 2 MW	100 kW to 4 MW
H2 acceptable production cost at electrolyser	Considering 5 €/kg (truck-in or small SMR substitution)			
Total electricity cost threshold	45 €/MWh	30 €/MWh	40 €/MWh	50 €/MWh
Regions where profitable business cases can be found	France, Germany, Great Britain, Denmark	Germany, Denmark	France, Germany, Great Britain, Denmark	France, Germany, Great Britain, Denmark

Table 64: Light industry – Example of total electricity cost threshold estimation based on business case extrapolation (2017)

6.5.3. Large industry business case extrapolation

As explained in section 5.1, large industry refers to large hydrogen consumers such as refineries, steel and chemical plants. They are generally supplied by onsite large SMR units and/or nearby pipeline. Power-to-Hydrogen system will substitute part of hydrogen demand increase in large industries in the short term. It can be assumed that large industry end-user would start considering Power-to-Hydrogen solution from 10MW system size. As presented in the section 5.1.1, H_2 production cost for refineries can vary from to 1.8 to 4.0 €/kg depending mainly on the SMR capacity availability.

As seen in Figure 84, Germany and Denmark have the cheapest electricity price ranging between 20-25 €/MWh. Profitable large industry business cases would require a hydrogen market of an equivalent of 25 MW electrolyser.

	Large industry applications
Electrolyser size to fulfil partial hydrogen demand of large industry	25 MW
H2 acceptable production cost at electrolyser	Considering 2.5 €/kg for SMR substitution
Total electricity cost threshold	20-25 €/MWh Based on Germany and Denmark with discounted electricity (see Figure 84)

Table 65: Large industry – Example of total electricity cost threshold estimation based on business case extrapolation (2017)

6.6. Market potential across Europe

6.6.1. Methodology

To assess the replicability potential of the business cases treated in the present study, two methods are used:

- A top-down approach, where the goal is to determine the market size of the considered business cases in 2025 in Europe, considering the expected businesses growths until then based on hydrogen demand outlook.
- A bottom-up approach, where the goal is to analyse to which extent the business cases conditions presented in this study can be replicated among the 4 modelled countries, with an additional extrapolation to Europe. This replicability analysis is performed based on the RES curtailment figures obtained in section 3.2.2 for the 4 selected non-island countries, which can have a significant influence on the average electricity cost as mentioned in section 6.1.2.1. Replicability potentials are presented for both the short- and long-term situations (2017 and 2025).

Those two approaches are then combined to determine how big the market potential is throughout Europe for the 3 selected business cases.

6.6.2. Top-down approach

6.6.2.1. INDUSTRY

The following graph shows the projected EU H_2 annual demand growth per industrial sector in 2014.

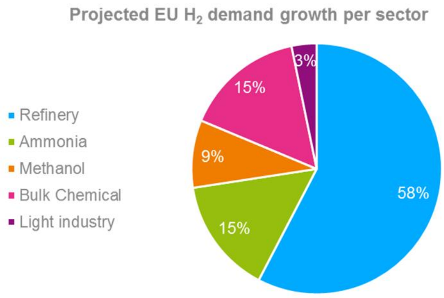


Figure 82: Projected EU H_2 demand growth per industrial sector [43]

6.6.2.1.1. Large industry

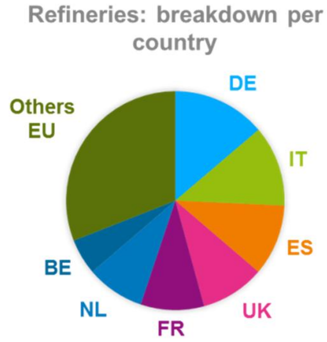


Figure 83: EU country breakdown in refining capacities

Refineries are the largest H_2 consumers in Europe with 46 billion Nm^3/year. Seven countries (DE, IT, ES, UK, FR, NL, BE) account for 70% of total refining capacities.

Refineries also account for 60% of H_2 demand growth in EU. This is mainly due to lower quality crude oil imports (high sulphur content) and higher quality fuel produced (de-sulphurization). This industry is expected to grow by 3.2%/year. This represents an increase of 127 000 t/year, the equivalent of **725 MW of electrolyser baseload capacity installed per year**.

6.6.2.1.2. Light industry

Light industry is composed of many applications (e.g. cooking oil and fats, glass manufacturing, semi-conductor, metallurgy…). They consume about 2 billion Nm^3/year. In general, the main driver is economic growth. Overall, light industry H_2 demand growth is expected to increase by 4.1%/year in EU. This represents an increase of 7 100 t/year, an equivalent of **40 MW electrolyser baseload installed per year**.

6.6.2.2. MOBILITY

Deployment of hydrogen mobility is currently strongly politically driven. Many EU Member States have published ambitious national roadmaps on hydrogen mobility. Most roadmaps estimate an exponential growth of hydrogen mobility after 2020. The most ambitious roadmaps are Germany, France, Scandinavia, Italy and UK.

EU-wide	2017	2020	2025
# FCEV	600	4 000	800 000
# Buses	85	575	1 800
# HRS	85	740	1 500
H_2 demand (t/yr) *	550	3 650	120 500
Equiv. Electrolyser (MW baseload/yr)	3	21	690

*Assuming FCEV 0.5 kg/d and buses 20 kg/d @ 270 days

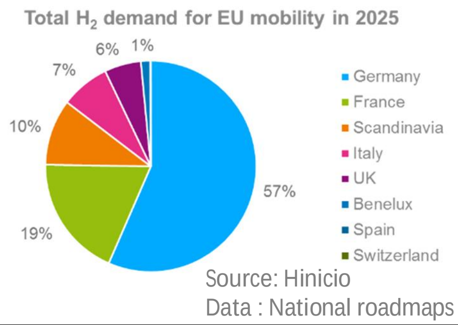


Table 66: EU Hydrogen mobility deployment projection in 2017-2020-2025

By 2025, total EU H_2 demand for mobility is projected to reach 120 500 t/year which represents an equivalent of **690 MW electrolyser baseload**.

6.6.3. Bottom-up approach

6.6.3.1. CONDITIONS FOR PROFITABILITY

To determine to which extent the presented business cases can be replicated among the 4 modelled countries, one must first identify the replicability of obtaining discounted electricity price based on curtailment. For that, similar curves as the local price duration curves mentioned in section 6.1.2.1 are derived with the national curtailment figures.

Figure 84 shows the total average electricity price that can be obtained for a 1MW electrolyser operating 100% of the time with and without price discount from curtailment in each of the 4 non-island countries.

Installing more (or larger) electrolysers at the same location requires a bigger volume of instantaneous curtailed electricity. Hence, the price discount can be applied a more limited number of times over the year, leading to an increase of the average total price with discount presented in Figure 84. At the limit where all the curtailed electricity is used (i.e. when electrolysers as set at every place where curtailment occurs), installing a new electrolyser can only be done at the normal electricity price without any discount.

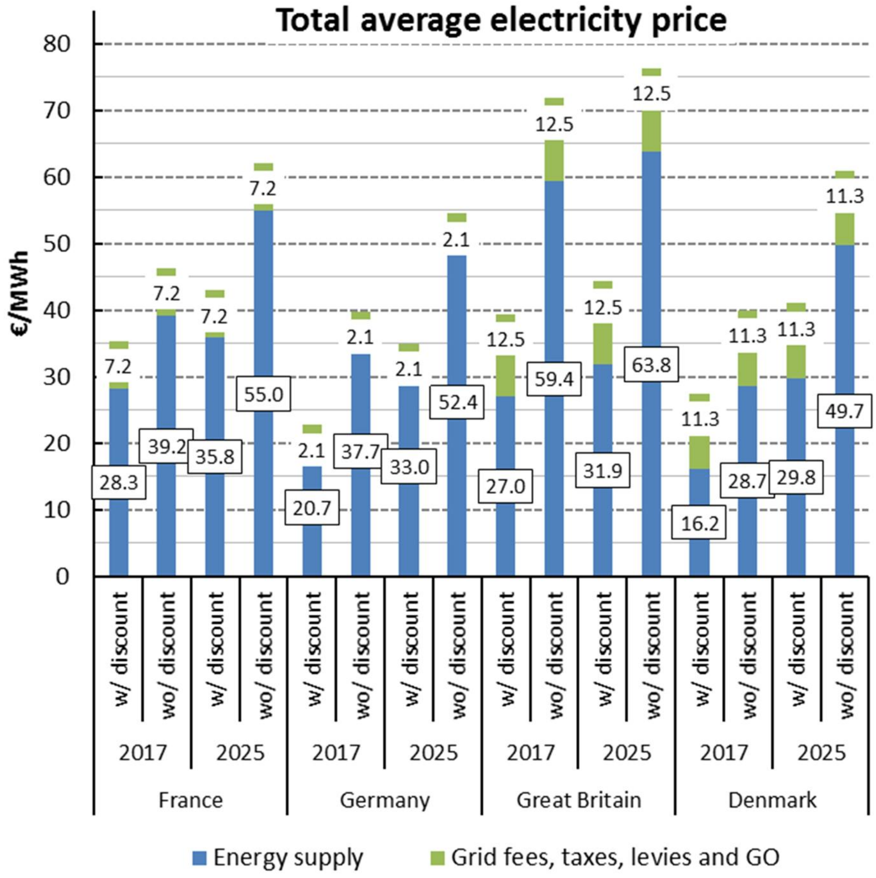


Figure 84: Total average electricity price structure per country assuming a 1MW electrolyser operating 8760 h/y

Depending on the business case, a different maximum total electricity cost can be used to allow the business case to be viable. This maximum value is obtained from the limit at which the business case reaches a 0 margin when running a sensitivity analysis on electricity cost, assuming an electrolyser running 8760h/y without providing frequency services.

The Table 67 presents this maximum, called threshold price, for each of the 3 studied business cases with a conservative value on hydrogen price. If an electrolyser operator can purchase electricity with an average price below the indicated threshold, the business case is profitable.

	Semi-centralised mobility		Light industry		Large industry
	2017	2025	2017	2025	2025
Hydrogen value (€/kg_{H2})	6	5	2.6	2.6	3.5
Threshold average total electricity cost (€/MWh)	40.3	50.3	37.6	45.2	52.8

Table 67: Replicability threshold average total electricity cost

6.6.3.2. EU-4 POTENTIAL: THEORETICAL VS. USABLE

6.6.3.2.1. Theoretical EU-4 potential

The electrolysis potential that can be derived with an average electricity price below the thresholds defined in section 6.6.3.1 is presented in Table 68 per country and business case.

For 2017, some of the threshold prices are above the total average electricity price without discount presented in Figure 84 (namely: Germany and Denmark for the semi-centralised mobility business case); the potentials would therefore be infinite following the current approach. This is however not valid since a significant increase of the load of the system would result in an increase of the overall instantaneous country price: the implicit assumption made that electricity can be purchased at the marginal price of the system without modifying it does no longer hold valid. Potentials are thus derived assuming that the additional electrolysis load induced in the system increases the average price of the system.

Electrolysis theoretical potential (MW)	Semi-centralised mobility		Light industry		Large industry
	2017	2025	2017	2025	2025
France	15	38	8	9	67
Germany	700	533	596	330	1183
Great Britain	8	43	6	15	96
Denmark	970	707	474	180	1182
Total EU-4	~1700	~1300	~1085	~535	~2500

Table 68: Theoretical replicability potential based on average electricity price

To those potentials, an extra potential can be obtained from providing frequency services to the grid operator. As those services induce an increase of profitability margin, they can be considered as a negative cost to the average electricity purchase price. This way, the comparison to the threshold prices defined in section 6.6.3.1 keeps valid and does not require recomputation of the thresholds.

As the FCR margins range from 11 to 18 €/MW/h depending on the country, the additional potential from FCR revenues is huge (in the order of magnitude of ~1 GW) for each business case and country. This does however not make sense since the frequency reserve constitution is limited. Assuming that a maximum potential of 20% of the frequency reserves can be obtained, an **additional potential of 335 MW** is obtainable **from frequency services** for each business case[28] for the four countries together, considering that the current reserves constitute 0.7% of the countries loads.

[28] Assuming only one of the three business cases will be deployed. If all business cases are getting developed, only a total of 335 MW for the three business cases together is permitted.

6.6.3.2.2. Derating to usable EU-4 potential

Out of the theoretical EU-4 potentials discussed in section 6.6.3.2.1, only a part of it must actually be considered because the treated business cases require an adequacy between the locations of the hydrogen demand and of the available curtailed electricity within the different countries. The Table 69 emphasizes the surface ratios of the usable areas (i.e. with both hydrogen demand and curtailment) within the demand areas to which refer the theoretical potentials. For this, curtailed areas from section 3.2.2.2 are matched with the locations of the business cases demands, which are:

- For the semi-centralised mobility business case: the mapping of the current and projected hydrogen refuelling stations in Europe [77]. For 2025, it is assumed, according to Figure 85 [67], that the refuelling stations distribution will be equally distributed over the country, as for the light industry business case.
- For the light industry business case, where it is assumed that the demand is equally distributed over the country: the curtailed area within the country.
- For the large industry business case: the mapping of the refineries presented in section 5.1.1 (see Figure 31).

Usable area / Country area (%)	Semi-centralised mobility		Light industry		Large industry
	2017	2025	2017	2025	2025
France	0.1 %	2.1 %	0.1 %	2.1 %	4.4 %
Germany	66.7 %	1.5 %	7.0 %	1.5 %	14.6 %
Great Britain	1.3 %	32.1 %	2.5 %	32.1 %	13.5 %
Denmark	70.0 %	30.2 %	30.2 %	30.2 %	0.0 %

Table 69: Usable potential determination: ratios of usable over country areas

Figure 85: Hydrogen refuelling stations in Germany expected in 2023 [67]

Based on those ratios, the expected usable potentials in the 4 considered countries are derived in Table 70.

Usable potential (MW)	Semi-centralised mobility		Light industry		Large industry
	2017	2025	2017	2025	2025
France	3	8	0	0	3
Germany	66	44	41	5	173
Great Britain	0	5	0	5	13
Denmark	353	471	143	54	0
Total EU-4, excl. FCR	**421**	**527**	**185**	**64**	**189**
Total EU-4, incl. FCR	**756**	**862**	**520**	**399**	**524**

Table 70: Usable replicability potentials for EU-4

6.6.3.3. EU-28 POTENTIAL

To extrapolate the potentials from the 4 modelled countries towards Europe (EU-28+Norway) without focusing on regulations of each country separately, a reasoning is applied based on publications on the average electricity price, average grid fees, taxes and levies, and electric load of each of those countries.

- The average electricity price considered for each country is the yearly average of the quarterly wholesale baseload electricity price published in electricity market reports of the European Commission, from the 4th quarter 2015 to the 3rd quarter 2016 [46]. A scaling up of the prices is achieved to obtain the prices in 2017 and 2025, so that the EU-4 average prices for 2017 and 2025 match those presented in section 6.6.3.1 (Figure 84). This scaling up is weighted by the country electricity consumptions.
- The average grid fees, taxes and levies are obtained from a publication of CEPS [12] for Italy, the Netherlands, Spain, Portugal, Czech Republic and Romania. For the other countries, results from Eurostat [48], which however exclude grid fees, are used.
- The yearly electric consumption is the sum of the monthly electricity consumption for 2015[29] presented by ENTSO-E [38].

The approach taken consists in scaling up, with the country loads as weights, the EU-4 theoretical potentials excluding FCR to each country whose average total electricity price (wholesale electricity price plus average grid fees, taxes and levies) is below the threshold prices defined in section 6.6.3.1 (Table 67). A derating factor is then considered to reduce this potential to a usable potential for those countries. The factor used is the ratio of the time during which the electrolyser can benefit from electricity sufficiently cheap without requiring an electricity discount based on curtailment, over the operability time of the electrolyser (baseload working – 8760h).

[29] Most recent year with data available for each country.

The Table 71 presents the theoretical and usable potentials for EU-24 (i.e. EU-28 without EU-4) and Norway. The Table 72 then summarises the usable potentials for EU-28 and Norway, with small pie charts representing the contribution of the Nordics, Central-Western Europe and Eastern Europe.

	Semi-centralised mobility		Light industry		Large industry
	2017	**2025**	**2017**	**2025**	**2025**
Theoretical potential EU-24+NO (MW)	171	417	109	67	912
Derating factor (%)	70 %	71 %	63 %	56 %	79 %
Usable potential EU-24+NO (MW)	**119**	**296**	**69**	**37**	**718**

Table 71: Theoretical and usable replicability potentials for EU-24 + NO

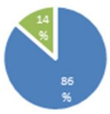
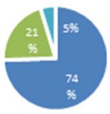
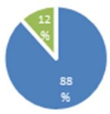
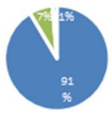
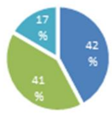
Usable potential (MW)	Semi-centralised mobility		Light industry		Large industry
	2017	**2025**	**2017**	**2025**	**2025**
Total EU-4, incl. FCR	756	862	520	399	524
Total EU-24+NO, excl. FCR	119	296	69	37	718
Total EU-28+NO, incl. FCR	**875**	**1158**	**589**	**437**	**1242**
CWE Nordics Eastern Europe					

Table 72: Usable replicability potentials for EU-28 + NO

6.6.4. EU-28 market potential

Table 73 shows a comparison between the potential obtained for 2025 via the top-down approach, which indicates the expected market potential in Europe, and via the bottom-up approach, which states the size of the market that can be captured to build profitable business cases. **For each business case**, it appears that **there is sufficient replicability potential to capture the whole size of the market**. In total for 2025, the **replicability potential** of the three business cases together amounts **2.8 GW** of **electrolysis** (meaning a total market value of €4.2bn) if each business case can reach 20% of the FCR market, **for a 1.5 GW demand**.

	Semi-centralised mobility		Light industry		Large industry
	2017	**2025**	**2017**	**2025**	**2025**
Top-down: EU-28 potential demand (MW)	-	690	-	40	725
Bottom-up: EU-28+NO usable potential (MW)	**540**	**823**	**254**	**102**	**907**
+ FCR Potential	**335**				

Table 73: Comparison between bottom-up and top-down potentials

7. REGULATORY RECOMMENDATIONS

Key findings

The following messages can be formulated based on the previous sections of this study concerning changes towards an enabling environment for Power-to-Hydrogen applications in Europe:

- Avoid inflating electricity prices with costs unrelated to electricity supply. A (partial) exemption from paying grid fees, taxes or levies can be justified on the grounds that electrolysers can operate in a system-beneficial mode.
- Provide a clear regulatory framework on how to access curtailed RES electricity to facilitate the uptake of bilateral contracts between RES operators and potential consumers.
- Develop EU framework guidelines to provide a level playing field for access to frequency control grid services, with a focus on asymmetric procurement (allowing load to provide frequency services on the one hand, and dissociating upwards and downwards frequency regulation on the other hand).
- Provide a level playing field for the injection of zero-carbon gas into the gas grid, be it bio-methane or green hydrogen.
- Allow for inclusion of green hydrogen in the carbon intensity calculation of conventional fuels in the forthcoming revision of the FQD and RED II.

7.1. Avoid inflating electricity prices with costs unrelated to electricity supply

Together from the cost of equipment, the total electricity cost is a key influential factor for the profitability of a Power-to-Hydrogen business case. What can be observed in today's electricity markets is that regulated components, i.e. components unrelated to electricity supply, make up for a large part of the electricity bill. These include grid fees, taxes and levies.

For an average industrial consumer in Germany, taxes & levies alone can make up for 50% of the bill. Being electricity consumers, electrolysers can therefore be subject to significant costs, potentially suppressing the uptake of Power-to-Hydrogen.

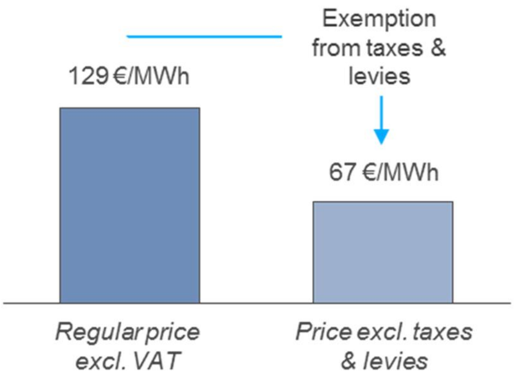


Figure 86: Electricity price for an average industrial consumer in Germany (2016)[30]

Exemptions from taxes & levies are an effective way of supporting the uptake of Power-to-Hydrogen implicitly. From a policy perspective, this is a consistent strategy to incentivise the decarbonisation of sectors other than power, i.e. industry, heat and transport. Levies are heavily driven by RES support in some countries, following a strong deployment of solar in the mid-2000s and early 2010s. It is recommended to rethink the way these energy transition costs are allocated to consumers. In view of the overall low-carbon targets, it is recommended to provide exemptions from these levies for sector coupling solutions (so-called *Power-To-X*).

Grid fees also add up to the overall electricity cost. Already today, **electrolysers and batteries are exempted from paying grid fees in some EU member states; provided that they operate in a system-beneficial mode**, i.e. do not consume electricity during system peak load. It is recommended to expand this practise to other EU member states.

7.2. Provide clear regulation on accessing curtailed RES electricity

Curtailed RES electricity is a significant phenomenon in a large number of EU member states today, with Germany being at the forefront with 4 TWh of curtailed RES electricity in 2015, corresponding to 2.5% of total RES production. **A clear regulatory framework on how to access this electricity should be provided to facilitate the uptake of bilateral contracts between RES operators and potential consumers, thus avoiding or at least reducing curtailment.**

[30] Based on Eurostat, consumption band ID (2-20 GWh/yr).

From a policy perspective, there are good reasons to develop such a framework. In view of legally binding RES targets, curtailed RES electricity will have to be replaced by deploying additional RES capacity, leading to unnecessary costs. This cost can be avoided with flexible, modular consumers such as electrolysers. Apart from this, stress on electricity grid assets can be reduced, if injection peaks of RES are absorbed by electrolysers. In the long run, this could also avoid grid reinforcements at local level.

7.3. Enable level playing field for electricity grid services

Markets for grid services such as FCR (frequency containment) and FRR (frequency restoration) are currently dominated by thermal generation and are not easily accessible for Power-to-Hydrogen systems.

Phasing out thermal generation will create a demand for new providers of these services, be it batteries, electrolysers or flexible demand. The most cost-effective solution will emerge, if a level playing field is provided.

EU framework guidelines for electricity grid services should be developed, focusing on:

- **Asymmetry**: separate procurement of upward + downward regulation
- **Neutrality** between load & generation

A separate procurement enables an easier participation of electrolysers and the demand-side in general, because these can reduce *consumption* while at full load. At the same time, this will also facilitate the participation of intermittent RES to electricity grid services, because these units can reduce generation, while running. Overall, this will increase system efficiency and thus benefit all electricity consumers.

7.4. Enable level playing field for gas grid injection

The greening of gas network can contribute to reach the EC targets for renewable energies by 2020. Biomethane injection is the most common way to green the gas grid. It benefits from feed-in tariff and streamlined procedure for interconnection in most countries.

Even though hydrogen injection into the gas grid requires can require changes to standards and regulation, it has the same greening potential as biomethane when produced from renewable sources (e.g. renewable electricity). In fact, gas grid injection can help to integrate renewable energy into the energy system by providing a constantly available outlet for valorizing electricity which would otherwise be curtailed. Furthermore, gas grid injection can accelerate hydrogen mobility deployment by de-risking the ramp-up period. For these reasons, **hydrogen injection into gas grid should benefit from the same rules and tariffs as bio-methane injection**.

More specifically, it is recommended to:

- Create feed-in tariff scheme for green hydrogen injection into gas grid;
- Harmonize hydrogen injection limit among Member States.

7.5. Integration of green hydrogen as emission reduction in refineries in calculation of carbon intensity

Current regulations do not recognize green hydrogen production in refineries. However, **current revision of FQD and RED II is a unique opportunity to recognise emissions from hydrogen production in refineries for the carbon intensity calculation on conventional fuel beyond 2020**.

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ANNEX 1. COUNTRY ELECTRICITY PRODUCTION DATA

1.1. Country fuel mix

The fuel mixes used for each country are emphasized in the following figures in terms of installed capacity per country. Those serve as inputs for the PLEXOS and SCANNER simulations handled to determine the best locations for Power-to-Hydrogen applications in the 5 selected countries.

As illustrated, the capacity mix is expected to change between 2017 and 2025. The main drivers of these changes concern a nuclear phase out in Germany foreseen by 2022 and an increase in renewable capacity (most notably wind and solar) across Europe as a result of the CO_2 abatement policies. Results for all the selected countries at once are presented in Figure 87, with detailed views per country in Figure 88 (France), Figure 89 (Germany), Figure 90 (Great Britain), Figure 91 (Denmark) and Figure 92 (Sardinia).

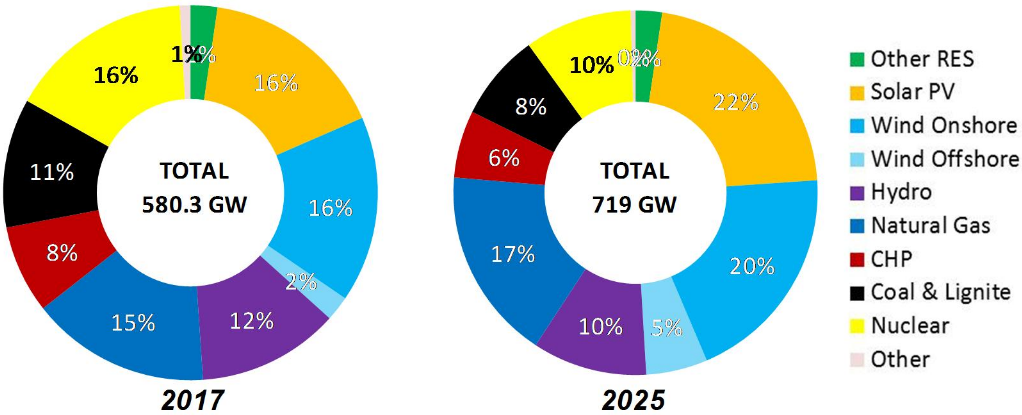

Figure 87: Capacity Mix of whole Scope (CWE, UK, IT, Denmark)

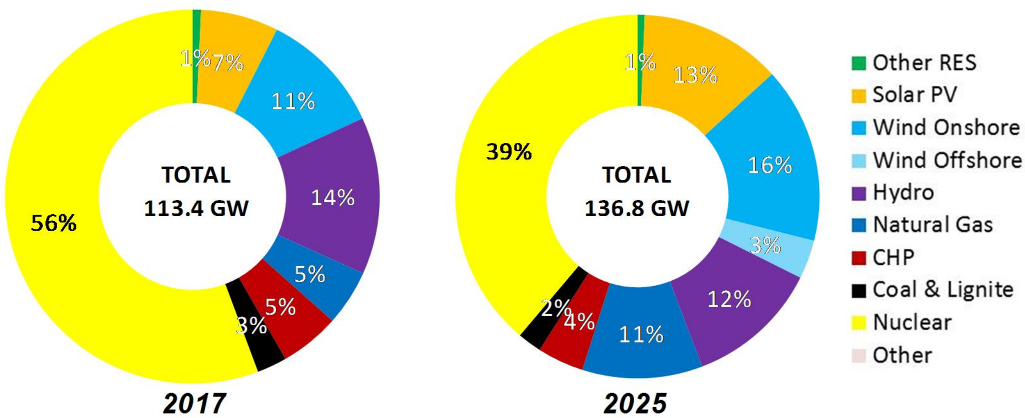

Figure 88: Capacity Mix (France)

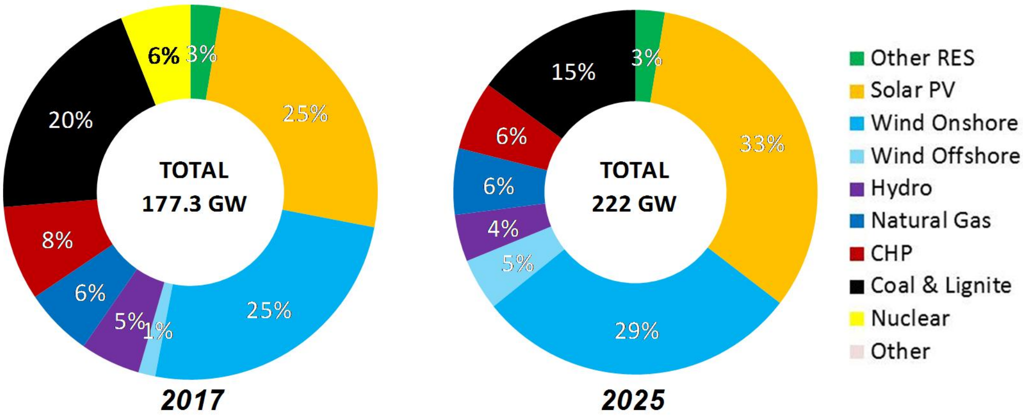

Figure 89: Capacity Mix (Germany)

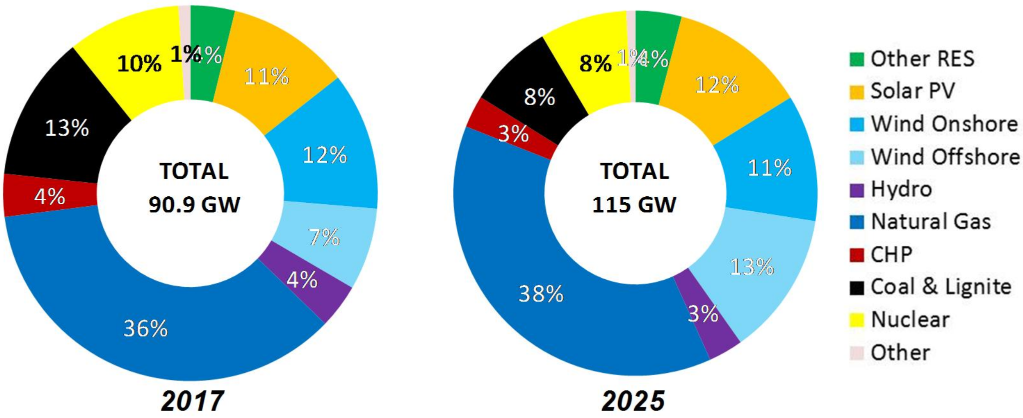

Figure 90: Capacity Mix (Great Britain)

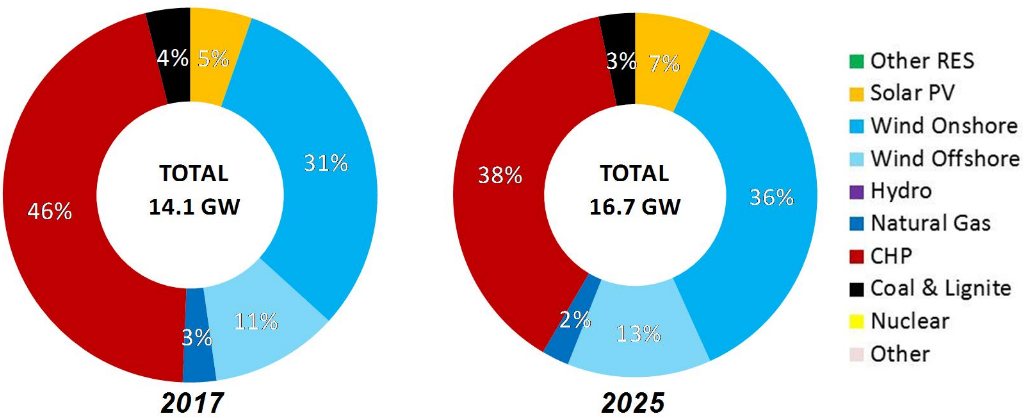

Figure 91: Capacity Mix (Denmark)

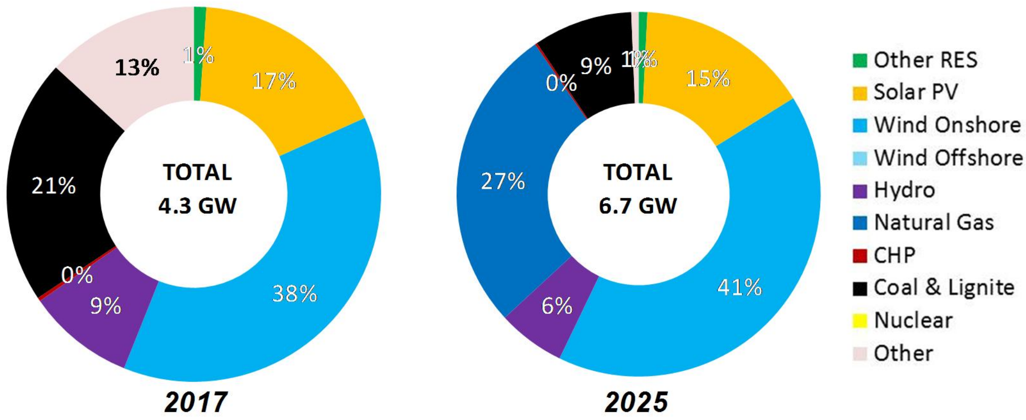

Figure 92: Capacity Mix (Sardinia)

1.2. Country wholesale electricity price

One main output of the PLEXOS simulations is the hourly wholesale electricity price curve obtained for each country based on the energy mixes presented in Annex 1.1. This is shown in the following figures (93 to 98) through price duration curves that sort the hourly prices down over the entire year for visualization purposes.

Regarding their expected evolution between 2017 and 2025, the following observations can be made:

- General tendency to more high-price hours in 2025
- Extreme peak and off-peak prices are highly dependent on the conditions (interconnection capacity, RES share, nuclear policy) in 2025 in each country:
  - Zero-price hours tend to increase due to a rise in RES penetration, with the exception of Denmark because of the increasing number of interconnections coming with the rest of Europe
  - France experiences the least drastic changes of all countries due to its nuclear policy and moderate RES deployment
  - In contrast to most of continental Europe, Great Britain is expected to see less extreme peaks in 2025 since additional interconnection capacity and investments in power plants mitigate the current tightness in supply and demand balance for power.

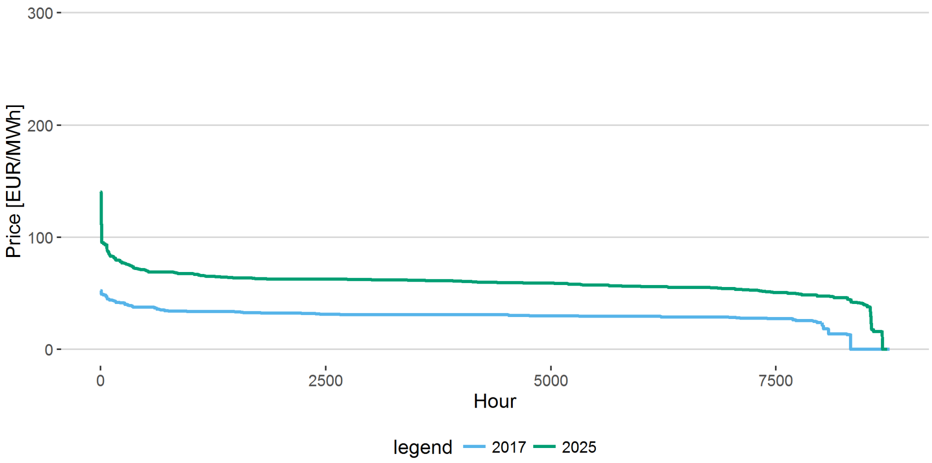

Figure 93: Price duration curves in Denmark (2017 and 2025)

For Denmark in particular (Figure 93), almost all the zero price hours disappear from 2017 to 2025. This can also be seen in Table 74, which depicts the minima and maxima of the hourly prices per country. In 2018, the Danish interconnection capacity almost doubles as new connections with The Netherlands and Germany come online. This allows Denmark to export its cheap renewable energy, but results in an increase of its own energy price. Similar but less extreme changes can be seen in other countries.

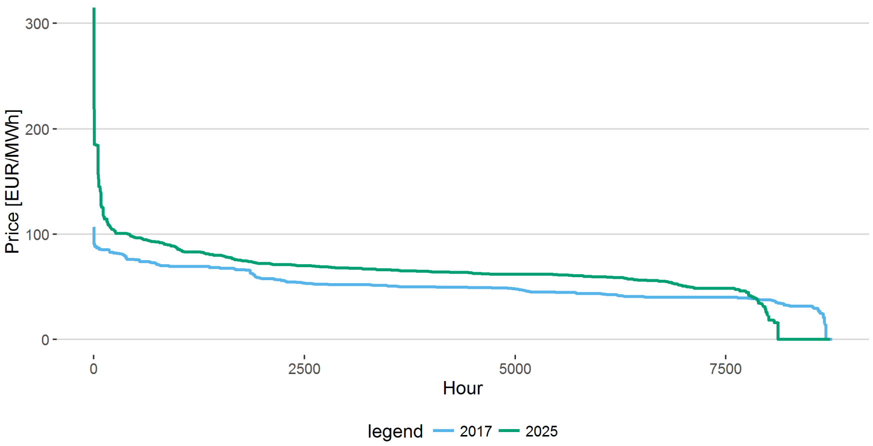

Figure 94: Price duration curves in Sardinia (2017 and 2025)

From Figure 94, Sardinia clearly has a more extreme profile than the other countries (see also Figure 98, which shows a comparison of all price duration curves for 2025). It has more hours at zero prices but also more hours with peak prices. The peak prices are due to the activation of expensive peaking units and the occasional occurrence of scarcity, leading to curtailing of the load at a high price. The zero prices are due to the increase of renewables and the limited interconnection capacity with Italy, leading to curtailment of RES production and a drop in prices to zero. From Annex 1.1, an increase in wind capacity can be observed from 38% to 41% between 2017 and 2025 as well as an increase, in absolute terms, of 300 MW for solar PV.

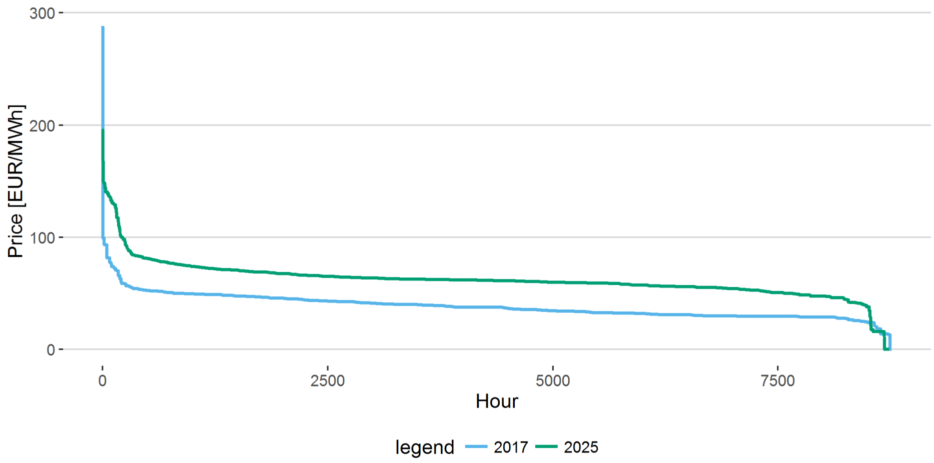

Figure 95: Price duration curves in Germany (2017 and 2025)

Concerning Germany, Figure 95 shows that zero-price hours actually slightly increase between 2017 and 2025 due to the extensive RES expansion policy. The share of wind on- and offshore in the capacity mix increases from 26% to 34% and solar PV from 25% to 33%. The same reason enforces more peak price hours in 2025 when expensive peaking units have to balance intermittent renewables.

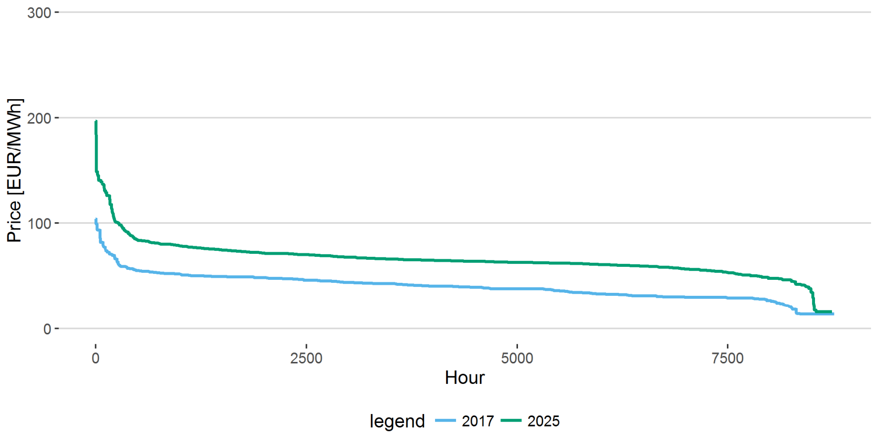

Figure 96: Price duration curves in France (2017 and 2025)

Compared to other countries, France is the only which does not see any hours with zero prices neither in 2017 nor in 2025, which is an indicator of the French nuclear policy and its moderate RES expansion plans (see Figure 96). In 2025 still about 64% of the total generation is coming from nuclear power plants. However, similar to the other countries one can also witness a trend to more hours with high prices.

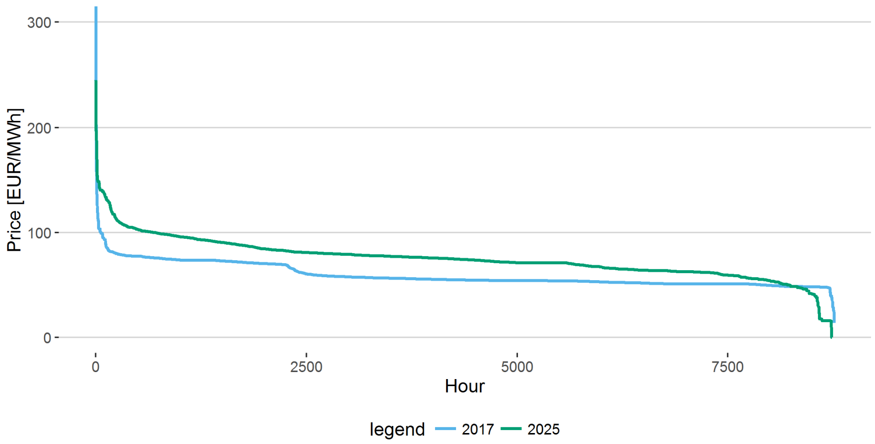

Figure 97: Price duration curves in Great Britain (2017 and 2025)

Figure 97 displays the British price duration curves for 2017 and 2025. Results are similar to the Sardinian ones though in a less pronounced way. It is important to mention that high prices spikes occur in 2017 rather than 2025, which indicates the occurrence of scarcity in 2017. Additional interconnection capacity (coming online between 2017 and 2025) reinforces the connection of Great Britain to the rest of Europe and helps to prevent scarcity hours in 2025, leading to a decrease in the maximum of the hourly prices.

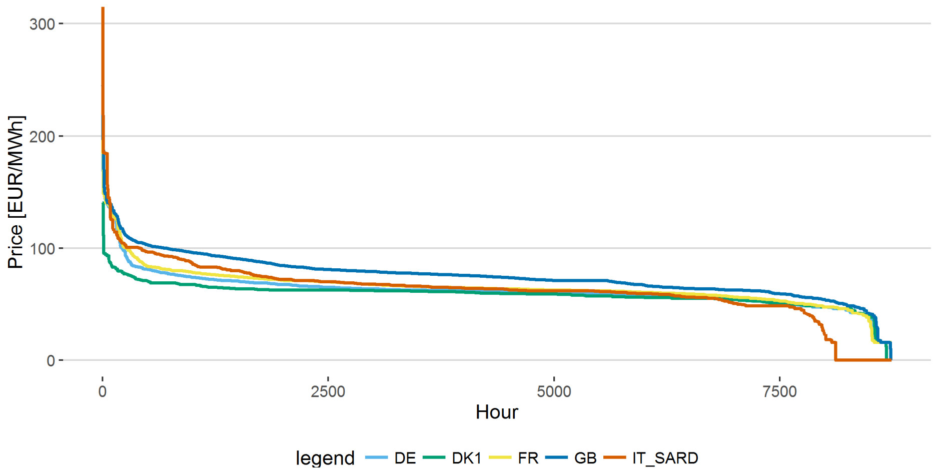

Figure 98: Price duration curves for Germany, Denmark, France, Great Britain and Sardinia in 2025

Table 74 summarises the minimum and maximum prices observable in the previous figures.

(€/MWh)	France		Germany		Great Britain		Denmark		Sardinia	
	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max
2017	13.6	103.7	0.0 (16h)	288.3	13.7	3000 (1h)	0.0 (431h)	52.7	0.0 (72h)	107.0
2025	15.8	196.9	0.0 (55h)	196.9	0.0 (8h)	244.9	0.0 (55h)	140.4	0.0 (623h)	3000 (1h)

Table 74: Minimum and maximum hourly prices per country

ANNEX 2. POWER-TO-HYDROGEN FAVOURABLE AREAS IN GREAT BRITAIN AND SARDINIA

This annex presents the power system results for the selected countries that are not used afterwards for the business cases that are built.

2.1. Great Britain

Recommended location for electrolyser installation:

Tongland (Scotland) in 2017 and Inverarnan (Scotland) in 2025, both due to highest curtailment of onshore wind production in the country.

RES curtailment analysis

GWh (% RES national production)	France	Germany	Great Britain	Denmark	Sardinia
2017	104 (0.3%)	2124 (1.8%)	**660 (1.1%)**	2242 (14.6%)	0 (0.0%)
2025	464 (0.6%)	1702 (0.9%)	**2108 (2.1%)**	2801 (13.4%)	8 (0.1%)

Table 75: Annual expected curtailment per country, focus on Great Britain

For **Great Britain**, an increase of curtailment between 2017 and 2025 is observed, from 0.7 to 2.1 TWh. This is in line with today's statistics: Wind Europe, the European wind power association, reported 659 GWh of wind power curtailment for 2014 and 1.2 TWh for 2015 [129], which was due to an above-average year in terms of wind speeds, as explained for Germany. The expected increase towards 2025 is mainly driven by the addition of wind power in Scotland (+1GW), while load is higher in the South of Great Britain.

In Great Britain, most of the RES curtailment comes from onshore wind production in Scotland as indicated in Figure 99. Indeed, wind onshore amounts to 104 GWh (77% of curtailed renewable energy) in 2017 and 1.9 TWh (93% of curtailed renewable energy) in 2025.

In 2017, some offshore wind farms see their production reduced near Canterbury. This curtailment problem is expected to be solved before 2025 with the NEMO project (HDVC interconnection with Belgium, 2019).

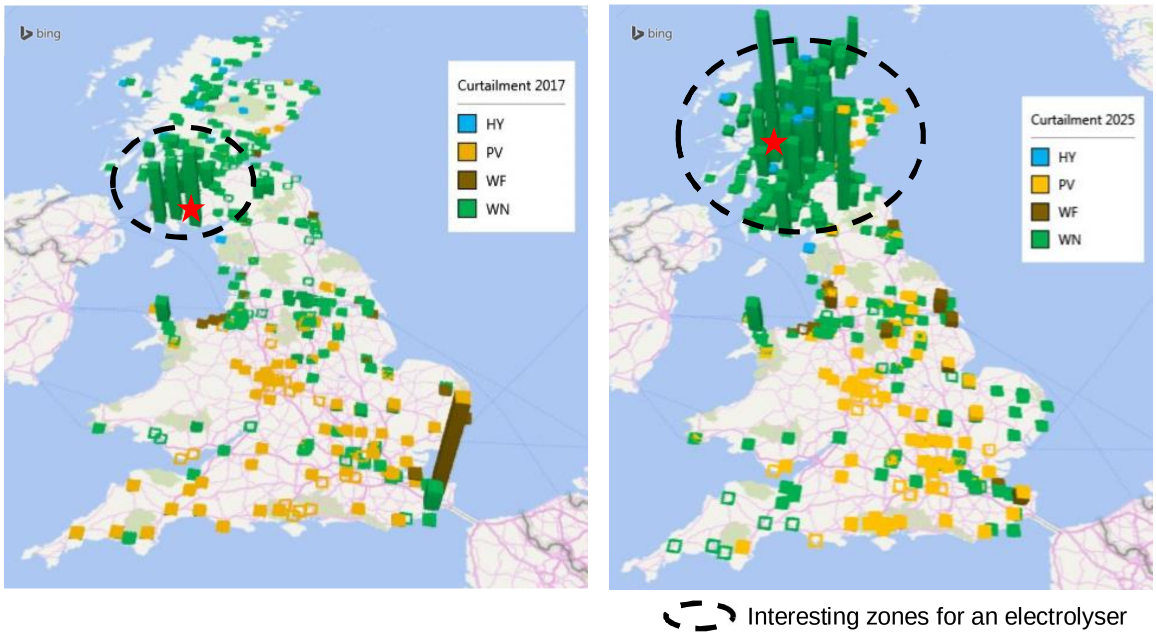

Figure 99: Annual curtailment per renewable technology in Great Britain (maximum bar height: 117 GWh)

Figure 100 shows the temporal distribution of curtailment of an onshore wind farm in Scotland for the two studied time horizons, where curtailment is the highest: Tongland in 2017 and Inverarnan in 2025 (indicated by ★ in Figure 99). Both figures present the same trends: more curtailment is foreseen in winter than in summer, in line with the generation profile of the wind farms, i.e. higher production in winter than in summer. In total, the curtailment of these two Scottish wind farms amounts to **71 GWh in 2017** and **117 GWh in 2025**. In both cases, this corresponds to roughly **20% of the annual production** of those 41 and 66 MW renewable power plants, with curtailment over approximately 6000 hour/year.

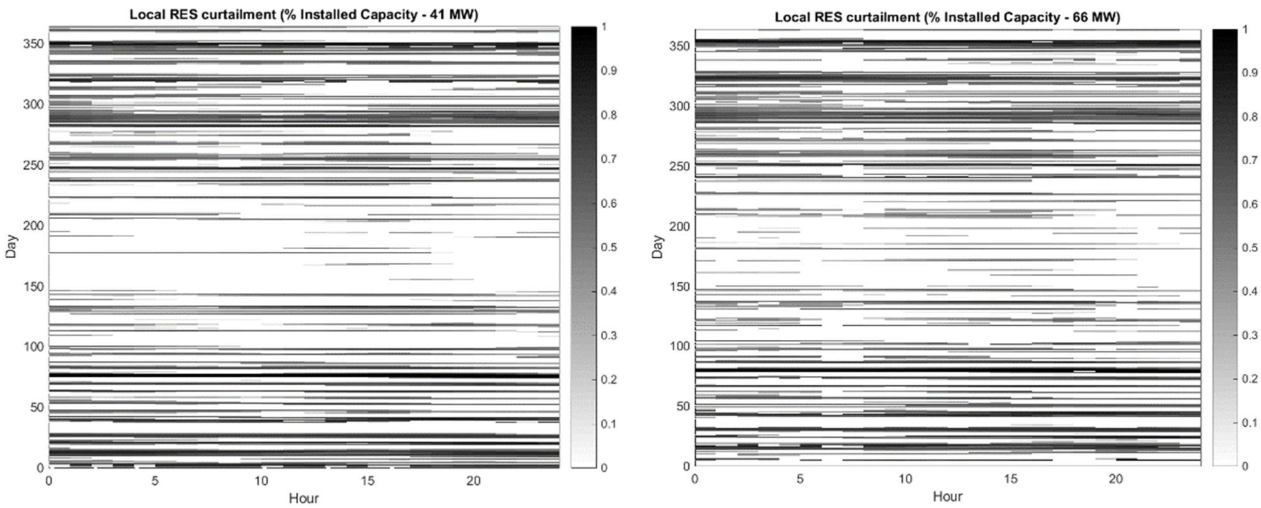

Figure 100: Temporal distribution of curtailment in the area of Scotland, Great Britain

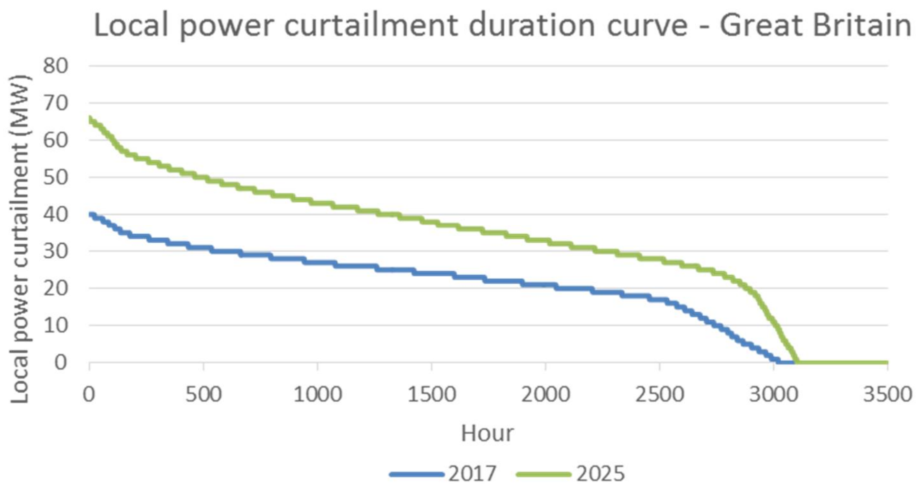

Figure 101: Power curtailment duration curve in the area of Scotland, Great Britain

Grid constraints analysis

The Table 76 presents the most important confirmed interconnection projects expected to be commissioned between 2017 and 2024 included [41]. They constitute the main grid differences between the two models 2017 and 2025.

Major Project		Line capacity (GW)	Commissioning year
Interconnections with France	ElecLink	1.0	2018
	Aquind	2.0	2019
	IFA2	1.0	2020
	GridLink	1.5	2021
	FAB	1.4	2021
Interconnection with Ireland (Moyle)		0.3	2018
Interconnection with Belgium (NEMO)		1.0	2019
Interconnection with Norway (NSN)		1.4	2020
Interconnection with Denmark (Viking Link)		1.4	2022

Table 76: Major grid reinforcements in Great Britain between 2017 and 2024

In Great Britain, the annual nodal marginal cost is quite homogeneous within the country for the year 2017 as showed in Figure 102, at a global market price of 59.9 €/MWh. Extreme values can be observed:

- In the South West region for the highest values. They are caused by thermal (gas and oil) units that have higher production costs and that need to run due to the congestions observed between the South West and the South-East regions.
- At the East of London for the lowest values. Those are induced by the wind offshore curtailment emphasized in Figure 99.

In 2025, grid constraints become stronger. Indeed, concentration of wind generation in North and the power demand in the South, combined with a decommissioning of thermal assets in that region (-8.4 GW of gas and coal units), lead to increased congestion on the North-South transmission lines.

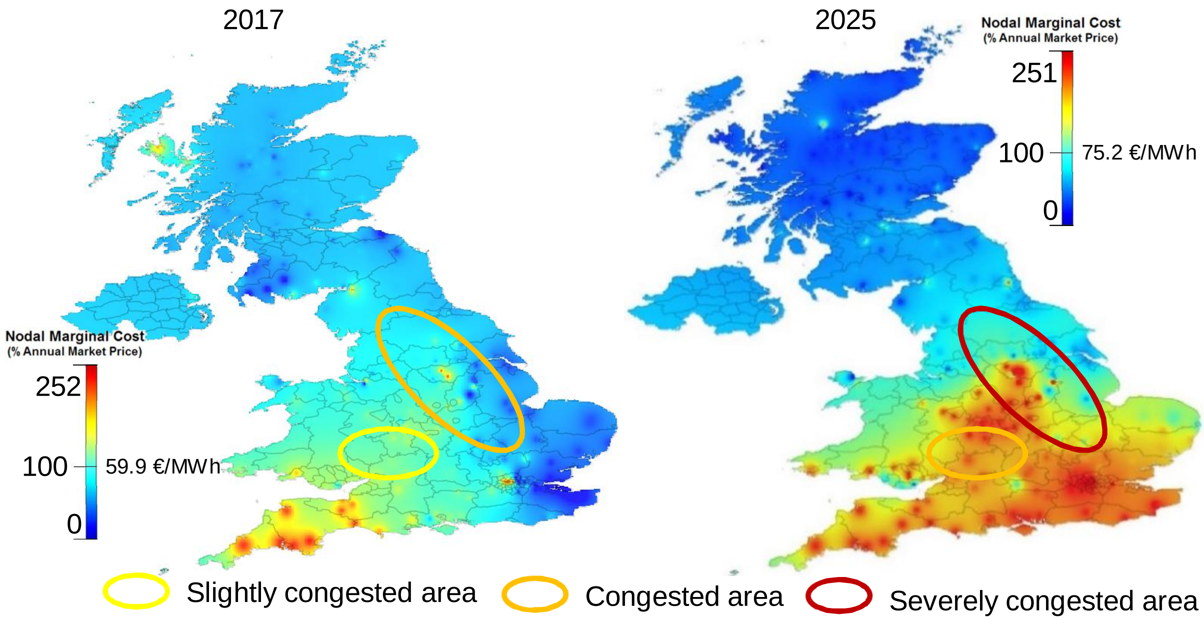

Figure 102: Nodal marginal costs and grid constraints thermal map of Great Britain

An overall increase of electricity price is visible at the national level between the two scenarios (from 59.9 to 75.2 €/MWh), though within a limited extent thanks to the important increase of interconnection capacity with the neighbouring countries between 2017 and 2025 (+6.9 GW with France, +1 GW with Belgium and +1.4 GW with Norway and Denmark, as indicated in Table 76), which all allow importing electricity into Great Britain at a lower price than the price of producing locally.

2.2. Sardinia

Recommended location for electrolyser installation:

Sarlux (Sarroch industrial zone) due to close proximity to a refinery.

RES curtailment analysis

GWh (% RES national production)	France	Germany	Great Britain	Denmark	Sardinia
2017	104 (0.3%)	2124 (1.8%)	660 (1.1%)	2242 (14.6%)	**0 (0.0%)**
2025	464 (0.6%)	1702 (0.9%)	2108 (2.1%)	2801 (13.4%)	**8 (0.1%)**

Table 77: Annual expected curtailment per country, focus on Sardinia

For **Sardinia**, curtailment is negligible at transmission grid level in 2017. This is in line with today's figures: Wind Europe reported 119 GWh of curtailed wind power for Italy as a whole in 2014 [129]. Curtailment volumes in 2025 are only slightly higher than in 2017 (8 GWh or 0.1% of the total generation). This can be explained by two factors. First, the share of renewables is less high when compared to Germany or Denmark. Second, the Italian TSO (Terna) does not publish a grid model of Sardinia, as opposed to the other studied countries. Publically available sources include a grid map of ENTSO-E, which is the main basis of the grid model used in the analysis. However, it only includes high-voltage lines. It is therefore possible that the presented figures are an underestimation of the actual future curtailment figures, because congestion at low-voltage level is not modelled due to a lack of data.

In line with the results presented in the previous section, curtailment is negligible across the island in 2017 and only marginally higher in 2025 (see Figure 103). An analysis of all grid nodes reveals that maximum curtailment at node-level would be roughly 1.4 GWh, which is equivalent to less than 0.2% of annual RES production at this node. Consequently, the temporal distribution of curtailment is predominantly *null*, as illustrated for the example of the industrial area of Sarroch (see Figure 104).

Excess electricity would therefore not be a primary criterion for selecting the location of the electrolyser in Sardinia, but rather the proximity to the next refinery which offer the greater industrial application opportunity today and which is located in the southern part of the island.

Figure 103: Annual curtailment per renewable technology in Sardinia (maximum bar height: 1.4 GWh)

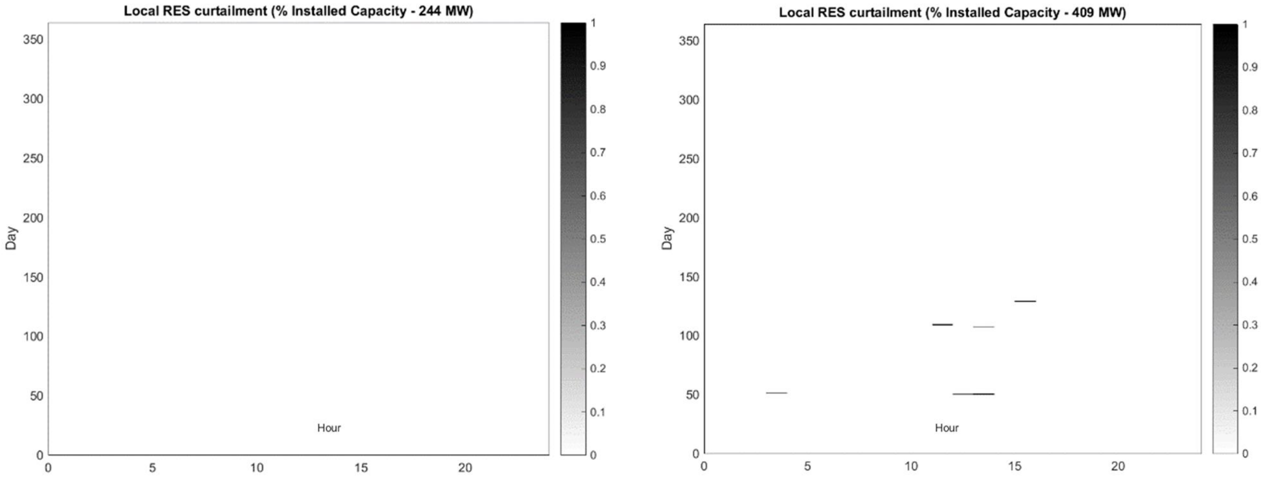

Figure 104: Temporal distribution of curtailment in Sarroch, Sardinia (Italy)

Grid constraints analysis

At electricity transmission level, no congestion is observed in 2017, nor in 2025 (for which the grid model includes an extra North-South corridor at the 150kV level, from Santa-Teresa to Selargius). It is important to note that this does not allow any conclusions as to whether there is congestion at distribution level. Value that can be captured at this level is assessed in section 5.5.

ANNEX 3. METHODOLOGY OF BUILDING THE COST AND PERFORMANCE HYDROGEN EQUIPMENT DATABASE

The cost and performance database is composed of Hinicio's internal database, literature research and industrial inputs.

The perimeter of the Business Cases includes the following elements:

- Hydrogen production;
- Hydrogen conditioning;
- Hydrogen injection skid (for injection into the gas grid)
- Hydrogen logistics and storage (including storage at the client's site, which is usually considered as part of the logistical chain in the conventional merchant market)

The installations within the final client's facilities (Hydrogen Refuelling Station, etc.) are outside the perimeter of the business cases.

In terms of physical and monetary streams, there is an output stream of hydrogen delivered at the end-client's location and an income stream of revenue paid in return.

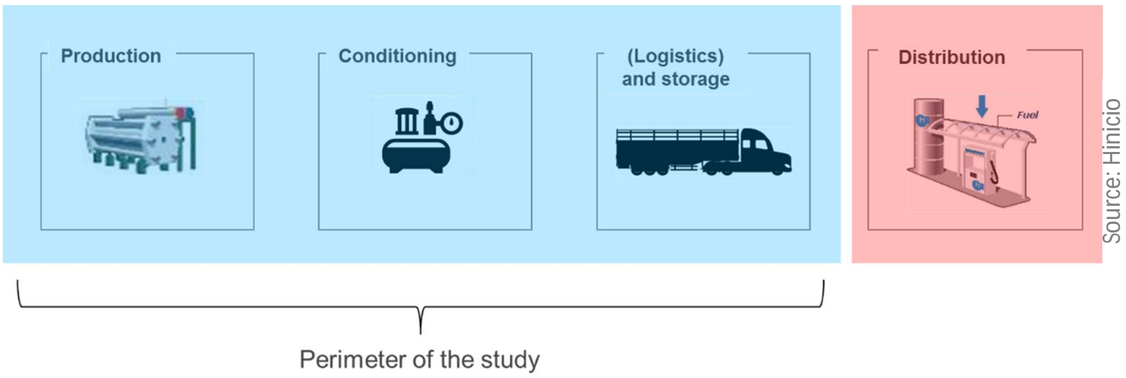

Figure 105: Business cases perimeter

In order to have consistent information on cost and performance, each equipment of the production plant needs to be defined by a system boundary. The systems boundaries are defined as follow.

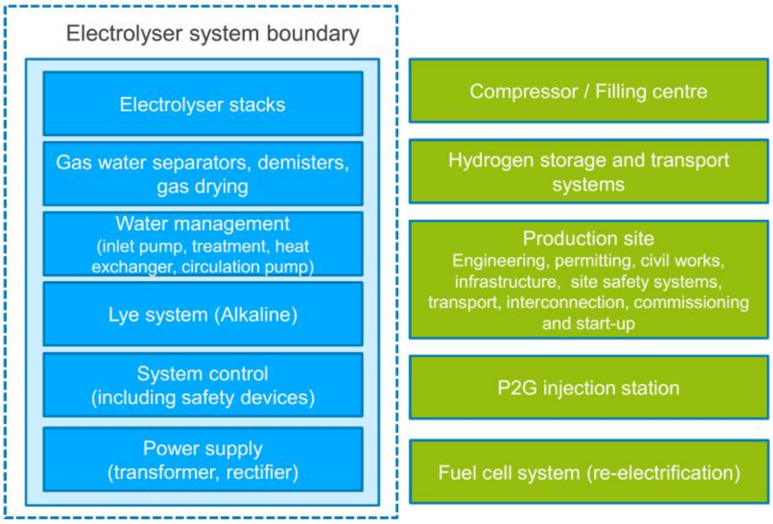

Figure 106: System definition

Figure 107 provides an overview of the costs and performance parameters that have been collected and analysed for each sub-system in the hydrogen supply chain. Some qualitative information on technical choices and market were also gathered to help building the business cases in section 6.

Average data were selected from the information compiled in the database and will be used in the construction of the hydrogen business cases in section 6.

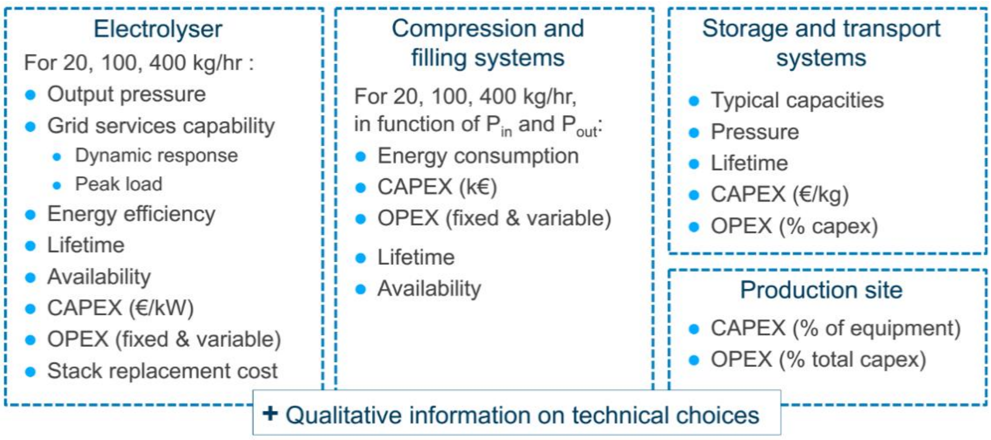

Figure 107: Summary of information collected

As a starting point, production plant capacity and is defined by the primary market applications:

- Refineries and ammonia plant are the world's largest hydrogen consumers. Typical plant's consumption ranges in the 10 000 Nm^3/h of hydrogen. The steel manufacturing is also a potential large scale user of low carbon hydrogen. New processes are being developed to reduce the carbon footprint of steel, though specific regulatory conditions (e.g. carbon tax) are needed to support the transition. For large scale consumers, on-site production is most cost-effective and the most reliable way of supply.

- Merchant gas market includes the food, glass, electronics, chemical and metallurgy industry. The typical amount of hydrogen needed and the consumptions patterns can be very variable from one sector to the next. H_2 supply can be provided both on-site and/or bulk delivery. Some processes can be critical in some instances, requiring the addition of buffer storage to insure uninterruptible hydrogen supply even during down time or failure.
- Hydrogen mobility is expanding in Europe. Hydrogen consumption by stations is still small. However, urban bus application can increase rapidly demand in the near future. On-site production is not expected to be over 5 MW without addressing other customers (merchant or other stations). Big scale production will need a filling centre or power-to-gas injection to clear surplus of production.

1 MW	200 Nm^3/h	500 kg/day	500 FCEV	25 buses
5 MW	1000 Nm^3/h	2 500 kg/day	2 500 FCEV	125 buses
20 MW	4000 Nm^3/h	10 000 kg/day	10 000 FCEV	500 buses

Table 78: Table of equivalence

Three typical system sizes were selected for the data collection (1, 5 and 20 MW) to cover the application cases spectrum. Smaller electrolysers can be considered in the business case at a later stage by extrapolating the data collected here for each of those sizes.

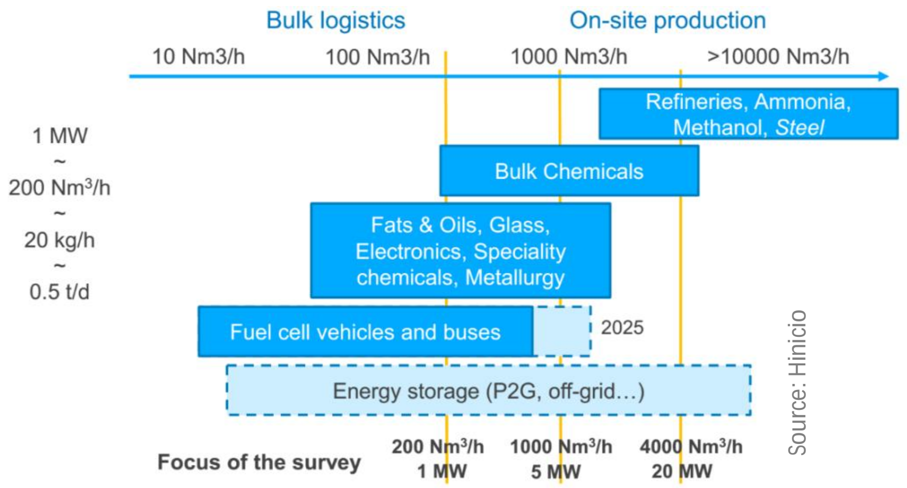

Figure 108: Selection of electrolyser size

Hydrogen applications require different pressure level, which affects the overall upstream supply chain, as represented on the following figure.

- Most industrial processes require low pressure hydrogen. In case of on-site hydrogen production, critical industrial process may require on-site storage and compressor skid redundancy to cover maintenance and failure.
- Regarding mobility and merchant consumers, centralised production plant will deliver hydrogen through a filling centre and a logistic of large bundles or tube-trailers. Current mobile storage standard is 200 bar. However, 500 bar storage is under development and may become commercially available by 2025.

- Regarding Power-to-gas, injection pressure largely depends on point of injection in the gas grid. As the acceptable concentration of hydrogen in natural gas is limited, injection where the flow of hydrogen is the largest, i.e. the gas transport grid, which typically operates at 60 or more will be preferred.

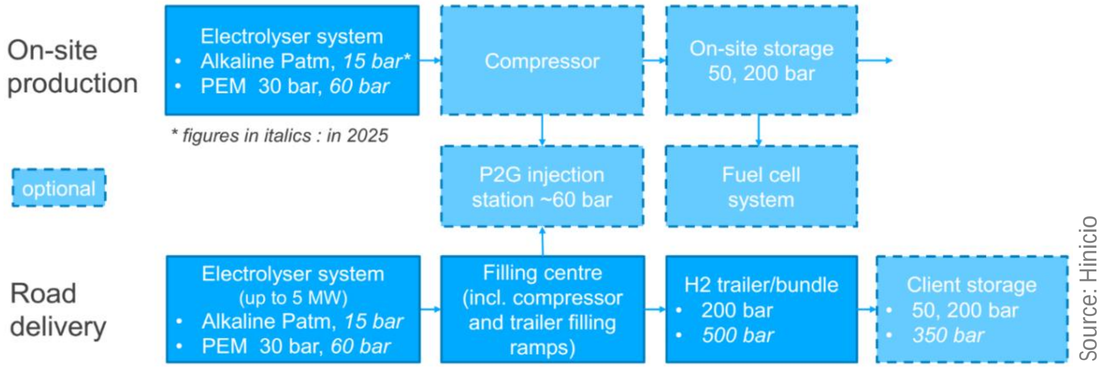

Figure 109: Pressure interface between H_2 equipment

3.1. Compressor and filling centre cost estimation

The cost model is divided into 2 parts: site cost and compression system cost. The site cost depends on site capacity (Q). The compression system cost depends on the site capacity (Q), the compression ratio $\left(\frac{P_{out}}{P_{in}}\right)$ and the pressure output (P_{out}).

$$CAPEX = \underbrace{A\left({}^{Q}/_{Q_{ref}}\right)^{a}}_{\substack{\text{Site}\\ \text{Capacity}}} + \underbrace{B\left({}^{Q}/_{Q_{ref}}\right)^{b}\left(\frac{{}^{P_{out}}/_{P_{in}}}{r_{ref}}\right)^{c}\left({}^{P_{out}}/_{P_{ref}}\right)^{d}}_{\substack{\text{Compression system}\\ \text{Capacity} \quad \text{Press. ratio} \quad \text{Pressure}}}$$

This model was approximated from a reference configuration of 850 k€ (excluding civil works, accounting for 150 k€) for a 50 kg/h (Q_{ref}) and 30 to 200 barg (r_{ref} and P_{out}) filling centre.

Coef.	Filling centre	Compressor skid
A	550 k€	100 k€
B	300 k€	300 k€
a	0,66	
b	0,66	
c	0,25	
d	0,25	

Figure 110: Cost function for filling centre and compressor skid

3.2. Project cost estimation

3.2.1. Capital expenditure (CAPEX)

Equipment costs include the electrolyser system, the filling centre or compressor skids and storage systems. Those equipment costs were covered in the previous sections (4.1, 4.1.2 and 4.1.3). Additional investments are needed to complete the project, such as civil works, engineering, DCS and EMU and Interconnection, commissioning, and start-up costs.

Civil works costs are expenses related to construction work. This includes foundation, industrial buildings, lighting, water supply, fencing, security. These civil works costs are determined by the facility's footprint, the construction of new building and whether or not the site is already prepared for industrial activities (brownfield vs greenfield). A cost function was developed for estimating costs based on these factors,

For the study, a "brownfield" configuration is assumed for Power-to-Hydrogen projects addressing industrial applications and on-site production for mobility applications, whereas a "greenfield" configuration is assumed for semi-centralised production facilities.

Systems under 2 MW can be considered containerized, allowing savings on the building.

$$CAPEX_{civil\ work} = (A + B) * \left(S_{adjust} * Area_{equipments}\right) + C * Coef * Area_{building}$$

Coef.	Definition	Value
S_{adjust}	Surface adjustment to consider	150%
A	Base cost	950 €/m^2
B	Additional cost for greenfield	150 €/m^2
C	Additional cost for building	200 €/m^2

Table 79: Civil work CAPEX parameters values [19]

$Area_{equipments}$ is the total surface area (m^2) of the electrolysers, compressors, filling centre and storage.

$Area_{building}$ is the electrolysers system surface area (m^2) fitted inside the building.

Both equipment and building surfaces are adjusted to consider spacing around the equipment. Civil work cost values are based on typical UK construction cost data [19].

Equipment	Surface area	Assumptions
Electrolyser ALK	0.10 m^2/kW	Based on 20 ft container solution
Electrolyser PEM	0.05 m^2/kW	Based on 20 ft container solution
Filling centre	75 m^2 for 20kg/h	1 $MW_{electrolyser}$
Compressor skid	11 m^2 for 2 stages compressor	Market product
Storage 200 bar	0,09 m^2/kg storage capacity	Based on 200 bar tube-trailer

Table 80: Equipment and building surfaces for an electrolyser

Engineering costs include architectural, engineering, studies, permitting, legal fees, and other pre and post construction expenses. Engineering costs depend on production capacity, complexity and storage size. Small scale projects can be exempt of environment studies for example.

They represent 15% of the equipment costs for a 2.5 MW electrolyser project.

Distributed Control System (DCS) and Energy Management Unit (EMU) are components that allows safe operation and optimisation of the production plant. DCS and EMU cost depends on the complexity of the production plant. Therefore, cost is estimated to 10% of equipment costs for a 2.5 MW electrolyser project.

Interconnection, commissioning, and start-up costs are defined as expenses related to piping, interconnection, inspection, test, commissioning, and start-up. This represents 20% of equipment costs for a 2.5 MW electrolyser project.

- Electrical grid connection additional costs depend on project capacity, existing grid infrastructure and distance of connection. This cost will be detailed in section 6 when the specific scenarios will be identified.

As a summary, project CAPEX breakdown is listed here:

	Project CAPEX
Equipment costs	*See previous sections*
Civil works costs	*Cost function*
DCS and EMU costs	10% equipment costs for 2.5 MW
Engineering costs	15% equipment costs for 2.5 MW
Interconnection, commissioning, and start-up costs	20% equipment costs for 2.5 MW

Table 81: Summary of project CAPEX

Non-equipment and civil costs (“other costs”) represents 45% of equipment costs for a 2.5 MW electrolyser project. In order to reflect the economy of scale on bigger projects, an equation model is proposed to adapt the costs.

$$Other\ costs = 10\% \left(\frac{2.5MW}{P_{project}}\right) + 35\%$$

Project scale	Other costs [% equipment costs]
1 MW	*60%*
2.5 MW	*45%*
5 MW	*40%*
20 MW	36%

Table 82: Other costs adjustment

3.2.2. Operational expenditure (OPEX)

Overall project OPEX includes the equipment and the facility OPEX.

Equipment OPEX, as described in the previous sections, covers the maintenance, spare parts and replacement associated to the equipment. It is a percentage of the equipment cost.

Facility OPEX covers the other operational expenditure related to the facility level. This includes:

- Site management;
- Land rent and taxes;
- Administrative fees (insurance, legal fees…);
- Site maintenance.

Facility OPEX is estimated at 4% of non-equipment costs.

	Project OPEX
Equipment OPEX	*See previous sections*
Facility OPEX fix	4% of non-equipment costs

Table 83: Summary of project OPEX

ANNEX 4. VALUE TO BE CAPTURED FROM POWER-TO-HYDROGEN APPLICATIONS

4.1. Value to be captured from large industry

4.1.1. Methodology

For each value stream, there are a number of potential situations. Each of those situations depend on specific parameters of the refinery such as configuration, mode of operation and geographic location. As a general approach an estimation will be made of the value or cost saving of each stream in € per ton of H_2 produced. This can be converted into € per MW of electrolyser capacity.

In the second part of the analysis, the possible value streams will be applied to an example refinery. The example will be based on a model of a typical German refinery using public available data from the German refining industry. [83]

4.1.1.1. CONVENTIONAL TECHNOLOGY DEFINITION

Production of hydrogen using conventional technology can be done either by SMR (Steam Reforming, partial oxidation and gasification).

For this analysis SMR using natural gas will be used as reference case for hydrogen production, because it is today the most commonly used method or hydrogen production [5].

4.1.1.2. VALUE OF THE MARGINAL HYDROGEN CAPACITY INCREASE

The first and necessarily most valuable value stream is the marginal value of hydrogen production increase. The value will consist out of 2 components

- **The CAPEX (capital expense) cost for the infrastructure:** CAPEX cost estimate is based on annual amortization of the total investment cost for the technology, the interest on capital and the start-up costs.
- **The O&M (Operation & Maintenance) cost for production of the hydrogen**: O&M is based on all variable costs for operating the hydrogen production plant
  - Raw material feedstock (natural gas)
  - Utilities (Power; Process water; Cooling water)
  - Labour cost (Operations; supervision)
  - Maintenance cost (Material & labour)
  - Insurance

Spare capacity available on onsite SMR / Transfer capacity from existing SMR

A refinery which has onsite hydrogen production capacity (typically by means of an SMR) may be operating below maximum capacity of the installation. In case additional hydrogen is required on such a site, the value of the marginal hydrogen production layer will not require additional capital investment.

The O&M price of hydrogen production using SMR depends on the NG price. For the business case NG price was estimated for the different regions of interest for potential business cases in Europe. Grid cost was added to the NG cost to define the predicted NG price range for 2025 per area.

	DE	FR	UK	DK	IT
Grid cost est. EUROSTAT [€/MWh]	4.00	4.80	1.60	9.20	2.40
Final price incl grid cost min [€/MWh]	25.24	26.04	22.84	30.44	23.65
Final price incl gird cost max [€/MWh]	27.31	28.11	24.91	32.51	25.71

Table 84: NG final price for industrial consumers in 2025

Typical SMR efficiency ranges between 65 and 75%[31] (conversion used 1 US$ = 0.9 €[32]). Calculation is based on HHV of 142 MJ/kg H_2[33]. In this price estimate it is assumed labour and maintenance related O&M related costs will remain unchanged relative to the existing layer of H_2 production. Increasing production output of an installation with spare capacity should not have a significant impact on labour requirements.

Utility costs such as power, process water, cooling water make up approximately 2% of the primary energy (NTG) input [6] and will be taken into account in the price range adding 25 €/t H_2.

Utilities	Required	Unit price	€/t H_2
Power	0.4 MWh/t H_2	50 €/MWh$_e$	20
Process water	14000 l/ ton	0.012 ct€/l	1.7
Cooling water	20000 l/t	0.012 ct€/l	2.4

Table 85: Hydrogen production utility costs

Cost of hydrogen produced on existing onsite capacity is calculated as follows:

Cost H2 on available onsite capacity [€/t] = HHV of 1 ton H2 [GJ/t H_2] * (1 / efficiency of SMR) * 0.278 [MWh/GJ] * Gas price [€/MWh] + 0.4 [MWh$_e$/t H_2] * (Price of power) [€/MWh$_e$] + 14000 [l/t H_2] * (Price of process water) [€/l] + 14000 [l/t H_2] * (Price of cooling water) [€/l]

31 Typical commercial available efficiency SMR with heat recovery = 65-75% [17]
32 1 US$ = 0.9 € [121]
33 HHV H2 = 142 MJ/kg [128]

The resulting production cost range of hydrogen using the different NG prices per region and SMR efficiency range is summarized per region in the table below:

	DE	FR	UK	DK	IT
O&M Hydrogen cost min [€/t H_2]	1352	1394	1226	1626	1268
O&M Hydrogen cost max [€/t H_2]	1682	1731	1536	1998	1585

Table 86: Existing SMR spare capacity hydrogen production price range per region

The price range of hydrogen using spare capacity of an existing SMR can therefore be estimated to range between **1200 and 2000 €/t H_2.**

Capacity increase by onsite SMR

A refinery which is operating at 100% of installed capacity of hydrogen production will require capital investment in order to produce the next marginal ton of hydrogen. Depending on the size of the required increase in hydrogen production, the capacity increase could be achieved by installation of an SMR.

Capital cost for an SMR plant were calculated in €/t based on a set of available investment cases. For the calculation following parameters were taken into account [6]:

- Annual operating hours: 8600 [34]
- Depreciation of the investment cost over 10 years
- Interest rate at 6%
- Start-up expenses 2%
- Cumulative rate of inflation 1997 to 2016: 150% [35]

Capacity [MNm^3/d]	Capacity [T/h]	CAPEX [M€]	CAPEX [€/t]	*REF*
1.4	5.2	112	301.2	(Park, 1994) [100]
2.8	10.5	146	193.9	(Steinberg & Cheng, 1989) [115]
2.9	10.7	149	194.0	(Gaudernack & Lynum, 1996) [53]
6.7	24.7	363	204.9	(Audus, Kaarstad, & Kowal, 1996) [3]
3.0	11.0	243	308.9	(Thomas & al., 1997) [123]
2.4	8.9	126	196.8	(Jülich, 1994) [73]

Table 87: CAPEX of an SMR plant of different sizes

[34] A refinery investing in additional hydrogen capacity will typically do so as part of a larger investment project. This could be to be able to process a more challenging (cheaper) crude slate, to increase conversion capacity and/or to be able to make deeper desulphurized and more valuable fuel. It is expected a new hydrogen plant would be operated at or close to 100% of its design capacity during the first year of startup.

[35] Cumulative rate of inflation US$ from 1997 to 2016: 150%

As an estimate for the annualised CAPEX component for SMR generated H_2 a value of 200 – 300 €/t H_2 can be used.

For the operational costs of hydrogen production, the same estimation as for the scenario "Spare capacity available on onsite SMR / Transfer capacity from existing SMR" applies: 1200-2000 €/t H_2. Unlike hydrogen production increase on installed capacity it would be required to include additional operational costs to run the new production installation:

- Operation:
  - Per 10 t/h capacity assume 9 FTE (1 central operator, 1 plant operator for 4 shifts + 1 supervisor) at average of 40 k€/y. This corresponds to 4 €/t H_2.
- Maintenance:
  - Annual labour and material cost for maintenance is estimated each at 4.3% of CAPEX [6]. This corresponds to 5 – 8 €/t H_2
- Insurance:
  - Insurance is estimated at 2% of facility investment [6] corresponding to 2-4 €/t H_2.

Therefore, in case additional CAPEX investment is required, the O&M cost estimation per ton of H_2 will be increase with 15 €/t H_2 to take into account these additional costs for operational and maintenance manpower and recurrent insurance cost.

The cost of hydrogen produced by capacity increase onsite is calculated as follows:

Cost H_2 by capacity increase onsite [€/t] = Cost H_2 on available onsite capacity [€/t] + CAPEX cost additional H_2 production capacity [€/t] + Cost operational extra manpower [€/t] + Cost maintenance extra manpower [€/t] + Cost insurance [€/t]

Total marginal cost of hydrogen per ton with production via additional CAPEX SMR infrastructure, will therefore be **1400 – 2300 €/t H_2.** This value is in line with other benchmark studies (1400 €/t; 1690 €/t). [5] [63]

Capacity increase by 3rd party supplier – pipeline

As an alternative to investing in additional SMR capacity, some refineries could also consider to source the marginal layer of added hydrogen capacity from a 3rd party supplier. This is in particular the case in the vicinity of a hydrogen pipe network [45]:

- Air Liquide hydrogen network in Benelux + north of France
- Air Liquide hydrogen pipeline in Rhine-Ruhr Area, Germany
- Linde hydrogen pipeline in Central Germany (near Leipzig)

Hydrogen supplied via pipeline by third party supplier will consist out of

- Production cost of the hydrogen production. The calculated price range of hydrogen produced by SMR can serve as a reference: 1200-2000 €/t H_2
- Cost of capital investment: 200-300 €/t H_2

- Cost of CO_2 emission: 290 (EU) or 440 (UK) €/t H_2[36]
- Cost of transport of hydrogen via pipeline: 100-200 €/t H_2 [t]
- Profit margin: 50-200 €/t H_2 [37]

The cost of hydrogen produced by capacity increase onsite is calculated as follows:

Cost H_2 from 3rd party supplier [€/t] = Cost H_2 by capacity increase onsite [€/t] + Cost of emissions paid by supplier [€/t] + Transport cost [€/t] + Profit margin [€/t].

Taking into account these assumptions, cost of hydrogen supplied by pipeline by a 3rd party supplier can be estimated around 1900-3000 €/t H_2.

Overview of hydrogen value stream:

	CAPEX [€/t H_2]	O&M [€/t H_2]	Total [€/t H_2]
Spare capacity available on onsite SMR / Transfer capacity from SMR	-	1200-2000	**1200 - 2000**
Capacity increase by onsite SMR	200 - 300	1200-2000	**1400 - 2300**
Capacity increase by 3rd party supplier – pipeline	-	1900-3000	**1900 - 3000**

Table 88: TOTEX overview of the hydrogen value stream

Prices per region would be as follows:

Spare capacity available on onsite SMR	**DE**	**FR**	**UK**	**DK**	**IT**
Minimum price [€/t H_2]	1352	1394	1226	1626	1268
Maximum price [€/t H_2]	1682	1731	1536	1998	1585
Capacity increase by onsite SMR	**DE**	**FR**	**UK**	**DK**	**IT**
Minimum price [€/t H_2]	1552	1594	1426	1826	1468
Maximum price [€/t H_2]	1982	2031	1836	2298	1885
Capacity increase by 3rd party supplier – pipeline	**DE**	**FR**	**UK**	**DK**	**IT**
Minimum price [€/t H_2]	1991	2033	2016	2265	1908
Maximum price [€/t H_2]	2671	2720	2677	2987	2574

Table 89: TOTEX overview of the marginal hydrogen capacity increase value stream

[36] 10.3 ton CO_2/t H_2; see paragraph “Cost saving from reduced CO_2 emission”
[37] Transport per pipeline is calculated at a surplus of the unit price of hydrogen increased with 30% accounting for CAPEX and profit. Based on this, the profit is calculated. [43]

4.1.1.3. VALUE OF OXYGEN STREAM

Electrolysis of water also produces oxygen as a by-product. For each unit of mass of hydrogen produced [1kg], there will be 8 units of mass of oxygen produced [8 kg]. This is because for each 2 molecules of hydrogen produced, 1 molecule oxygen will be produced, but an oxygen molecule is 16 times heavier than a hydrogen molecule.

$2\ H_2O \leftrightarrow 2\ H_2 + O_2$ (1)

Oxygen can have several uses in a refinery business for purposes such as [62]:

- Fuel flexibility and capacity in FCCU (=Fluidized Catalytic Cracking Unit) process
- Debottleneck Claus plant desulphurization capacity by reduction of pressure drop
- Increase capacity of waste water treatment plant
- Oxygen gasification of residues to allow full conversion of crude oil to valuable products

The value of the oxygen by-product will depend on the refinery configuration. If a site already uses enriched oxygen in its processes, the value will be based on the marginal layer of the today price in oxygen production or import. If no oxygen is used today, the value can at least be matched to the value of onsite oxygen production.

- Onsite produced oxygen: 20 - 35 €/t O_2
- Oxygen delivered per pipeline: 30 - 40 €/t O_2
- Oxygen delivered per truck: 80 €/t O_2

These values are to be multiplied with a factor of 8 to be expressed in €/t H_2 produced via electrolysis.

The value of the oxygen by-product by on-site electrolysis is calculated as follows:

Value of oxygen per ton of hydrogen produced [€/t H_2] = 8 [t O_2 / t H_2] * cost of oxygen supply onsite [€/t O_2].

Overview of oxygen value stream:

	Total [€/t H_2]
Oxygen by-product replacing onsite produced oxygen or new oxygen application onsite	160 - 280
Oxygen by-product replacing delivery oxygen by pipeline	240 - 320
Oxygen by-product replacing delivery oxygen by truck	640

Table 90: TOTEX overview of the oxygen value stream

4.1.1.4. COST SAVING FROM REDUCED CO_2 EMISSION

Production of hydrogen via conventional methods (SMR) results in significant GHG emissions from fossil fuel combustion and small amounts of methane emissions from the burner of the steam reformer[38]. GHG intensity for hydrogen produced from natural gas as primary energy input according to the EU default value is 10.3 t $CO_{2\,eq}$/t H_2[39].

Reduction of the GHG emissions for production of hydrogen using electrolyser technology depends very strongly on the carbon footprint of the electricity supplied. Typical energy requirement for hydrogen produced using an electrolyser is 45 - 60 MWh_e/ ton H_2 (4-5 kWh / Nm^3) [116]. Using typical CO_2 emission per MWh of electricity produced using fossil fuel based power plant of 0.75 t CO_2/MWh [h], the CO_2 emission per ton of H_2 would be significantly higher using electrolysis technology compared to SMR or methanol cracking technology. As much as 33 - 45 ton of CO_2 emission per ton of H_2. Any business case using electrolysis for hydrogen production should therefore use electricity originating from a source with a low carbon footprint.

ETS only take into account direct onsite GHG emissions. Therefore, the onsite GHG emissions within the refinery perimeter for renewable electricity produced on-site or electricity imported from the grid for hydrogen produced by electrolysis will be 0 t CO_2 / t H_2 [63].

It is assumed that any CO_2 emission costs from an external supplier will be passed on to the end consumer. This applies both to the electricity sourced for electrolysis as for hydrogen sourced from a 3rd party supplier (pipeline / truck).

Credit for CO_2 emission savings can be taken if electrolysis replaces onsite conventional hydrogen production. Cost saving of the direct CO_2 emission reduction depends on the price of carbon.

Carbon price is estimated to be 28.1 €/t (EU) and 42.8 €/t (UK) for 2025.

CO_2 emission reduction cost savings can be calculated as follows:

Cost savings per ton of hydrogen produced [€/t H_2] = {10.3 [t CO_2 / t H_2] (=CO_2 emission for H_2 production by SMR) – 0 [t CO_2 / t H_2] (=CO_2 emission for H_2 produced by electrolysis)} * EU ETS price of CO_2 [€/t CO_2]

Overview of CO_2 emission reduction cost saving:

Total [€/t H2]	EU	UK
Reduction of CO_2 emission for electrolysis replacing SMR	290	440
Marginal hydrogen increase by 3rd party supplier	0	0

Table 91: Overview of the cost savings linked to CO_2 emission reduction

[38] ~0.016 g CH_4 per MJ of hydrogen [63]

[39] 72.4 g CO_2 equivalent / MJ using HHV 142 MJ/kg H_2 [63]

4.1.1.5. COST SAVING DUE TO EXTRA DEGREE OF FREEDOM FOR REAL TIME OPTIMIZATION

Most refineries nowadays have some sort of real time optimization software implemented (Advanced Process Control). When an electrolyser is installed, this could serve as an extra degree of freedom in hydrogen generation. Cost saving resulting from having an electrolyser installed for production of hydrogen is very dependent on the site configuration and is therefore considered as an optimization, rather than a value stream.

To give an idea of the potential cost savings, following example will show the potential of this value stream. For this particular example, the following boundary conditions will be assumed:

- Refinery baseload requires max capacity of the SMR + 2 t/h of hydrogen. SMR has a capacity of 5 t/h; hence total required hydrogen is 7 t/h.
- Refinery has possibility to generate hydrogen by SMR, import via pipeline and electrolyser
- Maximum capacity of the electrolyser is 3 t/h
- Possible savings of the extra degree of freedom by hydrogen produced in the electrolyser are calculated relative to the previous situation with only SMR and import
- The site needs constantly minimum 24 t/h of oxygen valued at 37.5 €/t, which is imported by pipeline and import can be reduced without penalty[40]
- For each t/h H_2 produced with the electrolyser oxygen import can be reduced with 8 t/h
- Marginal cost of SMR generated hydrogen is assumed to be 1806 €/t (1516 €/t for the H_2 + 289 €/t H_2 for the CO_2 emissions)
- Marginal cost of imported hydrogen via pipeline is assumed 2330 €/t (price paid to the supplier)
- Electricity consumption for hydrogen produced using electrolyser is typically 45 - 60 MWh/ ton H_2 (4-5 kWh / Nm^3) [116]. For this case study, it will be assumed that the consumption is 50 MWh/t H_2 for the installed electrolyser
- The case study is based on the electricity price distribution of Germany in 2017

[40] An import contract may contain restrictions in terms of maximum rate of change of import or a penalty exceeding for minimum or maximum import quantity per time unit. For this example, it was assumed no such limitations are applicable.

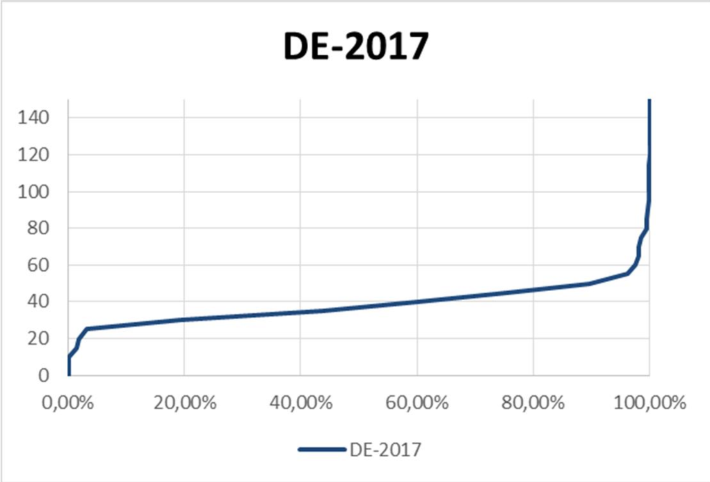

Figure 111: Electricity price cumulative distribution function, for Germany 2017

Optimization potential of following example:

In this business case the refinery can make use of the degree of freedom to increase or reduce the load of the electrolyser in order to optimize its operational cost for production of hydrogen in real time. The case is based on optimizing plant operations and therefore does not take into account CAPEX considerations.

Depending on the spot price in the electricity market it will be interesting to fully load either the SMR, the electrolyser or the import. The electrolyser price also takes into account that for each t/h H_2 produced on the electrolyser, the oxygen import can be reduced with 8 t/h.

Following table shows the most optimal utilization of the available infrastructure based on the electricity spot price for Germany in 2017.

Electricity [€/MWh]	Operational cost H_2 from electrolyser [€/t]	Priority signal
0 – 40	-300[41] - 1700	1. Maximize electrolyser capacity → 3 t/h 2. Increase SMR capacity (if needed) → 4 t/h 3. Increase import (if needed) → 0 t/h
40 – 50	1700 – 2200	1. Maximize SMR capacity → 5 t/h 2. Increase electrolyser (if needed) → 2 t/h 3. Increase import (if needed) → 0 t/h
50 – 120	2200 – 5700	1. Maximize SMR capacity → 5 t/h 2. Increase import (if needed) → 2 t/h 3. Increase electrolyser (if needed) → 0 t/h

Table 92: Most optimal utilization of available infrastructures for different electricity spot price ranges, for Germany 2017

[41] Cost of H_2 = Price per MWh_e * 50 MWh_e/t H_2 – 8 [t O_2 / t H_2] * 37.5 €/t O_2 à at 0 €/MWh price of H_2 by electrolysis is negative

This optimization case will be compared to a reference case is where 100% of the time SMR is maximized and 2 t/h of hydrogen is imported via pipeline + 24 t/h of oxygen is imported.

Based on the price distribution of electricity in the graph above titled "DE-2017" a calculation was made of the total annual cost of hydrogen production. The table below has the following columns:

- **Column 1 in [€/MWh]**: price range of electricity price with same optimal load distribution for hydrogen production between SMR; electrolyser and import.
- **Column 2 – 4 in [t/h]**: Optimal capacity load per unit. Always maximize the unit with the cheapest production cost for H_2. When electricity is cheap, maximize the electrolyser. When electricity is expensive minimize electrolyser.
- **Column 5 [%time]**: % of time in a year the specific price range of electricity is applicable
- **Column 6 [h/y]**: the number of hours per year a specific price range of electricity is applicable
- **Column 7 [ton]**: the total amount of H_2 produced in the time period a specific price range of electricity is applicable (site needs constantly 7 t/h H_2)
- **Column 8 [M€]:** the total cost of H_2 produced in each time period.
- **Column 9 [€/t]**: average operational production cost per ton H_2 for each specific time period

€/MWh	SMR [t/h]	Electr. [t/h]	Import [t/h]	%time	h/y	H_2 in layer [ton]	M€	€/t H_2
0 - 45	4	3	0	75.4	6602	46221	72.8	1575
45 - 50	5	2	0	20.8	1826	12782	23.9	1870
50 - 120	5	0	2	3.8	331	2317	4.5	1955
Total				100	8760	61320	101.2	1650
Reference case:								
NA()	5	0	2	100	8760	61320	114.8	1955

Table 93 – Annual total cost of H_2 production on a site with electrolyser depending on electricity cost versus reference case without electrolyser

As can be concluded from the set of boundary conditions, potential saving by real time optimization strongly depend on the available refinery infrastructure and configuration as well as the price distribution of electricity. In this example with an electrolyser that has a capacity of 3 t/h using this extra degree of freedom has the potential to reduce the annual operational production cost of hydrogen from 119 M€/y to 101 M€/y (average production cost of hydrogen reduces from 1955 to 1650 €/t). This is an additional saving of **18 M€/y or production cost savings of 305 €/t**.

4.1.2. Example Refinery

To estimate the typical value and cost saving potential of hydrogen produced by means of electrolyser technology, the above methodology was applied to a model refinery in Germany.

Based on the annual capacity report of German refining industry [83], it is possible to map out the typical processing capacity and refinery infrastructure for the German marked. These capacities can then be used to create a model for a typical German refinery. The two smallest refineries (Nynas and OMV) have not been taken into account, because their capacity is significantly smaller than the others (23% and 44% of the average respectively) and their conversion capacity is limited. Therefore, for the model refinery we will assume a crude processing capacity of 1000 t/h.

Refineries Germany [2015]	kt/y	[t/h]	Relative to avg. capacity
Raffinerie Heide	4200	479.5	53.5%
Holborn Europe Raffinerie	5150	587.9	65.6%
Raffinerie Emsland	4600	525.1	58.6%
Shell Rheinland Raff. Godorf	9300	1061.6	118.5%
Rheinland Raffinerie Wesseling	7300	833.3	93.0%
Ruhr Oel Gmbh	12800	1461.2	163.0%
MIRO Oberrhein	14900	1700.9	189.8%
Bayernoil (Vohburg)	10300	1175.8	131.2%
GUNVOR Ingolstadt	5000	570.8	63.7%
PCK Raffinerie Schewdt	11200	1278.5	142.7%
TOTAL Raffinerie Mitteldeutschland	12000	1369.9	152.9%
Total	**96750**	**11044.5**	**1004.0**

Table 94: Production of model refineries in Germany

By using the total capacity data of the considered refineries for the conversion process (reforming, desulphurization and cracking) it is possible to model the refinery configuration of a typical German refinery normalized against a typical capacity of 1000 t/h.

Process	kt/y crude	Normalized at 1000 t/h
Distillation		
Atmospheric pipestill	96750	1000.0
Vacuum pipestill	44230	457.2
Total desulphurization	**81860**	**846.1**
-Naphta	24480	253.0
-Diesel	46045	475.9
-Vacuum heavy fraction	11335	117.2
Conversion cracking		
Catalytic cracker	16882	174.5
Hydro cracker	11790	121.9
Visbreaker	8228	85.0
Coker	4850	50.1
Cat Reformer	14465	149.5

Table 95: Conversion process capacities of the considered refineries

Next step is to estimate the typical hydrogen balance of the model German refinery based on typical hydrogen consumption of the various processes. In this calculation, main consumers are the desulphurization process and the hydrocracker.

Hydrogen consumption of desulphurization depends on the sulphur content of the processed crude. Germany process relatively sweet and light crude with an average of 0.5 wt. % sulphur and 37.3 API gravity [49]. Distribution of hydrogen consumption for the different fractions are normalized against this crude composition based on typical refinery process [111].

The other major consumer is the hydrocracker process. Typical hydrogen consumption is 4 wt. % of the feed of the hydrocracker [111].

Hydrogen production has two main sources: hydrogen produced as a by-product from the catalytic naphtha reformer with a typical production of 2 wt. % of the reformer feed. The hydrogen balance is closed mainly by steam reforming.

Hydrogen consumption and production of the other process is small or zero compared to the above-mentioned streams [111].

Typical refinery hydrogen balance	t/h	H_2 w%	t/h H_2	Total [kt/y]
APS	**1000.0**		**0.0**	**0.0**
Total desulphurization	**846.1**	**-0.5**	**-4.2**	**-407.7**
-Naphta	253.0	-0.2	-0.4	-41.2
-Diesel	475.9	-0.6	-2.8	-271.2
-Vacuum heavy fraction	117.2	-0.8	-1.0	-95.4
Conversion units			**-4.9**	**-469.9**
Hydro cracker	121.9	-4.0	-4.9	-469.9
Cat Reformer	**149.5**	**2.0**	**3.0**	**288.1**
Hydrogen production required to close balance (Reformer / Import)			**6.1**	**589.4**
Total hydrogen demand of model refinery			**9.1**	**877.5**

Table 96: Hydrogen balance and demand of a typical refinery

From the hydrogen balance, it can be concluded that the hydrogen demand of a typical German refinery is 9.1 t/h for 1000 t/h of crude oil processing capacity. Since 3.0 t/h is produced in the catalytic reforming process an additional hydrogen production capacity of **6.1 t/h** is required for 1000 t/h of crude oil processing capacity.

For a total refinery capacity in Germany of 96750 kton/y (=11045 t/h) this corresponds to a total hydrogen demand of 589.4 kton/y (67.4 t/h) to be extra produced.

The total onsite hydrogen production capacity by SMR in Germany available in 2016 is 629.6 kton/y or 71.9 t/h (DOE EERE, 2016). Scaling this capacity pro-rata to the total production capacity for refineries (96750 kton/y = 11044 t/h) the SMR capacity of a typical German refinery processing 1000 t/h of crude equals **6.5 t/h**.

In summary, the total hydrogen demand of a model German refinery is 6.1 t/h and the typical installed capacity in this refinery is 6.5 t/h for 1000 t/h of crude oil processing capacity. Based on this we can conclude that **most hydrogen used in a German refinery will be produced onsite by means of SMR and that the available capacity is utilized at around 93%**. There is also a limited hydrogen network available in Germany, but based on this data we assume that the model refinery will typically not use imported hydrogen. When taking also into account that the installed capacity is not available 100% of the time due to maintenance and downtime, we can estimate that value of marginal hydrogen capacity assuming that an investment is needed in additional SMR capacity to increase hydrogen demand.

Because crude in Germany is overall very light and sweet, it can be expected that in the future there will be an increase in hydrogen demand to be able to process cheaper more challenging (heavier & more sour) crudes.

Therefore, based on section 4.1.1.2, most likely marginal value of hydrogen in the German model refinery is 1550 – 2000 €/t H_2.

On the model refinery, there will be for sure an outlet to use the oxygen by product, either to debottleneck the Claus plant when switching to more sour crudes or to debottleneck the FCCU plant. The oxygen by-product can by valued at 160 – 280 €/t H_2.

Finally using an electrolyser instead of natural gas fired SMR to produce the extra hydrogen demand will result in an additional cost saving of 289 €/t H_2 due to the reduced CO_2 emission.

Conclusion example refinery

In conclusion based on the configuration of a typical German refinery the value of hydrogen produced by means of electrolysis replacing conventional SMR can be estimated at 2000 - 2560 €/t H_2.

If the current German penalty of 470€/tCO_2 is applied and carbon intensity calculation on produced fuel includes upstream emissions, this hydrogen value.

4.2. Value to be captured from light industry

4.2.1. Value to be captured from light industry

Two approaches were used to estimate light industry hydrogen gas price:

- **Price-based**: Price extrapolation from literature and field data collection;
- **Cost-based**: Price extrapolation from a theoretical model.

Both approaches can give some insight a local market. However, both have limitations which will be further described below.

4.2.1.1. PRICE EXTRAPOLATION FROM LITERATURE (PRICE-BASED)

A recent report published by ESPRIT [43] gathered price data from local interviews and surveys. It is one of the only, if not the only, available and recent source on the light industry hydrogen market. The following table is the result of an extrapolation based on the prices provided in that report as a function of the market segment and the country. Based on ESPRIT data, it appears that the hydrogen price at the point of delivery with tube trailer is the lowest in Germany and in the UK among the four countries under assessment (the table excludes Sardinia as it has a limited or non-existent light industry hydrogen market). This singularity probably comes from the higher-than-the-average industrial density in both countries, which tends to lower the distance to hydrogen sources and boost competition among gas companies.

It should nonetheless be noted that the table only approximate prices and does not take into account a number of important factors such as the local competitive environment, contract type and the transport distances, etc.

Tube-trailer delivery		FR		DE		UK		DK	
	Price €/kg	Min	Max	Min	Max	Min	Max	Min	Max
Light industry	Fats and Oils	8.5	8.7	3.2	4.1	5.5	10.3	7.9	8.5
	Glass production	7.9	8.1	3.0	3.8	5.1	9.6	7.3	7.9
	Electronics	8.1	8.3	3.0	3.9	5.3	9.8	7.5	8.1
	Metallurgy	10.2	10.4	3.8	4.9	6.6	12.3	9.4	10.2

Table 97: Estimation of hydrogen prices for tube-trailer delivery depending on application and country (Hinicio based on ESPRIT data)

4.2.1.2. PRICE EXTRAPOLATION FROM A THEORETICAL MODEL (COST-BASED)

The second approach is to estimate the price based on cost and margin assumptions. This method is ideal as it considers the real cost of production and distribution. In reality, price can differ from the calculated cost due to competitive environment and contractual arrangement with the client (bundle and large purchase). Figure 112 provides the complete cost of logistics, including transport, delivery and cost of storage at the customer site.

$$H_{2_{price}} = \frac{\left(Cost_{production} + Cost_{transport}\right)\left(1 + \%_{overhead}\right)}{\left(1 - \%_{margin}\right)}$$

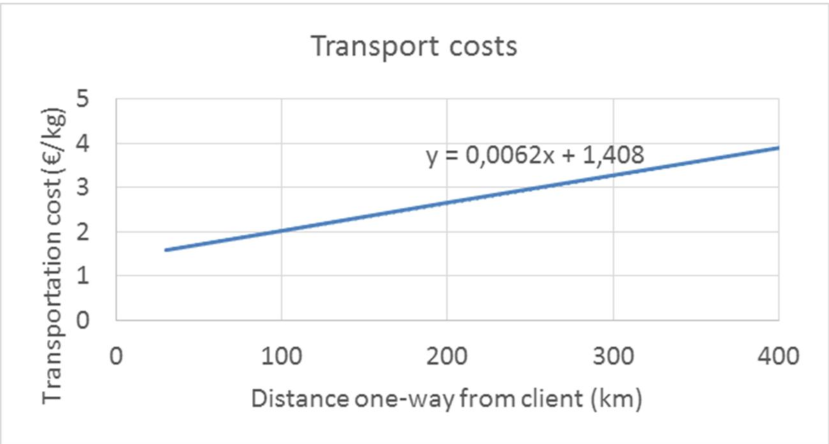

Figure 112: Hydrogen transportation cost in function of the delivery distance

Variable	Description	Value
$Cost_{production}$	H_2 cost at the production centre. Production by SMR = 3.00 €/kg Conditioning cost = 1.42 €/kg	4.42 €/kg
$\%_{overhead}$	Overhead of the gas supplier	15%
$\%_{margin}$	Margin of the gas supplier	10%
$Cost_{transport}$	Cost of transport based on Amortisation, OPEX and H_2 quantity delivered	
A		0.0062 €/km
B		1.41 €/kg

Table 98: Hydrogen transportation cost parameters details

The resulting model (Figure 113) shows a hydrogen price ranges between 7.5 – 11.0 €/kg from short distance to 500 km. The corresponding cost structure has a predominant fixed component related to fixed costs of the filling centre, storage, and logistics. Also, the model is coherent with ESPRIT data in France, UK and Denmark. However, Germany remains curiously low.

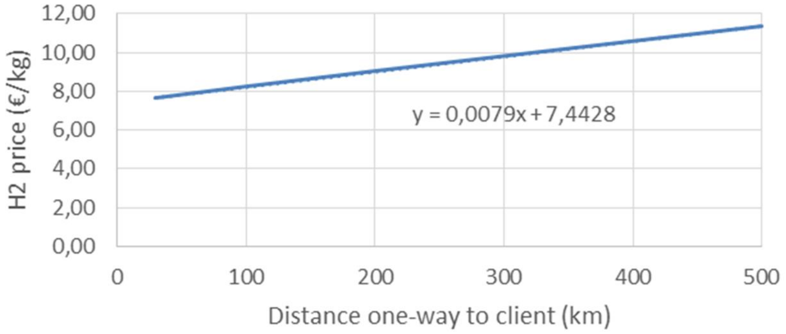

Figure 113: Hydrogen price in function of the delivery distance

4.2.2. Light industry description

The next sub-sections will describe hydrogen for light industry customers and estimate the typical size of the electrolyser as well as describe the operational modes (consumption pattern) and other typical operational constraints (need and size of storage…). In many cases, the industrial processes can vary significantly between plants (e.g. capacity, size, volume, quality…). For example, certain batch process can be streamlined so the production becomes continuous. This configuration may differ in every plant. This can be challenging to define an on-site hydrogen production plant. For this reason, assumptions were made to reflect a "standard" factory set up.

4.2.2.1. OIL AND FAT (HYDROGENATION)

Hydrogenation process is widely used in the food industry for oil and fat such as margarine, vegetable oils, animal fats. The purpose is to:

- Increase the melting point;
- Harden texture and lighten colour;
- Enhance resistance to oxidation and preservation.

Hydrogen (>99.5% purity) is continuously bubbled into a stirred tank reactor to react with the liquid phase oil with the aid of the finely divided nickel catalyst. Hydrogenation is commonly done in batches of 1 to 15 tons of oil. The process uses about 4-6 kg H_2/t oil hydrogenated and takes 4 to 6 hours to complete. Hydrogen flow is estimated at 10-50 Nm^3/h depending of batch size. Short interruption of hydrogen supply may affect plant operation but does not damage final product.

Plant capacity can range between few 1 000 to 100 000 tons of oil per year. European hydrogen consumption in hydrogenation process is estimated at 0.41 billion Nm^3/year.

Assuming a 50 000t capacity plant in continuous production, a suitable on-site electrolyser size would be 1.6 MW to satisfy the industrial demand. Hydrogen quality from electrolysis is compatible with the process. On-site storage is needed to ensure continuous supply.

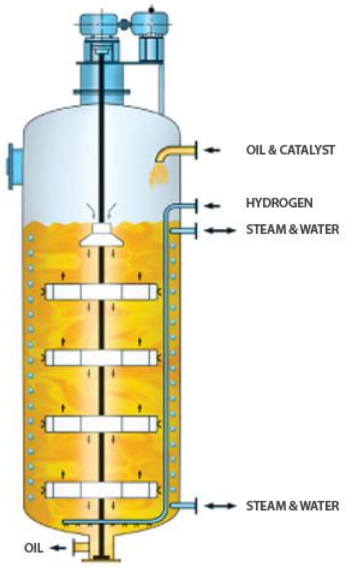

Figure 114: General hydrogenation process [80]

4.2.2.2. GLASS PRODUCTION

Nearly all flat glass production is made with a float process. Molten glass is cooled over a tin bed to ensure a perfectly flat surface. The cooling takes place in a nitrogen-hydrogen atmosphere. The hydrogen prevents oxidation of the tin and reacts with oxygen impurities in the atmosphere that cause residue formation on the glass and alter its properties. A reliable and pure supply of hydrogen is important for smooth glass production. Therefore, a reliable continuous gas supply is needed.

The typical hydrogen consumption is estimated at 5 Nm^3 per ton of glass or about 100 Nm^3/h depending on plant size. Float glass plant capacity can range between 300 – 700 ton per day. Europe has 55 float lines which produced 8.5 million tons of flat glass in 2014. The hydrogen consumption is estimated at 0.07 billion Nm^3/year.

Assuming a 500 ton per day capacity plant in continuous production, a suitable on-site electrolyser size would be 500 kW to satisfy the industrial demand. Hydrogen quality from electrolysis is compatible with the process. On-site storage is needed to ensure continuous supply.

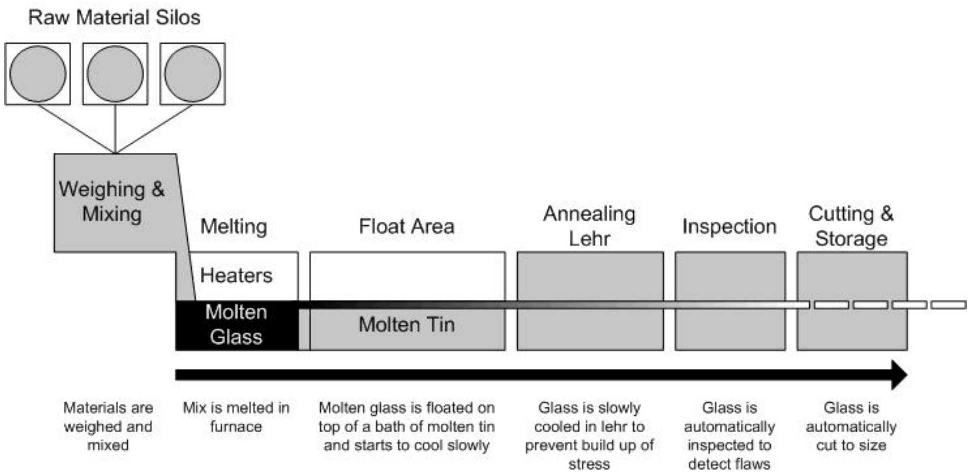

Figure 115: Float glass process[118]

4.2.2.3. ELECTRONICS

Hydrogen is involved in many steps in the semi-conductor production (from production of silicon wafer to the finished integrated circuits). Hydrogen is mainly used as a forming, carrier and scavenger gas. It is mixed with other inert gas such as nitrogen.

Semiconductor processes can be separated in two stages: the production of silicon ingot and wafer fabrication. Both stages are done in batches.

For wafer fabrication, batches can vary between 25-200 wafers. The process time can take up to 60 days depending of number of operations. Typical semiconductor foundry can produce between 80 – 120 000 WSPM (Wafer Starts per Month).[126]

High purity requirement involves liquid hydrogen supply or small SMR units with purification stage (>1 200 kg/month). On-site production by electrolysis is preferred on smaller volume. Water electrolysis offers easily and flexible supply high purity pressurised gas. European hydrogen consumption for the electronics industry is estimated at 0.33 billion Nm^3/year.

Assuming a need for 500 Nm^3/h of hydrogen, a suitable on-site electrolyser size would be 2 MW to satisfy the industrial demand. On-site storage is needed to ensure continuous supply. Fabrication plant have complex gas supply contract due to their need for other speciality gases (nitrogen, oxygen, fluorine, nitrous oxide…) and purity specification. This should be considered when choosing for on-site production.

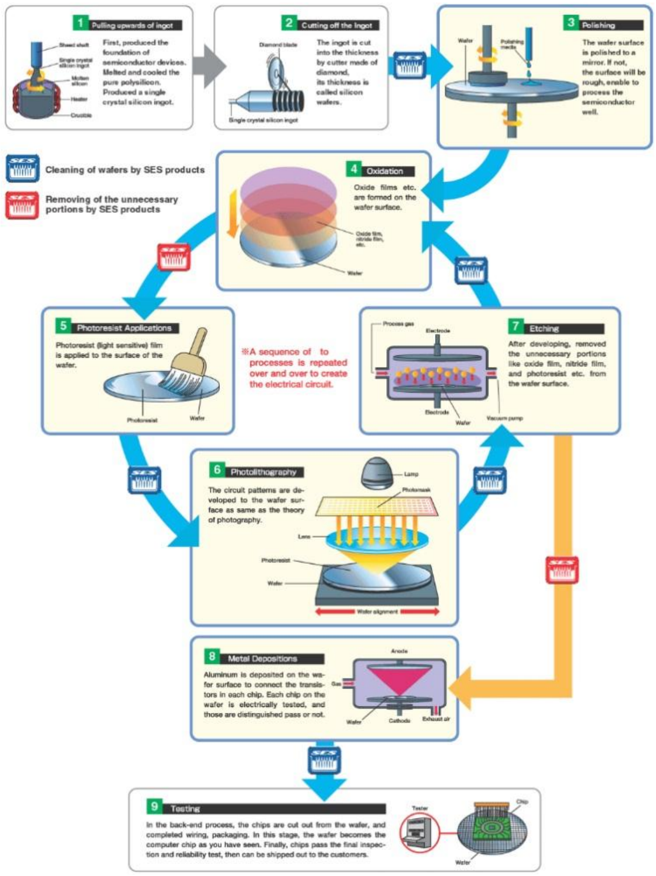

Figure 116: Diagram of semi-conductor production [112]

4.2.2.4. METALLURGY (HEAT TREATMENT)

The heat treatment processes for metals require a high controlled temperature and a controlled atmosphere. Hydrogen is used to prevent oxidation and reducing oxides. Hydrogen is often mixed with nitrogen or other inert gas to create the controlled atmosphere. The **GrInHy** (Green Industrial Hydrogen) is an example of European project, led by Salzgitter Group and supported by the FCHJU, with the objective is to investigate new ways of producing hydrogen and the aim of lowering CO_2 emissions in steel manufacturing in the future. A High Temperature Electrolyser (HTE) will be installed and operated in the production site of Salzgitter Flachstahl GmbH by 2017. The unit will substitute merchant hydrogen for heat treatment process on steel.

The table below tries to summarise the big families of processes and hydrogen use.

Typical Process	Supply of hydrogen	Hydrogen flow
Annealing	Batch	50-500 Nm^3/h
Brazing	Both	40-200 Nm^3/h
Sintering	Continuous	60 Nm^3/h
Hardening	Batch	Various
Carburising	Both	Various

Table 99: Typical metal heat-treatment processes [43]

Most of these processes consume hydrogen in batches. The quantity used largely depends on the furnace size and the treated material. Process time is also variable as it depends on the treated product, operational configuration of the plant. The treated product needs to be heated and cooled in a specific procedure. Typical process can take between 10 to 24 hours for annealing steel. Short disruption of hydrogen supply does not affect the quality of the final product.

Hydrogen consumption is estimated at 20-1000 Nm^3/h depending on plant size. European hydrogen consumption for the metal heat treatment industry is estimated at 0.32 billion $Nm^3/year$.

Assuming a need for 500 Nm^3/h of hydrogen, a suitable on-site electrolyser size would be 2 MW to satisfy the industrial demand. On-site storage is needed to ensure continuous supply. Similar to electronic sector, heat treatment facilities usually have a multi gas contract which needs to be considered when deciding for an on-site production.

4.3. Value to be captured from hydrogen mobility

4.3.1. HRS operator's acceptance price of hydrogen calculation

The equation below describes the HRS operator's acceptance price of hydrogen. In other words, it is the specific price of the station expressed in €/kg.

The following equation will be used for to determine the acceptable hydrogen price for the mobility applications.

$$H2\ acceptance\ price_{station} = \frac{\sum_{i=0}^{n} \frac{Cost\ in\ year\ i}{(1+WACC)^i}}{\sum_{i=0}^{n} \frac{Quantity\ of\ H2\ delivered}{(1+WACC)^i}}$$

The annual costs are described as follow.

$WACC$ = 5%	Weighted Average Cost of Capital
$CAPEX_{station} = A\left(\frac{Q}{Q_{ref}}\right)^{0,66}$	A = 750 k€ (for 350 bar) or 1500 k€ (for 700 bar) Q_{ref} is the reference HRS capacity = 200 kg/day Q is the selected capacity in kg/day
$OPEX = P_{elec}\eta_{station}m_{H2} + OPEX_{station}$	P_{elec} is the price of electricity = 100 €/MWh $\eta_{station}$ is the power usage = 3 kWh/kg (350 bar) and 4 kWh (700 bar) m_{H2} is the annual volume of hydrogen delivered in kg $OPEX_{station}$ is the annual OPEX = 4% of $CAPEX_{station}$ in €/year

Table 100: Hydrogen station annual cost details (Hinicio)

The following sub-sections will showcase scenarios of hydrogen mobility and determine for each the acceptable hydrogen price to the HRS.

4.3.2. Hydrogen forklifts

Hydrogen forklifts are considered as a commercially mature product based on a profitable business cases (under specific circumstances). This solution provides a cost-effective alternative for battery electric forklifts. The higher CAPEX of the fuel cell pack, and of the HRS and the more expensive fuel (compared to electricity) are compensated by the higher utilization rate of each forklift and lower labour costs made possible by fast recharging, extended range and, longer lifetime of the fuel cell. As a result, in the case of fleets of more than 30 forklift trucks with continuous operation, the productivity of the warehouse can be improved by several percentage points. Attractive market segments are for instance distribution centres and automobile manufactures, with a large fleet of forklift (> 100 units) running 2 to 3 shifts per day. Typical hydrogen forklifts users in Europe are in the 100 units range.

Most fleets of fuel cell forklifts operating in Europe are supplied by tube-trailers. Customers could be interested by on-site production for many reasons:

- Potentially lower hydrogen price,
- Green or low-carbon hydrogen,
- Independence from the gas provider.

Fleet

A reasonable fleet size would be about 100 forklifts operating 330 days per year in two or three work shifts. Typical daily hydrogen consumption is 1kg/day/forklift. Units are refuelled as they need. There is no schedule. Each forklift may be refuelled for every work shift.

HRS

As bus depot is considered as a captive fleet, only one 350 bar HRS is needed. The station would need to supply between 500 kg/day mainly during the night. In case of failure of an on-site production, additional storage (on-site or mobile) is needed to cover at least 24h of operation (500 kg). Station CAPEX is estimated at 1.4 M€.

Price acceptance of the HRS operator

Considering an end-user acceptance price of 6-7 €/kg, based on the above equation, $LCOH_{station}$ is estimated at 1.8 €/kg. **HRS operator price acceptance should be between 4.2 – 5.2 €/kg.**

4.3.3. Hydrogen buses

As cities are putting in place restrictive measures on combustion engines and/or incentives toward low carbon vehicles, bus operators are adapting to these new regulations integrating lower and/or zero emission buses. For instance, France has adopted the LTECV[42] which requires all new buses and coaches purchased by public transport services must be low emission vehicle from 2025. UK Office for Low Emission Vehicles (OLEV) allocated a £30 million for the Low Emission Bus Scheme (2015-2020).

Low emission vehicle typically refers to hybrid, biomethane, electric or hydrogen. However, only electric and hydrogen are considered zero-emission. When comparing both technologies, hydrogen is the most suitable for high power application such as buses.

Hydrogen bus offers interesting features as a zero-emission alternative.

- Possibility to be zero carbon and/or renewable
- Fast recharge time (10 minutes)
- Good autonomy (300-500 km)

Fleet

A typical fleet size in the launching phase would be about 20 FC buses operating 307 full days per year, considering public holidays and maintenance. The daily journey would be about 250 km in urban area. Fuel economy of the FC bus is about 10 kg/100km. The daily hydrogen consumption would be between 25 kg/day/FC bus which needs to be supplied during a low usage period such as the night.

HRS

As bus depot is considered as a captive fleet only one 350 bar HRS is needed. The station would need to supply between 500 kg/day mainly during the night. In case of failure of an on-site production, additional storage (on-site or mobile) is needed to cover at least 24h of operation (500 kg). Station CAPEX is estimated at 1.4 M€.

Price acceptance of the HRS operator

Considering an end-user acceptance price of 9-10 €/kg, based on the above equation, $LCOH_{station}$ is estimated at 1.8 €/kg. **HRS operator price acceptance should be between 7.2 – 8.2 €/kg.**

[42] Energy transition and green growth law (“Loi sur la transition énergétique et la croissance verte”).

4.3.4. Passenger cars and light-duty vehicles

The deployment of hydrogen vehicles has always been very challenging due to the classical chicken-and-egg dilemma requiring a simultaneous and coordinated deployment of vehicles and refuelling stations in sufficient numbers. The top-down, nation-wide deployment model is a challenging undertaking, requiring a long-term and coordinated effort by OEMs and infrastructure players to weather out a "valley of death" of several years without seeing any profit at all. Different paths, based on a bottom-up approach not focused on private vehicles but rather on captive fleets, have been put forward by several players in the field, leading the emergence of short-term business cases. This section will focus on a selection of these use-cases.

Since 2014, car manufactures have started to commercialise hydrogen cars and prices have dropped rapidly. The following table summarized the passenger cars and light-duty vehicles already or soon-to-be available on the marketplace.

	Hyundai	Toyota	Honda	BMW	Mercedes	Renault SymbioFC
Model	ix35	Mirai	Clarity	5GT	GLC F-Cell	KangooZE
Type	Full power H_2				Plug-in FC	Range extender
	SUV	Sedan	Sedan	Sedan	SUV	Light utility
Pressure	700 bar					350-700 bar
Autonomy	594 km	500 km	700 km	450 km	500 km	200-300- km
Release	2014	2015	2016	2020	2017-2018	2014

Table 101: Summary of hydrogen mobility market (Compilation by Hinicio)

4.3.4.1. CAPTIVE FLEETS WITH RANGE EXTENDER

Captive fleets have been identified early on as a high potential mobility business case. As cars operate around a fixed base contrary to passenger car, this enables the deployment of a full fleet of vehicle with limited infrastructure requirements. Additionally, large captive fleets in postal and distribution services for instance have high usage rate and are increasingly confronted with emission restriction in city centres, which makes hydrogen an interesting candidate versus batteries in some instances. Over the last years, a promising business case has emerged along those lines based on range extender light duty vehicles. It is briefly described in this section.

Fleet

A fleet of 50 small utility cars is considered operating operational 330 days per year, minus the annual public holidays and maintenance. The daily journey would be 100-150 km for letter and package delivery. It can be considered that only 100 km is used on hydrogen. The fuel consumption of the hydrogen range extender is about 1 kg/100km. The daily hydrogen consumption at the station would then be 50 kg/day for the whole fleet. Most refuelling will need to be done during a low usage period such as the night.

HRS

A captive fleet configuration typically involves the installation of one 350 bar HRS at the distribution centre. In case of failure of an on-site production, additional storage (on-site or mobile) is needed to cover at least 24h of operation (50 kg). Station CAPEX is estimated at 470 k€.

Price acceptance of the HRS operator

Considering an end-user acceptance price of 9-10 €/kg, $LCOH_{station}$ is estimated at 3.3 €/kg. **HRS operator price acceptance should be between 5.7 – 6.7 €/kg.**

4.4. Value to be captured from hydrogen injection into gas grid based on biomethane injection tariff

4.4.1. Germany

	H_2 limit	Biomethane injection tariff (EEG 2014)	Hydrogen equivalence
Germany	9.9%vol <2%vol in some conditions	134.6 €/MWh$_{el}$ Approx. 32.3 €/MWh	1.3 €/kg

Table 102: Summary of German hydrogen injection opportunities

4.4.1.1. HYDROGEN INJECTION

Germany is home to the highest number of power to gas projects in Europe with over 20 pilot and demonstration projects. The country's interest is mainly linked to the Energiewende[43] and high targets of renewable electricity production.

	Falkenhagen	Thüga	Hamburg	Energiepark Mainz
Grid connection	Transport	Distribution	Distribution	NA
Year	2013	2014	2015	2015
Location	Falkenhagen	Frankfurt	Reitbrook	Mainz
Production capacity	2 MW (360Nm^3/h)	300 kW	1 MW (265Nm^3/h)	6 MW
Injection level	5%vol with test to 15%vol	NA	NA	0-15%vol
Budget	NA	NA	13.5 M€	17 M€
Comments	55 bar grid (Green Car Congress, 2011)	No compression, direct injection	15 bar grid	6-8 bar grid [23]

Table 103: Example of hydrogen direct injection projects in Germany

[43] German energy transition

The current hydrogen injection limit is set by the DVGW G262 at 9,9%vol. This concentration limit is lowered in case of presence of downstream CNG refuelling stations or storage (e.g. underground). This is usually accessed on a case by case basis by project developers in cooperation with the local gas network operator. Under specification UN ECE R 110, CNG tank can tolerate up to 2%vol of H_2.

There about 921 stations mainly located west of Germany [16]. Due to the high number of CNG stations, most hydrogen injection projects will be limited to 2%vol. However, specific opportunity can be found in the distribution network in North-East of the country.

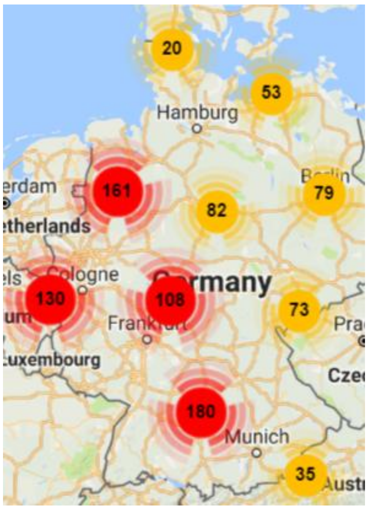

Figure 117: Map of CNG stations in Germany [16]

4.4.1.2. BIOMETHANE INJECTION

In 2014, there were more than 150 biomethane injection plants in Germany. German feed-in tariff (FIT) provide remunerations for the generation of electricity from renewable sources, under the Renewable Energy Sources ("the EEG"). Biomethane injection is remunerated indirectly by the electricity through CHP plant. Current electricity FIT is 134.6 €/MWh_{el}. [96]

As shown in the figure below, to better reflect the biomethane price, the CHP plant and gas grid fees costs needs to be deducted from the EEG FIT. By using an CHP electrical efficiency of 50%, CHP plant cost of 15 €/MWh_{Hs} and gas grid fees of 20 €/MWh_{Hs}, the equivalent tariff for biomethane injection is 32.3 €/MWh. This represents **1.3 €/kg if hydrogen was injected.**

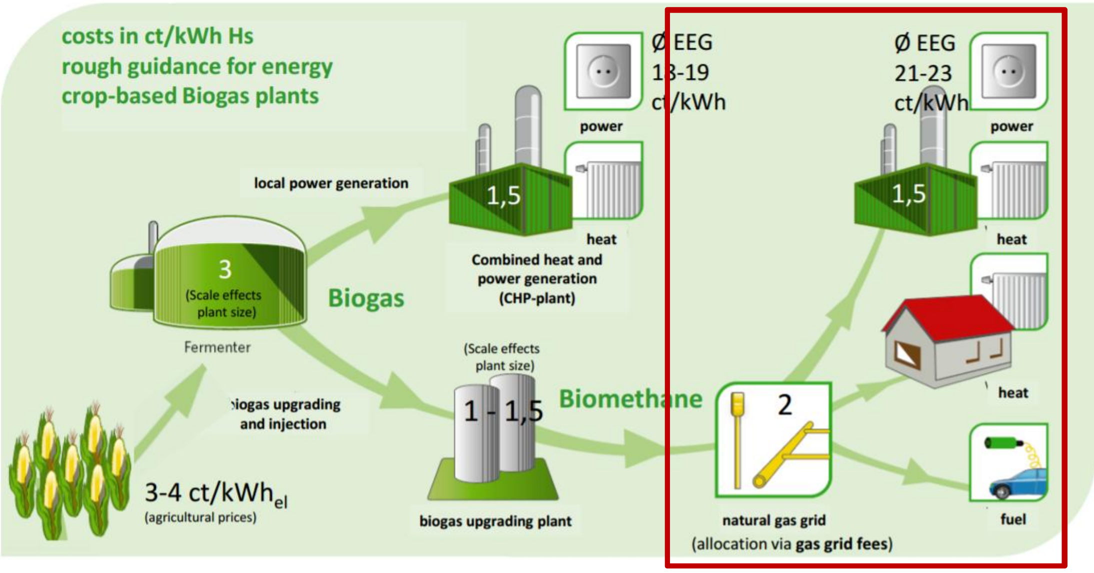

Figure 118: Biomethane supply chain under EEG [127]

Biomethane projects benefit also from a gas grid cost sharing between the biomethane producer and the grid operator (GasNZV). This reduces the investment to be borne by the biomethane producer. The cost, including the injection station, compression and pipeline, is dependent on distance between the biogas plant and grid connection point:

- if the connection distance is less than 1 km, the cost borne by the supplier is capped at 250,000€;
- For connections distances ranging between 1 and 10 km, the supplier bears 25 % of the cost with 75 % of the cost burden on the network operator,
- Beyond 10 km of distances, the supplier bears 100% of the grid connection costs.

These costs data will be used in the costing of the business cases in section 6, should injection be included.

4.4.2. France

	H_2 limit	Biomethane injection tariff (2015)	Hydrogen equivalence
France	6%vol	High: 140 €/MWh Low: 45 €/MWh	High: 5.5 €/kg Low: 1.8 €/kg

Table 104: Summary of French hydrogen injection opportunities

4.4.2.1. HYDROGEN INJECTION

Based on the requirements of both TSO [61] and DSO [55], the hydrogen limit is set at 6%vol in the gas mix. As an example, for a 200 Nm^3/h hydrogen injection project (corresponding to an electrolyser of around 1 MW), grid capacity would need to be over 3 333 Nm^3/h. Such capacities are generally found at the transmission grid level.

There are currently only two hydrogen injection demonstration projects in France. The key data of these projects are summarized below.

	GRHYD	Jupiter1000
Grid connection	Distribution	Transport
Year	2014	2015
Location	Dunkerque	Fos-sur-Mer
Production capacity	NA	1 MW electrolyser
Injection level	6% to 20%vol	Up to 4.4%vol[44]
Budget	16 M€	30 M€

Table 105: Summary of hydrogen direct injection project in France

4.4.2.2. BIOMETHANE INJECTION

The biomethane injection tariff varies from 45 to 140 €/MWh depending on the production source and injection capacity. The tariff is contracted for a legal period of 15 years. The equivalent tariff for hydrogen injection would be **1.8 to 5.5 €/kg.**

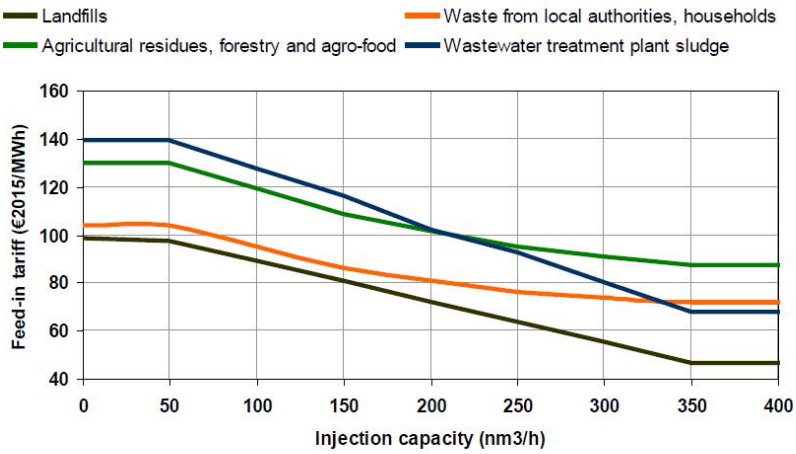

Figure 119: French FIT Scheme for biomethane in 2015 [96]

Unlike Germany, grid connection costs are treated differently on the transport and distribution grid. Typically, the DSO requires the renting of the injection station and the TSO requires an upfront investment for the injection infrastructure. [57]

[44] Based on 200 Nm^3/h hydrogen production (1 MW) injected in to a transport gas grid of 4500 Nm^3/h

4.4.3. Great Britain

	H_2 limit	Biomethane injection tariff (Oct 2016)	Hydrogen equivalence
UK	0.1%vol	43.2 £/MWh (50.50 €/MWh) for the first 40 000 MWh injected	2.0 €/kg for the first 1000 t H_2 injected

Table 106: Summary of British hydrogen injection opportunities

4.4.3.1. HYDROGEN INJECTION

UK has one of the most stringent gas quality standard in Europe. The Gas Safety (Management) Regulations 1996 (Schedule 3, Part I) limits hydrogen content to 0.1%vol in the gas mix [59]. It also requires full gas composition (Regulation 8) and odorisation when injecting gas below 7 barg (Schedule 3, Part 1). Exemptions are possible by the HSE (Regulation 11).

Changes in the current regulation are needed to enable hydrogen direct injection.

Content or Characteristic	Value
Hydrogen sulphide (H_2S)content	≤5 mg/m^3
Total sulphur content (including H_2S)	≤50 mg/m^3
Hydrogen content	≤0.1% (molar)
Oxygen content	≤0.2% (molar)
Impurities	shall not contain solid or liquid material which may interfere with the integrity or operation of pipes or any gas appliance (within the meaning of regulation 2(1) of the 1994 Regulations) which a consumer could reasonably be expected to operate
Hydrocarbon Dewpoint and Water Dewpoint	shall be at such levels that they do not interfere with the integrity or operation of pipes or any gas appliance (within the meaning of regulation 2(1) of the 1994 Regulations) which a consumer could reasonably be expected to operate
Wobbe Number (WN)	(i) ≤51.41 MJ/m3, and (ii) ≥47.20 MJ/m3
Incomplete Combustion Factor (ICF)	≤0.48
Sooting Index (SI)	≤0.60

Source: Gas Safety (Management) Regulations 1996, Schedule 3, Part I

Table 107: UK Gas Safety Regulation [64]

It is worth mentioning the H21 Leeds City Gate project [93] where a large-scale demonstration is under development to convert the existing gas network for 100% hydrogen grid. Hydrogen will be supplied by 4 SMR (total capacity of 1025 MW_{HHV}) at Teesside (100 km North of Leeds). Current state of the project only considers hydrogen for heating and cooking. Transportation and micro CHP is projected as an interesting evolution. As the project is still in the early phase, the earliest practical date for the initial hydrogen conversion of a UK city is 2025.

The project does not consider hydrogen supplied by electrolyser yet. However, electrolyser will need to compete against the local SMR.

4.4.3.2. BIOMETHANE INJECTION

By the end of 2015, 50 plants where injecting 2 TWh of biomethane in the UK gas grid. The target is to reach 100 plants by 2020. Biomethane injection is eligible to the Non-Domestic Renewable Heat Incentive (RHI) of the Department of Energy and Climate Change (DECC). This incentive is reviewed quarterly in in respect of government allocated budget. The tariff is secured over a 20 years contract. The following table shows the current tariff for biomethane injection. If hydrogen was eligible to this tariff, this would **represent 2.0 €/kg for the first 1000 tons of hydrogen injected.**

Tier 1	On the first 40,000 MWh of eligible biomethane	4.32 pence / kWh
Tier 2	Next 40,000 MWh of eligible biomethane	2.54 pence / kWh
Tier 3	Remaining MWh of eligible biomethane	1.96 pence / kWh

Table 108: UK Non-Domestic RHI tariff on October 2016 for biomethane injection [98]

All costs associated with a biomethane connection are funded 100% by the biomethane producer. The connection pipeline can be procured in the competitive market and is 'adopted' by the grid owner. [57]

In the UK, the typical gross calorific value is 39.0 – 39.5 MJ/m^3 while the heating value of 100% biomethane is about 37.7 MJ/m^3. Due to the high heating value requirement, significant amounts of propane or LPG are needed to adjust the heating value of the injected biomethane.

4.4.4. Denmark

	H_2 limit	Biomethane injection tariff (Oct 2016)	Hydrogen equivalence
Denmark	Up to 20 %vol (theoretical)	67.5 €/MWh (excluding gas certificate value)	2.6 €/kg

Table 109: Summary of Danish hydrogen injection opportunities

4.4.4.1. HYDROGEN INJECTION

Danish gas quality is stated in the Gas regulation (“Gasreglementet afsnit C-12”) from the Danish Safety Technology Authority (“Sikkerhedsstyrelsen”). The regulation defines the requirements of hydrogen quality and monitoring for injection in to the gas grid. [105]

- At least 98% by volume of hydrogen (H_2)
- no more than 0.1% by volume of oxygen (O_2)
- no more than 0.2% by volume of carbon dioxide (CO_2)
- no more than 0.5% by volume hydrocarbons ($C_n H_m$) measured as methane,
- water dew point below -50 °C, measured at atmospheric pressure

The volume content of hydrogen in the natural gas network must be approved by the Safety Technology Authority. No odorisation is needed for H_2 injection. Continuous monitoring is required on hydrogen content, dew point and oxygen level. Periodic monitoring must be done to determine the CO_2 content.

However, the rule does not explicitly state the hydrogen limit in gas mix. Instead, the natural gas Wobbe number must range between 50.76 and 55.8 MJ/m^3. Based on Figure 120, hydrogen limit appears near 20%vol where the gas mix overshoot the Wobbe range tolerance.

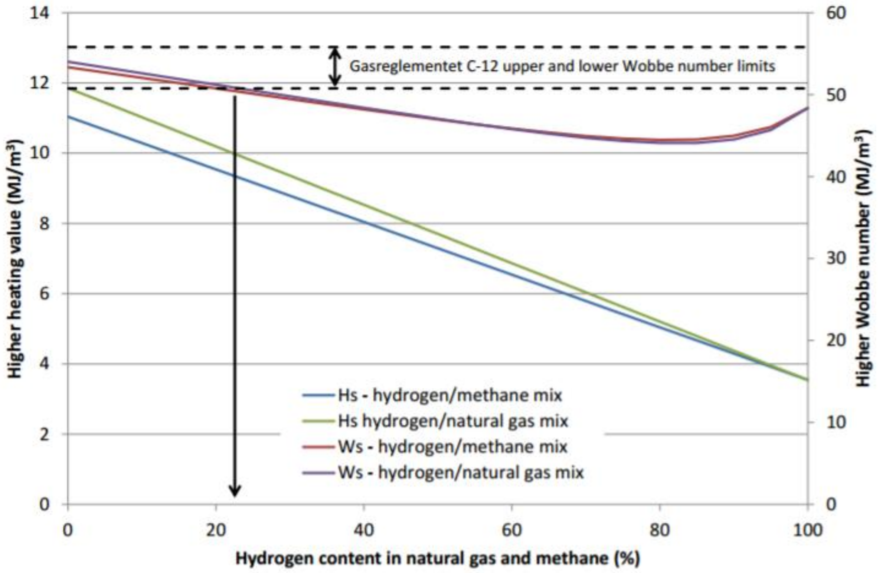

Figure 120: Heating value and Wobbe number for methane natural gas with added hydrogen [86]

4.4.4.2. BIOMETHANE INJECTION

The liberalisation of the Danish natural gas market in 2004 made possible for everyone to set up as a gas supplier in Denmark. Biomethane producer have 3 cumulated remunerations possibilities:

- Subsidy
- Gas market
- Gas certificate

Subsidy for upgraded and cleaned biogas consists of three parts:

- Subsidy 1: Annual indexation
- Subsidy 2: Indexed to the natural gas price
- Subsidy 3: Annually reduced by 2 DKK/GJ from 1 January 2016

In 2016, the total subsidy for upgraded biogas was 53.5 €/MWh (0.398 DKK/kWh$_{HHV}$).

As a gas supplier, the biomethane producer can participate on the **Danish and European gas market**. The following figure shows the gas price in Denmark. Latest price in October 2016 was around 14€/MWh.

Figure 121: Natural gas wholesale price in Denmark [36]

Finally, the producer can register for **gas certificate** ("bionaturgascertifikater") as a guaranty of origin. 1 MWh of biomethane generate 1 certificate that can be sold independently to the actual gas. There are about 30 participants eligible to trade and sell the gas certificate. No information was found on the value of the certificate. Anyhow, green hydrogen certificate will most likely rely on a separate certification scheme with its own price market.

Adding the subsidy and gas market revenues, the producer can generate 67.5 €/MWh for his biomethane production. When translated in to hydrogen, this represent **2.6 €/kg** as potential value.

4.4.5. Sardinia

Sardinia has currently no natural gas network. Therefore, hydrogen injection is not considered in this region. However, it is worth mentioning that Sardinia has two ongoing projects to interconnect a gas network to the neighbouring regions:

- GALSI (Algeria – Sardinia – Italy)
- CYRENE (Sardinia – Corsica)

These projects may have a great impact on Sardinia's energy and economic landscape. New supply of natural gas can stimulate industrial development such as paper, timber, agri-food and construction industry. This gas network interconnection could change the energy landscape of Sardinia with the access of cheaper natural gas which can evolve toward a distribution gas network, allowing a better management of the electrical network by promoting heating and cooking with gas. It is estimated that the pipeline will save 30-40% from other fuel importation.

It is reasonable to consider this gas interconnection by 2025 as the projects are already identified as Projects of Common Interest (PCI) by the European commission.

	GALSI pipeline (Hydrocarbons Technology, 2016) (GALSI, 2008)	CYRENEE pipeline (GRTgaz, 2011)
Sections	Algeria-Sardinia – 285 km – 182 bar Sardinia – 272 km – 75 bar Sardinia – Tuscany – 280 km – 200 bar	Terrestrial – 200 km – 68 bar Underwater – 100 km – 68 bar
Capacity	8 billion m^3 per year	NA
Budget	3 635 M€ 120 M€ (EU - EEPR[45])	424 M€
Consortium	Sonatrach, Edison, Enel, Hera Group, Region of Sardinia, SNAM Rete Gas	GRTgaz

Table 110: Gas network interconnection projects in Sardinia

4.5. Value to be captured for load frequency control

Ancillary services for Load-Frequency Control greatly differ across EU member states, both in terms of regulation and remuneration. In the following, the current regulatory framework will be presented for each of the selected locations, followed by a quantification of historical revenues. The analysis will focus on FCR and FRR as defined by the EU regulatory body ACER. These services were previously known as primary and secondary reserves in most countries. The assessment of the regulatory framework is based on [95] and [39] and is complemented by national sources when necessary.

This section describes the regulatory framework of each selected country used to build the summary table on the value to be captured for load frequency control in section 5.4.2.2 (Table 44).

4.5.1. Germany

4.5.1.1. REGULATORY FRAMEWORK

In Germany, ancillary services for Load-Frequency Control are procured by the four German grid operators through organised markets. A summary of the regulatory framework is given in Table 111.

Both FCR and FRR are procured in weekly auctions with a price-inelastic demand set by the transmission grid operators. This means that units have to commit for a period of one week, in which the grid operator may request the contracted service at any time. However, FRR awards separate contracts for peak- and off-peak periods. It is therefore possible to commit to supplying FRR only during the night and on weekends.

[45] European Energy Plan for Recovery

A key difference between the two services is that FCR remunerates capacity only, while FRR remunerates both capacity and energy activated. To this end, tenderers submit both a capacity price and an activation price bid in FRR. Activation of the service is therefore based on a merit-order, i.e. less expensive units are activated first.

Another relevant aspect from the perspective of an electrolyser operator is that FCR is a symmetrical product, i.e. upward and downward regulation is contracted at the same time. This is different from FRR, where there are separate auctions for positive and negative reserves. Consequently, an electrolyser would have to be able to both increase and decrease consumption in order to be pre-qualified for FCR. This constraint has to be taken into consideration in the dispatch planning.

The minimum bid size is in the megawatt-class for both services. Yet, it is possible to aggregate multiple smaller units since a couple of years. In general, the services are open to both the demand- and the supply-side, as well as storage.

PEM electrolysers can offer both FCR and FRR, while Alkaline eletrolyzers are unlikely to comply with the activation time of less than 30s required for FCR.

	FCR (Frequency Containment)	**FRR (Frequency Restoration)**
Procurement	Organised market	Organised market
Forward period	Week-ahead	Week-ahead
Commitment period	1 week	1 week, peak or off-peak periods
Product type	Symmetrical (Upward and downward)	Asymmetrical (Upward or downward)
Remuneration	Capacity	Capacity + energy activated
Settlement	Pay-as-bid	Pay-as-bid
Minimum bid size	1 MW	5 MW
Full activation time	<30sec	<5min
Current providers	Generation, load, storage	Generation, load, storage

Table 111: Overview of regulatory framework for Load-Frequency Control in Germany

4.5.1.2. HISTORICAL PRICES

The German TSOs have been publishing auction results on a joint internet platform since 2011. [104] Result files include the full list of bids in an anonymised form that can be post-processed in order to deduct both average and marginal prices of the service. Being a pay-as-bid auction[46], there is a tendency to bid close to the expected marginal price, i.e. the highest bid that is expected to be accepted.

The historical development of average capacity prices for FCR and FRR (positive and negative) since 2011 is shown in Figure 122. Prices generally show some seasonality, with high peaks around the end of the year, where load is generally low and less units are online that could provide FCR or FRR. Another observation is that price levels for negative FRR have decreased significantly over the last years. Possible reasons are overcapacity and changes in the regulatory framework that enabled more resources to participate in the auctions. Among these changes are shorter commitment periods and a smaller minimum bid size. For FCR, the transition towards a joint procurement with Belgium, the Netherlands, Switzerland and Austria also had a price-dampening effect in recent years.

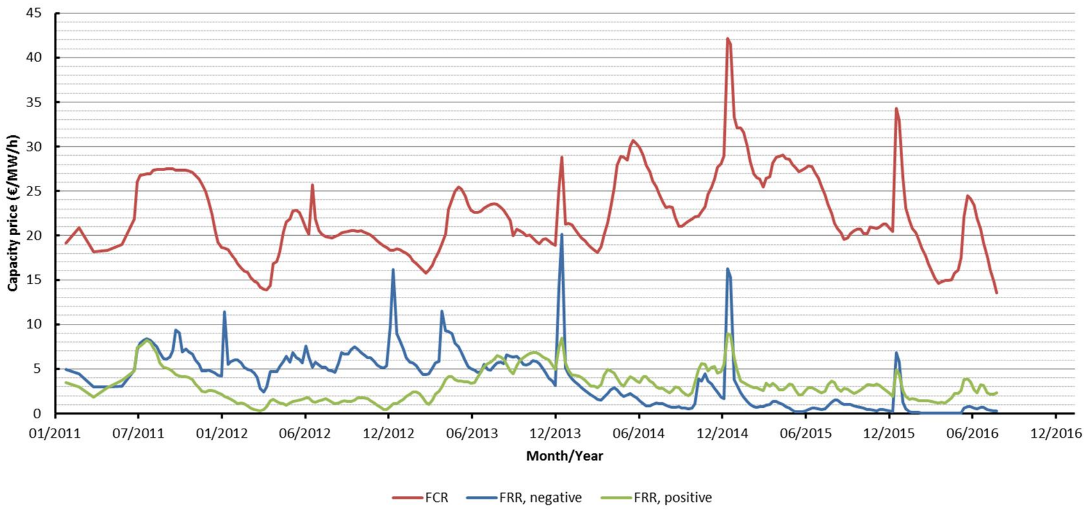

Figure 122: Historical development of capacity prices in the German FCR and FRR markets (2011-16)

Annual values for the capacity and activation prices are shown in Table 112. These represent average values of all accepted bids. To allow for a better comparison between countries and different services, the capacity price has been converted from the unit €/MW/h (given by the German TSOs) to k€/MW/year.

[46] The opposite of a pay-as-bid auction is an auction with a uniform clearing price. In the latter case, every successful bidder receives the marginal price bid, i.e. the price bid that is necessary to clear the auction. In the former case, accepted bids receive exactly their price bid, which is typically lower than the marginal price bid.

From 2015 to 2016, capacity prices of all ancillary service types decreased, while activation prices increased. The negative activation price in downward FRR means that providers receive remuneration when they get called, i.e. a payment for consuming more electricity or producing less.

Product & remuneration		2015	2016[47]
FCR	Capacity price (€/MW/h)	25.56	19.06
	Capacity price (k€/MW/yr)	223.9	167.0
	Activation price (€/kW/yr)	0	0
FRR, upward	Capacity price (€/MW/h)	3.11	2.17
	Capacity price (k€/MW/yr)	27.2	19.0
	Activation price (€/MWh)	700.0	1103.3
FRR, downward	Capacity price (€/MW/h)	1.28	0.47
	Capacity price (k€/MW/yr)	11.2	4.1
	Activation price (€/MWh)	-992.2	-1217.0

Table 112: Historical prices in the German market for Load-Frequency Control

4.5.2. France

4.5.2.1. REGULATORY FRAMEWORK

In contrast to Germany, FCR and FRR are mandatory services for grid-connected generation units in France, i.e. the services are not procured through a market. A summary of the regulatory framework is given in Table 113.

Mandatory provision essentially means that a part of a unit's nameplate capacity has to be reserved to provide frequency containment and frequency restoration, if requested by the French TSO. In return for this service, there is a pre-defined remuneration (regulated price), both for holding ready the capacity and for activating it. Activation occurs on a pro-rata basis, i.e. all contracted units will be activated when the service is called, unless grid constraints do not permit activating a specific unit.

The French system is generally more accessible for small-scale units than the German one, which requires a minimum bid size of 1 MW. It is open to load, generation and storage, provided that the units can comply with the technical requirements, especially the activation time. From the perspective of an electrolyser operator, it is important to note that both FCR and FRR are symmetrical products, i.e. both upward and downward regulation are contracted at the same time with the same capacity.

It is subject to uncertainty whether the regulatory framework for FCR will be kept given the plans of France to join the FCR procurement platform of Germany, Belgium, the Netherlands, Austria and Switzerland. There are, however, no concrete plans to procure FRR jointly with neighbouring EU member states at this stage.

[47] Preliminary data is shown for the year 2016. The average value is based on auction results until the 31st of July 2016.

PEM electrolysers can offer both FCR and FRR, while Alkaline eletrolyzers are unlikely to comply with the activation time of less than 30s required for FCR.

	FCR (Frequency Containment)	FRR (Frequency Restoration)
Procurement	Mandatory provision	Mandatory provision
Forward period	not relevant	not relevant
Commitment period	not relevant	not relevant
Product type	Symmetrical (Upward and downward)	Symmetrical (Upward and downward)
Remuneration	Capacity + energy activated	Capacity + energy activated
Settlement	Regulated price	Regulated price
Minimum bid size	<1 MW	<1 MW
Full activation time	<30sec	<15 min
Current providers	Generation, load, storage	Generation, load, storage

Table 113: Overview of regulatory framework for Load-Frequency Control in France

4.5.2.2. HISTORICAL PRICES

The French TSO has been publishing capacity and activation prices on a web portal since 2015, earlier prices are not available. [109] Capacity prices are generally fixed for a whole year, i.e. there is no seasonal component reflecting the different needs during the year. The same applied to activation prices until recently, i.e. the price was fixed for the whole year. Since April 2016, activation prices show variation between days but are still regulated. Interestingly, the regulated price for FCR and FRR is the same, unlike in other countries.

To allow for a better comparison between countries and different services, the capacity price has been converted from the unit €/MW/30min (given by the French TSO) to k€/MW/year. Annual average values are shown in Table 114.

Product & remuneration		2015	2016[48]
FCR	Capacity price (€/MW/30min)	9.16	9.18
	Capacity price (k€/MW/yr)	160.5	160.8
	Activation price (€/MWh)	10.5	26.48
FRR	Capacity price (€/MW/30min)	9.16	9.18
	Capacity price (k€/MW/yr)	160.5	160.8

[48] Preliminary data is shown for the year 2016. The average value is based on auction results until the 30th of October 2016.

	Activation price (€/MWh)	10.5	26.48

Table 114: Historical prices in the French market for Load-Frequency Control

4.5.3. Great Britain

4.5.3.1. REGULATORY FRAMEWORK

The British TSO has not yet fully adopted the new taxonomy proposed by ACER in 2012, which makes a comparison to other countries more difficult. There are a couple of services grouped under the name ‘Frequency Response’ that are comparable to Frequency Containment Reserves operated in continental Europe. Among these, there is a mandatory service for all large-scale (>100 MW) generators that are connected to the transmission system (Mandatory Frequency Response). These units are obliged to offer a part of their unit’s nameplate capacity to the British TSO. Moreover, there is a commercial service named ‘Firm Frequency Response’ covering smaller units (~10 MW). Remuneration is based on an availability fee, i.e. on capacity price.

A fairly new service is Enhanced Frequency Response (EFR). The first procurement auction was held in July 2016. As explained in section 3, this is a new type of service that requires units to achieve 100% active power output 1 second (or less) after registering a frequency deviation. For comparison: FCR in continental Europe has an activation time of 30 seconds.

PEM electrolysers can offer both Firm and Enhanced Frequency Response, while Alkaline eletrolyzers are unlikely to comply with the activation time of less than 30s required for both EFR and FFR.

	Firm Frequency Response	Enhanced Frequency Response
Procurement	Organised market	Organised market
Forward period	Month-ahead	Year-ahead
Commitment period	1 month	1 year
Product type	Symmetrical (Upward and downward)	Symmetrical (Upward and downward)
Remuneration	Capacity	Capacity
Settlement	Pay-as-bid	Pay-as-bid
Minimum bid size	10 MW	1 MW
Full activation time	<30sec	<1sec
Current providers	Generation, load, storage	Generation, load, storage

Table 115: Overview of regulatory framework for Load-Frequency Control in Great Britain

4.5.3.2. HISTORICAL PRICES

An overview of historical prices in the British ancillary services market is given in Table 116. To allow for a better comparison between countries and different services, the capacity price has been converted from the unit £/MW/h (given by the British TSO) to k€/MW/year. Given the highly dynamic currency exchange rate in recent months, the values might have to be updated at a later stage of the project. The indicated values are based on an exchange rate of £1=1.17€.

Being a fairly new service with only one auction held so far, prices and remuneration are subject to greater uncertainty compared to prices in well-established services. The auction results revealed successful bids between £7 and £11.97/MW/h, corresponding to €8-14/MW/h, i.e. slightly above the French capacity price for FCR but slightly below the German capacity price for FCR. In terms of annual remuneration, this would be equivalent to k€70-123/MW.

Firm Frequency Response has a lower remuneration: the latest analysis of market results estimates a value of k€58-64/MW/yr.

Product & remuneration		2014/15	2016
Firm Frequency Response [88]	Capacity price (£/kW/yr)	50-55	n/a[49]
	Capacity price (k€/MW/yr)	58-64	
Enhanced Frequency Response [87]	Capacity price (£/MW/h)	n/a	7-12
	Capacity price (€/MW/h)		8-14
	Capacity price (k€/MW/yr)		70-123

Table 116: Historical prices in the British market for Load-Frequency Control

4.5.4. Denmark

4.5.4.1. REGULATORY FRAMEWORK

As discussed in section 3, Denmark's electricity system is grouped in two distinct zones, namely Denmark West and Denmark East. The areas are not synchronised, meaning that frequency-related grid services cannot be offered across zones. Consequently, the grid operator contracts distinct ancillary services for each zone. The Danish TSO has not yet adopted the new taxonomy proposed by ACER in 2012, which makes a comparison to other countries more difficult. For this reason, we focus on frequency-controlled reserves in Denmark East and Denmark West which are equivalent to FCR in other EU member states. In Denmark West, this service is called primary regulation, while Denmark East refers to this service as FDR, i.e. a "frequency-controlled disturbance reserve".

[49] No data for the year 2016 available yet.

A summary of the regulatory framework is given in Table 117. Both ancillary services are procured through organised markets. Auctions are held on a day-ahead basis with the possibility to commit also for specific hours only instead of a full day. The bid of the marginal supplier sets the price for all successful bidders, unlike the German market where pay-as-bid is the settlement rule. Another common element is the compensation method, which is capacity-based. It is called availability compensation in DK-East and standby payment in DK-West.

A key difference between DK-West and DK-East is that the former zone allows for separate contracts for upward and downward regulation, while the latter zone requires symmetry in a unit's ability to offer upward and downward regulation. Frequency containment reserves in the eastern part of Denmark are procured jointly with Sweden. This is not the case for DK-West, i.e. there is no joint procurement with Germany. The main blocking point is the incompatible definition of products.

PEM electrolysers can offer both FCR and FRR, while Alkaline eletrolyzers are unlikely to comply with the activation time of less than 30s required for FCR.

	DK-West (Frequency Containment)	**DK-East (Frequency Containment)**
Procurement	Organised market	Organised market
Forward period	Day-ahead	Day-ahead
Commitment period	Hours	Hours
Product type	Asymmetrical (Upward or downward)	Symmetrical (Upward and downward)
Remuneration	Capacity	Capacity
Settlement	Marginal pricing	Marginal pricing
Minimum bid size	1 MW	1 MW
Full activation time	<30sec	<30sec
Current providers	Generation, load	Generation, load

Table 117: Overview of regulatory framework for Load-Frequency Control in Denmark

4.5.4.2. HISTORICAL REVENUES

Procurement results for ancillary services are published by the Danish TSO on a web portal. [35] To allow for a better comparison between countries and different services, the capacity price has been converted from the unit €/MW/h (given by the Danish TSO) to k€/MW/year. Annual average values are shown in Table 118.

Capacity prices in Denmark East are lower than the ones in France or Germany. Activation is not remunerated. The DK-West zone splits upward and downward regulation for frequency containment - something unique compared to all other countries. This allows for an easy entry point for flexible consumers like electrolysers, as it is typically straightforward for these units to provide upward flexibility (i.e. to reduce consumption).

Comparing the price levels of upward and downward regulation, a similar trend as for German FRR can be observed: downward regulation is less valuable than upward regulation.

Product & remuneration		2015	2016[50]
DK-East	Capacity price (€/MW/h)	6.89	6.34
	Capacity price (k€/MW/yr)	60.3	55.6
	Activation price (€/MWh)	0	0
DK-West, upward	Capacity price (€/MW/h)	13.73	17.36
	Capacity price (k€/MW/yr)	120.2	152.0
	Activation price (€/MWh)	0	0
DK-West, downward	Capacity price (€/MW/h)	1.49	1.46
	Capacity price (k€/MW/yr)	13.1	12.8
	Activation price (€/MWh)	0	0

Table 118: Historical prices in the Danish market for Load-Frequency Control

4.5.5. Sardinia

4.5.5.1. REGULATORY FRAMEWORK

With Sardinia being connected to the Italian mainland, regulation for ancillary services in Sardinia is very similar to the regulation in Italy. The main elements are summarised in Table 119.

Similar to France, FCR is a mandatory provision in Italy. This means that a part of a unit's nameplate capacity has to be reserved to provide frequency containment, if requested by the Italian TSO. In return for this service, there is a pre-defined remuneration (regulated price), but only if the service is activated. There is no holding payment (capacity price) for this service in Italy.

Procurement of FRR, on the other hand, is organised through mandatory *offers*. This means that all generators connected to the grid are obligated to offer the remaining available capacity (essentially: what was not sold on electricity markets or in bilateral contracts) to the Italian TSO. Timing-wise, mandatory offers have to be submitted after the day-ahead wholesale market has been cleared. Just like for FCR, there is no remuneration simply for holding ready capacity. The settlement for activated energy is pay-as-bid.

In terms of access for different types of resources, the Italian system is one of the most restrictive. Currently, FCR and FRR services are provided by generation units only.

[50] Preliminary data is shown for the year 2016. The average value is based on auction results until the 30th of October 2016.

	FCR (Frequency Containment)	FRR (Frequency Restoration)
Procurement	Mandatory provision	Mandatory offers
Forward period	Not relevant	Day-ahead
Commitment period	Not relevant	Hours
Product type	Asymmetrical (Upward or downward)	Asymmetrical (Upward or downward)
Remuneration	Energy activated	Energy activated
Settlement	Regulated price	Pay-as-bid
Minimum bid size	<1 MW	1 MW
Full activation time	<30sec	5min
Current providers	Generation	Generation

Table 119: Overview of regulatory framework for Load-Frequency Control in Italy

4.5.5.2. HISTORICAL PRICES

Price levels in the ancillary services markets are reported by the Italian regulator in its annual report. [4] The newest available data is from 2013/2014, as the last annual report was released in December 2015, reporting the market trends up to the previous year, i.e. 2014. In line with the structure of the Italian electricity system with its 6 wholesale electricity price zones, separate figures are also reported for ancillary services in Sardinia. Annual average values are shown in Table 120.

As explained earlier, there is no remuneration purely for holding capacity ready in Italy. For this reason, the capacity price is zero. Activation prices show a split between upward and downward regulation, especially for FRR. In absolute terms, these price levels are higher than in France but lower than in Germany. Combined with the inexistent availability payment, ancillary services are a rather insignificant value stream in Italy.

Product & remuneration		2013	2014
FCR	Capacity price (€/MW/h)	0	0
	Activation price, upward, Sardinia (€/MWh)	129	121
	Activation price, downward, Sardinia (€/MWh)	105	92
FRR	Capacity price (€/MW/h)	0	0
	Activation price, upward, Sardinia (€/MWh)	136	128
	Activation price, downward, Sardinia (€/MWh)	30	25

Table 120: Historical prices in the Italian market for Load-Frequency Control

4.6. Value to be captured from distribution grid services

This section presents the computations of the value to be captured for the electrolyser flexibility in its distribution grid, presented in section 5.4.2.3. This was made via Tractebel's Smart Sizing tool, which uses generic network data for modelling, such as: local load and decentralised production, grid equipment costs and characteristics, grid structure…

4.6.1. Modelling methodology

To identify the revenues that can be expected from bringing flexibility to the distribution grid with a new electrolyser, two types of distribution grids are modelled in a general way. Those typical grids correspond to the type of distribution networks that can be found in the locations predetermined based on the SCANNER simulations (see section 3.2.2).

- **A typical semi-urban distribution grid**, **fitting for France, Germany and Sardinia**. The locality of **Albi (France)** is used for the modelling (with the load and generation input data corresponding to 2017).
- **A typical rural distribution grid**, **fitting for Denmark and Great Britain**. The locality of **Trige (Denmark)** is used for the modelling (with the load and generation input data corresponding to 2025).

For each type of network, typical CAPEX and OPEX structures are derived via Smart Sizing to determine the cost of building the network from scratch (i.e. as if no network at all was present in the initial state) with and without the electrolyser, the difference between the two indicating how financially interesting is to put the electrolyser at this place.

To cope with the incertitude on the input data at the distribution level concerning the exact amount of RES installed and the peak consumption within the locality, extensive sensitivity is achieved on these two parameters.

4.6.2. Distribution grids flexibility revenues computation

4.6.2.1. TEST CASES PRESENTATION

The single line diagram used for the two test cases is presented in Figure 123: the decentralised load of the distribution grid is located in low voltage (~400V) while the renewable power plants – mainly wind – are located in medium voltage (10-20kV). The 1MW electrolyser is connected in medium voltage too when considered[51].

[51] The goal being to identify the financial and structural impact of the integration of the electrolyser into the distribution network, two simulations are performed: one without the electrolyser and one with it.

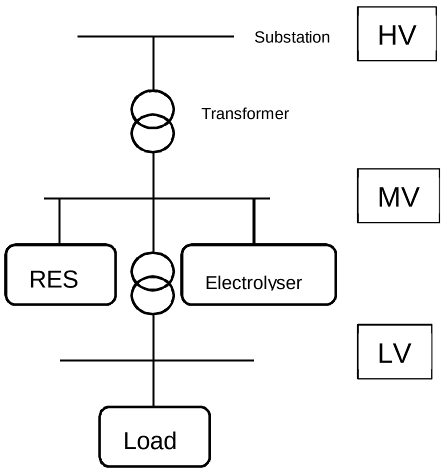

Figure 123: Single-line diagram of distribution grid.

The selected two cases are different in terms of ratio local production/local consumption: the semi-urban case consumes more than it produces (24.1 MW load for 11.3 MW installed RES, leading to an energy generation/consumption ratio of 18%) while the rural case produces more than it consumes locally (0.8 MW load for 4.8 MW installed RES, leading to an energy generation/consumption ratio of 147%). To cope with the difference of installed RES & load sizes between the two cases, an electrolyser of 1 MW is considered for the weakest structure (rural) and a combination of electrolysers up to 20 MW is used for the strongest one (semi-urban).

Consequently, the perturbations for the investment in distribution introduced by the installation of a new electrolyser will at first glance be the following:

- For the semi-urban case: the electrolyser load will mainly add up to the overall load existing in LV in case of no RES production, and will therefore require reinforcement of the HV/MV transformer to cover the new peak load.
- For the rural case: the electrolyser load can help reducing the local RES overproduction that needs to flow through the HV/MV transformer to be injected into the transmission grid, reducing potentially the size needed for this transformer.

The generation/consumption ratios are indicated for each location in Table 121.

Network	Country	Location	Year	Generation/Consumption
Semi-urban	France	Albi	2017	18%
			2025	25%
	Germany	Lübeck	2017	28%
			2025	57%
	Sardinia	Sarlux	2017	8%
			2025	11%
Rural	Denmark	Trige	2017	249%
			2025	147%
	Great Britain	Tongland	2017	35%
			2025	56%

Table 121: Installed production and load in the distribution grids of the selected subnational locations

4.6.2.2. SITUATION WITHOUT ELECTROLYSER

First, the analysis is done without electrolyser. This illustrates where the biggest parts of the TOTEX cost are located (transformer LV/MV, lines …).

Semi-urban distribution grid, Albi (FR)

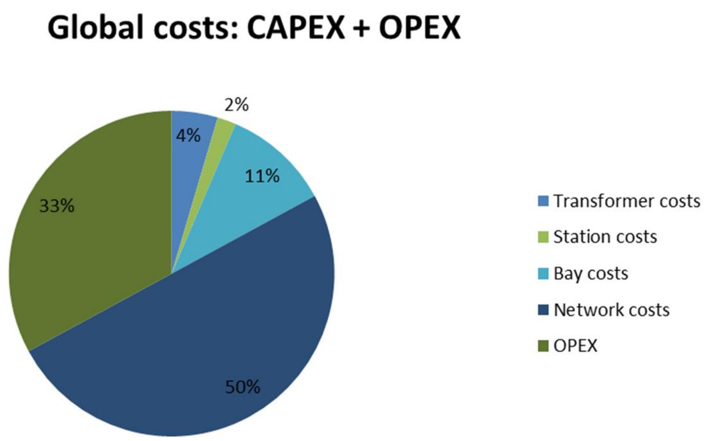

Figure 124: Pie chart of CAPEX costs of Albi

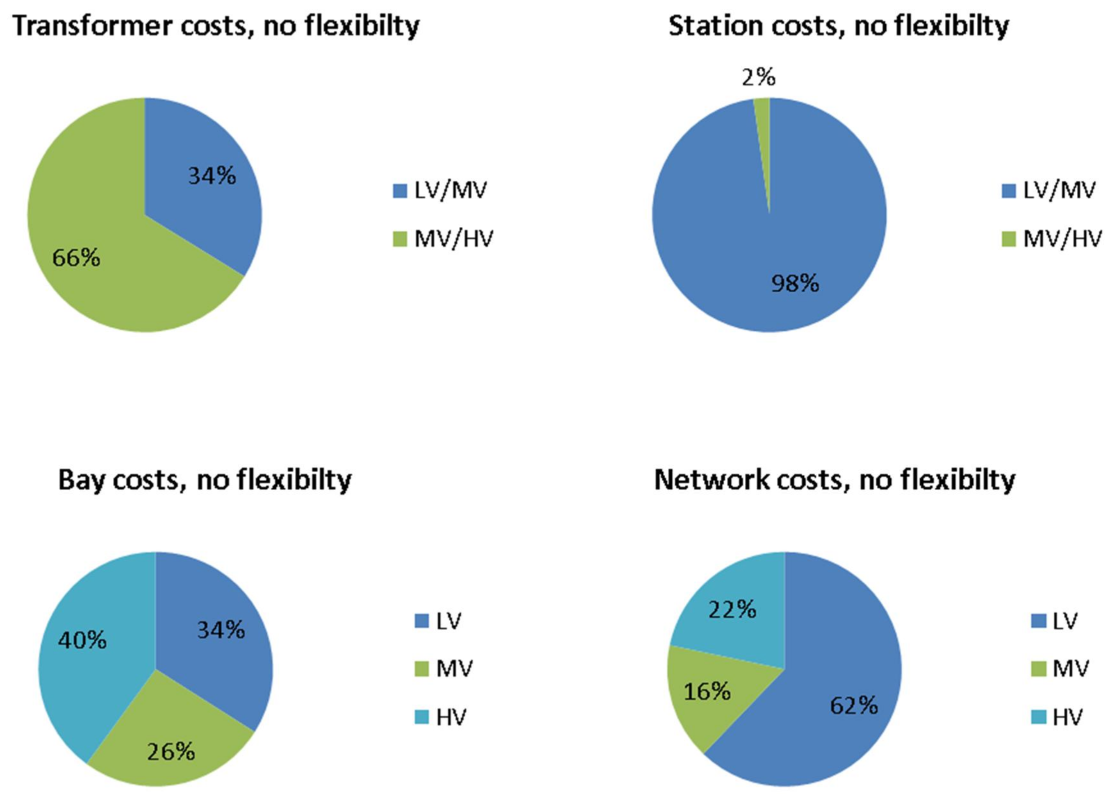

Figure 125: Pie charts of detailed CAPEX costs of Albi

As emphasized in Figure 124 Figure 125, the highest investment costs lie in the LV network costs (i.e. cable and equipment in LV), with 62% of 50% of the overall CAPEX.

Rural distribution grid, Trige (DK)

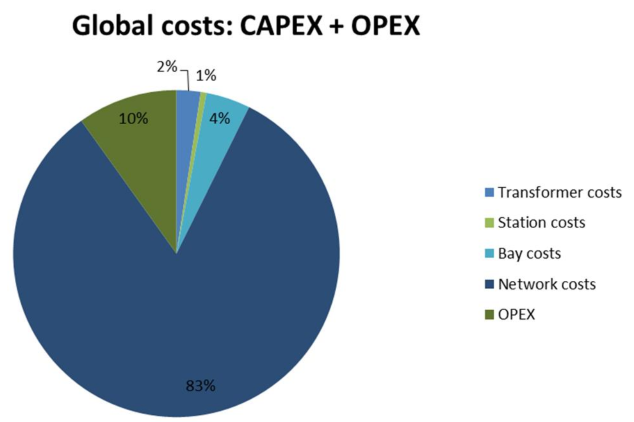

Figure 126: Pie chart of CAPEX costs of Trige

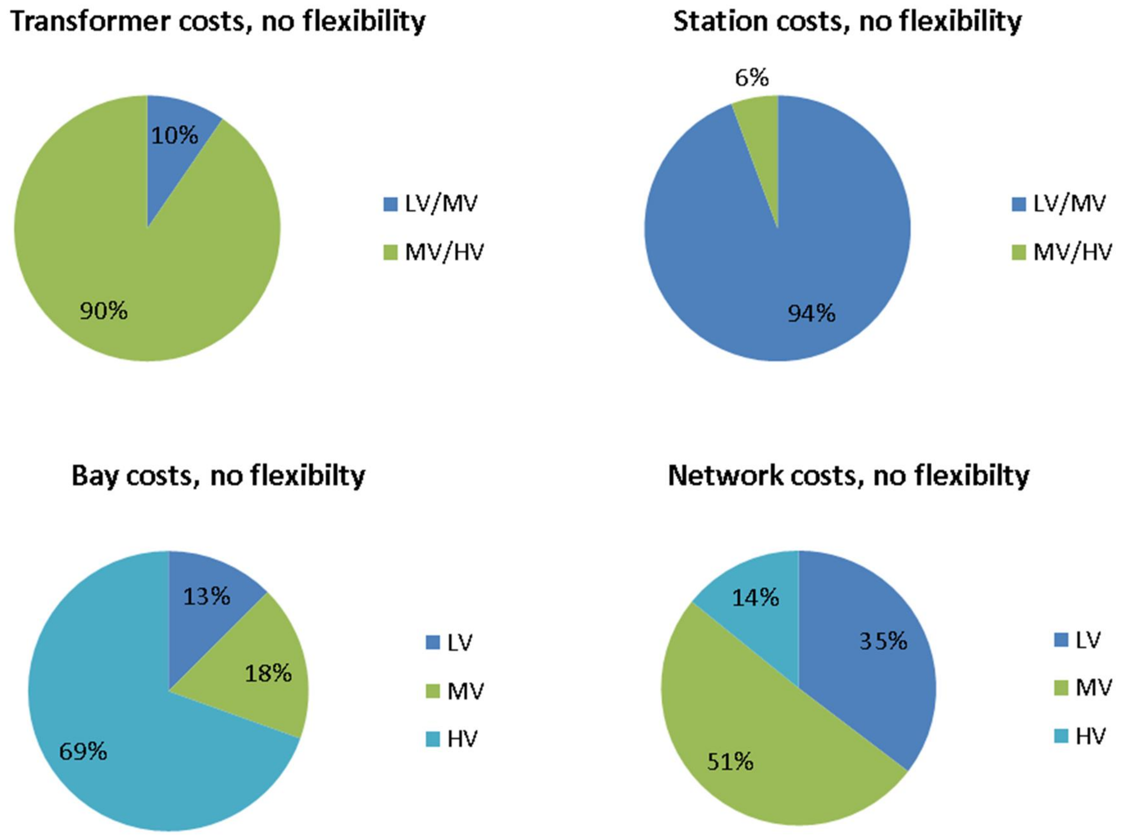

Figure 127: Pie charts of detailed CAPEX costs of Trige

As shown in Figure 126 and Figure 127, the biggest CAPEX lies this time in MV network costs, with 51% of the 92% total network costs. This is due to the fact that in Trige at MV level, RES are connected with a nominal production of about 6 times as high as the peak load, imposing therefore the MV network equipment sizing to be bigger than at LV level.

4.6.2.3. SITUATION WITH ELECTROLYSER

Semi-urban distribution grid, Albi (FR), peak load 24.1 MW

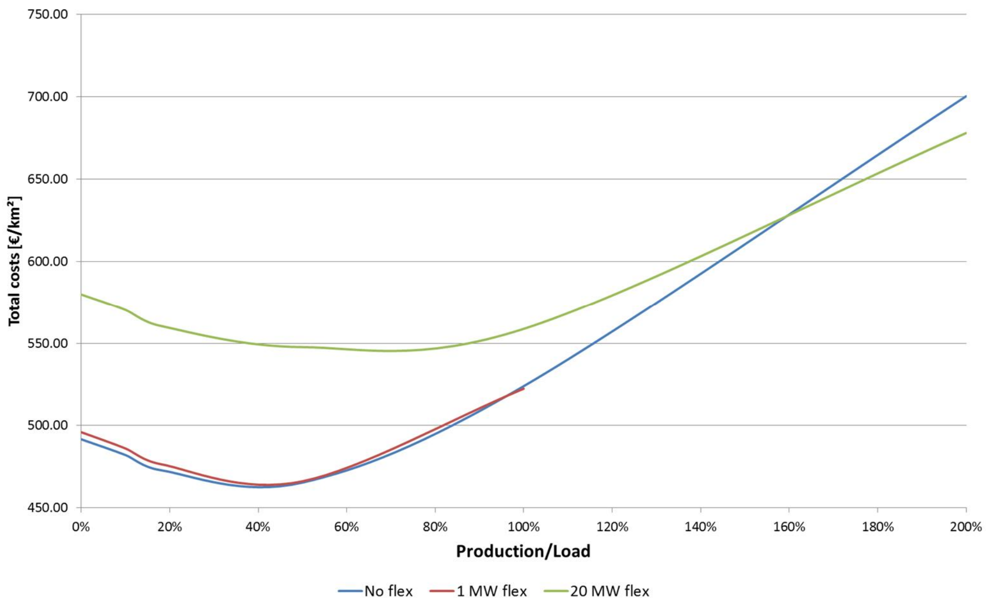

Figure 128: TOTEX in function of ratio production-load for semi-urban distribution case.

In Figure 128, the total costs (TOTEX, i.e. CAPEX + technical OPEX) are displayed in function of the ratio production/load. A minimum can be found around 70%, afterwards the TOTEX increases. Reason for that is that adding RES reduces first the required grid reinforcements because it allows reducing the net peak load for which the HV/MV transformer needs to be designed, while adding more RES imposes that this transformer gets designed to allow injecting the local RES overproduction to the transmission network.

Adding an electrolyser (and its flexibility) is interesting (blue curve more expensive than the red or green one) only if the network is already ready to absorb an additional load, i.e. if the ratio generation/consumption is sufficiently high. For the semi-urban case, inserting an electrolyser of 1 MW is interesting only above a generation/consumption ratio of 95% (and above 160% for a 20MW electrolyser). The gain in investment stays low in every interesting case, with a **maximum of 3% gain on TOTEX for very high production/load ratios**.

For Albi (France), where this ratio is of 18%, **inserting an electrolyser appears thus not interesting**. **For Lübeck (Germany) and Sarlux (Sardinia), the conclusion is the same** with a ratio of 28% and 8% respectively.

Rural distribution grid, Trige (DK), peak load 0.8 MW

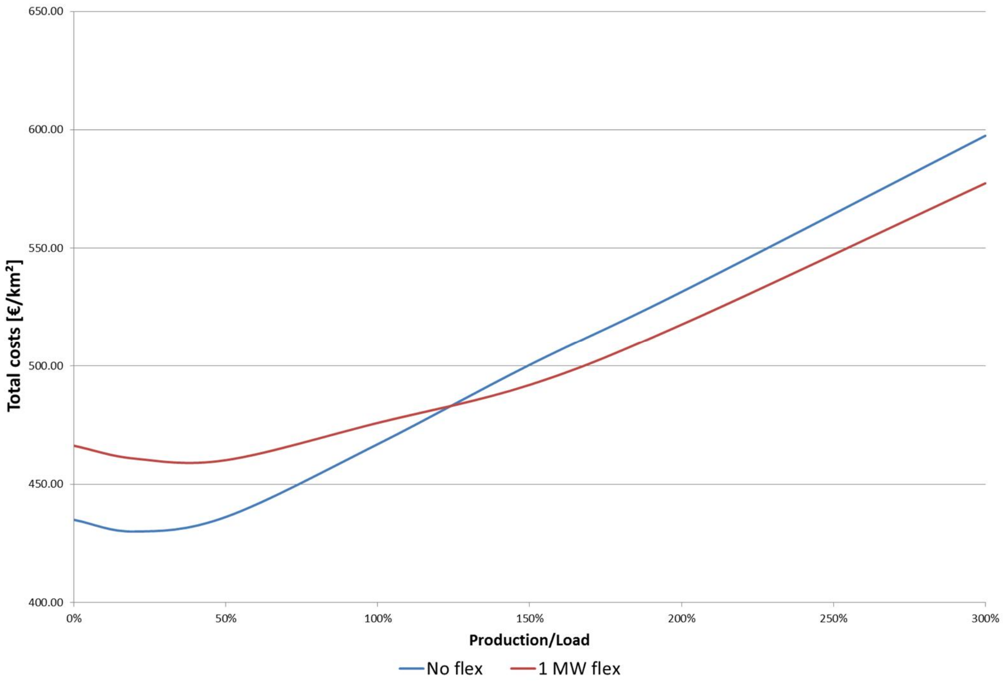

Figure 129: TOTEX in function of ratio production load for the rural distribution case.

In Figure 129, similar conclusions as in the semi-urban case are obtained, with **gains around 3% of the total TOTEX** after a generation/consumption ratio of 125%. **In Trige (Denmark)**, this situation is thus interesting since the production/load ratio is of 147%, but with **total earnings <1 k€/MW /y** considering the small area over which the distribution network is considered (< 50km²). **For Tongland (Great Britain)**, on the contrary, this ratio is of 56% and leads to a **non-interesting** situation.

4.6.2.4. CONCLUSION: INTEREST OF ELECTROLYSER FLEXIBILITY IN DISTRIBUTION

Based on the previous simulations, installing an electrolyser can lead to **positive earnings around 1k€/MW /y in Trige (Denmark) but not in the other studied subnational areas**. Indeed, in those places, installing the electrolyser leads to addition of a non-negligible load that requires reinforcement of the HV and MV networks while flexibility aims at delaying this investment. In Trige, the amount of installed renewables in the vicinity exceeds the local load, causing the electrolyser to reduce the RES injection fluxes from the MV to the HV network, lightening hence the constraints on the HV/MV transformer during peak production periods.

ANNEX 5. CONTRACTUAL ARRANGEMENTS & DE-RISKING – DETAILS PER BUSINESS CASE

This section presents the contractual arrangements and de-risking aspects treated in section 6.3 in the particular cases of the developed business cases.

5.1. Semi-centralised mobility in Albi (France)

For the analysed semi-centralised mobility business case, in which the electrolyser belongs to the logistics operator, green hydrogen is sold to local H_2 consumers through hydrogen refuelling stations via standard packaged H_2 supply contracts. The objective would be to define take-or-pay contracts over at least one year, in order to limit the volume risk. Each contract would be a case-by-case negotiation, however.

The interactions between the H_2 logistics operator and the other stakeholders are summarised in Figure 130 and Table 122.

For France, 1-year baseload contracts are available for electricity, limiting the risk of short-term spikes in the electricity price. A similar time visibility is given for grid fees, which can typically be updated in an annual rhythm by the grid operator. The same applies to the remuneration of electricity grid services: the availability price is defined year-ahead.

Access to curtailed RES electricity would have to be negotiated with the wind farm operator directly. No known precedent exists in France, likely linked to the fact that RES curtailment due to grid congestion is currently not a massive phenomenon in France. The objective would be to define a long-term PPA with the wind farm operator, with power being capped to the electrolyser capacity. Such an agreement would be beneficial to both sides, since the wind farm operator would be able to recuperate part of his lost revenues, while the electrolyser operator would have access to low-cost electricity.

Taxes and levies are subject to national legalisation and thus more difficult to predict. An important attention point is the exemption from taxes and levies, which can be removed also for existing installations. This constitutes a substantial regulatory risk.

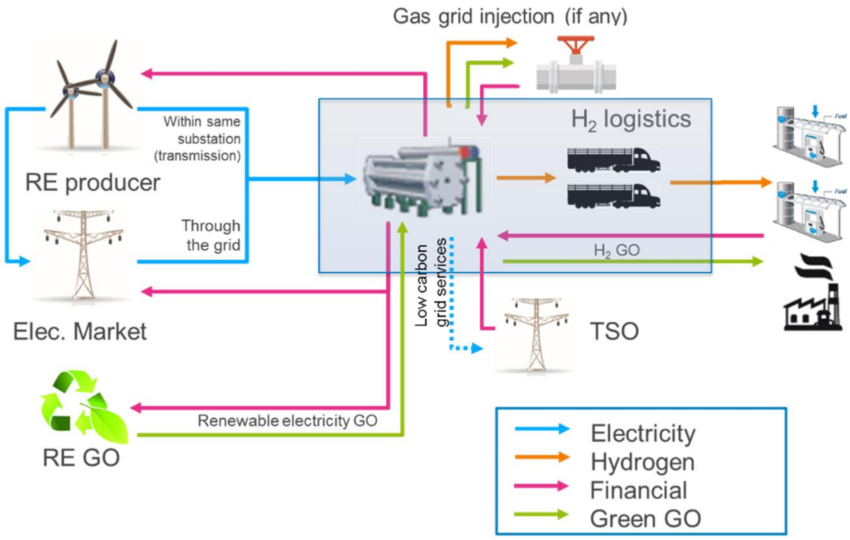

Figure 130: Interaction between the electrolyser operator (H_2 logistics operator) and the other business stakeholders

Contractual arrangements between ↓ and →	H_2 electrolyser operator = H_2 logistics operator
Electricity supplier	Directly buys on wholesale electricity market (~1yr baseload contract available)
Curtailed renewable electricity supplier	Regulation defines counterparty (grid vs. RE operator) No long-term visibility
Supplier of guarantee of green origin	European GO markets Alpine/Nordic Hydro
TSO (Grid fees)	Defined by TSO upfront, Subject to approval of national regulatory authorities
Local H_2 consumers	Standard packaged H_2 supply contract
TSO (Grid services)	Regulated price (defined year-ahead)
Gas grid operator	Gas grid injection contract

Table 122: Semi-Centralised mobility contractual arrangements, with the logistics operator as H_2 electrolyser operator

5.2. Light industry in Aarhus (Denmark)

For the light industry business case, the electrolyser belongs either to the hydrogen supplier of the considered light industry, or to the light industry itself. The former supplies hydrogen to the light industry via hydrogen supply contracts or backup supply arrangements, while the latter can guarantee its resource supply from autonomous production, requiring then only backup H_2 supply.

The interactions between the electrolyser operator and the other stakeholders are summarised in Figure 131 and Table 123.

Being part of the internal electricity market, Danish consumers have access to a sufficiently liquid wholesale market, which offers 1-year baseload contracts. A similar time visibility is given for grid fees, which can typically be updated in an annual rhythm by the grid operator.

Electricity grid services are contracted via weekly auctions, thus providing very limited visibility on future revenue streams.

Access to curtailed RES electricity would have to be negotiated with the wind farm operator directly. No known precedent exists in Denmark, likely linked to the fact that RES curtailment due to grid congestion is currently not yet a massive phenomenon in Denmark, thanks to market-driven curtailment, i.e. wind producers curtailing when market prices drop below zero. As in France, the objective would be to negotiate a long-term PPA on curtailed RES electricity, with power being capped to the electrolyser capacity (see previous subsection).

Taxes and levies are subject to national legalisation and thus more difficult to predict. An important attention point is the exemption from taxes and levies, which can be removed also for existing installations. This constitutes a substantial regulatory risk.

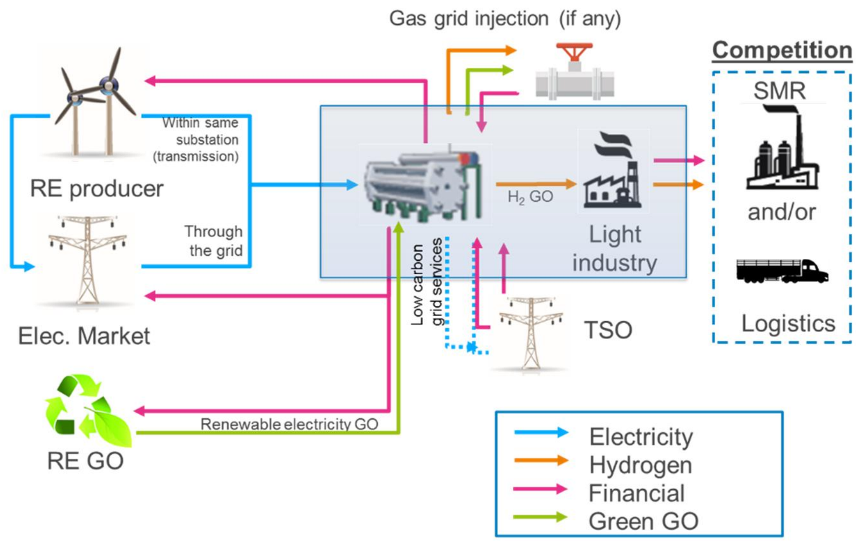

Figure 131: Interaction between the electrolyser operator (H_2 light industry) and the other business stakeholders

<table>
<tr><th>Contractual arrangements between ↓ and →</th><th>H_2 electrolyser operator = Existing gas supplier</th><th>H_2 electrolyser operator = Light industry H_2 consumer</th></tr>
<tr><td>Electricity supplier</td><td colspan="2">Directly buys on wholesale electricity market
(~1yr baseload contract available)</td></tr>
<tr><td>Curtailed renewable electricity supplier</td><td colspan="2">Regulation defines counterparty (grid vs. RE operator)
No long-term visibility</td></tr>
<tr><td>Supplier of guarantee of green origin</td><td colspan="2">European GO markets
Alpine/Nordic Hydro</td></tr>
<tr><td>TSO (Grid fees)</td><td colspan="2">Defined by TSO upfront,
Subject to approval of national regulatory authorities</td></tr>
<tr><td>Light industry H_2 consumer</td><td>If pre-existing SMR is operated by the gas supplier: terminate & renew the existing contract
Continue backup supply arrangement</td><td></td></tr>
<tr><td>Existing gas supplier</td><td></td><td>Terminate contract for existing H_2 supply
Maintain H_2 backup supply</td></tr>
<tr><td>TSO (Grid services)</td><td colspan="2">Small market, subject to disruptions if supply increases
Day-ahead auction</td></tr>
<tr><td>Gas grid operator</td><td colspan="2">Gas grid injection contract</td></tr>
</table>

Table 123: Light industry contractual arrangements, with the existing gas supplier as H_2 electrolyser operator, and with the light industry H_2 consumer as H_2 electrolyser operator

5.3. Large industry in Lübeck (Germany)

For large industries, the Power-to-Hydrogen electrolysis process must feed the industry with hydrogen at a competitive price compared with SMR-based H_2 production.

The interactions between the electrolyser operator and the other stakeholders are summarised in Figure 132 and Table 124.

German electricity consumers also have easy access to 1-year baseload contracts. A similar time visibility is given for grid fees, which can typically be updated in an annual rhythm by the grid operator. In Germany, the national regulatory framework foresees exemption of grid fees for new Power-to-Hydrogen installations for 20 years, as discussed in section 6.1.2.3. This provides a high visibility on hydrogen production cost.

Electricity grid services are contracted via weekly auctions, thus providing very limited visibility on future revenue streams.

Access to curtailed RES electricity would have to be negotiated with the wind farm operator directly. In Germany, the regulatory context is more complex than in the other EU member states. In general, wind farm operators are partly compensated by the grid operator in case of curtailment. The counterparty for contracting access to curtailed RES electricity would thus be the grid operator who can avoid paying compensations, if curtailment can be avoided.

As in France and Denmark, the objective would be to negotiate a long-term PPA on curtailed RES electricity, with power being capped to the electrolyser capacity (see previous subsections).

Taxes and levies are subject to national legalisation and thus more difficult to predict. The by far biggest cost component in the German electricity bill is the levy for supporting renewables (so-called “EEG-Umlage”). An exemption from this RES support levy is currently a case-by-case decision.

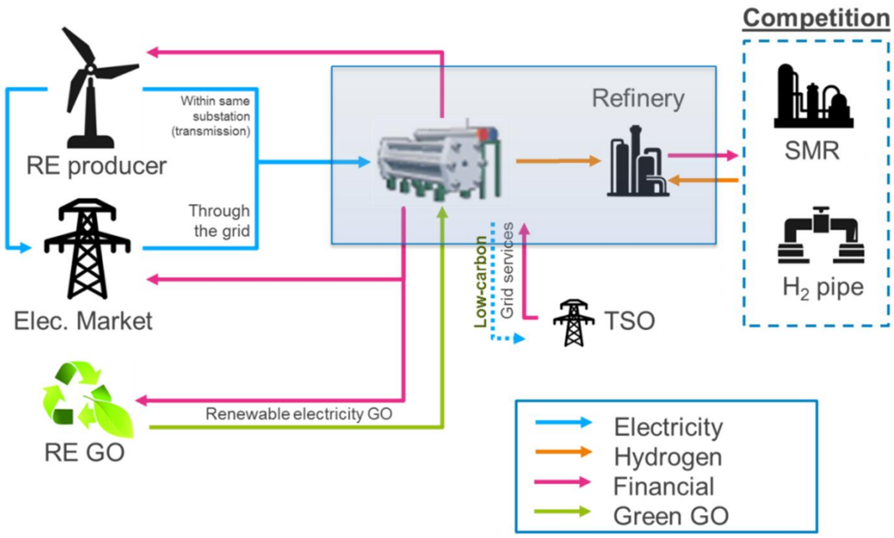

Figure 132: Interaction between the electrolyser operator (H_2 refiner) and the other business stakeholders

Contractual arrangements between ↓ and →	**H_2 electrolyser operator + Refinery operator**
Electricity supplier	Directly buys on wholesale electricity market (~1yr baseload contract available)
Curtailed renewable electricity supplier	Regulation defines counterparty (grid vs. RE operator) No long-term visibility
Supplier of guarantee of green origin	European GO markets Alpine/Nordic Hydro
TSO (Grid fees)	Legislative certainty: exemption for 20 years for new Power-to-Hydrogen installations
Onsite SMR or pipeline operator	Potential impact on volume of take-or-pay contract Use of SMR as backup
TSO (Grid services)	Week-ahead auction Small market, i.e. subject to disruptions if supply increases

Table 124: Large industry contractual arrangements, with refinery and H_2 electrolyser operators

ANNEX 6. SUMMARY OF BUSINESS CASES ASSUMPTIONS

The present annex presents the key assumptions taken for each of the business cases developed in this study.

6.1. Business cases general cost assumptions

General cost assumptions	
WACC	5%
Project lifetime	20 years
Electricity GO price	0.40 €/MWh
Water price	3.8 €/m^3
Carbon price	2017: 12.7€/tCO_2 (EU); 28.8 €/CO_2 (GB) 2025: 28.1 €/tCO_2 (EU); 42.8 €/CO_2 (GB)

Table 125: General cost assumptions common to all business cases

6.2. Semi-centralised production for mobility business case

Cost assumptions (k€/MW)	2017 (2 MW system)	2025 (12 MW system)	Comments
Electrolyser system	1415	765	PEM
Filling centre	330	185	2017: 30-250 bar @ 85 kg/h 2025: 60-200 bar @ 230 kg/h
Storage and Tube-trailers	665	450	2017: 5.5 t H2 2025: 9.4 t H2
H2 injection	-	30	
Civil work	390	240	Greenfield without building
Other (engineering, interconnection)	860	230	
TOTAL	**3660**	**1900**	

Table 126: Cost assumptions specific to the semi-centralised mobility business case

6.3. Light industry business case

Cost assumptions (k€/MW)	2017 (6 MW system)	2025 (6 MW system)	Comments
Electrolyser system	870	610	ALK
Compressor skid	130	105	2017: 0-50 bar @ 120 kg/h 2025: 15-50 bar @ 120 kg/h
Storage	190	195	~2.5 t H2 storage
H2 injection	-	-	None
Civil work	240	240	Brownfield with building
Other (engineering, interconnection)	330	250	
TOTAL	**1760**	**1400**	

Table 127: Cost assumptions specific to the light industry business case

6.4. Large industry business case

Cost assumptions (k€/MW)	2017 (40 MW system)	2025 (40 MW system)	Comments
Electrolyser system	1130	660	PEM
Compressor skid	60	55	2017: 30-200 bar @ 775 kg/h 2025: 60-200 bar @ 775 kg/h
Storage	50	55	~4.7 t H2 storage
H2 injection	-	-	None
Civil work	75	80	Brownfield with building
Other (engineering, interconnection)	165	110	
TOTAL	**1480**	**960**	

Table 128: Cost assumptions specific to the large industry business case

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