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Economics of Hydrogen: Scenario-based Evaluation of the Power-to-Gas Technology

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Abstract

Power-to-gas (PtG) facilities apply the chemical process of water electrolysis to produce hydrogen and represent a low-carbon alternative to conventional hydrogen production methods when coupled with renewable energy sources. This thesis aims to evaluate the economic potential of the PtG technology and explore how policy changes can affect its profitability, measured by the break-even price of hydrogen. For the derivation of the break-even price, I rely on a net present value model that considers cost and revenue components as levelized terms, which I adapt by incorporating energy policy instruments. I develop an algorithm for the investment analysis of PtG projects, which considers both the capacity of the PtG facility and the renewable energy source as variables and optimizes their ratio for profitability. My analysis shows that large-scale PtG facilities can already compete on the market for medium-scale hydrogen supply at a price of 3.55 € /kg. However, profitable operations of small-scale PtG plants still depend on the implementation of policy changes. I find that small systems could produce pure renewable hydrogen at a break-even price below 3.00 € /kg and thus more than halve their costs, if supportive policy measures were adopted.

Keywords: Hydrogen economics; power-to-gas; renewable energy; capacity optimization.

1. Introduction

In view of climate change, the German government set the goal to reduce the emission of greenhouse gases drastically and transform the electricity mix toward using renewable sources to an extent of 80% of gross electricity consumption by 2050.[1] In addition to the current consumption, increased power generation will be necessary to cover the added demand from sectors being electrified by then, such as mobility. This will require a massive deployment of renewable energy sources in the coming decades, particularly of onshore and offshore wind power and solar PV. Due to the intermittency of these technologies, long-term energy storage will be required at a large scale, to balance the seasonally diverging supply and demand of electricity.[2] Stored energy can then be reconverted to supply power during calm period, i.e., an interval of several days without wind and solar power generation due to meteorological conditions occurring in winter. Currently no technologies other than chemical energy storage methods, mainly power-to-gas (PtG), are capable of providing the required long-term storage capacities.[3] This has also been acknowledged by the German government, which plans for the announcement of a strategy concerning hydrogen, the energy carrier produced by the PtG process, toward the end of 2019. The main component of a power-to-gas facility is the electrolyzer, which performs the chemical process of water electrolysis. This process consumes water and electricity as input materials to generate hydrogen and oxygen. In addition to long-term storage, PtG has the potential to provide ancillary services rapidly due to electrolyzer flexibility, when preferential short-term storage capacity is already utilized at full capacity.

Hydrogen cannot only be reconverted to power but could also replace fossil feedstock to cut carbon emissions in hardly electrifiable industries, such as steel production, aviation or ammonia production for fertilizers. For instance, steelmaking, which is among the largest industrial carbon emitters, could become fossil-free through the application of renewable hydrogen in the reduction of iron ore.[4] Due to its potential to satisfy the needs of various different energy consumers, PtG is considered to be a key element when it comes to “coupling of the electricity sector with other energy sec-

[1] Cf. BMWi (2010), p. 5.

[2] Cf. Sterner et al. (2019b), p. 110.

[3] Cf. Sterner et al. (2019a), p. 327 and Schenuit et al. (2016), p. 28.

[4] Cf. Vogl et al. (2018), p. 736.

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tors".[5]

Considering the current electricity mix of Germany, which still exhibits a high share of fossil fuels, the production of renewable hydrogen requires the immediate integration of PtG technology with renewable energy sources, e.g., wind turbines or solar PV. In this thesis, I refer to such systems, where the electrolyzer directly relies on a renewable energy source, as vertically integrated energy systems.

The focus of my thesis lies on the examination of the economics of vertically integrated energy systems based under current legislation and considering potential policy changes. In particular, I will identify suitable instruments to incentivize investment in vertically integrated energy systems in favor of renewable hydrogen production. The profitability of such systems is measured by the break-even price of hydrogen generated by the PtG subsystem, which is derived based on a net present value (NPV) model.

One aim of the thesis is the implementation of a tool, that facilitates the evaluation of vertically integrated systems under various scenarios covering both current legislation and a range of potential future policy designs. Such a tool could serve policymakers to understand the implications of their decisions on power-to-gas profitability and help investors when assessing the economic potential of vertically integrated systems. It also allows the simulation of a wide range of system compositions in order to optimize the ratio of the PtG and renewable energy subsystems.

Section 2 describes the analyzed scenario and introduces the relevant regulatory aspects, followed by the methodology based on an adopted net present value model and some model alterations. Section 3 of my thesis concerns the implementation of the mentioned analysis tool and addresses some issues resolved throughout the development of the algorithms for the break-even price detection and capacity optimization. In section 4 I describe the selected model input variables and present the results of various scenario simulations, followed by an interpretation of the results and an examination of the sensitivity of the hydrogen price with respect to key model input parameters. Finally, section 5 gives a conclusion of the thesis.

2. Methodology

2.1. Scenario description

The objective of this thesis is the evaluation of the power-to-gas technology for a series of scenarios and under consideration of current regulation and potential future modifications of the regulatory framework. All underlying scenarios are based on a vertically integrated energy system, composed of a power-to-gas facility and a renewable energy source (RES). The RES itself can be composed of stand-alone wind turbines or solar PV technology for power generation, or of a hybrid RES comprising both technologies. Thus, the PtG plant can either utilize renewable power or electricity sourced from the power grid to produce hydrogen by application of water electrolysis. With regard to grid power, access to wholesale electricity prices is assumed. The PtG facility is able to run flexibly and can be switched on and off at any time without technological restrictions, thus enabling an optimization of the power conversion to hydrogen in reaction to the development of real-time electricity prices. The gained value from converting renewable electricity to hydrogen is traded off against the earnings that would result from feeding electricity into the grid at any point in time.

In some of the analyzed scenarios the capture of oxygen, a by-product of water electrolysis, is considered for the evaluation, in order to find out if the commercialization of oxygen could help electrolytic hydrogen to become more cost-competitive.

For the profitability analysis of the vertically integrated system, I take the perspective of an investor in search of the ideal sizing of the PtG and RES subsystems, which yields a minimum break-even price of hydrogen.

2.2. Literature review

The economics of hydrogen production based on water electrolysis have been extensively investigated in the past decades and several research projects have been established around the power-to-gas technology, such as "FCH JU"[6], an EU-funded consortium composed of fuel cell and hydrogen industries and academia. Many research papers regarding power-to-gas refer to the use of renewable power but generally do not examine power-to-gas directly coupled with a renewable energy source. Furthermore, the focus of research seems to lie on PtG as an energy storage technology and profitability many times is not assessed in terms of a hydrogen price. However, many articles and reports exist which analyze integrated energy systems, as defined in this thesis, and compute comparable profitability measures. A recent study[7] provides an insightful literature review concerning clean hydrogen production, including based on water electrolysis with solar or wind power, and offers a cost-based comparison of the identified literature. The review reports costs of renewable hydrogen between 5 - 8 $/kg in the case of wind power and finds electrolytic hydrogen from solar power at a cost of 8 - 9 $/kg.[8]

Glenk and Reichelstein[9] examined the economic potential of PtG facilities integrated with wind power and derived a net present value model for the profitability assessment of vertically integrated energy systems, based on time-variant electricity prices and renewable energy capacity factors, while leveraging the concept of unit cost, e.g., by relying on the common measure of levelized cost of electricity (LCOE).

None of the studies, I have found, directly compare the effects of legislation on PtG economics. Therefore, I set the

[5] Sterner et al. (2019c), p. 758.

[6] Fuel Cells and Hydrogen Joint Undertaking.

[7] Cf. El-Emam and Özcan (2019).

[8] Cf. El-Emam and Özcan (2019), p. 603-604.

[9] Cf. Glenk and Reichelstein (2019b).

focus of my thesis on the profitability analysis of vertically integrated energy systems under the legal framework effective in Germany and highlight the implications of policy changes on PtG profitability. In particular, I will identify instruments necessary to incentivize the production of renewable hydrogen, in contrast to grid-supplied electrolysis.

For this purpose, I build on the model framework developed by Glenk and Reichelstein and add components to represent the policy options and the possibility to consider wind turbines and solar PV as a hybrid renewable energy system integrated with a PtG facility. Additionally, I accounted for the capture of the by-product oxygen and included a scenario for consideration of a rising price of carbon emission allowances, which affects the price of competing fossil hydrogen, as well as the cost associated to grid electricity consumption. Both the analysis of a hybrid renewable energy system and the consideration of the oxygen by-product can rarely be observed in literature.

2.3. Legal environment

The described scenario setup is mainly subject to regulations under the Renewable Energy Sources Act (EEG[10]), which was initially introduced in 2000. The latest amendment took effect in January 2017. The EEG guarantees a subsidy for renewable energy systems during a period of 20 years. The subsidy is granted in the form of a feed-in premium, which compensates for the difference between the guaranteed tariff and the market price of electricity. The premium is only paid if power is fed into the public power grid. For renewable energy systems above 750 kW the tariff is determined by auctions, in which future system operators need to submit bids. Below the threshold of 750 kW, the subsidy value is calculated based on the accepted bid values from past auctions. While the subsidy is only granted to solar PV systems with a size of up to 10 MW[11], subsidization of wind turbines does not depend on the installed capacity volume.

The entitlement to EEG subsidy comes along with some restrictions. The consumption of own electricity from a renewable energy system is only permitted to owners of small systems with a size not exceeding 750 kW.[12] This threshold applies to wind turbines and solar PV separately[13], therefore a combined system of up to 1500 kW could benefit from this permission. The concept of own consumption is very narrowly defined. Own consumption – in the legal sense – is only given, when the generated electricity is consumed by the same legal entity, meaning that the consumption by a subsidy is not considered as own consumption, legally. Moreover, consumption must occur within immediate vicinity to the renewable energy source and cannot pass through the public power grid.[14] As a consequence of the consumption of self-generated power, operators can avoid various levies or even benefit from complete exemptions, e.g., from fees incurred by utilization of the public grid.

However, operators of renewable energy systems with a size above 750kW can still utilize electricity from their own facility when consumption occurs through another legal entity, which can be a subsidiary of the system operator. From a legal standpoint, this is not considered own consumption, but a direct sale[15] of electricity, which applies when electricity is sold to a third party within immediate vicinity without feeding the power through the public grid.[16]

The proposed scenario is subject to various statutory levies, charges and taxes, which can incur at different rates depending on the type of electricity consumption.

Grid-supplied electricity generally is burdened with the EEG levy[17], which allocates the cost of the EEG subsidy to all electricity consumers, and various levies and charges for grid access and utilization. Those grid-related burdens are composed of the transmission charge[18], which is the main fee for grid utilization, and various levies coupled to the transmission charge. Those levies include the concession charge, which results from fees payable by grid operators to local authorities for installation of the electricity infrastructure on public property, the CHP levy[19], which covers the cost of a subsidy granted to promote combined heat and power (CHP) plants, the offshore grid levy, charged to cover the costs related to the network link between offshore electricity generation facilities and the public grid, and the so-called §19 StromNEV levy, which covers any missing amount for transmission grid expenses resulting from reductions or exemptions from the transmission charge. In addition, there is a levy for interruptible loads for allocation of the cost accrued due to reduction of the grid load to ensure power grid stability at times of electricity undersupply.[20]

Besides those levies and charges, electricity tax, value-added tax and income tax are imposed. The value-added tax is not considered in the calculation, since it is reimbursed.

There are several reliefs on taxes and levies applicable to the described scenario, primarily due to the use of a power-to-gas facility. Electricity applied by industrial companies in an electrolysis process is exempt from the electricity tax[21]. Another exemption is provided for the transmission charge, which is not imposed on facilities for the production of hydrogen by water electrolysis.[22] After a law change entered into effect in May 2019 the current wording of the relevant law requires re-electrification of the generated hydrogen for eligibility of the exemption. This requirement was

[10]German term: „Erneuerbare-Energien-Gesetz“.
[11]Cf. § 37 (3) EEG.
[12]Cf. § 27a EEG.
[13]Since wind turbines and solar PV are different renewable technologies, no aggregation of the two systems is required for legal purposes in accordance with § 24 (1) Nr. 2 EEG.
[14]Cf. § 3 Nr. 19 EEG.
[15]German term: „Direktlieferung“.
[16]Cf. § 21b (4) Nr. 2 EEG.
[17]German term: „EEG-Umlage“.
[18]German term: „Netzentgelte“.
[19]German term: „KWKG-Umlage“.
[20]Cf. Bundesnetzagentur (2019d).
[21]Cf. § 9a (1) Nr. 1 StromStG (Electricity Tax Act).
[22]Cf. § 118 (1) EnWG (Energy Industry Act).

recently revoked retroactively and therefore the exemption is still valid irrespective of the hydrogen utilization further down the value chain.[23]

In addition, companies with high electricity cost burdens can benefit from reduced rates with regard to almost all of the other levies. For instance, electricity consumers with a yearly consumption above 30 MWh and a load exceeding 30 kW in at least two months of a year receive a rebate on the concession charge. There is an enormous potential for reduction of the EEG levy for companies operating within specific industrial branches, provided their electricity cost intensity lies above a certain threshold. Producers of industrial gases, such as hydrogen, are generally eligible for a reduction of the EEG levy, as regulated under the special compensation scheme.[24] In addition to activity within one of the specified branches[25], eligibility for the cost relief requires a high electricity cost burden, measured as the proportion of electricity cost to the company's gross value added. The applied electricity rate is standardized and depends on the company's consumed full load hours per year and the total yearly electricity consumption. The lowest rate for 2019 lies slightly above 11 € ct/kWh.[26] For a rough estimate, to explore if PtG facilities are eligible for a reduction of the EEG levy, the gross value added per unit is approximated based on a medium-scale supply price of industrial hydrogen of 3.0 € /kg[27] and assuming an electricity consumption of 50 kWh/kgH_2. The application of the least beneficial electricity cost rate of 11 € ct/kWh results in an electricity cost per kilogram of hydrogen of 5.50 € /kg. This value compared to the revenue per kilogram, which for calculation of the gross value added would still be reduced by variable and fixed costs, lies well above the threshold required for eligibility. This is even true, when a price much higher than the industrial price of hydrogen applies. Hence, PtG facilities satisfy the requirements and can benefit from a reduced EEG levy under the special compensation scheme. The reduced levy does not apply on the entire electricity consumption. The first gigawatt hour is always non-exempt and subject to the full EEG levy. Electricity consumption beyond the non-exempt volume is burdened with a levy rate reduced to 15% of the base rate. However, the total cost of the levy for consumption above 1 GWh is limited to a maximum of 0.5% of the company's gross value added, while the resulting levy can never fall below the absolute minimum of 0.1 € ct/kWh.[28] Again, using the industrial hydrogen price as upper bound of the gross value added the maximum levy cost would result in a total of 0.015 € [29], which must be allocated to the 50 kWh required per kgH_2. Since the levy per kWh results in a value much lower than the defined minimum of 0.1 € ct/kWh, the minimum rate is the applicable levy rate for electricity consumption above 1 GWh. This does not change, even when calculating with a hydrogen price of 10 € .

The same scheme – but with another minimum rate – applies to the CHP levy[30] and the offshore grid levy[31], which refer to the section on the special compensation scheme of the EEG. Applying the same logic as above to determine the applicable levy rates, shows that the specified minimum rates also are the determining rates, which is 0.03 € ct / kWh in both cases.

Although, the §19 StromNEV levy does not refer to the EEG provision of the special compensation scheme, it follows a similar approach. The full base rate is charged for the first gigawatt hour, above that a reduced rate exists for industrial companies with an electricity cost burden above 4%, measured as the proportion of electricity cost to sales. This is also given, in accordance with the estimate shown above.

All grid-related burdens can be avoided by consumption of self-produced electricity from the renewable energy system due to the lack of grid utilization. Hence, in case of own power consumption only the EEG levy is charged and the described scheme for reduction of the levy also applies. In addition, when own consumption – in the legal sense and in contrast to a direct sale – is given, the EEG levy is reduced to 40% of the base rate.[32] Remember, this discount is only available to operators of renewable energy systems not exceeding 750 kW, with wind and solar power being considered separately for this threshold.

Table 1 gives an overview of the relevant levies, charges and taxes and indicates which fees are imposed depending on the source of power supply:

It should be noted that the EEG subsidy is only granted when the electricity generated by the renewable energy source is fed into the public power grid – in the form of a feed-in premium. Hence, under the current legislation electricity absorbed by the PtG facility is not entitled to the EEG subsidy, which creates a huge barrier for the conversion of electricity from the RES and thus the production of renewable hydrogen.

In a very limited scope, the EEG provides ways for an entire relief from the EEG levy payable on the consumption of own electricity in a few, rather unfavorable, cases. The only case, compatible with the described setup, would require the operator of the vertically integrated energy system to entirely forgo the EEG subsidy and utilize exclusively renewable energy for hydrogen conversion, no grid power, to be eligible for a complete waiver of the EEG levy.[34] Excess power, which cannot be absorbed by the electrolyzer could still be sold at the power exchange, but without a subsidy granted.

This scenario has a huge disadvantage, since the loss of the subsidy needs to be compensated for by the profits on hydrogen sale. However, this scenario will also be analyzed

[23] Cf. Resolution 383/19 (30 August 2019).
[24] Cf. §63 - 69a EEG ("Besondere Ausgleichsregelung").
[25] Cf. Appendix 4 EEG in connection with § 64 (2) EEG.
[26] Cf. BAFA (2019), p. 14.
[27] Cf. Glenk and Reichelstein (2019b), p. 218.
[28] Cf. § 64 (2) Nr. 2 a) and Nr. 3 a) and Nr. 4 b) EEG.
[29] 0.5% of 3.0 € /kg (medium-scale supply industrial hydrogen price).
[30] Cf. § 27 (1) KWKG.
[31] Cf. § 17f (5) EnWG in connection with § 27 (1) KWKG.
[32] Cf. § 61b EEG.
[33] Own research.
[34] Cf. § 61a Nr. 3 EEG.

Table 1: Statutory levies, charges and taxes imposed on electricity consumption.[33]

	Own consumption	Direct sale	Grid supply
EEG levy	40%	100%	
Transmission charge	Exemption for PtG facilities		
Concession charge	No		Yes
CHP levy	No		Yes
Offshore grid levy	No		Yes
§ 19 StromNEV levy	No		Yes
Levy for interruptible loads	No		Yes
Electricity tax	Exemption for PtG facilities		

in one case in section 4 of the thesis.

2.4. Model framework

2.4.1. Requirements to the model framework

In addition to the implementation of the regulatory framework presented in the previous section, the effects of conceivable policy changes shall be analyzed. Therefore, the proposed model framework should be designed to support a range of policy changes, explained briefly below. In addition, some other features are presented, which need to be considered within the model framework.

One analyzed policy measure is the decoupling of the EEG subsidy from the feed-in requirement and the payment of a production premium instead, which the operator of the renewable energy system receives irrespective of a power feed-in. This measure would remove the barrier to utilize electricity from the renewable source, especially for sizes above 750 kW, where the benefit of a reduced EEG levy is not provided. Thus, such a measure could promote the generation of renewable hydrogen, compared to a grid-power hydrogen production.

Another supportive policy involves an extension of the permission of own consumption in the legal sense, which under current legislation is only granted to systems sized up to 750 kW. As a consequence, the addressed systems would benefit from the reduction of the EEG levy to 40% of the full rate. The NPV framework should also allow for a waiver of the entire EEG levy and other statutory fees on self-produced renewable energy and/or grid-supplied power absorbed by a power-to-gas facility. Not only the system operators would benefit from such a policy, but it could also help to balance demand and supply and relieve the power grid, if the right incentives are set. Furthermore, a scenario based on (rising) carbon emission prices needs to be implemented within the model framework.

Beyond the representation of the regulatory framework and the described policy changes, the developed tool shall support several other features.

The framework must allow for either the use of a stand-alone wind turbine or solar PV system, or a hybrid system combining both electricity generation technologies. It should also be feasible to switch between different operating modes: an integrated mode, which allows power consumption from the renewable energy source and the public grid, a grid-only mode and a res-only mode, which consider electricity consumption from one of the two sources only. Regarding the EEG subsidy, there must be the possibility to compare a scenario with and without granting of the subsidy. There should exist a mode considering the capture of oxygen, a by-product from water electrolysis, to allow for an assessment of the effect on profitability resulting from oxygen commercialization.

2.4.2. Base model

The methodology of my thesis builds on the model framework developed by Glenk and Reichelstein[35], which can be applied to calculate the net present value of a vertically integrated system. I will present the main characteristics of the model in this section based on its derivation in the referred article. In the subsequent section I will show the model adjustments, which I conducted in order to satisfy the defined requirements. For a detailed insight into the model construction, I recommend the referenced article for a read.

The authors derived a formula for the calculation of the net present value of vertically integrated systems, which can be separated in three terms: the stand-alone NPVs of the two subsystems renewable energy system and power-to-gas facility, and the synergistic value resulting from their integration. The NPV derivation is based on an optimized management of the PtG operations, which is adjusted to the time-variant electricity prices and power output from the intermittent renewable energy source in order to identify the best scheduling strategy for power conversion.[36] Therefore, the selling price of electricity from the renewable energy source, denoted by $p^s(t)$, is compared with the buying price of electricity from the grid $p^b(t)$, and the conversion value of hydrogen CV_h. The model assumes constant yearly prices and an unchanging distribution of the yearly power generation during the system lifetime, denoted by T. While the price of grid-supplied electricity can fall below zero, own electricity is never sold at a negative price, but the renewable energy system is rather

[35] Glenk and Reichelstein (2019a).

[36] Cf.Glenk and Reichelstein (2019a), p. 6.

switched off or the generated power is consumed internally, provided that grid power is not available at a lower rate.

Formally, the model builds on the assumption:

$$p^s(t)\begin{cases} \leq p^b(t) & \text{if } p^b(t) \geq 0 \\ = 0 & \text{if } p^b(t) < 0 \end{cases} \qquad (1)[37]$$

In accordance with equation (2), the conversion value is computed as the product of the contribution margin per kilogram (kg) of produced hydrogen (H2) and the conversion rate of the PtG facility, denoted by η with the unit kg/kWh. The contribution margin in € /kg equals the difference between the time-invariant selling price of hydrogen, denoted by p_h in € /kg, and the variable cost of hydrogen conversion, denoted by w_h in € /kg, excluding the cost of electricity.

Thus, the conversion value of hydrogen is:

$$CV_h = \eta \cdot (p_h - w_h). \qquad (2)$$

Whenever CV_h exceeds $p^s(t)$ or $p^b(t)$, running the PtG facility yields a positive contribution margin, because the value of each kWh converted to hydrogen exceeds the cost of electricity. Thus, the PtG facility would be switched on.

When $p^s(t)$ falls below $p^b(t)$ and CV_h, synergies arise from the system integration. At that point in time, a stand-alone PtG facility would either use the more costly grid power or would be idle, while in the integrated scenario the cheaper power from the renewable energy source can be leveraged.

There are four phases with varying constellations of the electricity prices and the conversion value, as displayed in Figure 1.

The optimized contribution margin representing all phases of the integrated system equals:

$$\begin{aligned} CM(t \mid k_e, k_h) =& p^s(t) \cdot CF(t) \cdot k_e + \left[p^{b+}(t) - p^b(t)\right] \cdot k_h \\ &+ \left[p^+(t) - p^s(t)\right] \cdot z(t \mid k_e, k_h) \end{aligned} \qquad (3)[39]$$

where $p^{b+}(t) = \max\left\{p^b(t), CV_h\right\}$
and $p^+(t) = \max\left\{\min\left\{p^b(t), CV_h\right\}, p^s(t)\right\}$
and $z(t \mid k_e, k_h) = \min\left\{CF(t) \cdot k_e, k_h\right\}$

The variables k_e and k_h refer to the system sizes of the RES and PtG facility in kilowatt (kW) with the subscripts e and h, respectively. $CF(t)$ represents the time-variant capacity factors of the RES. The term $z(t|k_e, k_h)$ equals the maximum amount of electricity from the renewable source, which can be utilized by the PtG facility at a point in time. It is determined by the lower value of the power output from the RES or the installed capacity of the PtG plant.

The authors leveraged a general NPV formula, composed of the sum of all yearly discounted cash flows minus the total cost of the investment as shown in equation (4), and transformed it into an NPV term based on unit cost expressions and average prices.

$$NPV(k_e, k_h) = \sum_{i=0}^{T} CFL_i(k_e, k_h) \cdot \gamma^i - \text{ Investment}. \qquad (4)$$

The yearly cash flows are determined by the sum of the hourly optimized contribution margin reduced by the yearly fixed operating costs. The investment cost is determined based on system prices and installed capacities of the subsystems. A convenient transformation of equation (4) results in the net present value term of vertically integrated systems:

$$\begin{aligned} NPV(k_e, k_h) = (1-\alpha) \cdot L \cdot [(\Gamma^s \cdot p^s - LCOE) \cdot CF \cdot k_e \\ + \left(p^{b+} - p^b - LFCH\right) \cdot k_h \\ + (p^+ - p^s) \cdot z(k_e, k_h)]. \end{aligned} \qquad (5)[40]$$

The first of the three terms, $(1-\alpha) \cdot L \cdot (\Gamma^s \cdot p^s - LCOE) \cdot CF \cdot k_e$, equals the stand-alone NPV of a RES, the second term, $(1-\alpha) \cdot L \cdot \left(p^{b+} - p^b - LFCH\right) \cdot k_h$, is the stand-alone NPV of a PtG facility and the third term, $(1-\alpha) \cdot L \cdot (p^+ - p^s) \cdot z(k_e, k_h)$, represents the synergistic value attributed to the integrated system.

α denotes the applying income tax rate. $L = m \cdot \sum_{i=0}^{T} x^{i-1} \cdot \gamma^i$ is the levelization factor, which "expresses the discounted number of hours that are available from the facility over its entire lifetime".[41] m is the number of hours per year and equals $365 \cdot 24 = 8760$. The yearly degradation is denoted by the factor x, which leads to a reduction of the capacity of both the renewable energy system and PtG facility. The discount factor is expressed by $\gamma = \frac{1}{1+r}$, where r is the weighted average cost of capital (WACC). The variables CF, p^s, p^b, p^{b+} and p^+ denote the average value of the underlying time-variant data. For instance, the average capacity factor (CF) is computed by $CF = \frac{1}{m}\int_0^m CF(t)dt$. The other variables are computed accordingly.

The levelized cost of electricity (LCOE) allocates the investment cost and fixed operating costs of the renewable energy source to its lifetime electricity production and thus expresses the discounted average cost per kWh of the produced energy:

$$LCOE = w_e + f_e + \Delta \cdot c_e \qquad (6)$$

Since a renewable energy system has insignificant variable operating costs: $w_e = 0$.

[37] All formulas in section 2.4.2 are cited from Glenk and Reichelstein (2019b).

[38] Source: Glenk and Reichelstein (2019a), p. 7.

[39] Refer for the proof to "Proof of Lemma 1" in the Appendix of Glenk and Reichelstein (2019a).

[40] For a mathematical proof refer to "Proof of Proposition 1" in the Appendix of Glenk and Reichelstein (2019b).

[41] Glenk and Reichelstein (2019b), p. 10-11.

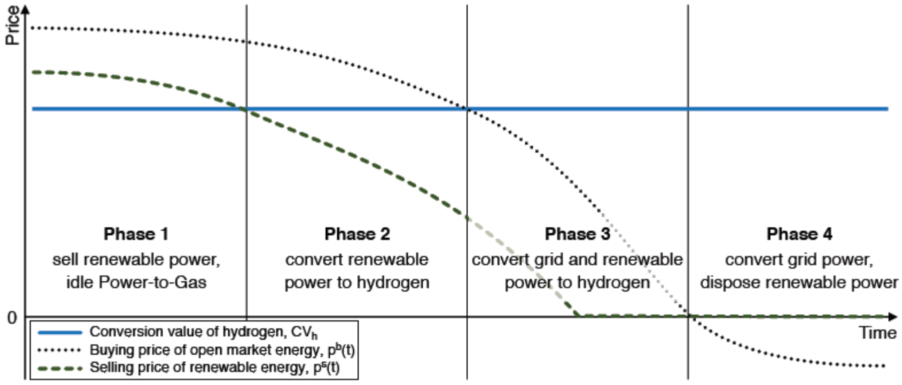

Figure 1: Phase diagram.[38]

The levelized fixed operating costs $f_e = \frac{\sum_{i=1}^{T} F_{ei}\gamma^i}{CF\cdot L}$ are based on the yearly fixed cost F_{ei}, where i denotes the year. The levelized capacity cost $c_e = \frac{SP_e}{CF\cdot L}$ is based on the system price SP_e, which indicates the cost per installed kW of the RES. Both costs are levelized on a per kWh basis.

The tax factor is expressed by $\Delta = \frac{1-\alpha\cdot\sum_{i=1}^{T} d_i\cdot\gamma^i}{1-\alpha}$ and is based on the income tax rate α, the yearly tax depreciation rate d_i and the discount factor γ.

The construction of the levelized fixed cost of hydrogen (LFCH) follows the same logic, but does not consider the variable operating cost of hydrogen production, which are already accounted for in the conversion value of hydrogen CV_h in equation (2):

$$LFCH = f_h + \Delta \cdot c_h \tag{7}$$

where $f_h = \frac{\sum_{i=0}^{T} F_{hi}\gamma^i}{L}$ and $c_h = \frac{SP_h}{L}$.

The denominators disregard a capacity factor, since PtG is a dispatchable technology. LFCH therefore expresses the investment and fixed cost of the PtG facility allocated to every kWh, which could be converted to hydrogen assuming a full load of the electrolyzer during its lifetime. Thus, at times when the PtG facility is idle, LFCH represents the loss resulting from the investment in PtG, which must be compensated for by the contribution margin gained during production hours for overall profitability of the PtG subsystem.

The term for the stand-alone net present value of a renewable energy system, applies the co-variation coefficient Γ^s to the average revenues p^s per kWh produced. This factor adjusts for the variation between electricity price and power generation output based on their average values.[42] This adjustment allows that the NPV term is computed based on the average values of the electricity selling price, p^s, and the capacity factor, CF.

The co-variant coefficient is defined as:

$$\Gamma^s = \frac{1}{m}\cdot\int_0^m \frac{CF(t)}{CF}\cdot\frac{p^s(t)}{p^s}dt. \tag{8}$$

Similarly, the third component of the NPV term in equation (5), needs to be adjusted for the variation between the price premium of hydrogen, $p^+(t)-p^s(t)$, and the hydrogen output at every point in time.[43] This adjustment is carried out by the term:

$$z(k_e,k_h) = \frac{1}{m}\cdot\int_0^m z(t\mid k_e,k_h)\cdot\frac{p^+(t)-p^s(t)}{p^+-p^s}dt \tag{9}$$

2.4.3. Model alterations

In order to align the model framework of Glenk and Reichelstein with the effective legislation, described in section 2.3, and provide the flexibility to switch between different scenarios, some adaptations of the original model are necessary.

The model shall support the current legislation and conceivable policy changes, such as the waiver of the feed-in requirement and supplementary reliefs regarding the statutory fees on electricity imposed on PtG operators. It shall also account for the possibility of a carbon price and the commercialization of the oxygen by-product. Furthermore, the model framework should allow for hybrid renewable energy systems composed of solar PV and wind turbines and be compatible with different operating modes.

To facilitate an easy implementation of the net present value model, I introduce Boolean parameters, which can take the value 0 or 1 to specify the analyzed scenario (see Table 2).

For instance, when the renewable energy system is entitled to the EEG subsidy ($sub = 1$) in the form of a production premium: $fit = 0$; and in the form of a feed-in premium: $fit = 1$.

In case the parameter $tax^{res} = 0$, the electricity absorbed directly from the renewable energy source is assumed to be exempt from statutory levies, charges and taxes. The Boolean parameter tax^{grid} controls the fees applicable to grid-supplied electricity, accordingly.

The selling price of electricity from the renewable energy source and the buying price of grid-supplied electricity is

[42] Cf. Glenk and Reichelstein (2019b), p. 12.

[43] Cf. Glenk and Reichelstein (2019b), p. 13.

Table 2: Boolean parameters for scenario specification.

Description	Boolean	Value
Eligibility to EEG subsidy	sub	
Feed-in requirement	fit	
Onsite consumption of hydrogen	$onsite$	
Liability to pay statutory fees on grid-supplied power	tax^{grid}	Yes = 1 / No = 0
Liability to pay statutory fees on renewable power	tax^{res}	
Consideration of an emission price	em	
Consideration of the oxygen by-product	$o2$	

based on the wholesale electricity price at the electric power exchange, in the case of Germany mainly at the European Power Exchange (EPEX). Therefore, I denote the time-variant electricity price by $epex(t)$. It is assumed that renewable energy systems, unlike other power generation technologies, have the flexibility to curtail power production immediately when prices become negative. Therefore, own electricity is not sold at a negative price, but at the rate expressed by $epex^+(t) = \max epex(t), 0$. In contrast, the price of grid-supplied electricity can fall below zero and is based on the unadjusted $epex(t)$.

Under the current legal framework both own electricity and grid-supplied electricity consumption are subject to statutory fees. As explained in section 2.3, some of fees are based on a fixed rate, while others have a varying average rate, that changes depending on the consumption quantity. Among the latter the EEG levy is the one with the greatest impact. It is convenient to group the statutory fees in two different variables based on their varying design, called $fees_{fix}$ and $fees_{var,i}$. They will be completed by the superscripts res and grid to indicate the source of power they refer to. $fees_{var,i}$, which expresses the average fee allocated per kWh, can vary along the years of system lifetime, since the system degradation leads to a decrease of the yearly power consumption, which again influences the average fee rate. Section 3.3 covers the derivation of the fee rates of $fees_{var,i}$, which must be determined in an iterative approach.

In addition to the wholesale electricity price and the statutory fees, grid-supplied power is also subject to a price markup resulting from the cost of electricity trading, and the cost of emissions in case carbon emissions are considered in the analysis ($em = 1$).

Overall, the buying price of electricity can be expressed by:

$$p^b(t) = \text{epex}(t) + \text{markup} + \text{tax}^{grid} \cdot \left(fees^{grid}_{fix} + fees^{grid}_{var,i}\right) + em \cdot \Delta\,\text{cost}^{el}_{em}(t) \tag{10}$$

Δ cost $^{el}_{em}(t)$ represents the hourly emission cost per kWh of electricity at time t. Its derivation will be shown later in this section.

Beyond statutory fees, the price of own electricity consumption includes the opportunity cost that results from the lost profit due to the internal power absorption instead of a sale at the power exchange. This cost does not accrue in reality but needs to be considered as part of the optimization of the electrolyzer operating strategy. It is composed of the cash flows, which would be obtained only when renewable electricity was sold at the market. These comprise the non-negative electricity price $epex^+(t)$ and the subsidy premium, provided the subsidy is tied to the power feed-in. If the feed-in requirement is waived, then the premium is not considered as an opportunity cost, since it is obtained even when own power is absorbed internally.

Note, the resulting price does not represent the electricity selling price, which is defined by $epex^+(t)$ only, but rather the imputed price for consumption of own electricity. Still, I remain with the original variable $p^s(t)$ and define it by:

$$p^s(t) = epex^+(t) + tax^{res} \cdot \left(fees^{res}_{fix} + fees^{res}_{var,i}\right) + fit \cdot premium(t). \tag{11}$$

The conversion value of electrolysis is initially based on the conversion value of hydrogen. As soon as the oxygen by-product is also captured and commercialized, the conversion value can increase, provided that the price of oxygen covers the additional variable operating costs.

During the process of electrolysis, water – chemically denoted by H_2O – is split into hydrogen (H_2) and oxygen (O_2). Since the water molecule is composed of two hydrogen and one oxygen atom, the resulting quantity of hydrogen molecules is twice the quantity of oxygen molecules. However, hydrogen and oxygen possess different standard atomic weights of 1.008 and 15.999, respectively.[44] To obtain the oxygen output per kg produced from 1 kWh electricity, it is necessary to relate the conversion rate of hydrogen (in kgH_2/kWh) to both the ratio of the molecule numbers and atomic weights.

The resulting conversion rate of oxygen (in kgO_2/kWh) is:

$$\eta_o = \frac{15.999}{2 \cdot 1.008} \cdot \eta_h \approx 8 \cdot \eta_h.$$

In other words, each kg of hydrogen captured through electrolysis, has a by-product of around 8 kg of oxygen, which

[44] CIAAW: Atomic weights of the elements 2017. Available online at www.ciaaw.org.

is generally vented as a waste product. The resulting total conversion value is composed of the conversion value of hydrogen and oxygen:

$$CV = CV_h + CV_o \cdot o2 \tag{12}$$

where $CV_o = \frac{15.999}{2 \cdot 1.008} \cdot \eta_h \cdot (p_o - w_o)$.

p_o and w_o denote the price of oxygen and the variable operating costs of oxygen capture, respectively. $o2$ is the Boolean operator, which determines whether oxygen is considered for the calculation of the NPV.

In addition to the variable operating costs, the capture of oxygen might require further investments and/or regular maintenance and thus can cause fixed costs.

Hence, the term levelized fixed cost of oxygen (LFCO) captures the capacity cost and yearly fixed operating costs related to oxygen operations, analogous to the construction of LFCH:

$$LFCO = (f_o + \Delta \cdot c_o) \cdot o2 \tag{13}$$

where $f_0 = \frac{\sum_{i=1}^{T} F_{oi} \gamma^i}{L}$

and $c_o = \frac{SP_o}{L}$

An adaptation of the conversion value of hydrogen $CV_h = \eta_h \cdot (p_h - w_h)$ is also necessary due to the distinction between onsite utilization of hydrogen and the sale of hydrogen. Furthermore, the price of carbon emissions, imposed on fossil hydrogen, needs to be incorporated into the equation. Both adjustments concern the price of hydrogen:

$$p_h = \text{ price }_{H_2} + em \cdot \Delta \text{ cost }_{em,i}^{\text{fossil}} + \text{onsite } \cdot \text{cost}_{\text{transport}} \tag{14}$$

price_{H_2} represents the base price of hydrogen, which generally already includes a carbon price, since hydrogen production is subject to the EU Emissions Trading System (EU ETS).

When putting into effect a rising carbon price, the emission price markup on fossil hydrogen, expressed by $\Delta \cos t_{em,i}^{fossil}$, raises the price of hydrogen. The consideration of emission prices is explained in the subsequent paragraph. The cost of transportation needs to be included in the hydrogen price in case the produced hydrogen is consumed onsite. It reflects the price advantage gained from onsite production from the avoided cost of transportation, which are payable for hydrogen obtained externally.

I assume that an emission price is entirely added to the price of hydrogen or grid power, respectively. $\Delta\text{cost}_{em,i}^{fossil}$ expresses the cost of emission certificates required to cover up for the carbon emissions per kg of fossil hydrogen, when considering a yearly varying emission price, denoted by $\sigma_{\text{target},i}$ in $€ /tCO_2eq.\sigma_h$ expresses the emission price relevant for the production of fossil hydrogen in the base year and thus needs to be deducted from the target price. The emission factor of fossil hydrogen ε_h (in $gCO2eq/kgH_2$) must be multiplied with the offset of the emission prices to obtain the emission cost in € /kg:

$$\Delta \text{ cost }_{em,i}^{\text{fossil}} = \left(\sigma_{\text{target},i} - \sigma_h\right) \cdot \varepsilon_h \cdot 10^{-6} \tag{15}$$

The buying price of grid electricity also has an emission cost component, which was mentioned in equation (10). $\Delta\text{cost}_{em}^{el}(t)$ represents the time-variant emission cost assigned per kWh at any point in time t based on the hourly national electricity mix:

$$\Delta \text{cost}_{em}^{el}(t) = \left(\sigma_{\text{target},i} - \sigma_{el}\right) \cdot \frac{\sum_{type=1}^{n} E_{type} \cdot G_{type}(t)}{\sum_{type=1}^{n} G_{type}(t)} \cdot 10^{-6} \tag{16}$$

Again, it is necessary to adjust the target emission price, $\sigma_{\text{target},i}$, by the actual emission price, σ_{el}, valid in the year from which the price data originates in order to account for absolute emission prices. Therefore, the difference between the two emission prices is calculated and then multiplied with the respective emission factor at time t, expressed by the fraction in equation (16). The emission factor is computed as the weighted average carbon intensity of the time-variant electricity mix, which is derived based on the carbon intensity E_{type} of each power generation type measured in gCO_2eq/kWh and the time-variant output $G_{type}(t)$ of each source of power generation in kWh.

This approach assumes a yearly constant electricity mix during system lifetime. Since a rising emission price would affect the composition of the electricity mix, the emission scenario can only suggest tendencies caused by a rising emission price and should not be interpreted in detail.

The original model was based on the distinction of four different price phases displayed in Figure 1. The four phases need to be extended to six phases in order to represent all price constellations potentially occurring in the altered model. This is due to the fact that some of the underlying assumptions of the original model are violated. In fact, the dependence of $p^s(t)$ on $p^b(t)$ does not follow the rule defined in (1), when statutory fees are imposed. In that case $p^s(t)$ never obtains the value zero due to the regulatory burden, while the original model is designed for $p^s(t)$ to be zero in case of a negative spot market price.

Therefore, the phases need to be extended as can be seen in Table 3

Based on these phases the term expressing the optimized contribution margin, presented by equation (3), needs to be updated to represent the changed definitions of the electricity prices and the conversion value, and its applicability needs to be validated.

In phase 1, the contribution margin of the vertically integrated system only comprises the revenues from the renewable energy system, since the PtG facility is idle. The contribution margin thus includes the gained electricity price and the subsidy premium, if granted:

$$CM_1(t \mid k_e, k_h) = \left(epex^+(t) + sub \cdot premium(t)\right) \cdot CF(t) \cdot k_e \tag{17}$$

In phase 2, as much power from the renewable energy system is utilized, as the PtG facility can absorb. Any re-

Table 3: Distinction of price phases in the adapted model.

Phase	Original model	Adapted model	PtG operating mode
1	$p^b(t) \geq p^s(t) \geq CV_h \geq 0$	$p^b(t) \geq p^s(t) \geq CV \geq 0$	PtG facility idle
2	$p^b(t) \geq CV_h > p^s(t) \geq 0$	$p^b(t) \geq CV > p^s(t) \geq 0$	Electrolysis from RES power
3	$CV_h > p^b(t) \geq p^s(t) \geq 0$	$CV > p^b(t) \geq p^s(t) \geq 0$	Electrolysis from RES & grid power
4	$CV_h \geq p^s(t) = 0 > p^b(t)$	$CV \geq p^s(t) > p^b(t)$	Electrolysis from grid power
5	n/a	$p^s(t) > p^b(t) \geq CV \geq 0$	PtG facility idle
6	n/a	$p^s(t) > CV > p^b(t)$	Electrolysis from grid power

maining power is fed into the grid. The contribution margin equals:

$$\begin{aligned} CM_2(t \mid k_e, k_h) = & \left(epex^+(t) + sub \cdot premium(t)\right) \cdot CF(t) \cdot k_e \\ & + [CV - p^s(t)] \cdot z(t \mid k_e, k_h) \end{aligned} \tag{18}$$

In phase 3, electricity from the renewable source is absorbed with priority. In case the PtG facility disposes any excess capacity beyond that, grid power is utilized to run the electrolyzer at full capacity:

$$\begin{aligned} CM_3(t \mid k_e, k_h) = & \left(epex^+(t) + sub \cdot premium(t)\right) \cdot CF(t) \cdot k_e \\ & + \left[CV - p^b(t)\right] \cdot k_h \\ & + \left[p^b(t) - p^s(t)\right] \cdot z(t \mid k_e, k_h) \end{aligned} \tag{19}$$

In phase 4, the entire renewable electricity is fed into the grid, or curtailed in case of a negative wholesale electricity price, and only grid-supplied electricity, which is cheaper at those times, is converted in the PtG facility, leading to the contribution margin:

$$\begin{aligned} CM_4(t \mid k_e, k_h) = & \left(epex^+(t) + sub \cdot premium(t)\right) \cdot CF(t) \cdot k_e \\ & + \left[CV - p^b(t)\right] \cdot k_h \end{aligned} \tag{20}$$

Phase 5 exhibits the same operation mode as phase 1 and the operations in phase 6 equal those in phase 4. This means that

$CM_5(t \mid k_e, k_h) = CM_1(t \mid k_e, k_h)$

and $CM_6(t \mid k_e, k_h) = CM_4(t \mid k_e, k_h)$

The contribution margin terms of all phases are aggregated in one term using the auxiliary price variables $p^{b+}(t)$ and $p^+(t)$ from the original model, defined under equation (3), such that:

$$\begin{aligned} CM(t \mid k_e, k_h) = & \left(epex^+(t) + sub \cdot premium(t)\right) \cdot CF(t) \cdot k_e \\ & + \left[p^{b+}(t) - p^b(t)\right] \cdot k_h \\ & + \left[p^+(t) - p^s(t)\right] \cdot z(t \mid k_e, k_h) \end{aligned}$$

(21)[45]

Based on the adapted optimized contribution margin the net present value term can be updated, following the approach of the original model.

The net present value of a vertically integrated system is defined as:

$$\begin{aligned} NPV(k_e, k_h) = (1-\alpha) \cdot L \cdot & \\ & \Big[\left(\Gamma^{ep^+} \cdot \overline{epex^+}_m + sub \cdot \text{ premium } - LCOE\right) \cdot \overline{CF}_m \cdot k_e \\ & + \left(\Gamma_{x\gamma}^{b^+b} \cdot \left(\overline{p^{b+}}_{Tm} - \overline{p^b_{Tm}}\right) - LFCH - LFCO\right) \cdot k_h \\ & + \left(\overline{p^+}_{Tm} - \overline{p^s}_{Tm}\right) \cdot z_{x\gamma}(k_e, k_h)\Big] \end{aligned}$$

(22)[46]

where $\Gamma^{ep^+} = \frac{1}{m} \cdot \int_0^m \frac{epex^+(t)}{\overline{epex}^+_m} \cdot \frac{CF(t)}{\overline{CF}_m} dt$

and $premium = \frac{1}{m} \cdot \int_0^m premium(t) \cdot \frac{CF(t)}{\overline{CF}_m} dt \cdot \frac{\sum_{i=1}^{T_{eeg}} \gamma^i \cdot x^{i-1}}{\sum_{i=1\,1}^{T} \gamma^i \cdot x^{i-1}}$

and $\Gamma_{x\gamma}^{b^+b} = \frac{1}{T \cdot m} \cdot \int_0^{T \cdot m} \frac{p^{b+}(t) - p^b(t)}{\overline{p^{b+}}_{Tm} - \overline{p^b}_{Tm}} \cdot \frac{xy(t)}{\overline{xy}_{Tm}} dt$

and $z_{x\gamma}(k_e, k_h) = \frac{1}{T \cdot m} \cdot \int_0^{T \cdot m} z(t \mid k_e, k_h) \cdot \frac{p^+(t) - p^s(t)}{\overline{p^+}_{Tm} - \overline{p^s}_{Tm}} \cdot \frac{xy(t)}{\overline{xy}_{Tm}} dt$

and $xy(t) = x^{\lfloor \frac{t-1}{m} \rfloor} \cdot \gamma^{\lfloor \frac{t-1}{m} \rfloor + 1}$

Again, the NPV term is composed of the stand-alone NPVs of the renewable energy and power-to-gas subsystems, and the synergistic value obtained by system integration.

Similarly, as done by Glenk and Reichelstein[47], I incorporate the levelized subsidy premium into the stand-alone NPV of a renewable energy system, if a subsidy is granted. Thus, the subsidy is always considered in the NPV of the renewable energy source, independent from the electricity utilization. In case the feed-in requirement is effective, and thus no subsidy is granted for electricity absorbed by the PtG facility, the subsidy is still attributed to the NPV of RES, but at the same time the synergistic value is reduced by the amount of the subsidy premium through $p^s(t)$. The levelization of the premium is necessary, since it is time-variant and the subsidy lifetime, denoted by T_{eeg}, might be shorter than the system lifetime T.

[45] The derivation of all contribution margin terms is shown in the Appendix A.1.

[46] The derivation of the NPV term is based on the updated contribution margin and follows the procedure shown in the Appendix of Glenk and Reichelstein (2019b) under "Proof of Proposition 1" (p. 28-30).

[47] Glenk and Reichelstein (2019a), p. 221.

Furthermore, additional co-variation coefficients were introduced, since the assumption of constant prices during system lifetime is violated by a yearly variation of the prices $p^b(t)$ and $p^s(t)$ in the new model framework, which can result from increasing emission prices or from varying statutory fees. Those price variations are compensated by co-variation coefficients, similarly as in the base model. The new coefficients are computed based on time-variant data over the entire lifetime in the interval $[0, T \cdot m]$, instead of originally over the data of one year and thus in the interval $[0, m]$. This changed approach expresses itself in the mean values of the price variables, present in the second and third NPV term. Those are now computed based on the entire lifetime. For clarity, I denote the mean value of a data series $f(t)$ over the time period $[0, T]$ by $\bar{f}_T$, which equals:

$$\bar{f}_T = \frac{1}{T} \cdot \int_0^T f(t)dt$$

Since the calculation of the stand-alone NPV of the renewable energy source, reflected by the first term of (22), still satisfies the assumption of constant prices over the system lifetime, the respective coefficient Γ^{ep^+} can still be calculated on a one year's basis. Consequently, the relevant mean values are constructed over the time span $[0, m]$ and are denoted by $\overline{epex^+}_m$ and $\overline{CF}_m$.

Finally, the term $xy(t)$ is the product of the yearly degradation factor and the discount factor, scaled down to an hourly granularity. Thus, it corresponds to the term "$\gamma^i \quad x^{i1}$", which expresses the same product, but on a yearly basis. All other terms not defined explicitly, such as $p^{b+}(t)$ and $p^+(t)$, are equally defined as in the base model.

The construction of the NPV framework, based on Boolean parameters throughout all layers of the model, allows for the flexibility to switch between scenarios conveniently, such as changing the subsidy form between production and feed-in premium or waiving the imposed statutory fees on renewable energy consumption. Due to its design the scheme can easily be implemented in programming code.

In order to make the NPV term applicable to hybrid renewable energy systems, further adjustments need to be made.

First of all, the total renewable energy system capacity is defined as the sum of wind turbine and solar PV capacity:

$$k_e = k_{wind} + k_{pv} \tag{23}$$

Now, the combined capacity factor, system price and yearly fixed operating costs are constructed from the respective values of both systems, weighted with the ratio of the installed capacity to the total system capacity, such that:

$$CF(t) = \frac{k_{wind}}{k_e} \cdot CF_{wind}(t) + \frac{k_{pv}}{k_e} \cdot CF_{pv}(t) \tag{24}$$

$$SP_e = \frac{k_{wind}}{k_e} \cdot SP_{wind} + \frac{k_{pv}}{k_e} \cdot SP_{pv} \tag{25}$$

$$F_{ei} = \frac{k_{wind}}{k_e} \cdot F_{wind,t} + \frac{k_{pv}}{k_e} \cdot F_{pv,i} \tag{26}$$

The subsidy premium also needs to be adjusted to the hybrid system by computing the average over the premiums received for each renewable technology, weighted by the time-variant power generation of each renewable system as a proportion of total power generation:

$$\begin{aligned} premium(t) = & \frac{CF_{wind}(t) \cdot k_{wind}}{CF(t) \cdot k_e} \cdot premium_{wind}(t) \\ & + \frac{CF_{pv}(t) \cdot k_{pv}}{CF(t) \cdot k_e} \cdot premium_{pv}(t) \end{aligned} \tag{27}$$

This assignment is convenient, since it does not require any further adaptation of the model, however it is subject to some limitations, which are caused by the design of the regulatory framework.

The two renewable subsystems always need to be scaled either both larger than 750 kW or not exceeding the threshold of 750 kW. This results from the policy framework, which favors smaller systems and therefore burdens consumption of self-produced electricity from small renewable systems not exceeding 750 kW with lower statutory fees. If the wind turbine component was sized above the threshold and solar PV below it, or vice versa, the imputed price of own electricity consumption, $p^s(t)$, would be different for the wind turbine and the solar PV system. This would add a fourth price component to the phase distinction shown in Table 3. Consequently, the number of distinguished phases could increase sixfold and thus complicate the model framework significantly.

Finally, the produced hydrogen quantity is measured at each point in time depending on the phase distinction and broken down to hydrogen production from renewable and grid-supplied electricity (see Table 4).

The variable $z(t|k_e, k_h)$ expresses the amount of renewable power absorbed by the PtG facility at any point in time. The degradation factor $x^{(i-1)}$ accounts for decreasing systems performances of the renewable power generation and the electrolyzer. The conversion rate of hydrogen, η_h, is applied to convert the absorbed power volume to the produced hydrogen volume in kg. The produced hydrogen quantity from grid power in phase 3 includes the term "$[k_h - z(t \mid k_e, k_h)]$", which expresses the excess capacity, that the PtG plant can still provide after all renewable electricity has been absorbed.

Beyond the presented characteristics of the adapted model framework, some of the features, mentioned in the specification of the model requirements in section 2.4.1, are not considered in the model design. Instead they are realized programmatically. This concerns the extension of the permission of own consumption, which would benefit systems exceeding 750 kW by a reduction of the EEG levy, and the option to switch between different operating modes of the PtG facility.

Table 4: Production quantity of hydrogen from the different energy sources.

Phase	Power source of PtG operations	Total hydrogen production	Hydrogen production from RES power	Hydrogen production from grid power
1	n/a	0	0	0
2	RES power	$\eta_h \cdot x^{i-1} \cdot z(t \mid k_e, k_h)$	$\eta_h \cdot x^{i-1} \cdot z(t \mid k_e, k_h)$	0
3	RES & grid power	$\eta_h \cdot x^{i-1} \cdot k_h$	$\eta_h \cdot x^{i-1} \cdot z(t \mid k_e, k_h)$	$\eta_h \cdot x^{i-1} \cdot [k_h - z(t \mid k_e, k_h)]$
4	Grid power	$\eta_h \cdot x^{i-1} \cdot k_h$	0	$\eta_h \cdot x^{i-1} \cdot k_h$
5	n/a	0	0	0
6	Grid power	$\eta_h \cdot x^{i-1} \cdot k_h$	0	$\eta_h \cdot x^{i-1} \cdot k_h$

3. Model implementation

3.1. Tool functionalities

Based on the presented model framework, I developed an easy-to-use application using the programming language Python to facilitate the profitability evaluation of vertically integrated energy systems. The tool provides the functionality to run an optimization analysis for detection of the ideally sized renewable energy system for a fixed PtG facility size, i.e., the capacity ratio which minimizes the break-even price of hydrogen.

Due to the efficient simulation of numerous scenarios along a wide range of capacity combinations the implemented tool has a great advantage compared to conventional analysis tools, like Microsoft Excel. It is better suited for the consumption of the large amounts of data and computations, necessary to solve the described optimization problem. The model input can be easily set by the user through a graphical user interface (GUI) and thus does not require knowledge of any programming language, which makes the tool accessible to businesspeople and policymakers without computer science background.

In addition to the capacity optimization mode, which covers the macro perspective of the profitability analysis, a scenario analysis mode enables a closer inspection of the details of a single case, where both renewable energy source and PtG facility have fixed capacities and a projected hydrogen price is set. This mode is helpful to determine the feasibility of an investment in a specific project.

The transformation of the model framework into the implementation of programming code and, in particular, the optimization problems posed some challenges. Later in this chapter, I will discuss the developed approaches to solve these issues.

Moreover, issues related to the cost allocation of the variable statutory fees and the circular dependency between the electricity consumption volume and the average rate of the variable statutory fees needed to be solved. I will describe the applied solution techniques to these problems and show the implementation of the operating modes of the PtG facility.

Selected screenshots of the implemented tool are shown in the Appendix A.6.

3.2. Allocation of statutory fees

PtG facility operators are granted various exemptions or reliefs from fees on the electricity price. Some of the reliefs are structured in a way that a non-exempt volume of electricity is charged with the base rate of the respective fee, while only beyond this volume a lower rate applies. The amount in excess of the reduced rate, which is charged on the non-exempt volume, must then be allocated adequately to the entire consumption volume.

Generally, the entire cost related to a fee is added up and equally allocated to all units of electricity consumed. The resulting mean value of this fee then directly adds to $fees_{var,i}$. This approach can create anomalies and wrong incentives[48], when one source of electricity is subject to a reduced rate, while electricity from another source is burdened with the full rate. This is the case with regard to the EEG levy, when the size of the renewable energy source does not exceed 750 kW[49]. In this case own consumption is burdened with an EEG levy reduced to 40% of the base rate, while power supply from the grid is subject to the entire EEG levy. As long as total consumption lies below the non-exempt threshold of 1 GWh, intuitively renewable energy is assigned its real fee amounting to 40% of the base rate, and the full rate is assigned to grid power. As soon as consumption exceeds the threshold of 1 GWh, the entire cost from the statutory fee is still allocated with the ratio 40:100 in order to avoid jumps in the assigned levy value and facilitate a continuous development of the assigned cost for varying power consumption scenarios. This results in a lower allocation of the burden to power consumption from the RES for calculative purposes. The mathematical expressions of the resulting EEG levy rates are provided in the Appendix A.2.

3.3. Circularity problem of the variable statutory fees

In addition to the EEG levy, there are other reliefs, which only apply for electricity consumption exceeding a non-exempt volume. Those fees, described in section 2.3, are grouped in the variables $fees^{\mathrm{grid}}_{\mathrm{var,i}}$ and $fees^{\mathrm{res}}_{\mathrm{var},i}$, which express the assigned average fee rates and are part of $p^b(t)$ and $p^s(t)$, based on which the operating hours of the PtG facility are determined in accordance with the distinction of the six presented phases.

This means, that the fee rates have a direct effect on the amount of power absorbed by the PtG plant. At the same

[48] Explanation is shown in the Appendix A.2.

[49] This threshold applies to the wind turbines and solar PV system separately.

time, both rates are determined as an average value based on the entire power consumption. Thus, there is a circular dependency, where the average fee rate affects the consumed electricity volume, while the volume serves as a basis to determine the average rate. This issue can only be solved by the application of an iterative approach, to determine the rates for which both components, electricity consumption and statutory fees, keep the balance.

Therefore, in the first iteration, the consumption volume is determined for the case of $fees_{var,i}^{grid} = fees_{var,i}^{res} = 0$. Based on the resulting consumption volume, now an initial value can be assigned to the statutory fees. Consequently, the prices $p^b(t)$ and $p^s(t)$ increase, which leads to a decrease of the consumption volume, since conversion to hydrogen becomes less profitable. Again, based on the new consumption volume, $fees_{var,i}^{grid}$ and $fees_{var,i}^{res}$ need to be updated. The updated rates will exceed the previous rates, since the fixed cost associated to the non-exempt consumption volume is allocated to less kWh. This, again, increases the prices for renewable and grid electricity, leading to yet another decrease of electricity consumption. This procedure is continued until the electricity consumption and the statutory fees are not exposed to further value changes, which implies that the final values of $fees_{var,i}^{grid}$ and $fees_{var,i}^{res}$ have been identified.

3.4. Implementation of the PtG operating modes

The model framework allows to calculate the NPV of vertically integrated energy systems, which operate in an integrated mode, using grid-supplied power and electricity generated by the own renewable energy system. This integrated mode is expanded by two additional modes, a "RES-only" mode, which only allows the use of power from the renewable energy source and the "Grid-only" mode, which deploys solely grid electricity for electrolysis. Those operating modes are only programmatically realized following a straightforward approach.

To implement the "RES-only" mode, I set the value of $p^b(t) > CV$ at all times. This guarantees that electricity supplied by the public grid is not utilized for power conversion at any point in time. In reference to the phase distinction in Table 3, it would have the effect that the phases 3, 4 and 6 never occurred. The same logic applies for the "Grid-only" mode based on the value assignment $p^s(t) > CV$, which prevents the phases 2 - 4 from happening.

This simple approach is beneficial, since it does not require any adaptation of the NPV framework.

3.5. Break-even price detection

As defined by Glenk and Reichelstein, a vertically integrated system breaks even, if its net present value equals the sum of the non-negative stand-alone NPVs of its subsystems, such that:

$$NPV\left(k_e, k_h\right) = \max\left\{NPV\left(k_e, 0\right), 0\right\} + \max\left\{NPV\left(0, k_h\right), 0\right\} \quad (28)$$ [50]

Consequently, an integrated system must compensate for the negative stand-alone NPVs of its components, while their positive NPVs are not attributed to the NPV of the integrated system for the purpose of determining its break-even point. Thus, a system's hydrogen price is considered its break-even price, if above-listed equation holds.

The break-even price of a vertically integrated energy system is detected by iteratively calculating its NPV while changing the value assigned to the hydrogen price until the break-even condition of Equation (28) is met.

The NPV term can be expressed as the stand-alone NPVs of its components – renewable energy system and PtG facility – plus the synergistic term resulting from their (vertical) integration:

$$NPV\left(k_e, k_h\right) = NPV\left(k_e, 0\right) + NPV\left(0, k_h\right) + NPV(synergies). \quad (29)$$

From now on, I denote the NPV components as: $NPV_{RES} = NPV\left(k_e, 0\right)$ and $NPV_{PtG} = NPV\left(0, k_h\right)$ and $NPV_{syn} = NPV(synergies)$.

The general behavior of the different NPV components for a varying hydrogen price is illustrated in Figure 2.

When the hydrogen price is modified, both the NPV of the PtG facility (NPV_{PtG}) and the value of synergies (NPV_{RES}) are affected, while the NPV of the renewable energy system (NPV_{RES}) remains unchanged, since it is unrelated to the price of hydrogen. Both NPV_{PtG} and NPV_{RES} can evaluate to negative or positive values.

For the break-even detection algorithm, it is convenient to differentiate between scenarios with a positive or negative stand-alone net present value of the RES, since NPV_{RES} remains constant.

Suppose the renewable energy system is profitable on its own ($NPV_{RES} \geq 0$).

1. Combining equation (28) and (29), we obtain for the case of $NPV_{PtG} < 0$:

$$NPV_{PtG} + NPV_{syn} = 0 \quad (30)$$

2. For the case of $NPV_{PtG} \geq 0$, we obtain:

$$NPV_{syn} = 0 \quad (31)$$

The second case can only occur for hydrogen prices close to zero, so that it is never favorable to convert power from the renewable energy source to hydrogen and thus no synergies of an integrated system exist.

For the low values of hydrogen prices where this applies, a PtG facility is never profitable considering current and projected future system prices. Therefore, ii) can be neglected and in case of a positive net present value of the RES, a break-even price is defined where equation (30) holds.

Now suppose the renewable energy system on its own shows a negative NPV ($NPV_{RES} < 0$).

[50] Glenk and Reichelstein (2019b), p. 14.
[51] Own figure.

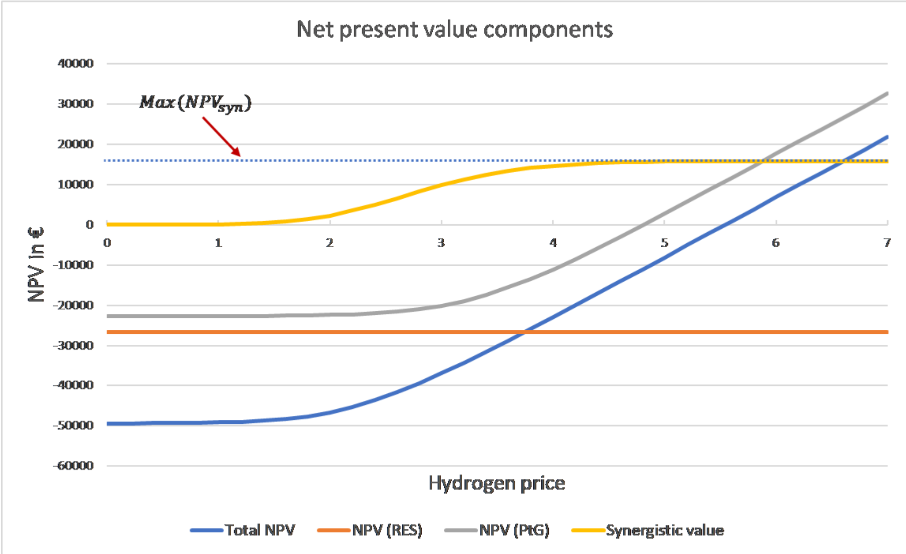

Figure 2: Development of the NPV components at a variation of the hydrogen price.[51]

1. For the case of $NPV_{PtG} < 0$ we obtain as break-even condition:

$$NPV(k_e, k_h) = 0 \tag{32}$$

2. For the case of $NPV_{PtG} \geq 0$ the condition evaluates to:

$$NPV_{RES} + NPV_{syn} = 0 \tag{33}$$

In a nutshell, the value of synergies in any case must make up for a negative NPV of at least one of the subsystems. The value of synergies only increases – at an increasing hydrogen price – as long as additional renewable power can be absorbed by the PtG facility. At some point either the entire power generation is absorbed or the electrolyzer runs on full load, which means that no additional power can be converted to hydrogen and thus no further improvement of NPV_{syn} can be realized. Thus, the synergistic value does not scale infinitely, unlike NPV_{PtG}, but possesses an upper bound and a maximum value.[52] If the maximum value lies below the absolute value of a negative NPV_{RES}, which remains constant, then the conditions 32 and 33 can never hold and a break-even price is not defined. In such a case the vertically integrated system cannot be cost-competitive compared to a stand-alone PtG facility.

Consequently, a vertically integrated system can only break even if:

$$NPV_{syn}^{\max} \geq |\min\{NPV_{RES}; 0\}| \tag{34}$$

The algorithm for the detection of the break-even price of a vertically integrated system is based on the preceding insights. First of all, it distinguishes between a profitable and a loss-making renewable energy subsystem.

For the former a break-even price always exists and is present for the hydrogen price, that satisfies the condition defined in equation (30).

In case of a loss-making RES, first of all it needs to be verified whether a break-even price is defined according to equation (34). If that is the case, initially the break-even price is searched using the condition stated in equation (32), which requires the entire NPV to be zero. Any identified break-even price candidate is only valid if $NPV_{PtG} < 0$, which is a prerequisite for the applicability of equation (32). In case of $NPV_{PtG} \geq 0$, search is continued using equation (33) until eventually the break-even price is found for the case $NPV_{RES} < 0$ and $NPV_{PtG} \geq 0$.

Hence, there are three different break-even terms, which must evaluate to zero for detection of a break-even price and vary depending on the NPV constellation of the subsystems (see Table 5).

From now on, I refer to the term to the left of the equal sign, which needs to be zeroed to detect the break-even price of a system, as the break-even term or simply term. All terms follow the same approach, in order to detect the break-even price of hydrogen. First of all, the term value is computed for an arbitrary start value of the hydrogen price. Depending on the sign (+/-) of the resulting value of the break-even term, in the next step another arbitrary value is selected above or below the start value. The actual algorithm can only unfold after these initial steps have been conducted. Now the approximation can be treated as a linear interpolation (or extrapolation) problem with the goal to identify the price at which the break-even term equals zero – i.e., the break-even price. For that purpose, in each iteration the break-even price is guessed based on the last two result values of the relevant break-even term and the tested prices. Based on those two points a linear curve can be constructed for a coordinate system with the vertical axis "Term value" and the horizontal axis "Price of hydrogen". Based on the curve function, which

[52]Proof is shown in the Appendix A.3 and A.4.

Table 5: Break-even conditions of a vertically integrated system.

NPVs of subsystems	Break-even condition
$NPV_{RES} \geq 0$	$NPV_{PtG} + NPV_{syn} = 0$
$NPV_{RES} < 0$ and $NPV_{PtG} < 0$	$NPV(k_e, k_h) = 0$
$NPV_{RES} < 0$ and $NPV_{PtG} \geq 0$	$NPV_{RES} + NPV_{syn} = 0$

is defined by its slope and vertical intercept, the term value is zeroed in order to calculate the next break-even price candidate. The real result of the relevant term value is computed by applying the price candidate, thus adding another data point. Based on the new data point a more precise break-even price candidate can be computed, again based on the last two points in the described coordinate system. This procedure is continued until the result value of the break-even term lies within a threshold close enough to zero, which is the stopping condition of the algorithm. The break-even price candidate meeting this condition first, is the sufficiently approximated break-even price of a vertically integrated system. The general procedure of the algorithm is illustrated in Figure 3.

3.6. Capacity optimization algorithm

The NPV model framework allows to calculate the net present value of a vertically integrated system, with fixed renewable energy and power-to-gas nameplate capacities and for a proposed hydrogen price. In section 3.5, I described how the framework can be utilized in order to derive the break-even price of hydrogen for a specified system with a fixed subsystem capacity ratio. As a next step, the break-even price can be leveraged to compare differently sized systems regarding their profitability and identify the ideal capacity ratio of the renewable energy system and the power-to-gas facility.

Generally, the search for an optimal capacity ratio could be easily solved by calculating the break-even price for a wide range of capacity combinations. This simple approach, though, would be very time-consuming, since the break-even price of hydrogen – itself already evoking multiple NPV calculations – would need to be calculated for numerous capacity combinations. Therefore, the derivation of the price minimizing capacity ratio of just one scenario could take several hours due to the inefficient approach.

In order to speed up this process and to create an agile tool, a capacity optimization algorithm is proposed, which can detect the price minimizing capacity of the renewable source for a given PtG facility size. This algorithm should also offer an adequate reconstruction of the break-even price curve.

From now on, the PtG system size is taken as a fixed value, while only the RES capacity is altered for optimization of the subsystem ratio.

The proposed algorithm is divided into the following subtasks: First, the whole capacity range is divided into its largest subintervals, in which the break-even price function is continuous. Next, for each subinterval the range is identified, where the break-even price function is defined. This range is denoted as the domain of the break-even price function. Then each identified domain is checked for extreme points and the general curve properties are sampled. The data points, collected in this process, will be enriched, wherever more detail is necessary in order to reduce the error of the resulting break-even price curve. In a final step, linear interpolation is applied on all collected data points in order to retrieve the final break-even price curve. Based on the derived price curve the profitability of the selected PtG facility can be analyzed for an integration with differently sized renewable energy systems. The price curve also allows to identify the ideal capacity ratio of the subsystems.

3.6.1. Division into subintervals

First of all, it is necessary to split up the whole capacity range of the renewable energy system into subintervals, within which the break-even price curve satisfies the condition of a continuous function, i.e., where it does not exhibit jumps in the function value. Those jumps can arise from the design of the regulatory framework. Considering the presented regulations, jumps can appear at the thresholds of 750 kW and 10 MW.

The jump at 750 kW, primarily, results from the increased EEG levy charged for the consumption of renewable power when the renewable energy source exceeds 750 kW. Secondly, for systems exceeding 750 kW the EEG subsidy value is determined by auctions instead of relying on the legally defined amount and thus, can be based on different values.

Another jump exists for systems including solar PV at 10 MW, since no subsidy is granted to open space solar PV installations above that threshold. Vertically integrated systems based on wind power only are not subject to the jump at 10 MW.

For a vertically integrated system with a hybrid renewable energy source the resulting subintervals would be:

[0 kW; 750 kW] and] 750 kW; 10 MW] and] 10 MW; 100 MW]

If no solar PV system is included the subintervals reduce to:

[0 kW; 750 kW] and] 750 kW; 100 MW]

The threshold of 100 MW was arbitrarily selected as an upper bound of the analyzed capacities.

3.6.2. Detection of the break-even price domain

Next, for each of the resulting subintervals the domain of the break-even price function needs to be determined by excluding any capacity ranges, where a break-even price is not

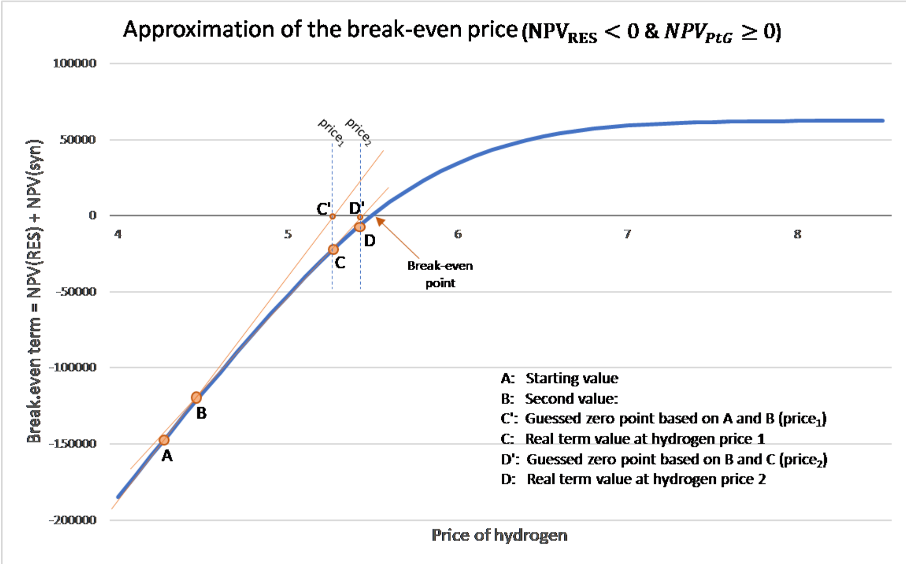

Figure 3: Procedure of the break-even price detection algorithm.

defined according to equation (34). This is the case where the absolute value of a negative NPV of the renewable energy system exceeds the maximum attainable synergistic value.

In order to verify which range satisfies the break-even condition, again, the distinction between stand-alone profitable and loss-making renewable energy systems is made. Remember, a break-even price is defined in the entire subinterval if the renewable energy source exhibits a positive stand-alone NPV, while the synergistic value might not be able to compensate for the loss of a highly negative NPV of the renewable source.

Therefore, I analyzed scenarios with a negative NPV_{RES} regarding their maximum value of synergies $NPV_{syn}^{\max}$[53] for an increasing RES capacity k_e. While NPV_{RES} always scales with factor k_e and thus proportionally to the sizing of the renewable source, $NPV_{syn}^{\max}$ can scale with a factor slightly above k_e for low values of k_e. For larger renewable energy systems, the growth factor of $NPV_{syn}^{\max}$ decreases toward zero.[54]

As an example, the development of the ratio of $NPV_{syn}^{\max}$ to the absolute NPV_{RES} is displayed in Figure 4. It shows to which degree the negative NPV of the renewable energy system can be compensated for by the maximum attainable synergistic value. A break-even price is only defined in the area, where the degree of compensation lies above 100%. The ratio curve does not in every case cross the threshold of 1, it might also lie entirely above or below the threshold.

In order to retrieve the bounds of the defined area, denoted as domain, the intersections of the ratio curve and the threshold line must be detected. They occur where:

$$\frac{NPV_{Syn}}{|NPV_{RES}|} = 1 \tag{35}$$

The algorithm to identify the boundaries of the domain proceeds in the following way: First the ratio is calculated at the borders of the subinterval. If the ratio already lies above 1 at both borders, any point in between also exhibits a ratio above 100% and therefore the break-even price can be computed in the entire range of the subinterval. If only one of the borders exhibits a ratio above 1, the other border must be searched for by application of a search algorithm described below. If none of the borders shows a ratio above the threshold, there might still be a range for which a break-even price is defined, if the ratio value is increasing at the left border of the subinterval, as shown in Figure 4. If the ratio is decreasing right from the subinterval's left border, the entire subinterval can be excluded from further analysis since a break-even price is not defined for any k_e. This is owed to the construction of the NPV of synergies, whose value development depends on two terms with reverse tendencies. One of them has an increasing and the other a reducing effect on the synergistic value. In some scenarios the increasing effect is stronger for small values of k_e resulting in an over proportional increase of NPV_{syn}^{max} compared to NPV_{RES} and thus the potential to exceed the negative NPV of the renewable source, even when the ratio at the left border lies below 1.[56] If this increasing tendency is not present at the left border, than it will not appear with an increasing k_e either and the respective subinterval can be excluded from the analysis.

The search algorithm for the domain borders follows an easy approach and does not require an optimization, since the performed calculations are not computationally expensive, and the algorithm is only applied rarely throughout program run.

Starting from the subinterval borders, the next compensation ratio is computed at the center of the subinterval. If

[53] Compare findings in the Appendix A.3 and A.4.
[54] Explanation is shown in the Appendix A.5.
[55] Own figure.

[56] Explanation is shown in the Appendix A.5.

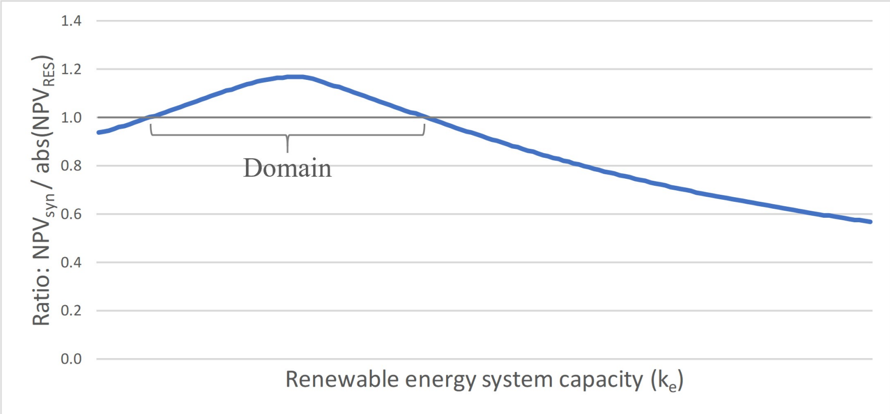

Figure 4: Degree of compensation of a negative stand-alone NPV of the renewable source.[55]

the resulting ratio is above 1, it lies within the domain and search must continue to the left or right of the current center, depending on whether the domain's left or right bound is searched for. Assuming that we are trying to locate the left border of the defined area, then the current center point would be set as the new right border of the search range and the next ratio would be computed for the center between the original left border and the new right border. If the center point exhibits a ratio below 1, meaning it is located outside of the defined area, it needs to be checked if the center point lies to the left or right of the domain. This can be detected by computing the ratio for a second point next to the current center to find out if the ratio is increasing or decreasing at the center point. Now, if the center lies to the left/right of the domain, it would replace the left/right border of the search range, respectively.

This procedure is continued until the searched domain border is approximated sufficiently. In the event no defined range was detected, the algorithm terminates, when the distance between the borders of the search range undercuts a threshold. For subintervals, where the domain lies somewhere in the middle of the range, this procedure is conducted twice, for the left and right domain border. The procedure is illustrated in Figure 5.

3.6.3. Detection of the minimum break-even price and reconstruction of the price curve

After the derivation of the area where a break-even price can be computed, the curve needs to be sampled in the domain in order to retrieve the curve characteristics and identify the extreme points. Particularly, the capacity of the renewable source k_e, where the break-even price of hydrogen reaches its minimum value, shall be detected.

Based on sample data, generated for a wide range of scenarios, it became evident, that the derivative of the break-even price curve with respect to k_e has at most one sign change (+/-) indicating the existence of a local extreme point. In some cases the price curve is even monotone decreasing or increasing and thus the derivative does not exhibit any sign change. The existence of a local minimum seems to be the prevalent characteristic of scenarios, for integrated systems with a loss-making renewable energy subsystem, while in case of a positive NPV_{RES} the price curve generally does not exhibit an extremum within the range. Instead the minimum price would lie at one of the domain borders. Compare Figure 6 and Figure 7 for typical break-even price curves of the respective vertically integrated systems.

The algorithm for detection of the minimum break-even price builds on the described insights. It applies varying approaches depending on the monotonicity of the price curve and therefore distinguishes between curves with a sign change of the derivative and those without.

Similar to the domain search algorithm, the capacity optimization algorithm starts by computing the function gradients, i.e., the values of the derivative, at the left and right border. The gradients are derived based on two neighboring points with a minimal offset in k_e and thus indicate the curve development in their proximate neighborhood. They are computed by subtracting the break-even price at one point from the break-even price at a neighboring point and dividing by the offset, such that:

$$\text{gradient}\,(k_e) = \frac{\text{price}_{k_e+\text{offset}} - \text{price}_{k_e}}{\text{offset}} \tag{36}$$

Next, the gradient is computed at the center point of the interval. In the following the left or right interval border is replaced by the center in a way that the critical point is located between the new borders. This manner of approximating the critical point corresponds to the procedure of the domain search algorithm. The critical point denotes the extreme point, where the gradient value is zero, in case of a sign change of the derivative. If no sign change can be observed,

[57] Own figure.

[58] Own figure.
[59] Own figure.

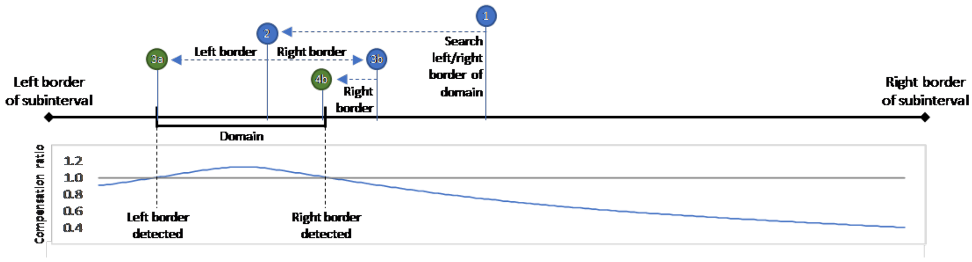

Figure 5: Algorithm of the detection of the domain borders.[57]

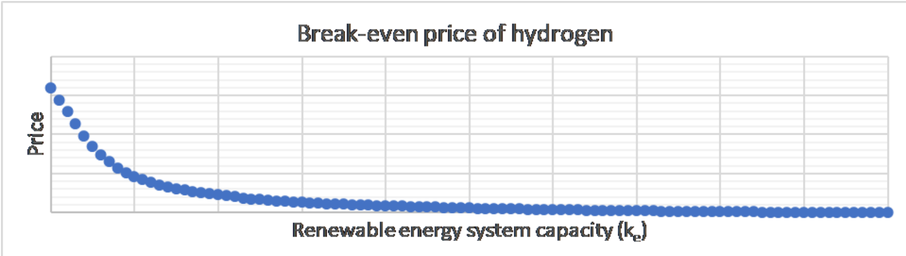

Figure 6: Typical break-even price curve for a system with a positive NPV_{RES}.[58]

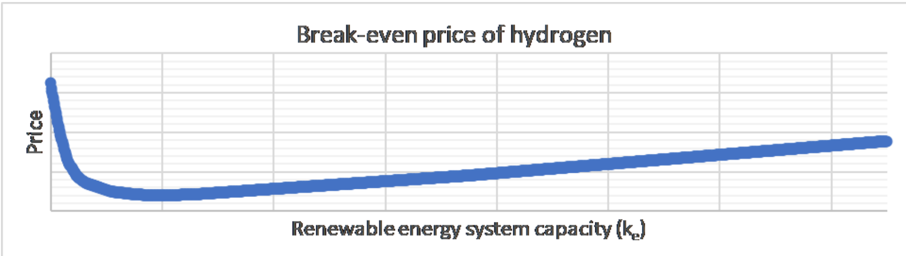

Figure 7: Typical break-even price curve for a system with a negative NPV_{RES}.[59]

the critical point refers to the area exhibiting the highest variation of the derivative, which is explored, in order to enable an adequate reconstruction of the price curve.

The application of the algorithm in this manner can lead to high inefficiencies, since each derivation of a break-even price is computationally expensive and the calculation of a gradient is based on two break-even prices and thus doubles the cost of computation. Several price curves from the produced sample data showed a high variation of the gradients only in a very limited range of the domain, while in the remaining parts the gradient only changes marginally. In such a case, the approach of a plain selection of the center point to approximate the critical point produces many data points with low significance. To avoid that, I followed a method, which enables approaching the critical point more quickly, in a partly expontential way. Therefore, the gradients at the three computed points – left/right border and intermediate point – are compared. When there is only a marginal change between the gradients at one border and the mid point, then it is expected that the critical area is considerably closer to the opposite border. I refer to this constellation as a border-sided extremum. Under those circumstances it is beneficial to move quickly toward the respective border and not simply select the center point of the interval. Whenever a border-sided extremum appears, in the first step the mid point is selected at that tertile of the current range, which is closest to the respective border, in the next steps at the quartile, quintile and so forth, thus moving quicker in each iteration toward the respective border, where the critical point seems to be located.

Provided that there is no sign change between the left and mid gradient, the condition to initiate the exponential approximation in case of a right border-sided extremum is:

$$\frac{\left|\text{gradient}_{\text{mid}} - \text{gradient}_{\text{left}}\right|}{\left|\text{gradient}_{\text{mid}} - \text{gradient}_{\text{right}}\right|} \leq 0.2 \tag{37}$$

Conversely, a left border-sided extremum is expected if the right and mid gradient have the same sign, and when:

$$\frac{\left|\text{gradient}_{\text{mid}} - \text{gradient}_{\text{right}}\right|}{\left|\text{gradient}_{\text{mid}} - \text{gradient}_{\text{left}}\right|} \leq 0.2 \tag{38}$$

In a nutshell, if the difference between the gradient at the mid point and at one of the borders is considerably lower than the difference between the gradient at the mid point and at the opposite border, the critical point is searched by exponentially approaching the opposite border.

The conditions 37 and 38 are verified after each selection of a new mid point. When none of the two criteria holds, the mid point is selected at the center of the current interval, following the conventional method. Each time the condition for a border-sided extremum is entered from another category, the selection of the intermediate point starts again at the tertile.

The algorithm has two stopping conditions, one of them treating the case of a local extreme point, the other taking effect when the underlying price curve is monotone.

In case of the former, the algorithm stops, when the distance between the current left and right border lies within a precision threshold. The latter can terminate on two criteria, but always presumes that all gradients show the same sign. Either, again, the distance between the current left and right border lies within a precision threshold, or the difference between the gradients at the left border, mid point and right border is only marginal, which implies that the underlying curve is practically linear.

The applied precision threshold is computed in each iteration as a proportion of the mean value of the current range and thus is adjusted to the system scale. This leads to a higher accuracy of the critical point, in absolute terms, for small systems compared to large-scale renewable energy subsystems and increases computation efficiency when deriving the ideal capacity ratio of a large-scale vertically integrated system, where a variation of the detected ideal capacity by a few kW does not have a high impact.

3.6.4. Curve enrichment

After termination of the algorithm, which provides a rough reconstruction of the break-even price curve, the collected data points are checked for major gaps, which might lead to inaccuracies of the result data. For that purpose, each pair of neighboring gradient data is compared, and the maximum potential error between the two points is calculated.

The approach for the derivation of the maximum error is illustrated in Figure 8. At each capacity of RES k_e, for which a gradient has been computed, the tangent to the break-even price curve can be constructed from the gradient, which equals the slope of the tangent, and the data point itself.

Then, for each neighboring data pair (A,B) the intersection I of their tangents is calculated. As a second step, the break-even price is calculated for the capacity k_e, where I is located, based on a direct line between the points A and B. The difference between the break-even prices of the points C and I (red line) represents the maximum potential error of the break-even price between the neighboring data points A and B, when applying linear interpolation. It should be noted that the calculated maximum error generally overestimates the real error, while it always constitutes an upper bound for the real error. Areas with a high break-even price, compared to the computed minimum price, are disregarded for the curve enrichment, since they have a low significance and their computation can be avoided.

3.6.5. Linear interpolation

As the last step, all collected data points are interpolated linearly to produce a curve plot, which allows to visually analyze the profitability of various system combinations and identify the price-minimizing capacity ratio of the renewable energy system and the power-to-gas facility.

4. Scenario evaluation

I now use the adapted model framework and apply the developed optimization algorithm on a vertically integrated system assuming a range of scenarios with different policy designs.

4.1. Model input selection

The calculations are conducted for an investment in a vertically integrated energy system in Germany with an expected project lifetime of 30 years and a guaranteed EEG subsidy during the first 20 years of operation. The projected investment starts in 2020, but I use electricity price data and power generation data for simulation of the renewable energy sources from the year 2015. I assume costs of capital of 4%[60] and an effective corporate income tax rate of 30%.[61] Concerning the depreciation of the fixed assets, for simplification I apply the depreciation schedule valid for wind turbines to the entire system. Thus, the investment cost is depreciated linearly over a period of 16 years.[62]

My calculations are based on the use of a polymer electrolyte membrane (PEM) electrolyzer, since PEM electrolyzers can operate dynamically at a wide range of loads and react quickly due to a short system response time within milliseconds[63], while technically more mature Alkaline electrolyzers are only capable of operating at low partial load ranges and can lack in hydrogen purity depending on the load. They are also inferior to PEM electrolyzers in terms of dynamic operations.[64]

For the system prices of the power-to-gas facility I rely on the price and cost regression of electrolyzers derived by Glenk and Reichelstein[65]. I only adjust the cost of the electrolyzer, which is the main component of the power-to-gas facility, since it has been and will be subject to significant price drops in the recent and coming years. This price adjustment is based on an average annual price drop rate of 4.77%, which was found by the authors through regression of the price development of PEM electrolyzers between the years 2003 and 2016.

Additionally, the fixed operating costs, which are generally expressed as a percentage of the system price, must also

[60]Data sources: Noothout et al. (2016), p.40 and ZSW and Bosch & Partner GmbH (2019), p. 43.

[61]Data source: OECD (2018).

[62]Bundesfinanzhof (2011). Ruling of the Federal Fiscal Court of Germany.

[63]Cf. Schmidt et al. (2017), p. 30472.

[64]Cf. Carmo et al. (2013), p. 4903-4904.

[65]Data source: Glenk and Reichelstein (2019b), p. 217-218.

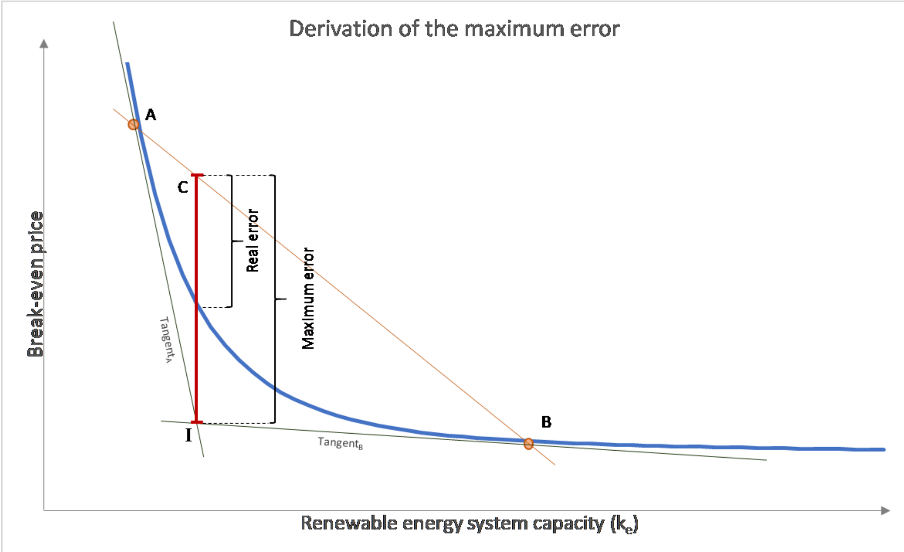

Figure 8: Approach to calculate the maximum price error between two neighboring points.

be adjusted. For my calculation I assume operational expenditure (OpEx) amounting to 2%[66] of the capital expenditure (CapEx), which coincides with the cost ratio present in the work of Glenk and Reichelstein.

Thus, the system price of the electrolyzer reduces from 1863 € /kW[67] to 1459 € /kW in 2020. For the remaining PtG cost factors, such as foundation, access, power connection, compression, which are valued at 424 € /kW, I do not assume price reductions. The system price of the entire PtG facility totals 1883 € /kW and the respective fixed operating costs amount to 37.66 € /kW.

Regarding the wind turbine, I assume a system price of 1180 € /kW and fixed operating costs of 38 € /kW.[68]

For the current system price and fixed operating costs of solar PV, I rely on a report prepared for the Federal Ministry for Economic Affairs and Energy of Germany, which found the current cost of solar PV systems – including inverter, mounting system, grid access, solar PV modules, planning and installation – at 770 € /kWp for open space installations with a nameplate capacity of at least 750 kW. The fixed operating costs are estimated 15 € /kW with a yearly growth factor of 1.5%.[69] Based on formulas of mathematical finance the growing operating costs are converted to an annuity over the system lifetime using the cost of capital as interest rate. The calculated yearly fixed operating costs result in a constant amount of 18 € /kW.

It should be noted that these are only average prices, since the CapEx and OpEx generally reduce with higher system scales.[70]

[66]Data source: Bertuccioli et al. (2014), p. 14.
[67]System price of PEM electrolyzers in 2015.
[68]Data source: Glenk and Reichelstein (2019a), p. 32.
[69]Data source: ZSW and Bosch & Partner GmbH (2019), p. 41-44.
[70]Cf. Bertuccioli et al. (2014), p. 14.

The yearly degradation rate of solar PV systems lies in the range of 0.4 – 0.7%.[71] Wind turbines are also impacted by degradation over their lifetime and an annual rate of 0.6% is assumed, which can be lowered by increased operations and maintenance procedures, such as blade erosion repair.[72]

The system lifetime and degradation of PEM electrolyzers has not received enough attention in research and is still changing significantly due to technological enhancements. Today many researchers expect a lifetime of up to 60,000 hours.[73] Those lifetime measures are generally not put into perspective by indicating the remaining electrolyzer capacity after a system reaches its lifetime. Though, Proton OnSite, a producer of electrolyzers, has "stated that it has achieved 60,000 hours lifetime in its commercial stacks without any detected voltage decay."[74] This implies that electrolyzers might already reach operating hours well above the often cited 60,000 hours. Degradation is at least to some degree reversible, e.g., by treatment with dilute sulfur acid.[75] Therefore, I account for potential degradation of the PtG system by applying additional maintenance fees at the cost of 1% of the system price, to recover electrolyzer efficiency. This requires an adjustment of OpEx of the PtG facility to the amount of 56.50 € /kW. Apart from that correction, I apply a unique degradation rate to the entire vertically integrated system amounting to 0.6%, which is consistent with the wind turbine and solar PV system components.

The summarized cost and degradation measures of the vertically integrated system are displayed in Table 6.

For simulation of the power generation by the wind turbine and solar PV system, I rely on the same wind turbine

[71]Data source: ZSW and Bosch & Partner GmbH (2019), p.44.
[72]Cf. Rubert et al. (2017), p. 12-13.
[73]Cf. Schmidt et al. (2017), p. 30472.
[74]Price (2017), p.50.
[75]Cf. Sun et al. (2014), Abstract.

Table 6: Technological system specifications.

	Wind turbine	Solar PV	Power-to-gas
System price	1180.00 € /kW	770.00 € /kW	1883.00 € /kW
Fixed operating costs	38.00 € /kW	18.00 € /kW	56.50 € /kW
Degradation factor	0.994		

capacity factors as Glenk and Reichelstein.[76] I obtained solar PV production data for Germany in 2015 from a tool provided by Pfenninger and Staffell. The average capacity factors are 30.31% for the wind turbine data and 12.85% for the solar PV data.

The electricity prices are based on the day-ahead auction price at the EPEX spot market from 2015. The mean electricity price of the respective year amounted to 3.16 € ct/kWh. In addition, a markup on grid-supplied electricity is necessary to account for the cost of electricity trading, which is estimated at 1.00 € ct/kWh.[77] Furthermore, a range of statutory fees is charged on grid-supplied and own electricity consumption, as described in section 2.3.

The statutory fee rates effective in 2020 are shown in Table 7.

There are no fixed fees charged on the use of renewable power, the fixed fees for grid-supplied power are composed of 1) and 2). The variable fees are determined in an iterative approach, which I described in section 3.3. The variable fees of renewable energy are only based on the EEG levy, while variable fees imposed on grid power are composed of items 3) to 6).

The conversion value of hydrogen depends on the conversion rate of hydrogen and the variable cost of hydrogen production. Additionally, in the event of onsite utilization, the avoided transportation cost is attributed to the conversion value.

The conversion rate is defined as the hydrogen output in kg per kWh of electricity utilized. For the calculation of the conversion rate I assume an electricity input of 48 kWh/kg, which corresponds to an electrolyzer efficiency of 68%[79], and an electricity intensity of the hydrogen compression amounting to 2-4 kWh/kg.[80] This amount considers the compression from the output pressure of the electrolyzer, assumed at ambient pressure, to 350 bar, a pressure level suitable for hydrogen storage or sale.

When combining the electricity consumption of conversion and compression, the conversion rate amounts to:

$$\eta_h = \frac{1\ kg}{52kWh} \approx 0.01923 \frac{kg}{kWh}. \tag{39}$$

For the variable operating costs of the PtG facility, I rely on the value assigned by Glenk and Reichelstein and therefore define $w_h = 0.10€\ /kg$.[81]

The cost of transportation depend very much on the specific use case. For the scenario of onsite hydrogen utilization, I consider an avoided distribution cost accounting for transportation by compressed gas trailer trucks for a distance of 300 km amounting to 1.05 € /kg[82].

Furthermore, the conversion value could be increased by the contribution margin resulting from the sale or use of oxygen, if the oxygen by-product is captured. In that case the price of oxygen and any additional variable and fixed cost components need to be considered.

There is a market for industrial and medical oxygen. While medical oxygen might yield a higher contribution margin, it could also be subject to stricter regulation. Since only few and almost no recent research articles seem to exist on the economic potential of oxygen, I rely on a price range between 24 and 40 $/t, which is the cost for industrial on-site oxygen production based on vacuum pressure swing adsorption.[83] I assume the average value, which corresponds to a price of 0.03 € /kg[84]. Higher prices might be achievable, since the produced oxygen possesses a high purity and is therefore suitable for the sale as medical oxygen.

Due to a lack of details about the subsequent processing of oxygen and which additional investments might be required, I account for no further costs. I consider this approach sufficient for an initial evaluation of the economic potential of the oxygen by-product. However, it remains unclear if additional compression capacity needs be acquired for the compression of oxygen, or if the existing compressor can be shared between hydrogen and oxygen.

The EEG subsidy premium is calculated as the difference between the guaranteed subsidy value[85] and the observed market prices of electricity, which are published on a monthly basis.[86] Renewable energy systems with a size up to 750 kW can rely on legally defined subsidy values, while systems above that threshold need to participate in auctions to get a subsidy granted. Thus, for systems exceeding 750 kW, I assume the weighted average value of the accepted auction bids[87] in 2019. As a result, the corresponding subsidy val-

[76]Data source: Pfenninger and Staffell (2016). Tool accessible at `https://www.renewables.ninja/`.
[77]Data source: Glenk and Reichelstein (2019a), p. 33.
[78]Refer for legal sources to section 2.3.
[79]Data source: Bertuccioli et al. (2014), p. 62. Electricity input and LHV efficiency estimates for 2020.
[80]Data source: Gardiner (2009), p. 3.
[81]Data source: Glenk and Reichelstein (2019a), p. 32.
[82]Data source: International Energy Agency (2019), p. 80: 1.20 $/kg; Conversion with the avg. exchange rate of Q1-Q3 2019: 1.1238 $/€ (European Central Bank (2019), p. 73).
[83]Data source: Dorris et al. (2016), p. 19.
[84]Conversion with the avg. exchange rate of Q1-Q3 2019: 1.1238 $/€ (European Central Bank (2019), p. 73).
[85]German term: "Anzulegender Wert".
[86]Cf. Netztransparenz (2019).
[87]Data source: Bundesnetzagentur (2019b).

Table 7: Current rates of statutory fees (in € ct/kWh).[78]

	Base rate	Reduced rate (above 1 GWh)	Own consumption	Grid consumption
1) Concession charge	0.110	-	-	X
2) Levy for interruptible loads	0.007	-	-	X
3) EEG levy (base rate)	6.756	0.100	40% / 100%	100%
4) CHP levy	0.226	0.030	-	X
5) Offshore grid levy	0.416	0.030	-	X
6) § 19 StromNEV levy	0.358	0.025	-	X
7) Transmission charge	Exempt			
8) Electricity tax	Exempt			

ues for wind turbines and solar PV systems amount to 6.17 € ct/kWh and 5.84 € ct/kWh, respectively. The subsidy values for small systems are determined based on the results of past auctions and are published on the website of the Federal Network Agency. Systems installed in January 2020 are supported with a subsidy amounting to 6.04 € ct/kWh for wind turbines and 7.20 € ct/kWh for open space solar PV installations.[88]

The subsidy value granted to wind turbines is adjusted to account for performance differences due to the turbine location. According to § 36h EEG, the proportion of the real electricity output to a reference output, determined by independent experts for each wind turbine type, needs to be calculated. Based on the computed proportion, the subsidy value from the auction bid is increased or decreased in accordance with a factor defined in the mentioned EEG section.

In this case, the reference output, which refers to a wind turbine of type Enercon E101 with a hub height of 149 m and a nameplate capacity of 3050 kW, is specified for a five years period at 49,221,048 kWh.[89]

The real output of the wind turbine in its first five years, based on the average capacity factor, the degradation rate and m as the number of hours per year, is determined by:

$$output_{Y1-Y5} = \sum_{i=1}^{5} 3050kW \cdot CF \cdot m \cdot x^{1-i}. \qquad (40)$$

The resulting electricity output adds up to 40,982,915 kWh, which corresponds to a proportion of 83.3% and leads to an adjustment with the factor 1.1303.

Consequently, the subsidy values granted to wind turbine operators increase to 6.97 € ct/kWh for turbines exceeding 750 kW and 6.83 € ct/kWh for smaller turbines. Eventually, the monthly subsidy premium is derived by deducting the gained market price from the respective subsidy value. The monthly premium is expressed on an hourly basis by the variable premium(t).

Finally, the input variables for the scenario accounting for emission prices need to be defined. The EU ETS regulates the allocation and trading of emission allowances. In general, both electricity generators and industrial installations of specific branches, including the production of hydrogen by reforming or partial oxidation, are subject to EU ETS regulations and therefore need to acquire emission allowances.

While power suppliers do not receive free allowances since 2013, allowances are allocated to industrial installations free of charge for a gradually decreasing proportion of their total emissions.[90] Furthermore, some activities receive 100% free allowances, if they belong to a sector with exposure to carbon leakage. Since such a waiver was effective for the production of fossil hydrogen in 2015[91], the emission price of hydrogen in the base year is zero. On the contrary, I assume that the cost of emission allowances, which amounted to 7.60 € /tCO_2eq in 2015[92], was entirely added to electricity prices.

For the emission scenario, a consideration of the entire emissions without free allocation of allowances is assumed during the projected system lifetime. I assume a linearly growing emission price between 20 € /tCO_2eq in 2020 and 100 € /tCO_2eq in 2049. As a result, the entire target emission price is applied to emissions from fossil hydrogen production. In the case of electricity, the carbon price of 2015 needs to be deducted from the target price. The adjusted target emission price is then applied on the emissions per kWh of electricity.

The emission factor of fossil hydrogen lies at 7330 gCO_2/kgH_2 in the case of steam methane reforming, which is the most frequent source of hydrogen production.[93] The hourly emission factor of electricity is determined by computing the average emission factor of all electricity generation sources weighted by their generation output for each point in time. Thus, an hourly emission factor of the German electricity mix is derived.

The emission factors displayed in Table 8 are considered for the different sources of electricity.

All factors are multiplied with the hourly electricity generation by their source. Their sum is then divided by the total electricity production to derive the hourly emission factor of the electricity mix. I retrieved the electricity generation

[88]Data source: Bundesnetzagentur (2019a).
[89]Data source: Wind-FGW.

[90]Cf. European Commission.
[91]Cf. Statute 2014/746/EU.
[92]Data source: DEHSt (Umweltbundesamt) (2016), p. 5.
[93]Data source: Kothari et al. (2008), p. 554-558.
[94]Data source: Agora Energiewende (2019), p. 13.

Table 8: Emission factors of fossil electricity sources (in gCO_2eq/kWh).[94]

	Brown coal	Hard coal	Natural gas	Others (incl. fossil waste, oil)
Emission factor	1100	850	370	1590

data from a platform provided by the European Network of Transmission System Operators for Electricity (ENTSO-E) on a quarter-hourly basis.[95]

4.2. Evaluation of results

For the calculations I considered a range of differently sized vertically integrated systems based on PtG facility sizes of 100 kW, 500 kW, 1 MW, 5 MW, 20 MW and 100 MW. These facilities are capable of producing between 46.15 kg/day and 46.15 t/day at full load. I computed the break-even price curves for various cases accounting for the current legislation and potential future policies and assuming vertically integrated systems, where the renewable energy system can be composed of wind turbines and/or a solar PV system. When analyzing hybrid systems, I base my calculations on equal nameplate capacities of wind and solar PV. The optimization of the renewable energy system composition would go beyond the scope.

Eventually, I compare the derived break-even prices with the prices of industrial hydrogen. The market for industrial hydrogen divides into three segments: supply on a large-scale, where prices between 1.5 - 2.0 € /kg are observed, a market for medium-scale supply exhibiting prices in the range 3.0 – 4.0 € /kg and the small-scale market with prices above 4.0 € /kg.[96]

Initially, it will be interesting to analyze the economic potential of electrolytic hydrogen under the effective legislation. Figure 9 shows the break-even price curves of a vertically integrated system for the defined scales of the PtG plant. The horizontal axis shows the combined installed capacity of the wind turbines and solar PV system. The figure reveals, what currently is the challenge for profitability of PtG on a small-scale. The power consumption of a PtG facility with an installed capacity of 100 kW does not exceed the volume of 1 GWh, which is not exempt from a reduction of statutory fees, and thus cannot benefit from the reliefs granted to large industrial electricity consumers under the EEG framework. This results in excessive break-even prices of electrolytic hydrogen of up to 7.28 € /kg above the 750 kW threshold. The minimum price of 6.13 € /kg can be observed for an installation of each wind turbines and solar PV sized 750 kW, which in the case of wind turbines would be a fairly small system. This result is a consequence of the reduction of the EEG levy to 40%, charged on own power consumption from small renewable energy systems. When considering investments in PtG capacity on a larger scale, the reduction of statutory fees, applying to electricity consumption above 1 GWh, can unfold its effect of reducing the cost of power supply. This leads to a substantial decrease of the break-even price level and facilitates that minimum prices of 4.42 € /kg, 3.93 € /kg or 3.55 € /kg can be accomplished by vertically integrated systems with a PtG component scaled 500 kW, 1 MW or 5-100 MW, respectively. However, the effect from scaling almost disappears for plants above 5 MW.

At 20 MW, where the hybrid system is composed of wind turbines and a solar PV system each sized 10 MW, the price curves "jump", which is caused by the non-eligibility to the EEG subsidy of solar PV systems above 10 MW. In the case of a feed-in requirement, the opportunity cost of the lost feed-in premium disappears for solar power above 10 MW. This leads to a lower barrier for absorption of own power by the PtG facility resulting in a higher load and decreased break-even price. At the same time, the NPV will decrease due to the lost subsidy. This shows a limitation of the sole consideration of the break-even price when comparing the prices of different subintervals[98] of the RES capacity range. Hence, investors need to look at the break-even price coupled with the NPV, when comparing different investment options.

Based on Figure 9 it also becomes evident that large-scale PtG facilities are favored by the design of the regulatory framework. In the next step, I will compare the effects of various conceivable policy changes on the profitability of PtG focusing primarily on small-scale installations. The proposed policy changes comprise, firstly, the replacement of the feed-in premium by a production premium, which is paid irrespective of the feed-in of the produced renewable power. This instrument would remove the barrier of a lost subsidy, when converting electricity to hydrogen. Secondly, an extension of the reduced EEG levy to renewable energy systems of any capacity is considered, which is currently only granted to operators of renewable systems of up to 750 kW. Lastly, a complete waiver of the statutory fees is proposed for renewable electricity consumption and for both renewable and grid electricity consumption. The price curves resulting from implementation of these policies are illustrated in Figure 10 for PtG facilities with nameplate capacities of 100 kW and 1 MW, respectively. All cases are implemented based on the current legislation, while only changing the parameters representing the described policy change. This ensures the comparability of the proposed policy measures regarding their effectiveness.

The figure shows that especially small power-to-gas

[95] Data source: ENTSO-E.

[96] Cf. Glenk and Reichelstein (2019b), p. 218.

[97] Own figure. Case: Feed-in premium | all statutory fees included | wind & solar combined.

[98] Refers to the subintervals of the RES capacity range as part of the optimization algorithm in section 3.6.

[99] Own figure. Case: PtG = 100 kW (left) / 1 MW (right) | wind & solar combined.

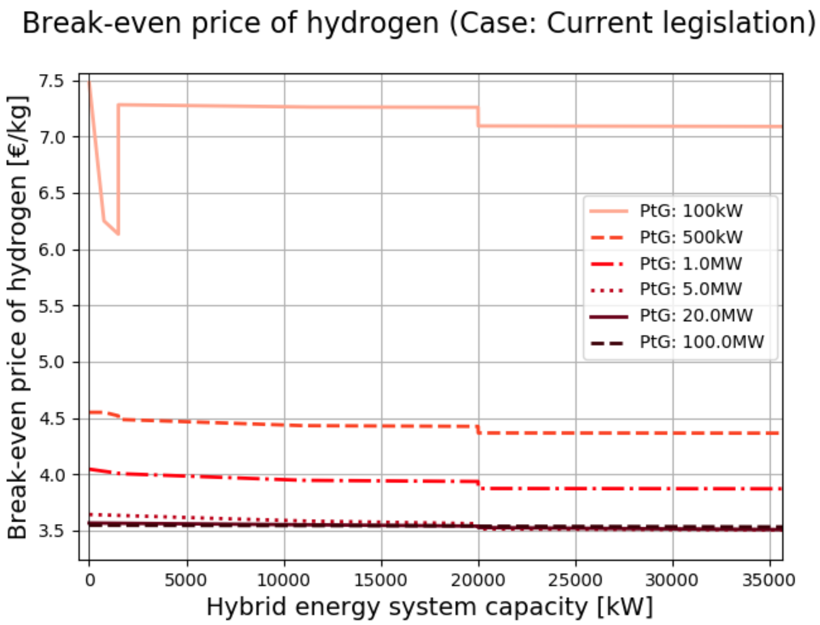

Figure 9: Break-even price of hydrogen under the current regulatory framework.[97]

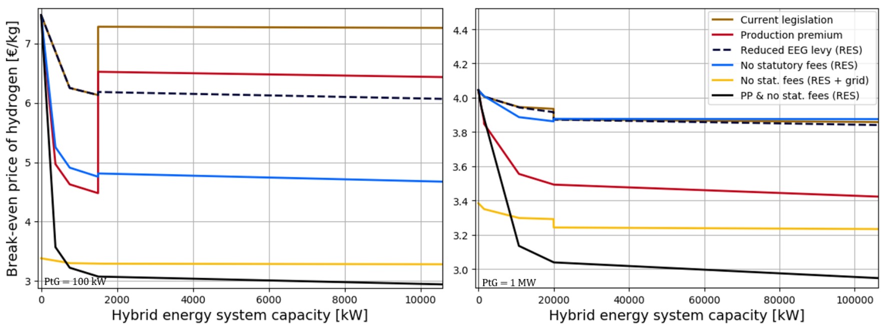

Figure 10: Effects of policy changes on the break-even price of hydrogen.[99]

plants depend on changes of the regulatory framework in order to be able to compete with industrial hydrogen, while large PtG facilities can already accomplish industrial hydrogen prices for a medium-scale supply. When waiving the feed-in requirement (red line), a break-even price of 4.50 € /kg can be reached for the optimal capacity ratio and electrolytic hydrogen could participate in the small-scale hydrogen market. Compared to the other policy measures, none can accomplish a price as low in the lower capacity range up to 1500 kW. However, above a combined capacity of 1500 kW, the waiver of the feed-in requirement loses much of its potential due to the increased EEG levy imposed on renewable power. In that range a waiver of the statutory fees on renewable electricity (blue line), i.e., the waiver of the EEG levy, performs much better and is able to lower the price to 4.80 € /kg for hybrid systems above the 1500 kW-threshold and down to 4.65 € /kg for a 20 MW renewable energy system. The extension of the reduced EEG levy to renewable energy systems above 750 kW (dashed line) is not able to shift the hydrogen price below 6.00 € /kg and thus will not be sufficient to make electrolytic hydrogen economical. Only a waiver of all statutory fees, imposed on renewable and grid power, or the introduction of a production premium combined with a waiver of the EEG levy payable on renewable power can shift the break-even price below 3.30 € /kg and in the case of the latter even under 3.00 € /kg and thus can help the profitability of small-scale PtG facilities substantially. It should not remain unmentioned that stand-alone PtG plants would also benefit extremely from a waiver of all statutory fees and could operate at a break-even price of 3.40 € /kg and thus at a price slightly below the price of 3.65 € /kg at which stand-alone PtG facilities with a capacity of at least 5 MW can already produce under the current framework. At the same time, the policy suggesting the waiver of the feed-in requirement and EEG levy for renewable power would not be to the benefit of stand-alone PtG facilities, thus setting an incentive for coupling of the PtG plant with renewable energy sources and promoting the production of renewable hydrogen.

Under limited circumstances, electricity consumption can already be exempt from the EEG levy under the current regulatory framework. The EEG levy does not apply when an electricity consumer is not connected to the grid and satisfy their power demand exclusively from an adjacent renewable energy source. The renewable source can still be connected to the grid and sell power on the wholesale market but is not entitled to the EEG subsidy.[100] This policy could benefit a vertically integrated system, where the PtG facility only absorbs power from the renewable source, while a subsidy is not received on the feed-in of any excess power.

The resulting break-even price curves are depicted in Figure 11. It becomes evident that all break-even price curves have a pronounced minimum point which indicates that off-grid operating power-to-gas facilities always have an ideal renewable energy system capacity. It is also visible that differently sized systems always exhibit the same minimum price, which lies for the hybrid, wind-only and PV-only scenario at 4.92 € /kg, 5.03 € /kg and 7.58 € /kg, respectively. The fact that the combined system shows the lowest price, proofs that a combination of wind turbines and solar PV in a hybrid system can have synergistic value. Although the price improvement of a hybrid system is only minor, compared to the wind-only scenario, an optimization of the ratio of wind turbine to solar PV capacity might lead to increased synergies. It should be noted, though, that good conditions for wind turbines and solar PV systems might not easily be found at the same geographical locations. The three scenario variations also show equal capacity ratios. In case of the hybrid system, the ratio of the PtG facility size to the size of the renewable energy system amounts to 26% and for the wind and PV scenario the ratio equals 35% and 30%, respectively (see Figure 11).

In particular, the consideration of this scenario could be relevant for solar PV open space installations exceeding the threshold of 10 MW and thus losing the eligibility for a subsidy in any case. The installation of such a system with a nameplate capacity of 175 MW in Germany was recently announced and start of construction is scheduled for early 2020.[102] However, the computed value for renewable hydrogen production from solar PV in this work is not applicable in that context, since such a project can enormously benefit from economies of scale and a much lower system price of the solar PV system must be assumed. The high intermittency of solar PV stations could be detrimental to such a project, though.

Finally, I ran analyses of the scenarios considering a rising emission price and the commercialization of the oxygen by-product, both based on the current legislation. The results, shown in Figure 12, indicate that an emission price, especially for large-scale PtG facilities, generates increased costs for electricity supply, since large PtG systems absorb high amounts of grid power, when not coupled with adequately sized renewable energy systems. The costs of emissions related to fossil hydrogen production, which raise the conversion value of hydrogen, appear to have a minor effect compared to the additional costs of emission allowances required for consumed grid power. Thus, for all PtG scales a rising emission price results in higher break-even prices of hydrogen almost along the entire vertical axis. However, emission prices can also serve as an incentive to couple the PtG facility with a renewable energy source, since the penalized grid power could be replaced by cheaper renewable power. It should be noted, that the analysis of the emission price is based on a constant electricity mix over the entire lifetime of the investment and should therefore be interpreted with caution.

The scenarios considering the commercialization of the oxygen by-product possess break-even price curves, which run almost perfectly parallel to the break-even price curves corresponding to the scenario under current legislation. This is not only valid for the scenario displayed in the figure, but for all PtG scales and hybrid, wind-only and PV-only renewable energy system. The price advantage of the oxygen scenario compared to the break-even price under the current legislation constantly lies around 0.24 € /kg. It is questionable, though, if and to what extent additional investment and operational costs could eat up this small margin. Also, the market price of oxygen must be explored in more detail, to find out if oxygen can really improve the economics of power-to-gas technology.

4.3. Sensitivity analysis

In order to evaluate the risks of an investment in a vertically integrated energy system accordingly and account for existing uncertainties, the sensitivity of the break-even price of hydrogen concerning various model input parameters needs to be analyzed. Therefore, I computed the sensitivity of the derived break-even price for a hybrid system composition of solar PV and wind turbines each 750 kW and a PtG facility sized 100 kW and for a larger system with both renewable components having a size of 10 MW and a 1 MW sized electrolyzer. The analysis results for the small-scale system are presented in Figure 13 for a range of discussed scenarios. The analysis of the large-scale scenario is available in the Appendix A.7. Both results show that the respective sensitivities exhibit almost equal characteristics among the different cases.

The break-even price exhibits the most pronounced sensitivity with respect to a variation of the conversion rate. The conversion rate depends on the efficiency of the installed electrolyzer and constitutes one of its key performance indicators. However, particularly, PEM electrolyzers are still being researched extensively and more long-term trials are required to validate their continuity in performance. Hence, the high sensitivity of the conversion rate currently expresses a high risk for investments in PtG technology. A decrease of

[100] Cf. § 61a Nr. 3 EEG.
[101] Own figure. Case: No subsidy | no statutory fees on RES power.
[102] pv magazine pv magazine Deutschland (2019).
[103] Own figure. Case: PtG = 20.0 MW | wind turbine only.
[104] Own figure.

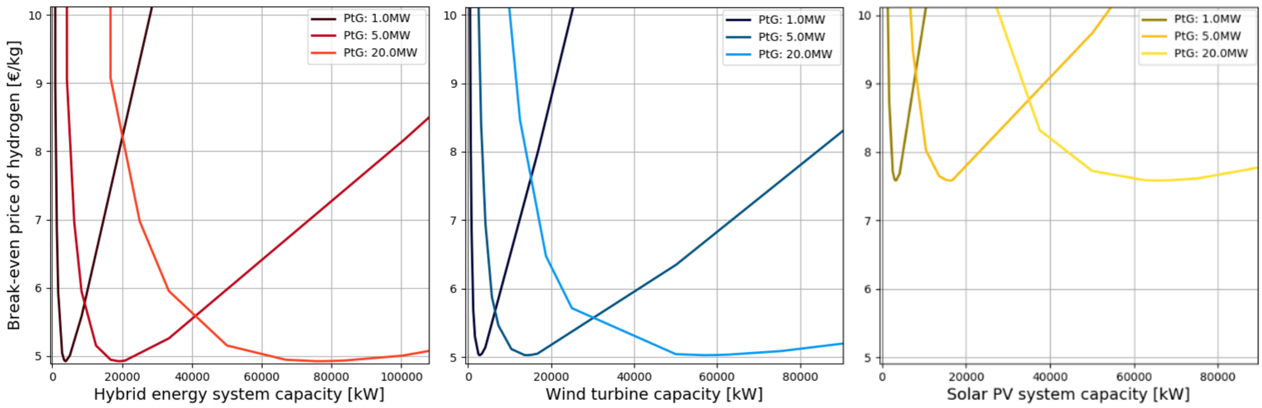

Figure 11: Break-even price of hydrogen of hybrid, wind-only and PV-only systems.[101]

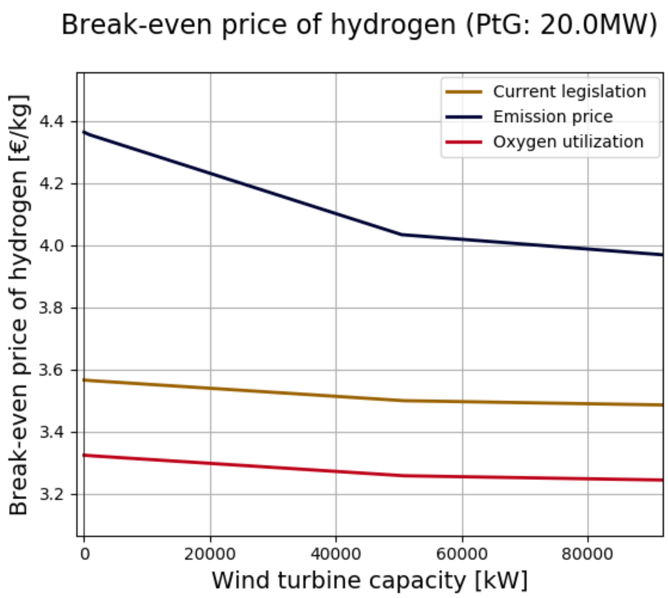

Figure 12: Effects of the emission price and oxygen commercialization scenarios.[103]

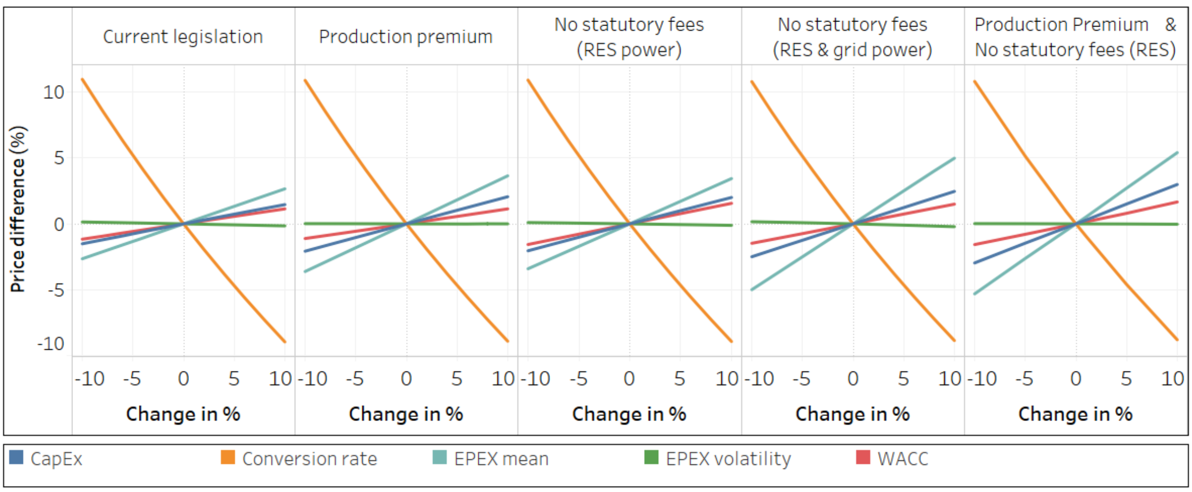

Figure 13: Sensitivity of the break-even price of hydrogen.[104]

the conversion rate by 10% would result in a significant increase of the break-even price slightly above 10%. The other analyzed input parameters have lower impacts on the break-even price.

I defined the volatility of the electricity price by its standard deviation. The volatility analysis is implemented such that only the volatility is changed, while the average electricity price remains constant.

To facilitate the interpretation, I calculated the mean electricity prices and price volatilities of the years of 2015 through 2018 as displayed in Table 9.

While the effect of price volatility seems to be negligible, a change of the electricity price level has a higher impact. This is, particularly, the case for scenarios, which are based on a higher consumption of grid electricity, such as the two scenarios on the right of Figure 13.

In 2018 the electricity price was extraordinarily high compared to the other years and 40% higher than in 2015. When running the analysis based on electricity prices of 2018, results would have shown a significant 10% and 16.6% increase of the break-even price for small and large system under current legislation, respectively. This shows, that the development of the electricity price can have a huge impact on the economics of electrolytic hydrogen.

In case of small-scale systems, an increased electricity price adversely affects the price of hydrogen, since the opportunity costs for the conversion of renewable power rise, due to higher yields of a feed-in resulting from higher electricity prices. Thus, the electricity price also has a significant impact on systems with a high internal power absorption, but still to a lower extent than on large systems that rely to a higher degree on power supply from the public grid.

Besides, the sensitivity of the WACC and CapEx are displayed as additional information but will not be discussed. The CapEx does not change during lifetime and thus only presents a risk prior to the installation of a vertically integrated system.

4.4. Implications for policymakers and investors

To conclude this section, I will sum up the implications of the analysis results and draw conclusions relevant for policymakers and investors.

The break-even price of hydrogen computed for large vertically integrated energy systems with a 5 MW sized power-to-gas facility gets as low as 3.55 € /kg and thus lies above the price of large-scale hydrogen (2.0 € /kg), but can already compete on the market for medium-scale hydrogen supply, where prices lie in the range 3.0 – 4.0 € /kg.[106] This result confirms the findings of Glenk and Reichelstein.

The relatively low prices of large-scale PtG can only be accomplished due to the reliefs from statutory burdens granted to large industrial electricity consumers with a consumption above the threshold of 1 GWh. Based on those reliefs the regulatory framework incentivizes large-scale PtG facilities. However, large systems involve substantial risks, due to high capital expenditure, technological uncertainties and a lacking market for electrolytic hydrogen. In addition, large-scale PtG facilities base their low break-even price to a certain extent on the absorption of grid electricity and have a higher dependence on the development of the wholesale electricity price.

Furthermore, large power-to-gas systems do not make much sense when producing hydrogen from grid power under the current German electricity mix. The resulting hydrogen product is not only more expensive than hydrogen produced by steam methane reforming but would also cause carbon emissions more than three times as high as the emissions resulting from the conventional technology for hydrogen production.[107]

Therefore, I consider it necessary to help accelerate the economy for renewable hydrogen by improving the economics of small-scale PtG facilities[108] coupled with renewable energy sources. The analysis in section 4.2 has shown that the waiver of the feed-in requirement, in favor of a production premium, coupled with a waiver of the EEG levy payable on self-generated renewable electricity would be the most effective instrument to improve the economics of small-scale vertically integrated systems. At the same time this measure would provide an incentive to couple power-to-gas technology with renewable power sources. When additionally adding an exemption from the statutory fees charged on grid electricity during times of negative or low electricity prices, such systems could also help to balance the electricity market and the power grid.

The introduction of a production premium would substantially lower the opportunity cost of converting electricity from an adjacent renewable energy system to hydrogen, since the subsidy premium would not need to be compensated for by the profits from hydrogen sale. As a consequence, electrolysis based on power from a renewable energy source would be incentivized and renewable hydrogen could be produced at a lower cost. The analysis results have shown that renewable hydrogen could be produced at a price below 3.00 € /kg in this case and already at 4.80 € /kg if only an exemption from the EEG levy for consumption of self-produced renewable energy was granted. These prices compare to the current minimum cost of production of a small-scale vertically integrated system of 6.13 € /kg.

The simulation of an integrated system with a 100 kW sized PtG facility and a hybrid energy system composed of wind turbines and solar PV, each with a nameplate capacity of 5 MW, has shown that such a system would utilize exclusively

[105] Data source: Bundesnetzagentur (2019c). Day-ahead auction prices at the EPEX spot market.

[106] Cf. Glenk and Reichelstein (2019b), p. 218.

[107] The average emission factor of the German electricity mix in 2018 of 474 gCO_2/kWh (Agora Energiewende (2019), p. 13) at a power consumption of 52 kWh/kg results in total emissions of 24648 gCO_2/kgH_2 compared to the emissions of 7330 gCO_2/kgH_2 for hydrogen produced by steam methane reforming.

[108] "Small-scale PtG facilities" here refers to facilities with a nameplate capacity in the range of 100 kW.

Table 9: Mean values and price volatilities of the wholesale electricity prices (2015 - 2018).[105]

Year	2015	2016	2017	2018
Mean price	3.16	2.90	3.42	4.45
% of 2015 mean value	0.0%	−8.4%	8.1%	40.6%
Price volatility	1.27	1.25	1.77	1.78
% of 2015 volatility	0.0%	−1.5%	39.4%	40.3%

power from the renewable energy source. This confirms that a small-scale PtG facility under the described policy change would be suitable for production of pure renewable hydrogen at an economical price. A production based on grid power is avoided due to the high statutory fees imposed on grid-supplied electricity, since a small PtG facility does not exceed the non-exempt volume of 1 GWh.

Small-scale hydrogen applications could substantially benefit from break-even prices below 5 € /kg, such as hydrogen filling stations with onsite hydrogen production, which do not face high daily demand volumes and therefore would not consider an investment in a large-scale PtG facility.

Small systems might also be more likely to attract investments since they have a lower capital expenditure and moderate risks associated to the price development of electricity.

The utilization of the oxygen by-product showed a small price advantage of 0.24 € /kg, compared to the break-even price under current legislation. This could improve the profitability of investments to a small degree if an oxygen consumer is located nearby. However, further analysis is necessary whether additional investment costs accrue and if the sale of medical instead of industrial oxygen could additionally improve the economics of power-to-gas.

5. Conclusion

This thesis has analyzed the economics of vertically integrated energy systems under the current regulatory framework and for potential policy changes to determine the factors which inhibit an economical production of renewable hydrogen and find out what action is required for its improvement.

For this purpose, I applied a net present value model that considers investment costs in the form of the levelized cost of electricity and levelized fixed cost of hydrogen. These costs are offset by levelized terms of the contribution margin, which originate from the sale of hydrogen and renewable electricity. The model is structured in a way that the stand-alone net present values of both subsystems are separately computed and a third term representing the synergistic value of the system integration is accounted for. I leveraged this model to develop an algorithm for the derivation of the break-even price of hydrogen and built an optimization algorithm to facilitate the analysis of a wide range of system compositions and identify the price-minimizing capacity combination of the renewable energy system and the power-to-gas facility. Based on the developed algorithms, I implemented a tool that allows for a relatively quick computation of the break-even price curve of a power-to-gas facility.

I find that small-scale power-to-gas facilities cannot be profitable stand-alone or in combination with a renewable energy source under current regulations, while large-scale facilities can compete on the market for medium-scale hydrogen supply due to the policies in favor of large industrial electricity consumers. However, hydrogen produced at large facilities would often be based on the use of grid electricity to a large share and thus cannot be considered renewable. The resulting hydrogen product would therefore be inferior to hydrogen from conventional production from an economic and ecological perspective, when comparing to hydrogen sourced on the market for large-scale supply.

Small-scale PtG facilities could be made profitable by two straightforward policy changes, which at the same time are suitable to incentivize the coupling of power-to-gas technology with a renewable energy source. These policies concern an exemption from the EEG levy payable on electricity consumed from the renewable energy source and the waiver of the EEG's feed-in requirement in favor of a production premium. When implemented, these measures would enable the production of truly renewable hydrogen at a break-even price below 3 € /kg, which could compete on the market for small- and medium-scale hydrogen supply and thus is suitable for deployment in some hydrogen applications. At the same time those PtG systems could be leveraged to balance the electricity market, if the statutory fees would be waived at times of negative electricity prices.

I also found that hybrid renewable energy sources, composed of wind turbines and solar PV, yield a lower break-even price of hydrogen, compared to systems only based on one renewable technology. However, further research is necessary, to find the ideal ratio of combination of solar PV and wind turbines. It must also be verified if suitable meteorological conditions for a joint operation exist.

My analysis has shown that the capture of oxygen as a by-product from water electrolysis, initially, has a low potential to improve the cost-effectiveness of electrolytic hydrogen. It remains open to explore the attainable oxygen price and whether the sale of medical oxygen would have a stronger effect on hydrogen economics.

Under real conditions, the described scenario is subject to uncertainties of various kinds, such as technological aspects concerning the system performance, meteorological conditions regarding the electricity output from the renewable energy source and uncertainties with respect to the electricity price movement at the power exchange, which might justify further model adjustments. For a more grounded simulation of the power-to-gas facility, additional technical parameters should be taken into consideration. For instance, PEM electrolyzers have the potential to operate at an overload, which could be utilized to some extent. But varying loads could also adversely affect the long-term electrolyzer performance. The data for power generation has been regarded as preexisting. A calculation of the break-even price should also be conducted based on forecasts of the capacity factors of the renewable energy source in order to validate the price of hydrogen under assumption of the meteorological uncertainties present for intermittent renewable energy sources. Instead of only relying on the day-ahead auction price of electricity, several other electricity products, such as intraday trading, could be included in future research to capitalize on the flexibility of PEM electrolyzers.

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