D7.2 Brief summary report on initial policy implications of the bulk electrolyser model

for FCHJU

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Executive Summary

The future role of hydrogen and current challenges

- Hydrogen produced via electrolysis using renewable electricity is seen as a key component of future decarbonized energy systems. It can provide critical flexibility to energy systems as it allows "excess" fluctuating renewable energy sources to be utilized, storing the produced hydrogen for long timescales, and for use at times of high demand. It can be used as an energy carrier in a broad range of applications in transport, heat and industry.
- While electrolysis technologies have been established for decades and are well understood, a major obstacle for a wider uptake of the technology in energy applications are the currently high costs.
- To achieve significant cost reductions via economies of scale, electrolysers need to be produced at a much greater volume.
- While hydrogen could play a significant role as an energy carrier in transport and heat, these sectors are nascent hydrogen users and do not currently provide the level of demand required to achieve a transformational cost reduction via scale-up of electrolyser technology.

Why hydrogen in refineries?

- Refineries are currently one of the largest sources of hydrogen demand, along with ammonia production. 76% of global hydrogen production is currently based on Steam Methane Reforming (SMR)[1], i.e. supplied from fossil fuels.
- The cost of hydrogen production via SMR is in the range of 1.2 – 2.2 €/kg (or 1.5 – 2.5 €/kg when including a CO_2 tax based on a current carbon price of €25/t, corresponding to about 0.3 €/kg H_2), depending on the natural gas price which has been seen in a range between 5 – 25 €/MWh in the last years in Europe. The relationship between natural gas price and the corresponding hydrogen production cost of SMR can be seen in Figure 1. 1.5 – 2.5 €/kg is therefore the benchmark price for hydrogen in industrial settings in Europe currently.[2]

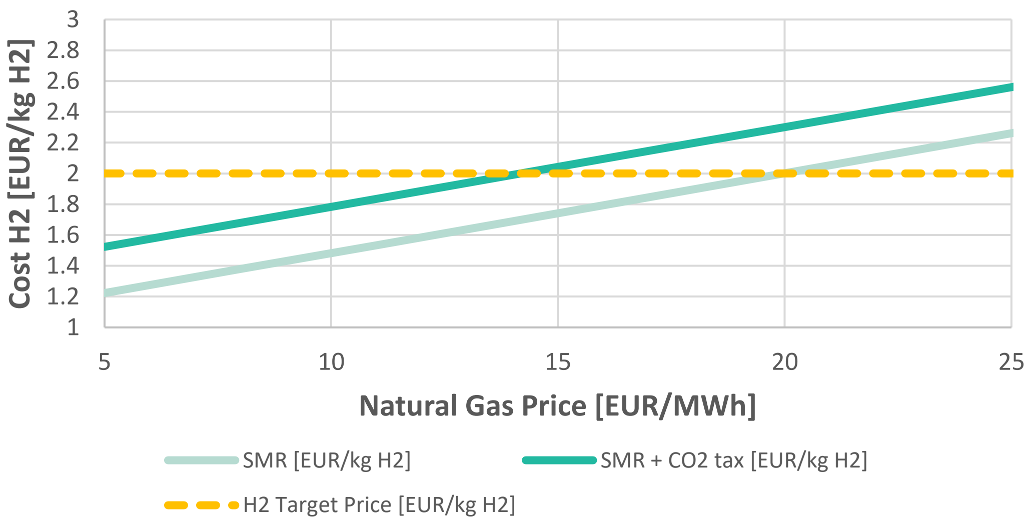

Figure 1: Hydrogen production cost with SMR as a function of the natural gas price, both with and without the inclusion of a CO2-tax. The target price of 2 EUR/kg H2 is also included.

- Electrolyser deployment for energy intensive industrial consumers such as refineries offers the following benefits:

[1] IEA, 2019, The Future of Hydrogen, p. 32; 23% is produced from coal feedstock, 0.7% from oil and 0.3% from electricity
[2] IEA, 2019, The Future of Hydrogen, p.52

- deployment at scale (multi MW) offering reduction of CAPEX per kW of electrolyser capacity
- faster uptake of hydrogen than only with nascent mobility applications (small number of low duty and high duty fuel cell vehicles expected in second half of the 2020s)
- power supply costs with reduced levies and grid fees[3]
- opportunity to test provision of balancing services by a large scale electrolyser to the transmission system operator and monitor the associated revenues. This opportunity is available to other deployments of large scale electrolysers which are above the minimum capacity thresholds, often set by the System Operator in each jurisdiction.

Even with access to electricity for energy intensive industries with reduced levies and grid fees, currently electrolysis cannot compete with SMR

- In the REFHYNE project, a 10MW PEM electrolyser is installed in the Wesseling refinery in Germany. Upon completion, this will be the largest PEM electrolyser installation in the Europe.
- Energy intensive industries such as refining have been granted specific reductions in levies in the German electricity feed-in tariff legislation (Renewable Energy Law 2017[4]) due to their high power cost intensity (related to gross value added) – this needs to be substantiated every year.
- In addition, exemptions (§ 118 EnWG) resp. reductions on German grid fees are allowed for (§ 19 of electricity grid fee regulation[5]) if the demand site has a high power demand and very even consumption throughout the year (high load factor).
- Energy intensive industries with a high energy bill are entitled to the above exemptions or fee reductions to maintain their international competitiveness. In these circumstances an electrolyser would have access to an electricity price 60% lower than the average industrial price, such that hydrogen production costs could be 50 % lower (cp. Figure 2 below).
- Due to the flexibility of its electricity demand, the electrolyser can in fact help the energy intensive customer to achieve the high load factor required for the reduction of grid fees (§ 19 of electricity grid fee regulation). As the reduction applies to the whole site and not just the electrolyser, the impact of lower grid fees could be significant, resulting in a substantial potential revenue stream for the electrolyser.
- Deployment of a large scale electrolyser in the REFHYNE project is expected to enable significant electrolyser CAPEX and OPEX cost reduction, leading to the electrolyser cost per kg of hydrogen as shown in Figure 2 (blue bars).
- Despite these cost reductions and the access to electricity for energy intensive industries, i.e. with substantially reduced fees and levies, the economics remain challenging and electrolysers are not able to compete with SMR in providing cost competitive industrial hydrogen (see right graph in Figure 2). For a cost break even between SMR incl. carbon cost and electrolysis based on the underlying assumptions regarding electrolyser costs and load factor the electricity cost would need to be as low as of 25 €/MWh (assuming an SMR cost of €2.3/kg).

Therefore, policy support is needed to underpin the economics of early deployment, which could lead to cost reductions through volume production of electrolysers.

Green hydrogen is still struggling to become competitive vs. fossil energy for several reasons: one is related to high capex of (relatively) small-scale electrolysers; secondly it is due to the high variable costs of electricity vs. the alternatives which are natural gas or coal. Finally, green hydrogen needs supporting policy mechanisms to

[3] Throughout the report the term grid fees refers to payments to electricity grid owners and operators whereas policy levies refer to payments collected by the government to finance energy policies such as support of renewable electricity.
[4] §§ 63 ff. Erneuerbare-Energien-Gesetz 2017
[5] § 19 Abs. 2 Stromnetzentgeltverordnung (StromNEV)

become economically competitive with inexpensive grey hydrogen or by-product hydrogen from other industrial processes.

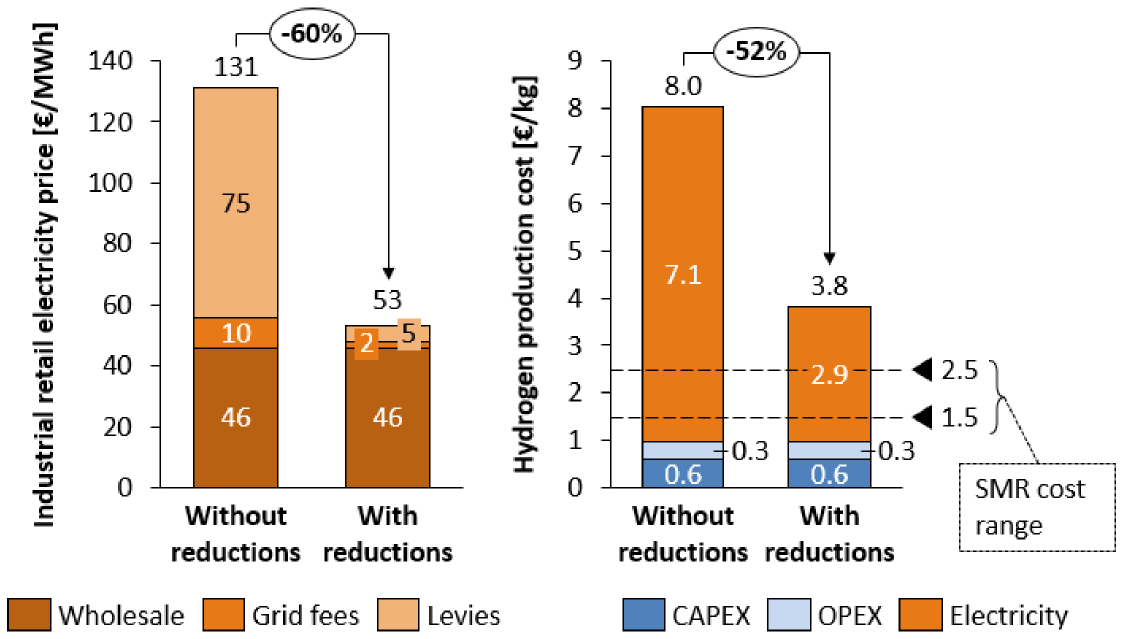

Figure 2: Left: industrial electricity price with and without exemptions for energy intensive industries in Germany; right: corresponding H_2 production cost in both cases (assuming a 90% load factor of the electrolyser, cf. main report for full set of assumptions); note that the production cost does not include the cost of distribution and retail infrastructure, which comprise a significant part of the hydrogen retail price; furthermore electricity prices will vary considerably during the lifetime of the electrolyser

In the following paragraphs two different policy pathways for deployment of green hydrogen are discussed: firstly hydrogen as a feedstock in refining/chemical industries, secondly its deployment in the mobility sector. Both pathways should be considered and could be implemented in combination, thus generating the economies of scale needed to develop the green hydrogen business.

Policy pathway 1: Support green hydrogen as a low carbon feedstock for refineries

- The revised Renewable Energy Directive (RED II), adopted in late 2018, requires an increase of transport fuels to be sourced from renewable energy from 6% in 2020 up to 14% in 2030.
- Using green hydrogen could be an economic choice for refineries to help fuel marketers to achieve these renewable fuel requirements which would in consequence open a significant market to green hydrogen in refineries.
- Using green hydrogen instead of SMR-based grey hydrogen corresponds to a carbon abatement cost of about €200/t CO2 (assuming zero carbon intensity of green hydrogen), much higher than the current carbon price at the EU Emissions Trading System (ETS). However, the alternatives to hydrogen (in refineries) have limitations: the contribution of food crop-based biofuels is limited in the RED II; and second generation biofuels are not sufficiently available at the time of writing.
- Given appropriate incentives and consequences in the case of non-compliance, using green hydrogen could become a cost-effective option. In Germany, current legislation implementing the Fuel Quality Directive, which will now be updated by the RED II, is imposing penalties of €470/tCO_2[6] to fuel suppliers failing to comply with its emission reduction requirement of 6% vs. fossil fuels.

[6] Bundesimmissionsschutzgesetz (BImSchG), § 37c Abs. 2; https://www.gesetze-im-internet.de/bimschg/BJNR007210974.html

- The criteria under which green hydrogen can contribute towards transport renewable fuel requirements as well as how it will be counted need to be clarified in each member state's RED II implementation.
- To achieve a significant emission reduction compared to the fossil fuel alternative (in this case grey hydrogen produced via SMR), the carbon intensity of the electricity used for hydrogen production would need to be lower than the average grid carbon intensity in most EU MS.
- Therefore, alternative routes to producing and crediting green hydrogen would have to be utilized, such as:
    - direct co-location with renewable generation assets
    - consuming electricity from the grid using a Power Purchase Agreement (PPA) with a dedicated renewable generation asset
    - consuming electricity from the grid in hours of low grid carbon intensity
    - trading renewable energy certificates
- It is indispensable to set clear rules for such arrangements which need to be complied with in order for the green hydrogen to be certified especially for grid connected electrolysers. Furthermore, such rules should be aligned as much as possible across different MS and international certification bodies (such as CertifHy). The EU Commission has announced its intention to publish a more detailed methodology for accounting hydrogen produced by grid-connected electrolysers towards renewable obligations by the end of 2021. In order to avoid diverging implementations of the announced/expected directive, this methodology should be published as early as possible.
- Above and beyond the sustainability criteria for electricity used to produce green hydrogen, all green hydrogen used in the refinery as a component to produce oil products should be fully and flexibly eligible for the mandatory greenhouse gas quota of RED I/II (flexible accounting method).
- Diverging and unclear regulation on green hydrogen increases uncertainty for investors and the administrative burden for international hydrogen supply chains.
- **Policy recommendations:**
    - *Member states need to set out clear definitions of green hydrogen and clear rules how green hydrogen can count towards renewable requirements of the Renewable Energy Directive II.*
    - *These rules should clarify in particular when and to which extent the electricity consumed by grid connected electrolysers can count as renewable.*
    - *It should be noted that stringent requirements regarding spatial and temporal correlation of fuel production and renewable generation are likely to limit electrolysers as a viable option for refineries. In order to enable an early scale-up of electrolysers in refineries and a subsequent cost reduction, early requirements should be flexible.*
    - *The EU Commission should provide guidance on such rules as early as possible. Such rules should be aligned as much as possible across MS as well as international certification bodies (such as CertifHy). This provides certainty and improves scalability of technology.*
    - *Furthermore, such rules should then be implemented by some MS early such that investments can be planned accordingly.*
    - *Where other options to comply with RED II have been exhausted, an economic framework needs to be put in place which ensures green hydrogen is more cost effective than non-compliance with the directive.*
    - *Figure 2 illustrates the importance to maintain the current exemption levels from grid fees and levies or potentially even completely exempt renewable electricity used to produce hydrogen from fees and levies for a limited time (e.g. 5-8 years) to foster the market uptake of green hydrogen in applications such as refineries or the chemical industry.*

Policy option 2: Enabling hydrogen in high value end uses such as mobility

- Mobility could be a high value end-use of hydrogen.
- Fuel price parity with taxed Diesel could be achieved at a hydrogen retail price of €6-8/kg (the lower number referring to buses, the higher number to cars)[7].
- The cost of hydrogen refuelling station (HRS) and distribution infrastructure is significant and sensitive to assumptions around asset utilisation. Assuming a fully utilised asset, which is extremely optimistic, FCHJU has estimated distribution and retail facilities add ca. €4/kg to the cost of hydrogen. These supply chain costs need to come down substantially but they can come down only with larger volumes, i.e. more vehicles and more high volume retail sites.
- Modelling has shown that under the electrolyser cost assumptions used here, and given sufficient demand for hydrogen for mobility, production of electrolytic hydrogen using electricity for energy intensive industries with reduced levies and grid fees as available in the refinery or for large industrial companies could break even at hydrogen selling prices of up to €4/kg. Adding the mentioned distribution cost of €4/kg would lead to a retail price of €8/kg.
- Given further electrolyser cost reductions and uptake of hydrogen mobility, sale of hydrogen to the mobility sector could therefore become an attractive business stream for refineries or other energy intensive companies with an already existing strong demand and dependency on power supply.
- A major obstacle is the currently small size of the FC vehicle fleets and low utilisation rate of HRS and distribution infrastructure, as this increases the cost per kg significantly.
- To achieve a fuel price parity with untaxed transport fuels is much more challenging as taxes comprise more than 50% of the conventional transport fuels retail price in many EU MS.
- **Policy recommendations:**
    - *To advance hydrogen mobility initiatives, policy support should focus on hydrogen deployment in projects with constant and reliable demand such long haul HDVs, buses and coaches as well as heavier and long-distance LD vehicle fleets. These fleet segments allow the build-up of hydrogen distribution infrastructure avoiding the risk of substantial infrastructure under-utilisation as today.*
    - *Policy should support the uptake of hydrogen in these transport segments via public procurement or enabling of low-cost finance.*
    - *Furthermore, policy should keep hydrogen exempt from fuel duty and apply a low VAT rate to the sale of hydrogen fuel. Acquisition and operation of FC vehicles should also benefit from temporary support mechanisms such as lower VAT upon vehicle purchase, exemption from vehicle tax, motorway tolls, etc.*

[7] Parity for buses: £4.6/kg: https://hynet.co.uk/app/uploads/2019/06/15480_CADENT_HYMOTION_PROJECT_REP.pdf; parity for cars: £7.5/kg: https://www.london.gov.uk/sites/default/files/london_-_a_capital_for_hydrogen_and_fuel_cell_technologies.pdf

1 Introduction and background

Electrolysis of water to generate hydrogen is seen as a key technology that could enable very high penetration of variable renewable energy sources in future power grids. Hydrogen can be generated from low cost electricity from renewable sources when it is abundant. The hydrogen can then be used in a range of sectors such as mobility (in fuel cell vehicles), heat (in hydrogen boilers or fuel cell home heating systems), power (to fuel gas turbines) and industry as a feedstock for chemical processes. Hydrogen as an energy carrier can allow coupling of different sectors of the energy system to increase the overall flexibility of the system and therefore its ability to accommodate increasing amounts of energy from variable renewable sources. Crucial for the flexibility added by hydrogen is the possibility to store energy in large amounts over long time periods to help manage seasonal mismatches of renewable supply and demand.

For any of these "Power to X" concepts to become commercially viable, a number of advances in the field of water electrolysis are necessary, specifically:

- **Electrolyser cost and efficiency improvements:** the deployment of multi MW or GW electrolyser systems (compared to maximum electrolyser capacities of about 1 MW currently) is expected to lead to significant cost reductions. These are enabled through economies of scale of production as well as through minimisation of parasitic losses associated with large scale electrolyser systems.
- **Low cost electricity:** once the capital costs of electrolysers have been reduced to €1,000/kW or below through further large-scale deployment of electrolysers, electricity constitutes the largest cost component of electrolysis. This cost can be reduced by a number of factors:
  - **Large Scale:** access to industrial electricity prices where many grid fees/levies are reduced.
  - **Flexibility:** the ability to buy power when it is cheap and to avoid consumption in high price periods.
  - **Revenues from providing balancing services:** utilising the responsiveness of the electrolyser to help stabilise the electricity grid.
- **Large scale end uses:** To achieve economies of scale and further learning for electrolytic hydrogen, large scale end uses are required. The first opportunity is likely to be in established uses of hydrogen such as in refineries and ammonia production[8]. If these markets can be developed, this will allow the electrolyser industry to scale up and enable further cost reductions.
- **High value end uses:** For economic viability of electrolytic hydrogen, high value end uses are required. Once the electrolytic hydrogen sector has achieved sufficient scale and cost reductions, it will be able to offer a viable low carbon alternative in high value end uses such as heat and mobility, which will in turn enable further growth of the sector.

The REFHYNE project, which is coordinated by SINTEF, addresses each of these three elements. Shell Deutschland Oil will install a large electrolyser at their refinery in Wesseling, near Cologne (Germany). This refinery has a need to balance power across the refinery's internal 100 MW-scale electricity network. This need creates a near term business opportunity, which allows the installation of a large electrolyser, with the help of FCH JU funding. Once installed, the electrolyser will be used to test a range of additional business cases for the use of electrolysers at the refineries of the future.

1.1 Key objectives of the REFHYNE project

The high-level objective of the project is to deploy and operate a 10 MW electrolyser in a Power to Refinery setting. In doing this, REFHYNE will validate the business model for using electrolytic hydrogen as an input to refineries, test and record revenues available from primary and secondary grid balancing in today's markets and create evidence for the policy/regulatory changes needed to underpin this market.

[8] https://blogs.platts.com/2019/12/19/hydrogen-interest-source-scale/

This overarching objective breaks down into a series of sub-objectives of which the ones most relevant for this report are the following, which are explained in more detail below

1. Achieving cost and efficiency targets with Multi-MW PEM electrolyser technology and testing its longevity
2. Providing a viable business case for electrolyser use at refineries which should be adoptable for other energy intensive industrial customers
3. Testing business models for electrolysers including cross-sector application potential for electrolytic hydrogen between industry, power and transport
4. Providing evidence for policy makers to develop and enact fit-for-purpose supportive regulations

1.1.1 Achieving cost and efficiency targets with Multi-MW electrolyser technology

Refineries are currently one of the largest sources of hydrogen demand, along with ammonia production. Installation of an electrolyser at a refinery allows deployment at scale (multi MW) offering reduction of CAPEX per kW of electrolyser capacity and constant uptake of hydrogen. Furthermore, large industrial consumer, have access to power at reduced levies due to the large electricity demand and the associated access to potential exemptions from levies and grid fees.

The project will install a new Proton Exchange Membrane (PEM) 10 MW electrolyser, designed and built by ITM Power. This system will be a CE marked, packaged and integrated 10 MW product, which scales up stack technology originally developed at a 1 MW scale. Its design is fully integrated with a new larger scale balance of plant designed to reduce parasitic losses and hence improve overall efficiency. The module is designed so that numerous units can be deployed in parallel to increase to a 100MW scale plant.

The project aims to achieve the 2014-2020 FCHJU's Multiannual Working Programme's cost and efficiency targets (FCHJU, 2018). Furthermore, it aims to prove the longevity of a multi-MW electrolyser operated at a high load factor, helping to de-risk the technology and thereby helping to reduce the financing costs of future similar installations.

In addition to achieving these ambitious performance metrics, the project will carry out analytic work to assess the potential to further reduce costs for the system via larger scale manufacture. This will involve a detailed design study for a 100 MW electrolyser to replace one of the existing methane reformers at the Rhineland refinery.

1.1.2 Providing a viable business case for electrolyser use at refineries

In spite of the mentioned advantages offered by the electrolyser installation in a refinery, provision of hydrogen to the refinery alone is not expected to provide a viable business case in the near future as refineries attribute a relatively low value to the hydrogen.

More than 70% of global hydrogen demand is currently based on Steam Methane Reforming (SMR), i.e. supplied from fossil fuels. The hydrogen production cost with SMR is about €1.2 – 2.2 /kg, €1.5 – 2.5/kg when the carbon cost is added, based on a current carbon price of €25/t. €1.5-2.5/kg is therefore the benchmark price for hydrogen in industrial settings currently.[9] The 10 MW electrolyser will provide up to 4t hydrogen per day to the refinery.

Energy intensive industries have been granted reductions on feed-in tariffs (Renewable Energy Law 2017) by the Federal government. In addition, grid fees are reduced as well (§ 19 of electricity grid fee regulation), if the site has a high power demand and very even consumption throughout the year (high load factor). Due to such reductions of levies and fees for such energy intensive industries with high constant load, the electrolyser would

[9] IEA, 2019, The Future of Hydrogen, p.52

have access to an electricity price 60% lower than the industrial price without such reductions. Assuming the electrolyser cost and efficiency targets are achieved, this would lead to 50% lower hydrogen production costs per kg. However even with these cost reductions, the production cost of electrolysis is significantly higher than the cost based on SMR (cp. Figure 3 below). In fact, assuming an SMR price of €2.3/kg including carbon cost, the electricity retail price would need to be as low as €25/MWh for electrolysers to reach cost parity.

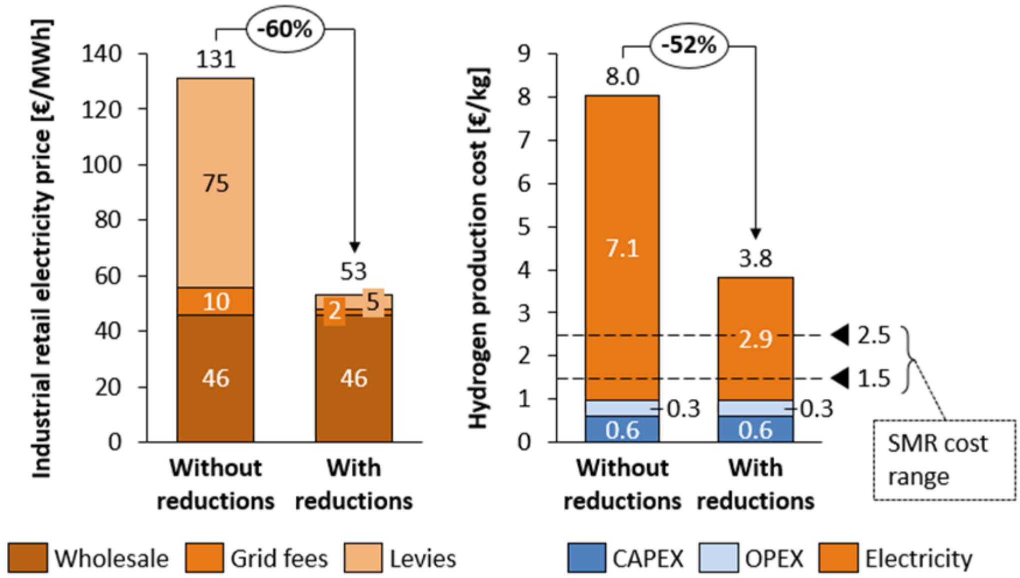

Figure 3: Left: industrial electricity price with and without exemptions for energy intensive industry in Germany; right: corresponding H_2 production cost in both cases (assuming a 90% load factor of the electrolyser, cp. section 2.1 for full set of assumptions behind these figures)

The project will explore the viability of business models for the operation of electrolysers in refineries by introducing additional revenue streams. By using the electrolyser load to balance the internal electricity network at the refinery, the electrolyser can contribute to electricity costs across the site to be optimised. In Germany, energy-intensive consumers with a constantly high offtake are allowed to claim a reimbursement of grid fees (§19 Stromnetzentgeltverordnung (StromNEV), paragraph 2[10]). This means the cost of network fees for all electricity supplied to the site can be reclaimed. To be able to reclaim through this regulation the annual average electricity offtake of the consumer needs to be maintained above 80% of the peak demand within that year. Mitigating the risk of not fulfilling this requirement can be achieved by installing flexibility-enhancing equipment, e.g. large batteries, emergency diesel generators or an electrolyser. Due to a remaining risk of having a peak and losing the reimbursement of grid costs, the full amount cannot be considered. Grid costs vary depending on the location of the industrial plant. Depending on the likelihood of achieving the reimbursement of grid costs and the allocation to existing flexible generation equipment the amount of annual grid fee reimbursement could be about € 1m per 100 GWh of annual offtake.

The electrolyser will provide a new flexible 10 MW load, which could be operated as a highly dynamic load to allow the refinery to help to maintain the 80% of peak threshold. This will require dynamic operation of the electrolyser, turning off rapidly at potential peak periods.

The demonstration of this near-term business model is a major advantage for the hydrogen sector as it is valid in the near term and could be replicable for other large power users in Germany (and other countries in Europe).

[10] https://www.gesetze-im-internet.de/stromnev/__19.html

1.1.3 Testing business models for electrolysers of the future

While the business model in the REFHYNE project is an excellent opportunity to deploy a large-scale electrolyser, it is specific to the regulatory environment where it is deployed, and is unlikely to enable growth of the electrolyser sector to a GW scale in Europe. Therefore alternative business models for hydrogen which use alternative ways of creating value need to be understood. The partners of the REFHYNE project will use the opportunity to deploy and operate a large-scale electrolyser to investigate in particular the following alternative models.

- **Providing balancing services to the Transmission System Operator (TSO)** - Due to the possibility to store hydrogen for use at a later point of time, the production can be shifted in time, making electrolysis a source of flexible electricity demand. This flexibility can be used e.g. to consume electricity only in times of low prices but also to provide balancing services to the transmission system operator (TSO). The TSO relies on sources of flexible demand and generation to adjust their electricity consumption and generation, respectively, close to real time, in order to ensure the balance of demand and generation, which has to be ensured on a second by second basis to ensure the safe and stable operation of the system.

- **Supplying Green hydrogen to the refinery in return for credits** –The revised Renewable Energy Directive (RED II), which entered into force at the end of 2018, gives member states more freedom to support electrolytic hydrogen, compared to the Fuel Quality Directive and RED I (which is superseded by RED II). This could allow the green hydrogen from the electrolyser to count towards fuel suppliers sustainability requirements. This in turn has a monetary value which would justify expansion of the plant and allow explicit links to green electricity. This model is expected to become viable after mid of 2021 onwards. There is some debate around the way in which green electricity is defined for the purposes of these emerging policies. These relate to the degree of coupling (in space and time) between the electrolyser and sources of renewable generation as well as its additionality. Shell Energy Europe will use this project to test the type of trading strategies which are required to procure electricity to meet the emerging renewable electricity requirements associated with the Renewable Energy Directive. This, coupled with an economic and environmental analysis by SINTEF and Sphera will allow a thorough test of this business model in preparation for the emerging green hydrogen policies.

- **Hydrogen for mobility** – The hydrogen mobility market offers currently the highest price per kg of hydrogen at the retail site of all the main options for using large quantities of hydrogen. Once mature, direct sales of hydrogen to the mobility market has the potential to be more attractive than sale to the refinery. Furthermore, the hydrogen produced by the electrolyser is at a sufficient purity level that it meets automotive grade purity requirements without need for further purification. The ITM Power electrolyser has been certified to this level in the UK and the USA. This level of purity is higher than that produced by the refinery's existing methane reformers. This gives the electrolyser an additional advantage over reformers, which would require expensive purification equipment to allow supply to the mobility sector.

Shell is a major partner in the German H2Mobility joint venture which is rolling out a new fleet of over 100 refuelling stations for fuel cells cars. The level of demand for hydrogen in this system is currently very low due to a lack of fuel cell vehicles on the roads. However, as this demand increases (from road vehicles and also buses and rail vehicles), it will become increasingly attractive to supply fuelling stations using the electrolytic hydrogen developed here.

During the electrolyser project, Shell will continuously evaluate and report on the economics of a move to supplying the mobility sector. If the demand (and therefore economics) permit, Shell will work with their H2Mobility partners to install equipment to divert electrolytic hydrogen from the refinery's main pipeline to a compressor station where hydrogen can be used to fill tube trailers to supply the hydrogen stations in the H2Mobility initiative.

In addition to investigating business models for hydrogen in the transport sector, the project also aims to explore the overall cross-sector application potential for electrolytic hydrogen between industry, power and transport.

The high level objective of the project is that each of these business models is understood - firstly in isolation and then in terms of how the different sources of value can be stacked to create a business model which is appropriate for the future expansion of the sector.

1.1.4 Providing evidence for policy makers and regulators

Without new policy measures which allow the value of green hydrogen to be monetised by the refinery operator, achieving a sustainable business model for industrial use of electrolytic hydrogen against steam reformed hydrogen will be limited to niches. The transmission charge reimbursement used in Rhineland is specific to the German electricity market. There exist similar grid fee reductions in France and the Netherlands, but they are conditional to further requirements which make them available to only a small group of industrial consumers (PWC, 2019).

Hence, a substantial objective of this project is to collect and then present the evidence on the potential benefits of a change in the key elements of legislation which would help underpin the business model. More specifically, these include the revised Renewable Energy Directive including its delegated EU acts, their implementation into national regulation by member states as well as national policies on feed-in tariffs and grid fees and also grid-balancing service payments.

The objective here is to use the electrolyser deployment at the refinery to extrapolate:

a) the direct environmental benefits of a move to facilitate the Power to Refinery model (at a German, European and other member state level),
b) the indirect benefits in terms of facilitating the broader transition to a hydrogen energy system, by reducing electrolyser and other system cost, and
c) an analysis of the economics to demonstrate the viability of the business model under different configurations of the relevant policies
d) and hence give some relevant policy recommendations.

1.2 Focus of work package 7 and this report

Work package 7 of the REFHYNE project focuses on business models for large scale electrolysers and corresponding policy implications. For this purpose, a techno-economic model of bulk electrolyser operation has been developed by SINTEF and has been used to assess the viability of different business models, based on current as well as on future markets and policies. The evidence of this analysis is used to identify policy and regulatory changes which could help to make a range of business models viable and thereby scale up the market for electrolysis.

This report presents initial results of the techno-economic modelling of the electrolyser and the corresponding policy implications. It is written at a point in the project when the electrolyser operation has not started yet (this is expected for the second half of 2020). While the modelling has been undertaken to highlight challenges of electrolytic hydrogen in the current hydrogen and electricity market environment, an accurate representation of the economics of the REFHYNE project is not yet possible at this stage but will be conducted at a later stage when the electrolyser will have started operation and project cost and performance data will be available.

The remainder of this document is structured as follows:

- Section 2 describes the modelling methodology, main assumptions and main results

- Section 3 discusses the results of the modelling and their policy implications.

2 Techno-economic modelling

This section presents techno-economic modelling results which are based on the bulk electrolyser model used in the REFHYNE project. The modelling aims to represent the production cost of hydrogen in an industrial setting with access to relatively low electricity prices as well as comparably low specific electrolyser cost due to the economies of scale offered by the bulk electrolyser compared to smaller installation sizes. The main outputs are the net present value (NPV) of the electrolyser installation in different settings and the associated hydrogen production cost.

The techno-economic analysis has been conducted using the mathematical model HYOPT, developed by SINTEF. The model simulates the operation of the electrolyser in quarter-hourly resolution for a period of half a year and then models the lifetime cash flow of the electrolyser assuming the same operation for the remainder of its lifetime. A more detailed description of this model can be found in the Appendix. A central scenario as well as further scenarios exploring additional revenues and impact of a change of particular input parameters have been modelled. The main input assumptions of the central scenario are described in the following section.

Section 2.2 describes the results of the central scenario, first in the case of Germany (section 2.2.1), then for several other European countries (section 2.2.2). Section 2.3 describes the results of the additional scenarios.

2.1 Main assumptions of the central scenario

The main assumptions of the central scenario are listed in the table below. Differing assumptions of the further scenarios are described in the sections reporting the respective results. The central scenario does not include balancing service provision to the TSO, this is included in an additional scenario.

Table 1: Main assumptions of central scenario

Parameter	Unit	Value	Source
Electrolyser CAPEX	€/kW	1000	Project target
Electrolyser OPEX	% of CAPEX/y	5	Project target
Electrolyser efficiency	kWh/kg	54	Project target
Project lifetime	y	15	(Carmo, et al., 2013)
Discount rate	%	4	Assumption by SINTEF
Electricity wholesale price	€/MWh	¼ hourly profile	(ENTSO-E, 2019)
Grid fees	€/MWh	10	(Westnetz, 2020)
Levies	€/MWh	5	(BDEW, 2019)
H_2 production cost SMR	€/kg	1.5-2.5	SINTEF and Shell
H_2 price received by electrolyser	€/kg	2-5	Modelling assumption
Grid CO2 intensity	$kgCO_{2e}$/MWh	hourly profile	(Agora Energiewende, 2019)

Electricity price

We divide the retail power price into three components: wholesale costs, grid fees and levies. More detail on levies in Germany can be found in the appendix (section **5.4**).

Similar to the REFHYNE project we assume in the central scenario, that the bulk electrolyser is added to an existing industrial site and pays the same retail price as the site. There are also specific exemptions available for standalone electrolysers which we represent in an alternative scenario (section **2.3.3**, case 2).

Wholesale price time series for the studied European countries have been taken from the ENTSO-E webpage. All-time series extend from 18.10.2019 to 07.04.2019. Balancing services prices (discussed in more detail in section **2.3.1**) are also taken from this period.

The grid fees of €10/MWh in the central scenario represent the case of a consumer connected to the high voltage level ("Höchstspannung", "Hochspannung" or "Hochspannung mit Umspannung auf Mittelspannung") with a high load factor which can vary significantly depending where a potential customer is located (grid fees in Germany contain a capacity payment in €/kW/y as well as an energy payment in ct/kWh).

The levies of €5/MWh are associated with an industrial consumer for whom significant levy reductions are available in Germany; these would otherwise amount to about €75/MWh. The most prominent of these levies is the renewable surcharge (also referred to as Erneuerbare Energien Gesetz (EEG) levy), which amounted to € 64.05/MWh in 2019. More details can be found in the appendix, section **5.4**. As shown in figure 3 these reductions of levies reduce the electricity price by more than 50%.

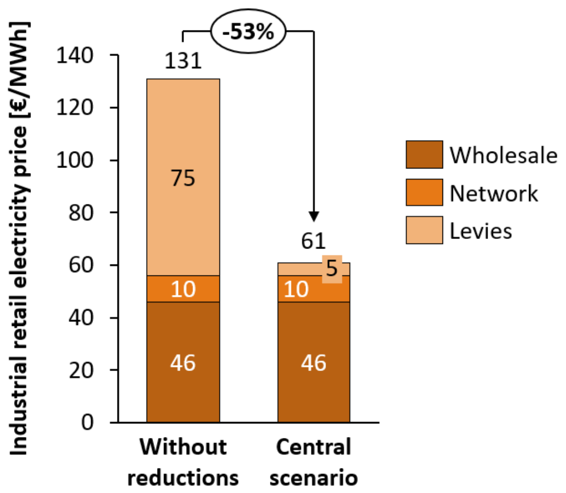

Figure 4: Industrial retail electricity price without reductions of levies and in the central scenario with levies assumed to be reduced to €5/MWh (see text above for description of levies)

Hydrogen price paid to the electrolyser

Based on the current production cost of hydrogen using Steam Methane Reforming (SMR), we first assume the electrolyser receives a payment of €2/kg for the produced hydrogen. In the case of the REFHYNE project, this represents the avoided cost of SMR based hydrogen produced on site through the use of electrolytic hydrogen (also produced on site). Note of course that this is an average value, in reality the cost is highly variable ranging between €1.5-2.5/kg (incl. carbon costs of €0.3/kg) depending on gas prices. To represent higher value end uses (such as in H_2 mobility or carbon credits for green hydrogen supplied to the refinery), prices of €3-5/kg paid to the electrolyser have been assumed in additional model runs.

These virtual prices attributed to the electrolyser only mirror the hydrogen production cost and not the cost of delivery for end uses. For the cost to transport the hydrogen to the end user, including intermediate storage, as well as the cost of retail infrastructure would need to be added .

2.2 Central scenario results

2.2.1 Model results Germany

One of the aims of the modelling is to capture the ability of the electrolyser to respond to varying electricity prices by shifting its consumption to periods of low electricity prices. Two modes of operation of the electrolyser have been modelled:

- either the electrolyser is only run when the revenue per kg of hydrogen (€2-5/kg in the different model runs) exceeds the (retail) electricity cost per kg or
- a 90% annual load factor is enforced onto the electrolyser.

Figure 5 shows the net present value and the levelized production cost per kg of hydrogen in both cases, assuming a revenue of €2/kg received by the electrolyser. Running the electrolyser only in hours when the revenue exceeds the electricity cost results in an annual load factor of only 6%.

In both cases the electrolyser installation has a negative net present value. Forcing a 90% load factor leads to a much more negative NPV, as in most hours, when the electrolyser is run, it makes a loss (electricity costs are higher than the revenue from hydrogen sale). On the other hand the 90% load factor leads to much lower production costs per kg of hydrogen, as the fixed cost of the electrolyser are spread over a larger quantity of hydrogen.

In spite of the assumed access to comparably low power retail prices the electrolyser is not able to provide a positive business case when assuming a payment of €2/kg reflecting the avoided gas-based H2.

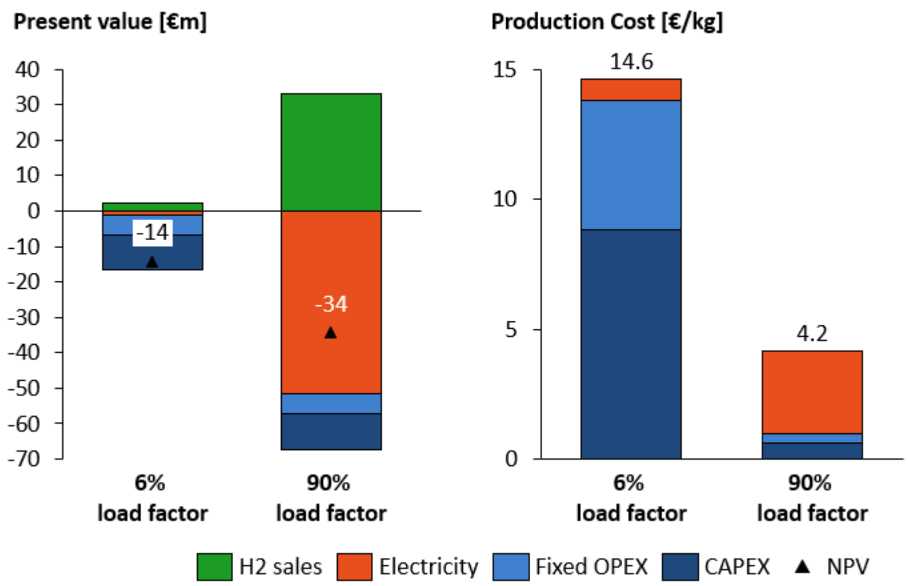

Figure 5: left: NPV of electrolyser in the central scenario in Germany assuming €2/kg revenues, either when run only in profitable hours or when enforcing a 90% load factor; right: corresponding levelized cost of H_2

The left hand side of Figure 6 shows the net present value of a 10 MW electrolyser installation in the central scenario in Germany, assuming hydrogen prices of €2-5/kg paid to the electrolyser and operation only in hours when H_2 revenues exceed electricity costs. The corresponding load factor and cost per kg of hydrogen are shown on the right.

Increasing the price per kg of hydrogen from €2/kg to €4/kg increases the load factor from 6% to 65% and brings the project close to breaking even (NPV -€1m). Furthermore, the cost per kg of hydrogen are reduced from €14.6/kg to €4.2/kg.

As mentioned before, the assumed prices paid to the electrolyser up to €5/kg in high value end uses do not represent the hydrogen retail price in most of these end uses. In the case of mobility, the cost for the transport of hydrogen to refuelling stations and the refuelling stations themselves would need to be added. Assuming €4/kg for distribution and retailing costs (assuming high utilisation) would lead to a retail threshold of €9/kg when assuming a price of €5/kg paid to the electrolyser. Note that no profit is included in these figures, and VAT has not been added, both of these would increase the required sale price of hydrogen. Even without these, this is above the cost of taxed diesel.

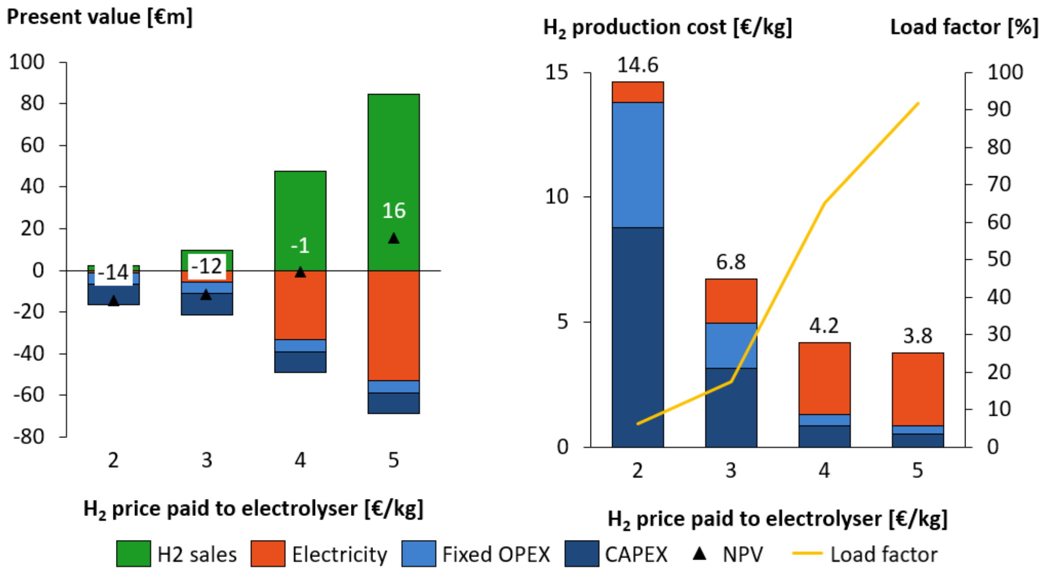

Figure 6: left: NPV of the electrolyser in the central scenario in Germany, assuming H_2 revenues of €2-5/kg for the electrolyser and operation only in hours when revenues exceed electricity costs;
right: corresponding annual load factor and levelised H_2 production cost per kg

2.2.2 Model results for further EU countries

To assess the economic viability of large-scale electrolysers in an industrial setting in the wider European context, analysis for four further European countries has been conducted. Figure 7 shows wholesale electricity prices during the modelled time period in Germany, Denmark, Norway, France and Spain. The main characteristics of the wholesale price in the different countries are summarised in Table 2. Average prices are significantly higher in France and Spain than in Germany, Denmark and Norway. The variability of prices is similar in Germany, Denmark and France, but much lower in Spain and Norway.

Grid fees paid by large industrial sites are in many cases specified via individual arrangements between the site and the grid operator. The level of further levies and fees which have to be paid by the site depend on the industrial policies of the particular country. A detailed comparative assessment of such policies in the investigated countries is out of the scope of this report. To model the retail price for an industrial site which is available to exemptions from grid fees and levies, the same total of grid fees and levies is added to the wholesale price as in the central scenario in Germany, i.e. €15/MWh. This approach has been chosen for the following reasons:

- The exemption in Germany is based on the policy to support domestic power cost intensive businesses and not caused by technological characteristics of the system. The level of grid fees and levies is significantly lower than what non-energy intensive industries pay (about €85/MWh in grid fees and levies, composed of €10/MWh grid fees and €75/MWh in levies).

- To compete with the location in Germany, other countries would need to introduce comparable policies leading to comparable levies and fees.

- Using the same grid fees and levies allows to single out the impact on the wholesale prices.

Further assumptions are the same as in Table 2.

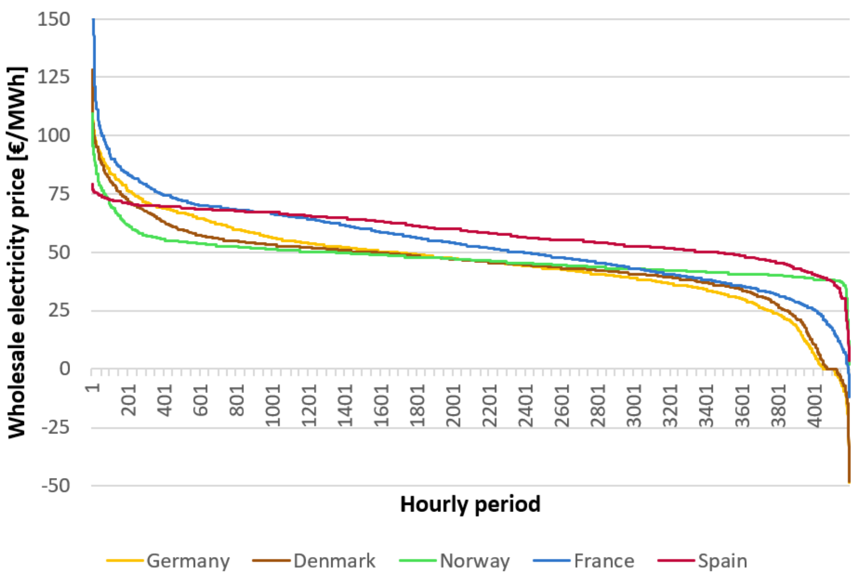

Figure 7: Wholesale electricity prices during the modelled time frame in Germany, Denmark, Norway, France and Spain; hourly periods are ordered from highest to lowest wholesale electricity price

Table 2: Characteristics of wholesale electricity prices of observed markets in the modelled time period

	Unit	Germany	Denmark	Norway	France	Spain
Average price	€/MWh	46	46	48	54	58
Standard deviation	€/MWh	19	17	8	19	10
Negative price periods		440	336	0	36	0

Figure 8 shows the costs and revenues as well as utilisation factors for the five different countries assuming a hydrogen price of €2/kg paid to the electrolyser in the case when the electrolyser is only run in hours when the hydrogen price exceeds the electricity retail costs per kg (left) and in the case when a 90% load factor of the electrolyser is enforced (right). The economics in Denmark, Norway, France and Spain are similar to those in Germany. In all cases the net present value is negative. As the hydrogen price of €2/kg is lower than the retail electricity costs per kg of hydrogen in all countries in most hours of the year, operating the electrolyser leads to additional net costs, leading to a lower NPV in the case of the 90% load factor.

Figure 9 shows the costs and revenues as well as utilisation factors for the five different countries both for a hydrogen price of €2/kg (left) and a hydrogen price of €4/kg (right) paid to the electrolyser and operation only in profitable hours. In all countries utilisation is profitable only in very few hours of the year in the case of a hydrogen price of €2/kg and subsequently the NPV is negative. Denmark and Germany have the highest utilisation due to the higher occurrence of low and negative price periods compared to the other countries.

At a hydrogen price of €4/kg, the utilisation differs significantly between the countries. It is significantly higher in Germany, Denmark and Norway than in France and Spain, since average electricity prices are lower in the former than in the latter. Even though the utilisation rate is higher in Norway than in Germany and Denmark, the NPV is lower in Norway, indicating lower net benefit per kg of produced hydrogen. This can be explained by the higher volatility of wholesale prices in Denmark and Germany compared to Norway leading to lower minimal prices in the former, even though average prices are similar (cp.Table 2).

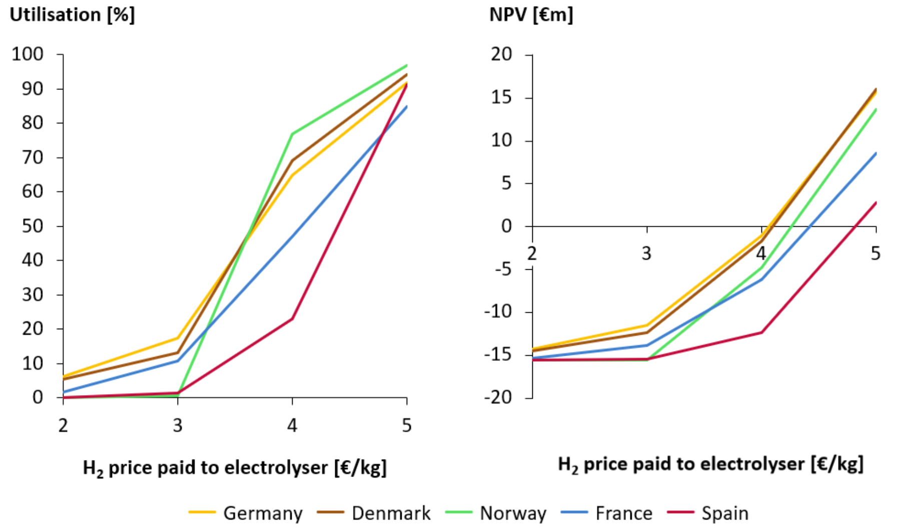

Figure 8: Utilisation and NPV in five European countries for different hydrogen prices paid to the electrolyser

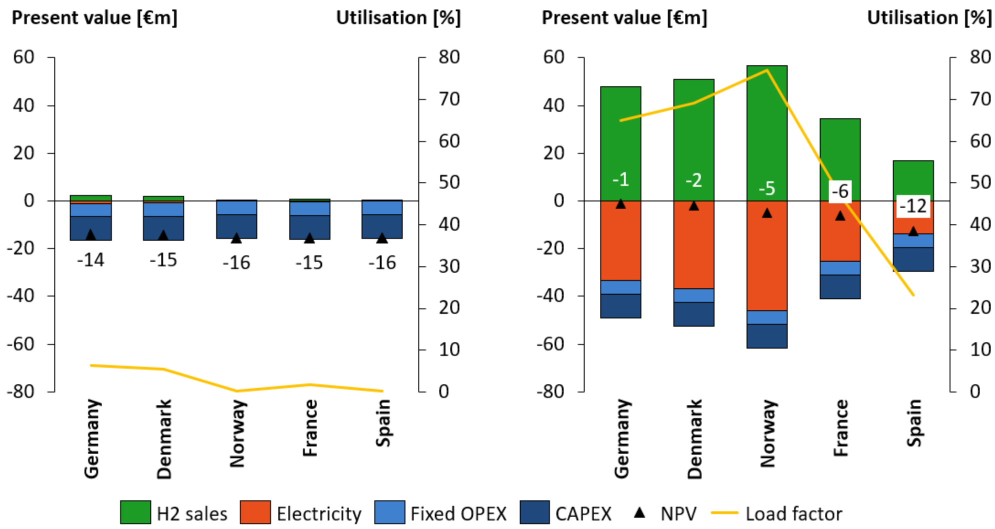

Figure 9: NPV of the electrolyser in the central scenario in several European countries when run only in profitable hours assuming either a price of €2/kg paid to the electrolyser (left) or a price of €4/kg (right)

Finally, Figure 9, shows the utilisation of the electrolyser and the NPV for the five European countries for hydrogen prices from €2-5/kg in the case when the electrolyser is only operated in profitable hours. In all countries the utilisation is low up to hydrogen prices of €3/kg and a positive NPV can only be achieved at hydrogen prices above €4/kg. NPVs for the cases in Germany and Denmark are very closely aligned and above the NPV in other countries' cases. The Spanish case has the lowest NPV of all.

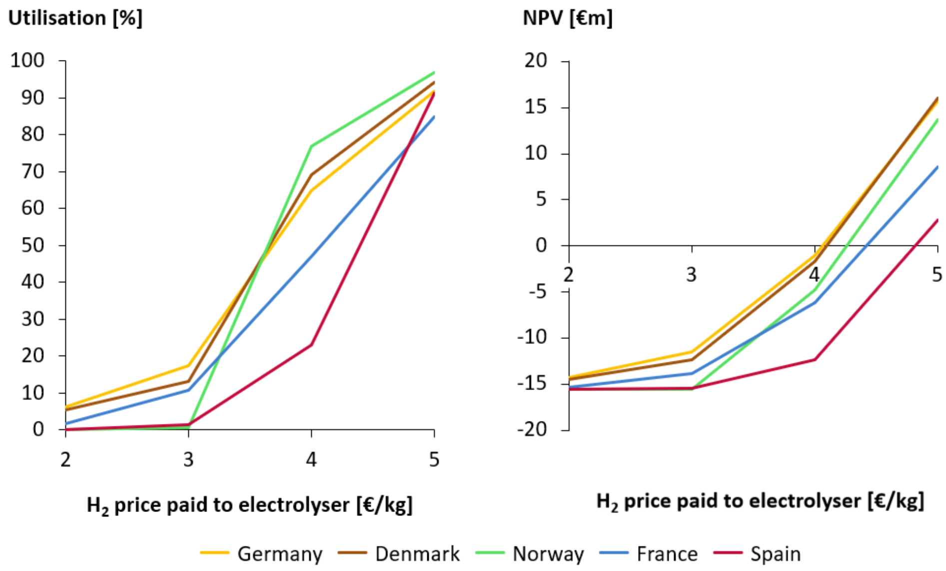

Figure 10: Utilisation and NPV in five European countries for different hydrogen prices paid to the electrolyser

2.3 Additional scenarios in the German market

In addition to the central scenario, which has been investigated in several European countries, additional scenarios exploring alternative revenue streams and the impact of regulatory changes have been analysed. These additional scenarios focus on the German market as this is the relevant context for the refinery in the REFHYNE project. The results can however inform further analysis of business models in other European markets which will be conducted at a later stage of the project.

2.3.1 Providing balancing services to the TSO

To assess how providing balancing services to the TSO could impact the business case of the electrolyser, model runs have been conducted, in which the electrolyser provides such services in addition to producing hydrogen. In these runs the electrolyser will operate in any hour, in which revenues from the sale of hydrogen and the provision of balancing services exceed the retail electricity cost (wholesale cost plus grid fees and levies).

The achieved balancing revenues are based on the current prices in the German balancing markets. In particular it is assumed the electrolyser provides either Primary Control Reserve (PCR) or Secondary Control Reserve to the TSO, depending on which service provides the higher revenue in the time period in question. The average prices achieved in these market segments in across the modelled time period (18.10.2018 – 07.04.2019) as well as the utilization profile of the service have been sourced from the common balancing services procurement platform of the four German TSOs (50 Hertz, Amprion, Tennet, Transnet BW, 2020). More information on the development of balancing services prices can be found in the appendix, section 5.2.

Figure 11 shows discounted costs and revenues for the operation when provision of balancing services is included. Figure 12, left, shows the utilisation factor of the electrolyser for different hydrogen prices with and without provision of balancing services. The utilisation is increased at hydrogen prices up to €4/kg compared to operation without balancing services provision, as the additional revenue from (positive) balancing services makes hydrogen production profitable in a larger number of hours than without balancing. Figure 12, right, shows the NPV for different hydrogen prices with and without provision of balancing services. With balancing a positive NPV can be already achieved at hydrogen prices above €3/kg (vs. €4/kg without balancing).

The revenues from balancing services do not have a significant impact on the business case when the value of hydrogen is very low or very high. However they help to make the business case when the business model is close to being economic. Provision of balancing services can thus be a valuable and in cases essential addition to the revenue stack but they should not be the main pillar of a business case of an electrolyser installation.

Business models of electrolysers will evolve along with the transition of the energy system. As the penetration of variable renewable energy sources increases, the flexibility offered by electrolysers' variable consumption and the ability to store hydrogen over long time periods might become increasingly valuable. As a consequence the revenue stack of electrolysers will evolve and balancing services could be a valuable option complementing new flexibility services provided by electrolysers.

Again it has to be recognized that the hydrogen prices mentioned above refer to the price paid to the electrolyser, not the retail price paid in a high value end use like mobility. Furthermore the achieved balancing revenues represent an upper bound on the revenues achievable in reality, as they are based on perfect foresight, while in reality, suboptimal operation decisions will occur due to imperfect foresight.

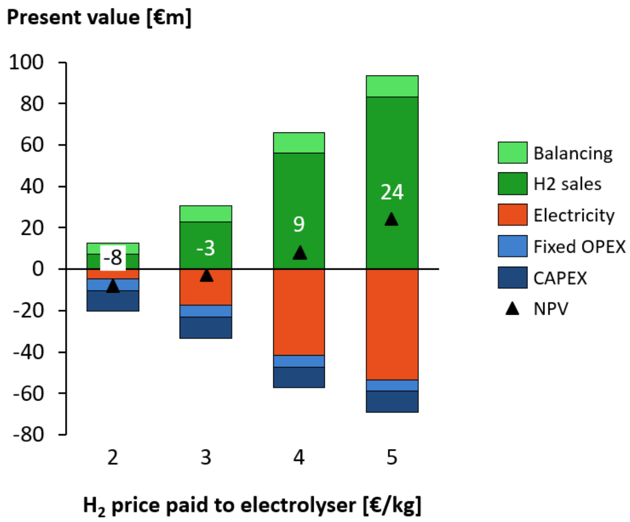

Figure 11: NPV of the electrolyser in Germany, assuming provision of balancing services to the TSO and H_2 revenues of €2-5/kg for the electrolyser; operation only in hours when revenues exceed electricity costs

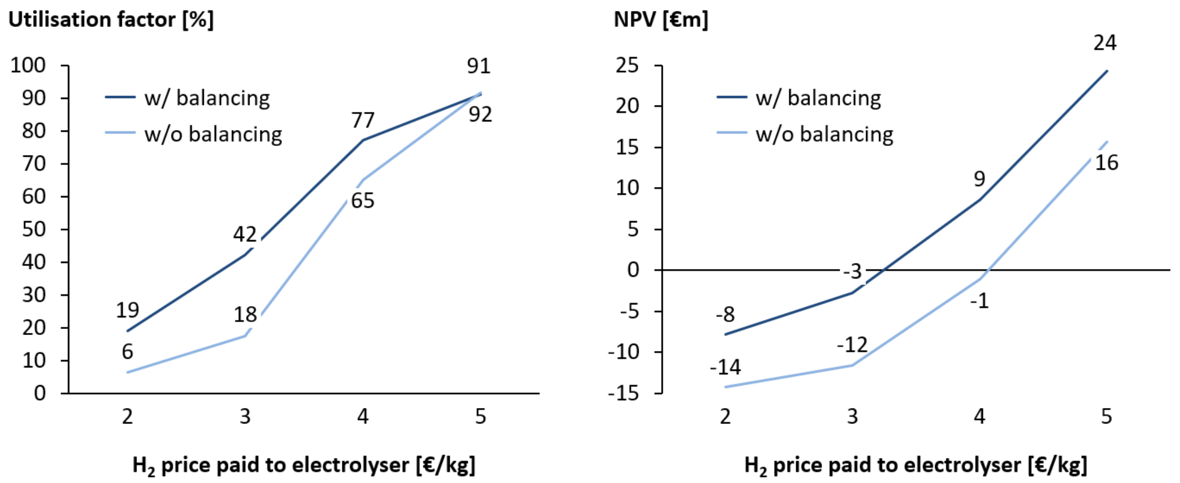

Figure 12: Utilisation and NPV of the electrolyser in Germany for different hydrogen prices paid to the electrolyser with and without provision of balancing services to the TSO

2.3.2 CO_2 adjusted electricity price

Despite the strong growth of the renewable share in the German power mix, the carbon intensity of electricity in Germany is relatively high, compared to other large economies such as the UK or France. During the modelled time period, the average electricity carbon intensity was 436 gCO_2/kWh (non-weighted average across the hours of the modelled time period, 18.10.2018 – 07.04.2019). This is due to the high share of coal fired electricity, the most carbon intensive form of electricity generation, in Germany at the moment. Subsequently electrolytic hydrogen has a high carbon footprint if the electricity consumed for its production has the same shares of generation sources as the average German power mix. In fact, based on the carbon intensity of the German grid mentioned above, the carbon intensity of electrolytic hydrogen would be 2.2 times as high as the carbon intensity of grey hydrogen[11].

However, the grid carbon intensity is changing with the power mix from hour to hour and there have been periods when the renewable penetration on the German grid was close to 100%[12]. Therefore, two additional model runs have been conducted to assess how much the carbon intensity of electrolytic hydrogen using electricity from the grid could be reduced when allowing the electrolyser to operate flexibly and to avoid the hours of highest carbon intensity.

The electrolyser was forced to run at a 50% overall annual load factor in these runs but was free to choose the least cost hours to achieve this load factor. In the first additional run the current price profile of the German wholesale price was used. In the second run, the hourly electricity wholesale price has been adjusted according to the carbon intensity of the power mix in that hour to incentivise the electrolyser to operate in hours of low grid carbon intensity. The price was increased in hours of higher than average carbon intensity (on average by 15% across such hours) and reduced in hours of lower than average carbon intensity (on average by 26% across such hours). The price was adjusted in such a way that the average across all modelled hours was not changed. In this way, this is a proxy for a carbon based electricity tariff. In both runs it was assumed the electrolyser is providing balancing services to the TSO and furthermore a hydrogen price of €2/kg is paid to the electrolyser.

Figure 13 shows the net present value as well as the carbon intensity of the produced hydrogen in both cases. The NPV can be increased while the carbon intensity is decreased, however both changes are only small. The

[11] 23.5 kgCO_2/kgH_2 vs 10.8 kgCO_2/kgH_2; the latter value is the carbon intensity of SMR based hydrogen assumed by CertifHy, cp. below; cp. also section 3.3.4 for the definitions of green, grey, and blue hydrogen
[12] https://www.cleanenergywire.org/news/renewables-cover-about-100-german-power-use-first-time-ever

benchmark carbon intensity of SMR based hydrogen as set by the green hydrogen certification initiative CertifHy is 91 gCO_{2e}/MJ_{H2}, based on the lower calorific value of hydrogen (33kWh/kg), which corresponds to 10.8 $kgCO_{2e}/kg_{H2}$ (CertifHy, 2019). While the annual average carbon intensity of electrolytic hydrogen is reduced by 7% when using the CO_2 adjusted electricity price, the intensity is still significantly higher than the intensity of SMR based hydrogen.

It is important to note that there is a correlation between cheap electricity prices and low carbon intensity, mostly due to the way in which wind and solar electricity generation is financed at the moment (Hirth, 2013). Therefore already in the base case (without adjustment of the electricity price) the electrolyser consumes electricity in hours of lower than average grid carbon intensity. Subsequently, the carbon intensity of the produced hydrogen is already 11% lower than that of hydrogen using electricity of the average carbon intensity of the German grid in the modelled period (20.9 $kgCO_2/kgH_2$ vs. 23.5 $kgCO_2/kgH_2$). In the case of the adjusted electricity price, the carbon intensity of the produced hydrogen is 17% lower than when using electricity of the average grid mix in Germany (19.6 $kgCO_2/kgH_2$ vs. 23.5 $kgCO_2/kgH_2$).

The renewable penetration will increase from 37.8% (share of gross electricity consumption) in 2018 (BMWi, 2019 a) to 65% in 2030 according to the German government's Climate Protection Programme 2030, adopted in late 2019 (Bundesregierung, 2019). Furthermore, coal will be phased out completely by 2038. Therefore, the average carbon intensity of the German electricity grid will be reduced significantly and furthermore the volatility of this intensity will also increase. The major supply of renewable electricity generation will come from wind and solar. This will increase the periods of high (close to 100%) renewable penetration and very low carbon intensity while the carbon intensity will stay comparable to today in hours of low wind and solar output.

The carbon intensity of electrolytic hydrogen based on the average power mix in Germany will therefore decrease significantly up to 2030. Furthermore, the potential to lower the carbon intensity of electrolytic hydrogen by operating the electrolyser flexibly will increase significantly as well.

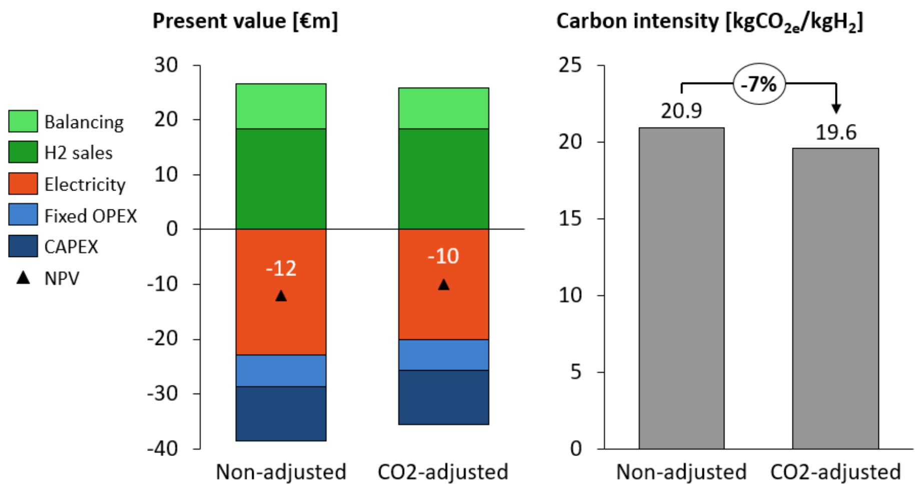

Figure 13: left: NPV of the electrolyser in Germany, enforcing a 50% load factor, and assuming H_2 revenues of €2/kg both for the non-adjusted and CO_2-adjusted electricity price; right: carbon intensity of produced H_2 in both cases

2.3.3 Grid fees and policy levies

Grid fees and levies are already significantly reduced in the central scenario compared to those paid by average industrial consumers in Germany. Still the cost of electrolytic hydrogen remained above the cost of SMR based hydrogen in the modelled cases (€4.2/kg vs about €2-3/kg, cp. section 2.2.1). To represent reductions of fees and levies further to those already assumed in the central scenario, three additional model runs have been conducted. They model the cases listed below and illustrated in Figure 14. In all cases the electrolyser is run at a 90% load factor and a hydrogen price of €2/kg paid to the electrolyser has been assumed.

Reduced grid fees: consumers with an annual consumption above 10 GWh/y are available for a reimbursement of 80% of their grid fees, if their power consumption profile corresponds to at least 7,000 full load hours (equivalent to an 80% load factor).[13] As a representation of this, the grid fees in the central scenario are thus reduced from €10/MWh to €2/MWh.

It is important to note that in the evaluation of this case here, we are accounting for the reduced grid fees for the electricity consumed by the electrolyser only. However, in the case of deployment on a larger industrial site with further electricity consumption, such as the refinery in the REFHYNE project, the electrolyser could help to achieve the required high load factor across the whole site. Subsequently grid fees would be reduced for the electricity consumed across the whole site, of which the electricity consumed by the electrolyser is only a small share. An evaluation of these savings and to what extent they can be attributed to the electrolyser is out of scope of this report but discussed qualitatively in section 2.3.4.

No grid fees: electrolysers in stand-alone applications are exempt from paying any grid fees according to the German law[14], compare (Juris, 2019). While we assume in the central scenario that the electrolyser is integrated into an existing industrial site and pays the same grid fees and levies as this site, here we assume a standalone application. We assume the same reduction of levies as in the central scenario. It is not clear yet if and under which conditions this reduction will be available for electrolysers[15] .

Wholesale price only: to assess the impact of a complete exemption from all grid fees and levies, an additional case has been modelled where electricity costs consist of the wholesale price only. Introduction of larger shares of VREs such as PV, onshore and offshore wind, is assumed to impact the variability of the wholesale price and the number of very cheap or negative price periods. This will be further evaluated in later stages of the REFHYNE project.

The net present value and hydrogen production cost in these three additional scenarios as well as the central scenario is shown in Figure 15. As can be seen Figure 14, the retail price in the additional scenarios differs only slightly from the one in the central scenario, which already assumes very significant reductions of grid fees and levies. Subsequently, the NPV achieved in the additional scenarios is similar to the one in the central scenario. Even when the electrolyser pays only the wholesale price for electricity the NPV is negative. In fact the levelized production cost in this case amounts to €3.3/kg, significantly higher than the €2/kg assumed to be paid to the electrolyser.

[13] § 19 Abs. 2 Stromnetzentgeltverordnung (StromNEV)
[14] § 118 Abs. 6 Satz 1, Energiewirtschaftsgesetz (EnWG)
[15] https://www.bundesregierung.de/breg-de/themen/klimaschutz/wasserstoffstrategie-kabinett-1758824

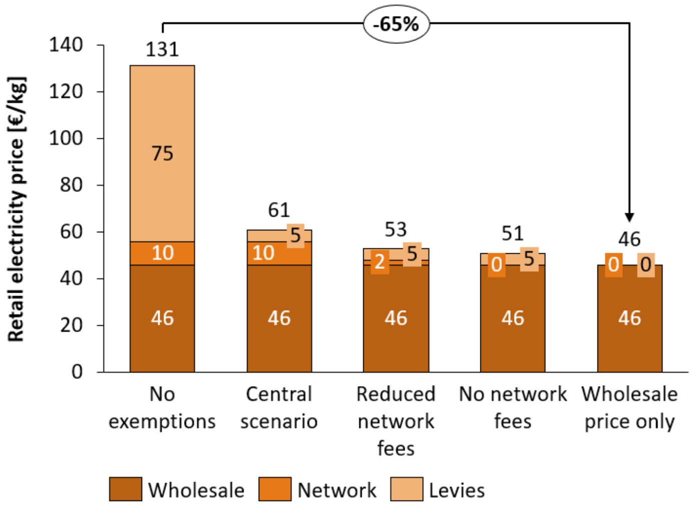

Figure 14: assumed retail electricity price in the central scenario and the three additional scenarios; the retail price without any reductions of grid fees and levies is shown for comparison

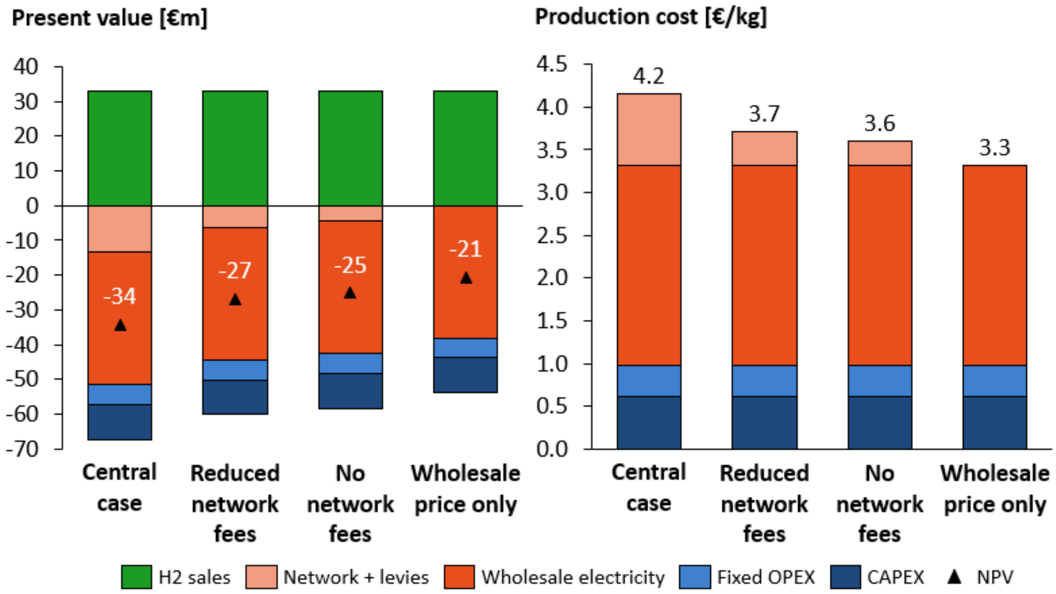

Figure 15: net present value and hydrogen production cost in the central scenario and the three additional scenarios

2.3.4 Electrolyser contributing to internal load balancing

As mentioned in previous sections, large electricity consumers get a reimbursement of 80% of their grid fees, if they are able to maintain the annual average demand of the site within 80% of the peak level of demand (§ 19 Abs. 2 StromNEV, nevertheless this ability to recoup grid fees is under threat.

The installation of an electrolyser, which provides a valuable chemical input to the refinery, is part of a strategy to manage this challenge. The electrolyser can be installed and operated flexibly to maintain the power demand requirements of the site. Because the electrolyser is part of a strategy to maintain the 80% of peak rule, the Rhineland refinery can allocate an internal revenue stream to the electrolyser, which, combined with the value of avoiding methane derived hydrogen, helps to make a viable business case well before any of the other markets for bulk electrolysers have matured. Achieving this value requires a highly flexible electrolyser with very fast modulation which can be turned on and off by the refinery to maintain the site's load balance.

Running the Electrolyser at full load of 10 MW increases the refinery electricity capacity demand by about 10%. Hence, the average load will be increased which helps in general to be above the 80% threshold. If an unplanned shutdown of own generation happens, in total 70% of the missing generation can be compensated by reducing the load of flexible assets in the refinery to secure the 80% threshold. The Electrolyser in addition with other equipment can play a significant role to mitigate the risk of losing the benefit of the grid-cost reimbursement.

The diagram below illustrates the operating strategy. In 2018, 389 consumers were available for the grid fee discount after § 19 Abs. 2 StromNEV. Their consumption corresponded to 59.2 TWh and €611m in reimbursed grid fees (Bundesnetzagentur, 2019). The applicability of the proposed business model among these industrial consumers would need to be assessed on a case by case basis. Such applicability would require an offtake for the produced hydrogen as well as challenges to achieve the grid fee discount similar to those of the refinery, which the electrolyser could help to address.

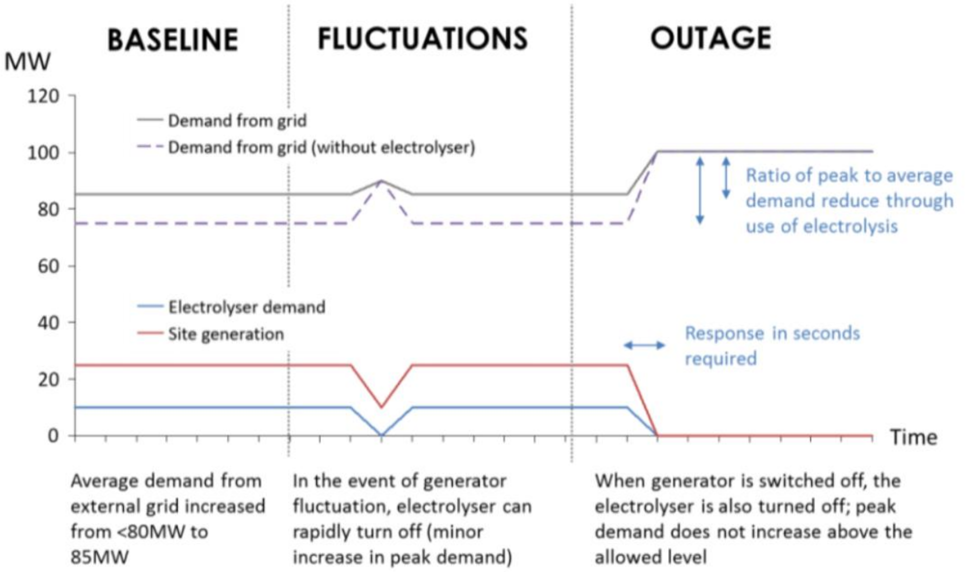

Figure 16: Diagram illustrating the operation of the electrolyser to achieve the grid discount

While the electrolyser can help the refinery achieve the significant grid fee reimbursement, a detailed evaluation of this business model would need to include a representation of the refinery operation to compare its financial, mass and energy flows with and without the electrolyser. Such an assessment is out of scope of this report. It should be noted though that several assumptions will have an impact on such an evaluation, among them:

- An assumption on the number of years during the lifetime of the electrolyser, in which the network reimbursement is achieved

- An assumption to which extent the achievement of the grid fee reimbursement is due to the electrolyser
- An assessment of alternatives to the refinery to achieve the grid fee reimbursement and their costs

3 Discussion and policy implications

3.1 Overview of policy implications of the modelling results

The analysis of business models for large scale electrolysers based on cost assumptions representative of the targets of the REFHYNE project as presented in the previous section leads to the following implications for policy needed to grow the electrolytic hydrogen sector in the short and long term.

- **Grid fees and levies are a significant cost for any electrolyser business model.** These components comprise more than 60% of the retail price for industrial consumers in Germany. In particular the EEG levy is the most significant of these components added to the electricity generation costs. Reductions of such fees and levies as available to large industrial consumers in Germany can reduce the hydrogen production cost by more than 50%. This shows the high impact of these price components on any business case of electrolytic hydrogen.
- **Established end uses for bulk electrolysers allow large scale deployment:** established end uses of hydrogen in the refining and chemical sector offer the deployment of large scale electrolysers with constant offtake of the produced hydrogen as opposed to the nascent hydrogen mobility sector. Deployment of such large-scale electrolysers offers to harness economies of scale in electrolyser manufacturing and reduces the specific cost. These cost reductions can then help to improve the competitiveness of hydrogen in future potential end uses, in which demand still has to develop such as hydrogen mobility and hydrogen in power generation.
- **Niche business models provide early opportunities for electrolysers:** the modelling has shown that business models to sell to industrial end uses are not commercially viable even at the favourable conditions given in this project. This is due to the significantly cheaper alternative of hydrogen produced via Steam Methane Reforming. The current level of carbon prices is not able to change these relative economics significantly. A viable business model for the REFHYNE project may require to add further revenue stream to the electrolyser in form of the reduction of grid fees for enhanced electricity consumption across the whole refinery, which the electrolyser could help to achieve. This business model relies on the very specific regulatory context of the refinery in Germany and cannot be expected to be replicable on a large scale. However, the scope of application of this and similar business models using the flexibility of the electrolyser load should be investigated. Such niche business models present early opportunities for electrolyser deployment and could support the wider role out of electrolysers.
- **Provision of balancing services could improve the business case of electrolysers.** Based on the example of the German market, which has been modelled using recent market data, balancing revenues could improve but not transform the business case of electrolysers in the near term.

  These markets are comparably small and are undergoing a phase of rapid transformation with highly uncertain outlook. On the one hand increasing levels of variable renewables in power systems lead to higher demand for such services. As the EU is committed to achieving greater penetrations of variable renewables in electricity networks the proportion of non- synchronous generation (wind, solar) will increase, while the proportion of non-synchronous generation by heat engines (coal, gas, nuclear) will decrease, and the temporal mismatch between electricity demand and renewables supply will increase both in magnitude and duration. This manifests as less system inertia, more volatility and greater periods per year when low cost renewable electricity is in plentiful supply. Therefore, network operators face increasing grid balancing challenges to achieve the desired transition to high-RES grids and it is likely that balancing services payments will increase for providers operating technologies that deliver the services without causing CO2 emissions. On the other hand, new low carbon technologies on the supply side such as batteries will compete with electrolysers in these markets to replace high carbon generation as the main source of supply. Increased integration of national and international balancing markets has furthermore contributed to either constant or decreasing prices in balancing markets in Germany in spite of renewable growth (Hirth & Ziegenhagen, 2015).

- The role of these services in business models for electrolysers in the long term is thus uncertain. Given further CAPEX reduction of electrolysers and increasing penetration of variable renewables in power grids, provision of flexibility to the power system could become a key value stream for electrolysers. Subsequently they might be run at lower load factors to be able to respond to variable renewable generation and their revenue stack might evolve. Provision of balancing services to the TSO could be a valuable complement to new flexibility services provided by electrolysers in emerging business models.
- **Contributing to renewable requirements could transform the business case of green hydrogen:** The business case of electrolytic hydrogen in refineries could be transformed if it is produced using renewable electricity and counts towards the renewable energy requirements of the refinery as provided by the revised Renewable Energy Directive (RED II). Due to the high cost and limited number of alternative ways for the refinery to achieve the renewable requirements, this contribution of green hydrogen would represent a significant additional value provided by the green hydrogen compared to SMR hydrogen and in turn improve electrolyser business case substantially. This is described in more detail in the following section.
- **H2 mobility could provide a future high value end use:** This sector presents a high value end use when considering current retail fuel costs of drivers in different mobility sectors. However, to supply hydrogen to this end use, the hydrogen needs to be transported to end users and retail infrastructure in form of hydrogen refuelling stations needs to be provided. Both components add significant cost on top of the production cost. Furthermore, the hydrogen mobility sector is currently still nascent, leading to low utilization of retail infrastructure and subsequently high costs per kg hydrogen supplied.

Contributing to the refinery's GHG reduction requirements as well as provision of hydrogen to mobility end uses represent future value streams which are most important to transforming the business case of electrolytic hydrogen, the former in the short term and the latter in the medium term. The policy context of both these future value streams is investigated in more detail in the following.

3.2 Carbon credits for green hydrogen

3.2.1 Policy context

Clean Energy Package and Long Term Strategy

The Clean Energy For All Europeans package is a comprehensive update of the EU's energy policy framework to facilitate the transition away from fossil fuels towards cleaner energy and to deliver on the EU's Paris Agreement commitments for reducing greenhouse gas emissions. It consists of eight legislative acts and has been completed in 2019 following first proposals presented by the European Commission in 2016. Member states have 1-2 years to transpose the new directives of the Clean Energy Package into national law. The Clean Energy Package also provides an important contribution to the EU's long-term strategy of achieving carbon neutrality by 2050, which was published in 2018. The Long-Term Strategy recognizes the importance of coupling the heat, mobility and electricity sectors and the role of hydrogen and the Power to X concept as an important option in these aspirations.

Renewable Energy Directive

The recast Renewable Energy Directive (RED II) is a central part of the Clean Energy Package, setting the renewable energy targets of the EU up to 2030. Originally established in 2009, the directive has been revised and its revised version (RED II) entered into force in December 2018. It sets out binding renewable energy targets for the energy sector as a whole but also specific targets for certain sub sectors, such as transport. It also specifies which fuels and energy sources can be counted towards the renewable target. It is a central driver of wider roll out of electrolytic hydrogen at the EU level. To count towards the renewable energy targets, the hydrogen needs to be produced using renewable electricity. We discuss the directive in more detail below.

CO_2 pricing

While the RED II can improve the business case of electrolytic hydrogen produced from renewable electricity by posing renewable requirements onto countries and fuel suppliers, another way to improve the business case is to establish a carbon price which adds a burden to the economics of fossil fuels compared to low carbon alternatives.

Emissions of the power sector, energy intensive industry and intra European aviation are already covered by the EU Emission Trading System (ETS), which requires businesses of these sectors to purchase allowances for their emissions. The price of such allowances is determined through the Cap and Trade principle of the ETS: the total amount of available allowances is fixed and emitters can trade allowances with each other. The price has recovered to a value of about €25/tCO_2 after staying below €10/tCO_2 in 2012 – 2018[16].

In Germany following a long policy debate the government has published its plans to introduce a carbon price also in the transport and building sectors in 2021. The price will be fixed by the government in the first years, starting at €25/tCO_2 in 2021 and increasing to €55/tCO_2 in 2025. From 2026, a national trading system similar the ETS will be introduced for emissions of the transport and building sectors, and the price will be determined by the market for emission allowances[17]in the range of €55/tCO_2 to €65/tCO_2.

As mentioned before, the current ETS carbon price of €25/tCO_2 is not sufficiently high enough to alter the relative economics of electrolytic hydrogen compared to SMR based hydrogen. A carbon price of €25/tCO_2 increases the production cost of SMR based hydrogen from about €2/kg to about €2.3/kg. This compares to a production cost of about €4.2/kg of electrolytic hydrogen given the cost reductions targeted in this project (cp. section 2.2.1).

The electrolytic hydrogen would therefore have a premium of about €2/kg. If the electrolytic hydrogen was produced from zero carbon electricity, using 1 kg of electrolytic hydrogen would help to avoid 10.8 kg CO_2 (the carbon footprint of 1kg of SMR based hydrogen). This corresponds to a carbon abatement cost of about €200/tCO_2, eight times as high as the current ETS carbon price.

The current carbon price for industry as well as further envisaged implementation of it in the heat and transport sector are therefore not sufficient to make a business case for green hydrogen.

3.2.2 Renewable requirements for the transport sector in RED II

RED II sets an overall target of a 32% share of renewable energy in gross final energy consumption in the EU in 2030 (Article 3.1). It also includes a specific target for the transport sector, requiring member states to set an obligation on fuel suppliers to ensure 14% final energy consumption in the transport sector is supplied by renewable energy sources in 2030 (Article 25.1), compared to 6% in 2020.

One obvious possibility for fuel suppliers to achieve the renewable requirement is to produce biofuels. However, the use of this approach is severely limited by the text of the directive. The share of biofuels in the transport sector produced from food and feed crops is not allowed to increase after 2020 and furthermore limited to 7% of final energy consumption in the road and rail sector (Article 26.1) with the possibility for member states to set lower limits explicitly stated in the directive. Furthermore, certain kinds of biofuels face potentially even higher restrictions. For example biofuels from resources sourced from high carbon content soils or areas of high

[16] https://sandbag.org.uk/carbon-price-viewer/
[17] https://www.bundesregierung.de/breg-de/themen/klimaschutz/co2-bepreisung-1673008

biodiversity, face the risk of indirect land use change and the share of such biofuels is required to decrease gradually to 0% by 2030 (RED II, Article 26.2, compare also Article 29).

Therefore, fuel suppliers will need to determine alternatives to biofuels to achieve the renewable requirement of 14% defined by RED II. The directive points out some of such alternatives explicitly: transport fuels which can contribute to the renewable share include renewable liquid and gaseous transport fuels of non-biological origin – this includes electrolytic hydrogen. More importantly, these fuels also count towards the transport target if they are used as intermediate product to produce conventional fuels, as would be the case with hydrogen used in refineries (Article 25.1).

Given that the RED II target for the transport sector is a mandatory requirement for fuel suppliers and the limited availability or high cost of alternatives, the use of electrolytic hydrogen might become an economic option for refineries (more detail on this is given in section 3.2.7).

The directive requires the commission to assess by 2023, if the target for the transport sector could and should be increased. In Germany, the council of the regional governments (Bundesrat) has prompted the federal government to increase the renewable energy target for the transport sector from 14% to 20% by 2030 in its implementation of RED II[18]. It has been argued that an increase to 20% is needed to establish a demand, an industry for and subsequently reduction of costs of electrolytic hydrogen in Germany[19]. The draft of the German government's national hydrogen strategy plans to implement RED II already in 2020 (the required implementation date is 30.06.2021[20]) and increase the renewable target for the transport sector to 20%[21].

3.2.3 Requirements for green hydrogen in RED II

There is currently no commonly agreed definition and classification of hydrogen at EU level. RED II contains certain requirements for electrolytic hydrogen in order to count as renewable fuel (Article 27) but leaves several questions open. The provisions in the directive for accounting renewable electricity used by electrolysers with a direct connection to a renewable asset are straightforward. However, the provisions for electricity from the grid used by grid connected electrolysers leave more room for interpretation. The directive in fact requires the Commission to adopt a delegated act by end of 2021 detailing the requirements under which grid electricity consumed grid connected electrolysers can count as 100% renewable.

In more detail, the requirements as specified in RED II for electrolytic hydrogen to count as renewable fuel include the following:

1. **GHG reduction requirement:** First, a minimum of a 70% GHG reduction compared to fossil fuels is required for renewable liquid or gaseous transport fuels of non-biological origin in order to count towards the renewable target (Article 25.2).

2. **Direct connection to renewable asset:** If an electrolyser is <u>directly connected to a renewable asset</u> (e.g. a wind farm), the electricity consumed may count as 100% renewable, provided that two further criteria are met (Article 27.3, subparagraph 5):

    a) The renewable asset comes into operation after or at the same time as the electrolyser.

    b) The renewable asset is not connected to the grid or if it is connected to the grid, it can be proven that the electrolyser still did not consume any electricity from the grid.

[18] https://www.cleanthinking.de/red-ii-bundesrat-joerg-steinbach-brandenburg/
[19] https://www.topagrar.com/energie/news/steinach-wir-brauchen-20-prozent-erneuerbare-energien-im-kraftstoff-11818727.html
[20] http://resource-platform.eu/news/final-deal-on-the-renewable-energy-directive-new-momentum-for-corporate-renewable-energy-sourcing-in-europe/
[21] https://www.euractiv.de/section/energie-und-umwelt/news/deutschlands-erste-wasserstoffstrategie-steht/

3. **Grid connected electrolyser:**

    a) If an electrolyser is consuming electricity from the grid **without further arrangements to procure renewable electricity**, Article 27.3, subparagraph 4, specifies that the renewable penetration in electricity in the respective country should be used to calculate the share of renewable energy: "*…where electricity is used for the production of renewable liquid and gaseous transport fuels of non-biological origin, either directly or for the production of intermediate products, the average share of electricity from renewable sources in the country of production, as measured two years before the year in question, shall be used to determine the share of renewable energy."*

    b) **Arrangements to procure renewable electricity:** Article 27.3 furthermore specifies that under certain conditions, electricity consumed by grid connected electrolysers can be counted as fully renewable (subparagraph 6): "*Electricity that has been taken from the grid may be counted as fully renewable provided that it is produced exclusively from renewable sources and the renewable properties and other appropriate criteria have been demonstrated, ensuring that the renewable properties of that electricity are claimed only once and only in one end-use sector."*

        - The article specifies that the EU Commission shall lay out the exact conditions which have to be met, such that electricity from the grid can count as 100% renewable, in a delegated act by the end of 2021 the latest.

        - Paragraph 90 of the general provisions lays out potential criteria which could be included in this delegated act:

            - The electrolyser could consume electricity via a bilateral power purchase agreement with a renewable electricity generation asset. In this case, a "temporal and spatial correlation" between the electricity generation of the renewable asset and the hydrogen production should be ensured. For example, the hydrogen could not count as 100% renewable if produced when the contracted renewable generation unit is not generating electricity. Furthermore, the renewable asset and the electrolyser should be situated on the same side of a grid congestion in order for the hydrogen to count as 100% renewable.

            - There is an element of "*additionality, meaning that the fuel producer is adding to the renewable deployment or to the financing of renewable energy*".

It is not clarified in the directive how hydrogen would count differently towards fuel suppliers' 14% renewable requirement, depending on whether the average renewable share in power grids or 100% renewable electricity is assumed. An obvious approach would be the following: suppose 1 kWh of electrolytic hydrogen, produced using grid electricity without any further arrangements, is used by a fuel supplier and the renewable share in the respective country is x% (two years prior to the years in question). Then x% of 1 kWh counts towards the renewable requirement.

3.2.4 Implications of definitions of green hydrogen

As the text of the directive leaves significant room for interpretation, it will to a large extent depend on the methodology for grid connected electrolysers developed by the Commission as well as on each country's implementation of the directive, to what extent and under which conditions hydrogen produced by grid connected electrolysers, can count towards the RED II targets for transport fuels. Subsequently engaged policy debates are ongoing on the national and EU level currently.

It has been suggested that the specifications of paragraph 90 mentioned above are too restrictive at the current level of renewable penetration and grid reinforcement in Germany and should therefore be relaxed to allow an earlier scale up of the electrolyser industry in Germany (BDI, 2019). On the other hand it is emphasized that a clear, simple and transparent classification of electrolytic hydrogen is needed with hydrogen produced from 100% renewable electricity as the baseline, to establish a labelling system trusted by consumers (Wind Europe, 2019). We discuss challenges to comply with the criteria as set out in paragraph 90 in the case of refineries below.

Spatial correlation: Clearly for the installation of electrolysers in refineries or for other energy intensive consumers, the requirement of location on the same side of a grid congestion as the renewable generation asset is likely to be a significant burden. In many there might not be e.g. a wind farm on the same side of a grid congestion as the site. Furthermore, it might even be challenging to build one in such a location due to lack of space. Also the wind resource close to the refinery might be suboptimal.

Temporal correlation: If the electrolyser was required to follow the generation of a renewable asset close to its location, it would run at a lower load factor than what would be economically optimal today using grid electricity. For example the average onshore wind capacity factor in Germany is below 20%.[22] Running the electrolyser at such a low load factor would increase the fixed cost per kg of hydrogen and subsequently the carbon abatement cost significantly (cp. Figure 5, right). However as power prices become more variable, as negative price hours increase, then optimal load factors can be expected to decrease in future, down towards the country-averaged capacity factor for renewables.

Additionality: Requiring refineries to prove that they contribute to additional renewable power generation capacity would increase the administrative burden for fuel producers. Consequently the cost of electrolytic hydrogen to refineries and its associated carbon abatement cost would be further increased. Furthermore, even if a fuel supplier built a wind farm, only a share of the wind farm's output would count towards the suppliers' renewables requirements, if there was no direct connection from the wind farm to the electrolyser. For in this case, if the electrolyser did not comply with the highly restrictive requirement of temporal and spatial correlation, only a share of the hydrogen produced corresponding to the renewable share in the country two years prior to the year in question would count as renewable. As an example the renewable share in power generation was 46% in 2019 in Germany[23].

In summary the requirements as suggested in paragraph 90 on grid connected electrolysers are likely to place a high burden on fuel producers, who then may look for alternatives to achieve the RED II renewable requirements (such as providing electricity to electric vehicles[24]). The requirements may not be effective in supporting an accelerated and early scale up of electrolysers in refineries and thus not deliver the anticipated cost reduction and subsequent further roll out of the technology. Should early deployment at scale of green H2 in refineries be an objective of RED II, the requirements on hydrogen to count as green/renewable, should be practical and achievable to support this initial deployment.

[22] https://windeurope.org/wp-content/uploads/files/about-wind/statistics/WindEurope-Annual-Statistics-2018.pdf

[23] https://www.ise.fraunhofer.de/de/presse-und-medien/news/2019/oeffentliche-nettostromerzeugung-in-deutschland-2019.html

[24] Several fuel suppliers have already started to enter the market of electric vehicle charging, among them Shell, BP and Total. RED II also includes an additionality requirement for electricity provided to EVs in order to count as renewable fuel. The additionality requirements still have to be determined by the EU Commission. However renewable electricity provided to EVs is treated preferentially in the text. It counts with four times its energy content towards the RED II requirements (Art. 27.2) and therefore it could be preferred by fuel suppliers.

3.2.5 Certification of green hydrogen

Once the definitions of green/renewable hydrogen is clarified, certification systems will be needed to enable appropriate enforcement and transparent and consistent application of the definition across the EU. RED II suggests an expansion of the system of guarantees of origin (GOs) applied to renewable electricity to other energy vectors, in particular hydrogen (Article 19.7). It is suggested that the requirements for such GOs for renewable gases have to be made more stringent than the existing ones for renewable electricity (BDI, 2019).

The establishment of a standard and certification scheme for green hydrogen is the aim of the Certifhy project (CertifHy, 2019). The development of such certification systems should be completely aligned with the EU Commission's methodology for grid connected electrolysers. For example, the Certifhy standard for green hydrogen so far required a 60% reduction of carbon intensity compared to hydrogen produced by SMR[25]. Due to the requirement of a 70% reduction of carbon intensity in RED II, the Certifhy standard might have to be updated to avoid incompatibility with RED II.

Standards and certification systems for green hydrogen should be aligned or a single European standard and certification system should be established to enable economies of scale in the European wide deployment of green hydrogen technologies. Furthermore these standards and certification systems should be implemented soon, ideally already in 2020 and in any case well before the end of 2021, the envisaged latest date in RED II, such that investment and planning decisions can be made.

3.2.6 Requirements on carbon intensity of electricity

As explained in the previous section, for electrolytic hydrogen to count towards the renewable obligation of the transport sector provided by RED II, a 70% GHG reduction of the electrolytic hydrogen compared to the alternative, SMR produced hydrogen, would need to be proved. In order to do this, the electrolyser will need to link the electricity used for hydrogen production to low carbon electricity sources in some way. To illustrate the scale of the challenge to achieve this 70% GHG reduction, we calculate the carbon intensity of electricity required for this reduction.

The CertifHy standard assumes a carbon intensity of 10.8 $kgCO_2/kgH_2$ for SMR based hydrogen (cp. section 2.3.2). The electricity carbon intensity required to achieve the same carbon intensity or a 70% reduction compared to this, can be derived from the assumed electrolyser efficiency of 54kWh/kg. The corresponding carbon intensities of electricity required are listed below.

Table 3: Electricity carbon intensities required for carbon reductions compared to SMR derived H_2

Carbon reduction compared to SMR derived H2	Required electricity carbon intensity (gCO_2/kWh)
0%	191
70%	57

The average grid carbon intensity in the three EU member states UK, France and Germany differs significantly and therefore the challenge to achieve carbon reductions compared to SMR produced hydrogen will vary between these countries. The table below lists the average carbon intensity of the electricity grid in the UK, France and Germany. As mentioned in section 2.3.2, flexible electrolyser operation can reduce the carbon intensity of the electricity consumed by the electrolyser considerably below the annual average grid carbon intensity. Furthermore the average grid carbon intensity in most EU countries will decrease significantly up to 2030 due to renewable and climate targets. For example, the UK government has been advised to target an electricity carbon intensity of 50g/kWh in 2030 by its own advisers[26]. Still it becomes clear that in the medium

[25] https://www.fch.europa.eu/news/certifhy-project-establishing-first-eu-wide-guarantee-origin-green-hydrogen
[26] https://renews.biz/54203/uk-urged-to-reduce-power-carbon-intensity/

term using simply electricity from the grid will not suffice to achieve the 70% GHG reduction required by RED II. Instead alternative arrangements will have to be made to reduce the carbon intensity of the electricity consumed by the electrolyser below the average grid carbon intensity.

Table 4: Average electricity grid carbon intensities in major European economies

Country	Average electricity carbon intensity (gCO_{2e}/kWh)	Source
UK	216	(Drax, 2020)
France	66	(Moro & Lonzo, 2018)
Germany	486	(Umweltbundesamt, 2019)

Some arrangements aiming to reduce the carbon intensity of the electricity consumed by the electrolyser are discussed below:

1. **Direct connection to a renewable asset:** as described in section 3.2.3, the provisions of RED II are straightforward in this case. The produced hydrogen will count as 100% renewable, provided the two conditions of Art. 27.3, subparagraph 5, are met. While this provides high legal certainty, it might not be feasible for refineries due to lack of space to build renewable assets such as a wind farm next to their site, poor renewable resource close to their site or simply due to lack of expertise and resources to build renewable electricity generation plants.

2. **Power purchase agreements**: a renewable power purchase agreement (PPA) is a long term contract between a renewable generation asset and a power buyer, in which the buyer agrees to buy power from the renewable generation asset for an agreed price during an agreed period (usually for 10 years or more). The most important distinction of PPAs is between two types: Sleeved (also Physical or Direct) PPAs and Virtual (also Synthetic) PPAs.

    a. **Sleeved PPAs**: In a Sleeved PPA the transfer of money and power between the renewable asset and the buyer is managed through a utility as an intermediary, "sleeving" the electricity (Urban Grid, 2019 b). The contract is on physical power delivered to the buyer. The utility takes on the risk that the renewable asset cannot deliver the electricity as required by the buyer, in which case the utility would be required to supply the electricity using other sources. While the utility will require a fee for taking on this risk, this option has the advantage that additionality is relatively straightforward to prove due to the physical delivery of energy from the renewable asset to the buyer. Depending on the exact additionality requirement in the regulatory framework, this characteristic of the sleeved PPA might be of significant value to the buyer.

    b. **Virtual PPA**: A Virtual PPA is not a contract on physically delivered power but a financial hedging instrument against volatile electricity prices (Urban Grid, 2019 a). In a Virtual PPA, the buyer agrees notionally to buy power from the renewable asset for a fixed price. If the market price is above the fixed price, the buyer receives the difference. If the market price is below the agreed price, the buyer pays the difference. It is the same principle as the contract for difference, the main renewable subsidy instrument in European countries. There is no physical delivery of power to the buyer, instead the buyer has a separate contract on physical delivery of electricity with a power utility. Still, a virtual PPA can have a significant impact on the feasibility of a renewable asset increasing its bankability by providing long term revenue certainty. In this way, virtual PPAs might comply with additionality requirements, however this might be less straightforward to prove than in the case of sleeved PPAs.

In both versions of the PPA, the buyer would receive the renewable asset's renewable generation certificates for the volume of contracted electricity. Power purchase agreements have evolved since their introduction and various contract structures have been developed to address particular regulatory, technical or corporate requirements (WBSD, 2018). A PPA with an electricity consuming business as the buyer is called a corporate PPA, in contrast to a PPA with a utility as the offtaker (Norton Rose Fulbright, 2017). In Germany PPAs have not been as prominent as in other markets, but have started to emerge as either as a potential complement (Huebler & Arndt, 2019) or alternative (Amelang, 2019) to renewable subsidies.

3. **Following the grid carbon intensity:** Another possibility to reduce the carbon intensity of electrolytic hydrogen is to operate the electrolyser flexibly and to follow the grid carbon intensity. This would mean reducing the consumption in hours of high grid carbon intensity and increasing it in hours of low carbon intensity. Section 2.3.2 investigated this approach based on the current national average carbon intensity in Germany. The potential to achieve a carbon intensity of electrolytic hydrogen lower than the one of SMR based hydrogen in this way is currently severely limited. The nr of hours per year in which the grid carbon intensity is sufficiently low is currently very low in the German grid. Subsequently the electrolyser would need to be run at a very low load factor, which would increase the fixed cost per kg of H_2 significantly. However due to the increasing VRE penetration and lower electrolyser CAPEX in the future, this approach could become more relevant. Furthermore the share of VRE in electricity varies significantly between regions. In states in the North of Germany it is as high as 173%, as most electricity is exported to the centers of demand in the South (AEE, 2019). In Britain, the Transmission System Operator has launched a website which predicts the national generation mix and carbon intensity of electricity 96 hours ahead of real time. The website also predicts the carbon intensity at the regional level over the next 24 hours (National Grid ESO, 2020).

4. **Trading renewable energy certificates:** Renewable Energy Certificates (RECs, or also Renewable Energy Guarantees of Origin) have been introduced to enable suppliers to prove to their customers the share of renewable energy sources in their power mix. RECs are provided by the regulator to renewable electricity generators per unit of electricity they produce. They are in turn sold on by generators to electricity suppliers which use them to offer green tariffs to their customers. Each REC can be claimed by a supplier only once.

   The refinery could opt for purchasing RECs for the electricity consumed by the electrolyser. However the systems of RECs (expanded in RED II Art. 19) has been criticised because power and RECs have been uncoupled to some extent. If the demand of RECs (due to green tariffs) is lower than the amount of renewable electricity generated, this creates a surplus of RECs. Surplus RECs can be purchased by suppliers at low cost in order to offer green tariffs. However the choice of a consumer to opt for a green tariff then has no impact on the electricity mix. The current cost of RECs in Britain is negligible compared to the cost of electricity[27]. The British regulator has declared its aim to improve transparency of the environmental impact of green tariffs and to address growing concerns on green washing (Lempriere, 2020). Such concerns are also addressed in several provisions of the RED II, which are supposed to ensure "additionality" of renewable electricity consumption in the transport sector. Besides the potential requirement of additionality in the case of electrolytic hydrogen, the directive also aims to

[27] RECs are not the same as Renewable Obligation Certificates (ROCs): ROCs are certificates received by renewable generators in the previous subsidy scheme in the UK, the Renewable Obligation (RO). ROCs are the main source of revenue for renewable generators in this subsidy scheme which has been replaced by Contracts for Difference in the UK. RECs on the other hand are an insignificant source of revenue for renewable generators. Their main aim is to improve the transparency of green tariffs. In 2017, the price of RECs was about 15p/MWh in 2017 in the UK (Good Energy, 2017) and 20ct/MWh in Germany (Tix, 2018). The price of ROCs in 2017 was about £46/MWh (Ofgem, 2020).

ensure that additional electricity demand from electric vehicles is met by additional renewable capacity (Art. 27.3, subparagraph 3).

3.2.7 Competitiveness of green hydrogen as option to comply with RED II

In section 3.2.1, a carbon abatement cost of €200/tCO_2 was calculated for electrolytic hydrogen when assuming zero carbon electricity. This is eight times as high as the current carbon price in the ETS of around €25/tCO_2. It is close to UK government projection for the carbon price in 2050 (£231/tCO_2) but still more than twice as high as the UK government's projection for the carbon price in 2030 (£81/tCO_2). Clearly the carbon price alone will not be sufficient as an incentive to install electrolysers at refineries.

However given the mandatory renewable requirement in RED II, electrolytic hydrogen in refineries won't be compared to use of unabated SMR. Instead its competitiveness will be assessed against alternative use of renewable energy sources in refineries accepted under RED II – or the cost of non compliance with RED II. The abatement cost of about €200/tCO_2 is low compared to the range of €600-1,600/tCO_2 estimated for synthetic fuel options in the transport sector in Germany.[28] Furthermore, as mentioned before, alternatives to green hydrogen in refineries based on bioenergy have limitations: the resources for biofuels is limited and contribution of certain kinds of biofuels is explicitly limited in the RED II due to problems with e.g. indirect land use change. Given appropriate incentives and consequences in the case of non-compliance, using green hydrogen could become a cost-effective option. In Germany, current legislation implementing the Fuel Quality Directive, which will now be superseded by the RED II, imposed penalties of €470/tCO_2[29] to fuel suppliers failing to comply with its emission reduction requirement. Such a penalty would clearly ensure that the installation of electrolysers in refineries is more economic than non-compliance with the directive.

3.2.8 Policy recommendations

- Member states need to set out clear definitions of green hydrogen and clear rules how green hydrogen can count towards renewable requirements of the Renewable Energy Directive II.
- These rules should clarify in particular when and to what extent the electricity consumed by grid connected electrolysers can count as renewable.
- Requirements on grid connected electrolysers should not be too restrictive. Too stringent requirements regarding spatial and temporal correlation of fuel production and renewable generation are likely to rule out electrolysers as a viable option for refineries. In order to enable an early scale up of electrolysers in refineries and a subsequent cost reduction, requirements should be practical and flexible.
- The EU Commission should provide guidance on such rules as early as possible. Such rules should be aligned as much as possible across MS as well as international certification bodies (such as CertifHy). This provides certainty and improves scalability of technology.
- Furthermore, such rules should then be implemented by some MS early such that investments can be planned accordingly.
- Where other options to comply with RED II have been exhausted, an economic framework needs to be put in place which ensures green hydrogen is more cost effective than non-compliance with the directive. Implementations of the Fuel Quality Directive could be a template for this.
- Modelling confirms the importance to maintain the current exemption levels from grid fees and levies or potentially even completely exempt renewable electricity used to produce hydrogen from fees and

[28] Renewables in Transport 2050 Empowering a sustainable mobility future with zero emission fuels from renewable electricity - LBST 2016 : http://www.lbst.de/news/2016_docs/FVV_H1086_Renewables-in-Transport-2050-Kraftstoffstudie_II.pdf

[29] Bundesimmissionsschutzgesetz (BImSchG), § 37c Abs. 2; https://www.gesetze-im-internet.de/bimschg/BJNR007210974.html

levies for a limited time (e.g. 5-8 years) to foster the market uptake of green hydrogen in applications such as refineries or also the chemical industry.

3.3 Advancing hydrogen end use in mobility and other end uses

3.3.1 Mobility as high value end use for hydrogen

Mobility is potentially a high value end use of hydrogen. Fuel price parity price with taxed Diesel could be achieved at a hydrogen retail price of €5-8/kg. Here, the lower number refers to buses, e.g. (Cadent, 2019) propose a parity price of £4.6/kg for buses. The higher number refers to cars, e.g. (Hydrogen London, 2016) propose a parity price of £7.5/kg for cars. If we assume €4/kg[30] for the cost of the hydrogen refuelling station (HRS) and distribution, this leaves about €1-4/kg for hydrogen production.

Note that €4/kg is calculated based on an assumed very high utilisation of the distribution and retail/refuelling infrastructure. A hydrogen for transport is in a very early stage of development, it is more likely that load factors on infrastructure will for some time be quite low. Therefore, this figure should be treated as optimistic as in reality the true cost of such infrastructure is likely to be higher (per kg sold)

As shown in section 2.2.1, under the used electrolyser cost assumptions and given sufficient demand for hydrogen for mobility (translating into a high utilisation factor of the electrolyser), production of electrolytic hydrogen using electricity for large energy intensive industries with reduced levies as in the refinery could break even at a "refinery gate" hydrogen selling prices of about €4/kg. Given further electrolyser cost reductions and uptake of hydrogen mobility, sale of hydrogen to the mobility sector could therefore become an attractive business stream to refineries, albeit one very exposed to the cost of distribution and retail infrastructure.

The electrolyser at the refinery in the REFHYNE project will be a PEM electrolyser. PEM electrolysers produce hydrogen which is of very high purity, suitable for mobility applications (fuel cell quality 5.0). The hydrogen could therefore be provided to hydrogen refuelling stations for buses or passenger cars without any further requirement for purification, unlike hydrogen produced via SMR, whose purification can add significant costs.

In summary, a major obstacle for business cases in the hydrogen mobility sector is the currently small size of the hydrogen mobility sector and low utilisation rate of HRS and distribution infrastructure, increasing the cost per kg significantly. Fuel price parity with untaxed Diesel is much more challenging as taxes comprise more than 50% of the Diesel retail price in many EU MS (Bundesfinanzministerium, 2019).

3.3.2 Buses and trains as early opportunities for hydrogen mobility

Although there are currently far less hydrogen vehicles than electric vehicles, hydrogen is still expected to play an important role in the future of mobility, in particular in segments in which other solutions (such biofuels or battery electric vehicles) are not practical either due to technical reasons or high costs (Committee On Climate Change, 2019). In particular the long range of hydrogen fuel cell electric vehicles as well as the short fueling time can make them an attractive low carbon alternative for heavy duty vehicles and bus fleets (Bundesregierung, 2019).

Low utilization of hydrogen transport and retail infrastructure currently increases the cost of hydrogen in the mobility sector significantly. On the other hand the low penetration of hydrogen infrastructure across nationally and internationally constitutes a major determent for further uptake of hydrogen mobility. In Germany there

[30] A typical value in recent studies by Element Energy; the cost is however highly sensitive to the HRS utilization, the distance of the electrolyser to the HRS as well as the size of the HRS and the tube trailer used to transport the hydrogen

are currently more than 80 hydrogen refueling stations (HRSs) in operation with an aim to increase this to 100 HRSs (BDI, 2019).

Bus fleets and trains have become a focus for demonstration projects for hydrogen vehicles and infrastructure as these captured fleets provide a more reliable demand for H2 (Ricardo, 2019). These transport sectors offer a reliable and very regular demand from the beginning of deployment, allowing to roll out infrastructure and vehicles at the same time. If for example a bus fleet is converted to hydrogen, a dedicated HRS for this bus fleet can be built. This HRS will have a guaranteed offtake of the hydrogen it supplies and is guaranteed to have a high utilization rate. Consequently the fixed costs can be spread over a larger amount of hydrogen and the unit costs of hydrogen are reduced. Furthermore the guaranteed offtake of the hydrogen will increase the bankability of the project and reduce the cost of finance.

There are currently 83 hydrogen buses in operation in Europe (Stafell, et al., 2019). The H2 Bus consortium plans to deploy 600 buses in Latvia, Denmark and the UK in by 2023 in the first phase of the project and 1,000 busses over the full project length (H2 Bus, 2019). In the second phase further countries might join, currently Norway, Sweden and Germany are under consideration. The FCHJU's roadmap for hydrogen envisages 250,000 buses and 5,000 hydrogen trains in operation in Europe in 2050. While hydrogen fueled vehicles are expected to make up only 15% of the 2050 small cars fleet, they could reach adoption rates of 30% for large cars and vans (FCHJU, 2019). Analysis commissioned by the UK government concluded that a focus on hydrogen vehicles in the HGV sector would lead to the lowest infrastructure costs up to 2060 compared to other low carbon solutions (Ricardo, 2019).

Hydrogen vehicles and their infrastructure are currently significantly more expensive than their fossil fuel and in some cases their battery electric alternatives. Innovation will be essential to lower costs and improve performance. Support for R&D will therefore be a further critical pillar for enabling the wider roll out of hydrogen mobility. The German government has recently announced to support hydrogen R&D with funds of €100m per year to test hydrogen technologies in real world applications and at industrial scale (BMWi, 2019 b).

Apart from innovation, economies of scale will be crucial to reduce costs. To achieve a larger uptake of hydrogen mobility, the risk premium of hydrogen infrastructure deployment will need to decrease significantly. Focusing on sectors providing reliable and regular demand such as buses and trains helps to reduce this risk to some extent. Governments should furthermore help to reduce the cost of financing e.g. through targeted and time-limited loans to help the private sector to invest, learn and share risks and rewards (IEA, 2019).

To support uptake of hydrogen mobility, the government should focus support on applications which allow the simultaneous roll out of vehicles and dedicated infrastructure such as buses and trains. Such applications could be supported through public procurement of hydrogen buses or trains if public transport is owned and operated by public entities, as envisioned in the draft German hydrogen strategy (DIHK, 2020). If public transport is owned by private businesses, the government should enable low cost finance through loan, loan guarantees or tax credits. Hydrogen should furthermore be kept exempt from excise duty as is currently the case in the UK[31] and Germany[32]. Furthermore, a low VAT rate should be applied to the sale of hydrogen fuel and vehicles. Such fiscal incentives have been very successful in other areas, e.g. in promoting roll out of EVs in Norway[33], and will help to foster the uptake of hydrogen technologies in mobility markets.

3.3.3 Carbon emissions of ICE vs FCEV depending on grid carbon intensity

We would like to assess the implications of the 70% GHG reduction threshold of RED II for use of hydrogen directly in the transport sector as a fuel in fuel cell electric vehicle (FCEV). In this case, the emissions due to the

[31] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/709655/ultra-low-emission-vehicles-tax-benefits.pdf
[32] https://www.dena.de/fileadmin/dena/Publikationen/PDFs/2019/181123_dena_PtX-Factsheets.pdf
[33] http://www.oecd.org/futures/the%20way%20ahead%20for%20hydrogen%20in%20transport%20in%20norway.pdf

production of the hydrogen can be compared with the emissions of fossil fueled ICEV. Assuming a 5l Diesel consumption per 100km of a Diesel passenger car and a carbon intensity of Diesel of 2.652kgCO_{2e}/l, leads to emissions of 13.3kgCO_{2e}/100km. Assuming a hydrogen consumption of 0.8kg/100km[34] and an electrolysis efficiency of 54kWh/kg leads to the electricity carbon intensities as noted in the table below to achieve given emission reduction targets.

Table 5: Electricity carbon intensities required for emission reductions compared to Diesel

Carbon reduction compared to Diesel	Required electricity carbon intensity (gCO2e/kWh)
0%	307
70%	92

The required carbon intensity of electricity is not as low as when replacing SMR based hydrogen but still significantly lower than the average grid carbon intensity in Germany and the UK at the moment (see section 3.2.6). Therefore as in the case for replacing SMR based hydrogen, rather than using simply electricity from the grid, alternative arrangements would need to be made to comply with the GHG reduction threshold, such as power purchase agreements with renewable generators and alternatives as discussed in section 3.2.6. In France however the current grid carbon intensity is sufficiently low, such that hydrogen produced by grid connected electrolysers would comply with the GHG reduction requirement of RED II.

3.3.4 Blue versus green hydrogen

Hydrogen produced via SMR is usually referred to as grey hydrogen. If CCS is added to the SMR process, the hydrogen is referred to as blue hydrogen.[35] It should be noted that the carbon intensity of grey hydrogen is lower than that of Diesel. Assuming a carbon intensity of 10.8 kgCO_2/kgH_2 of grey hydrogen as in the CertifHy standard, and a hydrogen consumption of 0.8 kgH_2/100km for a passenger car leads to emissions of 8.6 kgCO_2/100km, a reduction of 35% compared to a Diesel car. If equipped with CCS and fuelled by a mix of biomethane and natural gas, SMR based hydrogen could even be carbon neutral (Element Energy, 2019). In Germany, the question whether blue hydrogen should be supported in addition to electrolytic hydrogen, has caused a controversy between different government departments (Stratmann, 2020).

It is argued that classifying blue hydrogen as carbon neutral and supporting it could impede the roll out of hydrogen as it would link hydrogen to CCS, a technology with low public acceptance in Germany. Supporting different ways to produce hydrogen could also reduce the scaling up of electrolysis technology and therefore lead to lower cost reductions of electrolysers.

On the other hand it is suggested that SMR based hydrogen provides a cheaper alternative to electrolytic hydrogen, can be scaled up more quickly in the medium term, and could thus be an important bridging technology. Furthermore, to supply enormous demand of hydrogen in industry, transport and power, all forms to produce it in a carbon neutral way should be supported. Allowing only one production technology for hydrogen could increase the risk of not being able to supply this future demand. Forcing applications in transport and industry to use only electrolytic hydrogen would make the fuel use more expensive and might prevent uptake of demand in these nascent markets.

Blue hydrogen is currently not supported via the RED II. However it is expected to be included in the upcoming hydrogen strategy of the federal government in Germany. Instead of committing to a particular technology, the strategy will only refer to generally carbon neutral hydrogen (Gröh, 2020). The techno-economic potential of

[34] Consumption of the Toyota Mirai, cp.: https://media.toyota.co.uk/wp-content/files_mf/1444919532151015MToyotaMiraiTechSpecFinal.pdf
[35] https://www.bmbf.de/de/eine-kleine-wasserstoff-farbenlehre-10879.html

producing hydrogen by pyrolysis of methane (referred to as turquoise hydrogen) is currently investigated in industry and academia as an alternative to SMR based and electrolytic hydrogen.

3.3.5 Policy recommendations

- To advance hydrogen mobility initiatives policy support should focus on hydrogen deployment in projects with constant and reliable demand such as busses or commercial fleets. These sectors allow the simultaneous roll out of vehicles and dedicated infrastructure avoiding the risk of low infrastructure utilisation.
- Policy should support the uptake of hydrogen in these sectors via public procurement or by enabling of low-cost finance.
- Furthermore policy should be keep hydrogen exempt from fuel duty and apply a low VAT rate to the sale of hydrogen fuel as well as vehicles it as a support mechanism to allow the technology to grow and thereby reduce costs.

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5 Appendix

5.1 Model description

The HYOPT model – representing electrolyser investment and dispatch

For the economic analysis, the mathematical model HYOPT, developed by SINTEF, is used. HYOPT is a decision support tool which can be used in acquisitions of hydrogen producing electrolysers and other infrastructure required. HYOPT can be used to conduct a wide-ranging techno-economic analysis of such investments, including sensitivity studies, which in turn will help the users thoroughly examine the business opportunities of installing an electrolyser for the production of hydrogen. HYOPT allows the user to include the whole value chain from production, varying electricity cost to one or several markets for the hydrogen, thus enabling the user to assess the overall profitability of the investment. All cashflows in the model are discounted at a user-defined rate, and the model will return the net present value of the investment. The model can be used to maximize this net present value by varying installation sizing as well as operation within user defined constraints. The model constraints can either be determined by reasonable equipment size or be project specific requirements.

It is possible to investigate several aspects of the investment problem, ranging from determining the optimal electrolyser size, to calculating the net present value of the investment project. Due to the underlying uncertainty of several of the input parameters, there is a need to investigate how the model outcome changes under different input parameter alterations. The model allows the user to conduct such sensitivity analyses which can provide valuable decision support information.

Model adaption for the REFHYNE project

The HYOPT model has been used to analyse the case presented in this report. The system that is modelled can be seen in Figure 17. The refinery buys electricity from the power market, but also receives power from its onsite power generation unit. The electrolyser will buy the necessary electricity from the grid and will also buy water from the market.

The model represents all necessary equipment required for the project. Each equipment component is sized appropriately and the model accounts for the component's CAPEX as well as OPEX, using cost data representative of current technology developments. The product flows of hydrogen, water, heat, oxygen and electricity are also considered, and these are restricted to the capacity of the infrastructure equipment installed. Furthermore, the model utilizes refinery load profiles and an onsite generator profile. The hydrogen produced through the electrolyser will be valued at the alternative cost of production, i.e. through steam methane reforming (SMR), for which the current production cost is around 2 EUR/kg. All the relevant model parameters are listed in Figure 17, together with the corresponding references for these values.

The mathematical model also includes the possibility to participate in the market of both Primary and Secondary Control Reserve (PCR and SCR). PCR is a symmetric service whereas SCR is differentiated into positive and negative SCR. The model is based on perfect foresight and therefore the calculated revenues rather present an upper bound to revenues, as in real life auction prices won't be known in advance and therefore suboptimal decisions might be taken. However as the revenues from providing PCR or SCR are relatively small compared to the main drivers of the project outcome, the potential over estimation of these revenues are considered to be of low importance to the overall profitability of the investment project.

The model represents the operation of the electrolyser in 15 minutes – resolution over the period of half a year. This operational profile is then repeated in the model over the whole lifetime of the project, i.e. for a lifetime of 15 years, the operational profile is applied 30 times.

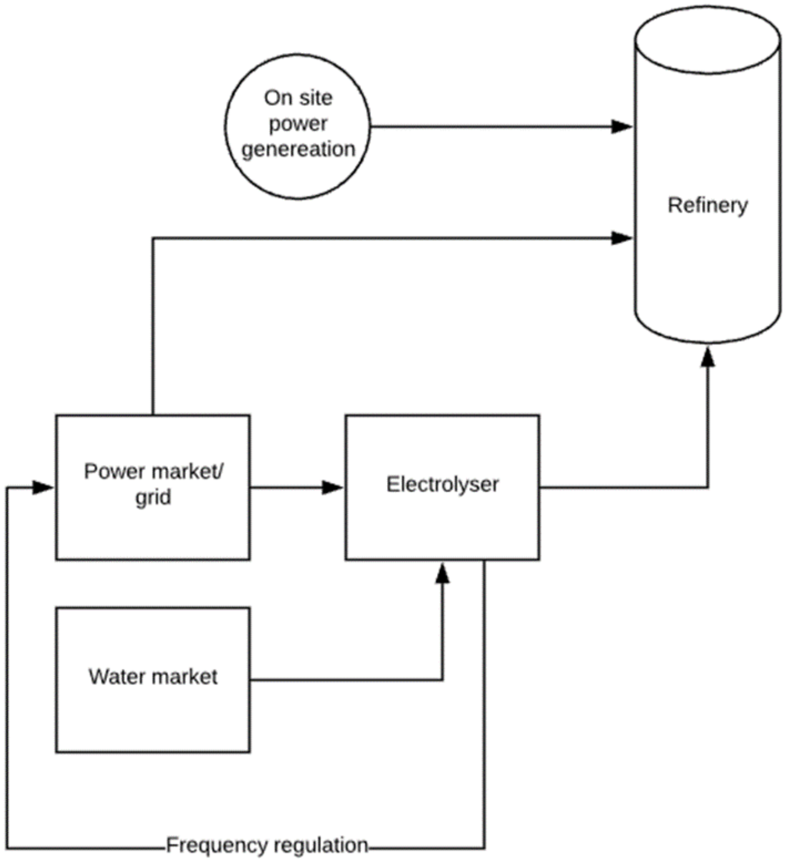

Figure 17: Flow chart of the REFHYNE energy system

5.2 Observations on balancing revenues

SCR is more lucrative than PCR. The electrolyser operational model is able to choose to provide either Primary Control Reserve (PCR) or Secondary Control Reserve (SCR) depending on which of both is more profitable. In all conducted runs, the model chose to provide exclusively SCR and never PCR. This is mainly due to a decrease in the prices of PCR in the German market.

Batteries have started in 2014 to enter the German PCR market and since then the number of battery projects participating in the PCR market has steadily increased. In 2018, more than 230 MW of battery capacity had been prequalified for providing PCR, which is significant given the market size of about 600MW. This unprecedented growth has had an impact on the prices, which have been reduced by 40% in 2018 compared to 2014[36]. As shown in Figure 11, the prices of PCR have been significantly reduced further in 2019 to about €9/MW/h.

As PCR is a symmetric service, this price is for provision of 1MW upward as well as 1MW downward reserve. Therefore, the electrolyser can never offer more than 5MW of PCR. On the other hand, the electrolyser can offer up to 10MW SCR and it can do so when operating at 10MW (offering positive SCR (pSCR)) as well as when operating at 0MW (offering negative SCR (nSCR)).

Up to July 2019, PCR was procured in weekly auctions and a fixed amount of capacity had to be offered for a whole week. In July the procurement switched to daily auctions and capacity has to be offered for 24 hours[37]. On the other hand, SCR is procured in daily auctions in Germany for six four-hour blocks for which providers can offer availability. Providers are paid an availability price (in €/MW/h) as well as a utilisation price (in €/MWh).

[36] https://www.energate-messenger.de/news/185014/schaefer-netzstabilisierung-fuer-batteriespeicher-kein-nachhaltiges-geschaeftsmodell-

[37] https://www.energy-storage.news/blogs/europes-changing-frequency-control-reserve-auctions-and-their-impact-on-the

The daily average availability prices as well as utilisation prices are shown in Figure 12. The annual average utilisation rate for pSCR is 8%, the utilisation rate of nSCR is 4.2%[38]. One can combine the availability price with the utilisation price multiplied with the average utilisation rate to get an effective availability price, which gives an indication of the expected total payments per offered MW/h of availability. This effective availability price is shown in Figure 13.

The effective availability price of pSCR averages at €10/MW/h whereas the effective availability price of nSCR averages at around €4/MW/h. This can be compared to the average PCR price of €13/MW/h in the observed period. The fact that the electrolyser can offer up to two times as much SCR volume as PCR volume as well as the shorter SCR availability windows (4h for SCR compared to 24h and previously one week for PCR) giving the electrolyser more flexibility to react to the wholesale prices leads to SCR provision being more lucrative for the electrolyser than PCR provision.

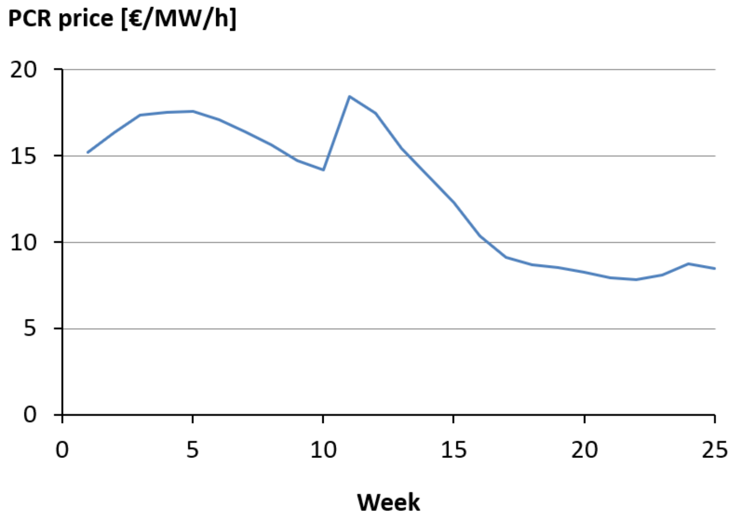

Figure 12: German PCR prices during the modelled period of time (average availability price paid in the weekly auctions during the period of 15.10.2018 - 07.04.2019)

[38]https://www.bundesnetzagentur.de/SharedDocs/Downloads/EN/Areas/ElectricityGas/CollectionCompanySpecificData/Monitoring/MonitoringReport2017.pdf?__blob=publicationFile&v=2

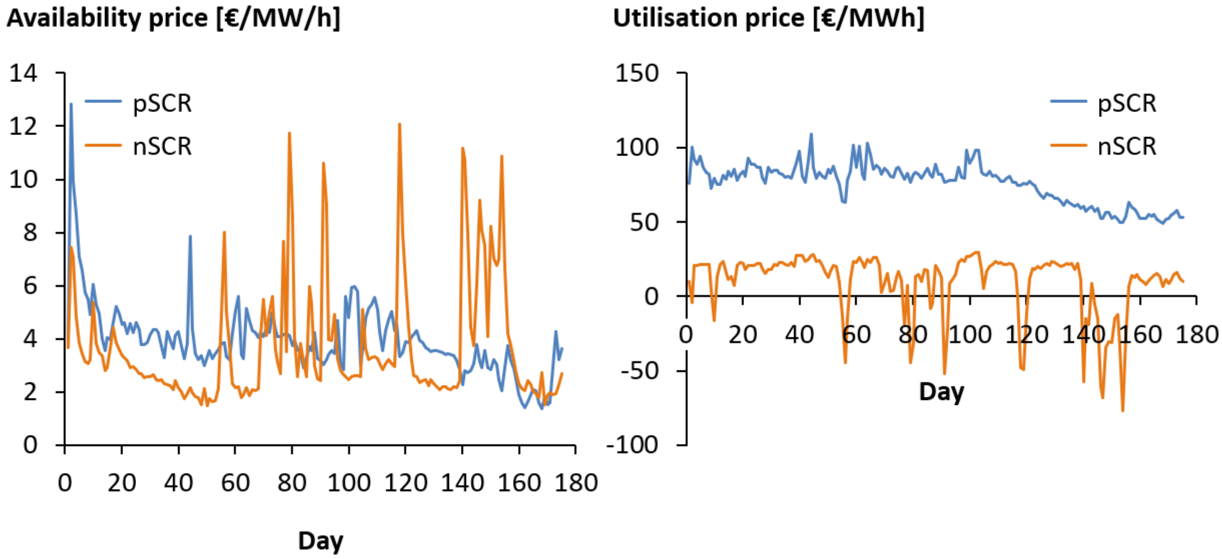

Figure 13: German SCR prices during the modelled period of time (average availability (left) and utilisation (right) price paid in the daily auctions during the period of 15.10.18 – 07.04.2019)

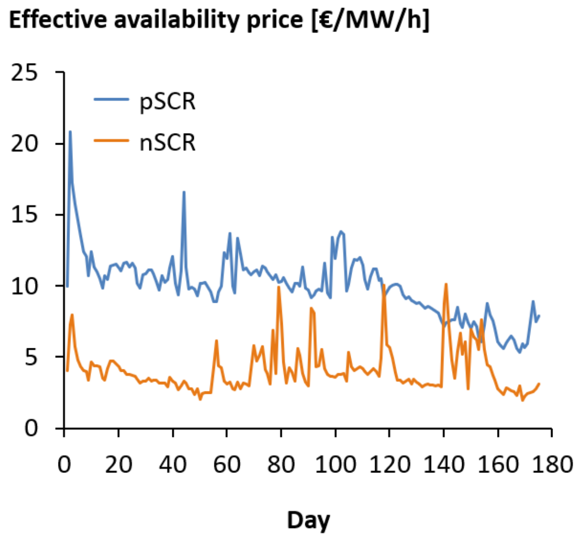

Figure 14: Effective availability price of SCR in the German market in the modelled period of time (combining average availability prices and utilisation prices using average utilisation rates)

Provision of SCR has a small effect on the operational profile of the electrolyser. The differentiation of SCR into a positive and a negative service, allows the electrolyser to choose to provide the service which comes at the lowest opportunity cost: it will provide positive SCR (pSCR) in hours when it is running (offering to turn down its consumption) and it will provide negative SCR (nSCR) in hours when it is not running (offering to turn up its consumption). As the utilisation rate of SCR is low (less than 10% of contracted availability), the electrolyser will rarely be instructed to change its consumption due to utilisation of SCR.

The electrolyser chooses between the two kinds of SCR service according to its operational profile. While at low utilisation, it provides mainly negative SCR, at high load factors, it provides mainly positive SCR and thus the revenues from provision of pSCR are higher than those from provision of nSCR.

5.3 Outlook on balancing revenues

Many factors impact future balancing services prices, but prices are not expected to increase soon. Balancing prices have been decreasing in the German market since 2012 despite unprecedented growth of wind and solar. This growth was expected to lead to significant increases of prices and required volumes of balancing services due to reduced inertia of the power system as well as forecast errors of wind and solar output leading to higher required reserves. However, competition and efficiency of the balancing markets have improved due to the consolidation of the balancing areas of the four German transmission system operators (TSOs) into one as well as increased international cooperation of European TSOs. Furthermore, forecasting of wind and solar output have improved significantly and no significant increase of procured PCR and SCR volumes has been observed. The emergence of batteries has led to significant price decreases in the PCR market as described above.

Hard coal and lignite plants still provide more than 40% of German electricity generation[39] and are providing a significant share of balancing services to the German TSOs[40]. The phase out of coal and lignite in Germany, planned to be completed in 2038[41], will thus also have an impact on the balancing markets. However, a look at the power grid in Britain suggests that phase out of coal does not have to lead to an increase of balancing services prices. The share of coal in Britain's generation mix has decreased from 39% in 2012 to 5% in 2018[42]. However, the costs of balancing services have stayed constant and prices of frequency response, a service comparable to PCR and SCR in Germany, have more than halved since 2017[43], to a large extent due to increased competition in the market caused by the emergence of new supply technologies such as demand side response[44] and battery storage. The TSO in Britain has set a goal to manage the power system operation without reliance on fossil power plants by 2025[45].

5.4 Exemptions from policy levies for power intensive industry in Germany

In the following we list the policy levies for industrial electricity consumers in Germany and the extent to which they are assumed to be reduced in the central scenario for an exemplary power cost intensive business. More detail can be found in (BDEW, 2019).

There are two main criteria which have to be met by a business to be available for reductions of policy levies in Germany:

a) The business has to belong to a sector which is among a list of sectors available for exemptions.

b) The business' power cost intensity, given by the ratio of the business' power costs to its gross value added, has to be higher than a certain threshold.

For most levies, the full levy has to be paid for the first GWh consumed annually, the exemptions only apply to the amount of electricity exceeding the 1 GWh.

1. **Renewable surcharge** (also referred to as EEG (Erneuerbare Energien Gesetz - renewable energy law) levy): The renewable surcharge was €64.05/MWh in 2019. The list of sectors available for reductions is specified in attachment 4 of the EEG 2017. For a business with a power cost intensity equal or greater than 20% the total payments for the surcharge are capped at 0.5% of the GVA with a minimum value of €1/MWh. We assume a value of €2/MWh for the power cost intensive business in our central scenario.

[39] https://www.unendlich-viel-energie.de/mediathek/grafiken/der-strommix-in-deutschland-2018
[40] https://www.regelleistung.net/ext/download/marktbeschreibung
[41] https://www.bmwi.de/Redaktion/DE/Artikel/Wirtschaft/kohleausstieg-und-strukturwandel.html
[42] https://www.gov.uk/government/statistics/electricity-section-5-energy-trends
[43] https://smartestenergy.com/info-hub/blog/two-years-on-battery-storage-and-new-opportunitites-1/
[44] https://limejump.com/limejump-to-operate-30-of-all-uk-firm-frequency-response/
[45] https://www.nationalgrideso.com/document/141031/download

2. **CHP (KWK) and offshore network levy**: The CHP levy was €2.8/MWh in 2019. The offshore network levy was €4.16/MWh in 2019. Similarly to the EEG levy, both levies are reduced for power cost intensive industry, depending on the power cost intensity. We assume the levies are reduced to 15% of their original value.
3. **Concession fee**: This fee was €1.10/MWh in 2019. No reduction is assumed.
4. **Levy under Article 19 of the Network Charges Ordinance** ("Article 19 StromNEV-levy"): this levy was €0.5/MWh in 2019 (€3.05/MWh for the first GWh).[46] No reduction is assumed.
5. **Levy for interruptible loads**: this levy was €0.05/MWh in 2019. No reduction is assumed.
6. **Power tax**: The power tax was €22.50/MWh in 2019. Certain energy intensive businesses are completely exempted from this tax (§ 9a Stromsteuergesetz (StromStG)). We assume the power cost intensive business is completely exempted from the power tax.

Adding the levies under the taken assumptions in our central scenario gives a value of €4.69/MWh, which we round up to €5/MWh.

[46]https://www.netztransparenz.de/EnWG/-19-StromNEV-Umlage/-19-StromNEV-Umlagen-Uebersicht/-19-StromNEV-Umlage-2019

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COORDINATION

DEMONSTRATION

DATA ANALYSIS & DISSEMINATION