Hourly versus annually matched renewable supply for electrolytic hydrogen

Elisabeth Zeyen[a], Iegor Riepin[a], Tom Brown[a]

[a] *Department of Digital Transformation in Energy Systems, Faculty of Process Engineering, TU Berlin,Einsteinufer 25 (TA 8),Berlin, 10587, Berlin,Germany*

Abstract

Electrolytic hydrogen produced using renewable electricity can help lower carbon dioxide emissions in sectors where feedstocks, reducing agents, dense fuels or high temperatures are required. Several standards are being discussed to certify that the grid electricity used is renewable. The standards vary in how strictly they match the renewable generation to the electrolyser demand in time and space. In this paper, we compare electricity procurement strategies to meet a constant hydrogen demand in a computer model for selected European countries in 2025 and 2030. We compare a case where no additional renewable generators are procured with cases where the electrolyser demand is matched to additional supply either on an annual, monthly or an hourly basis. We show that local additionality is required to guarantee low emissions. If no storage is available to buffer the hydrogen, the electrolyser must run at full capacity at all times. For the annually matched case, constant operation means using fossil-fuelled generation from the grid for some hours that results in higher emissions and increased electricity prices compared to the case without hydrogen demand. In the hourly matched case, emissions and prices do not increase, but baseload operation results in high costs for providing constant supply if only wind, solar and batteries are available. Buffering the hydrogen with storage, either in steel tanks or underground caverns, reduces the cost penalty of hourly versus annual matching. Hydrogen production with annual matching can reduce system emissions if the electrolysers operate flexibly or coal is phased out and the renewable generation share is above 80%. The largest emission reduction is achieved with hourly matching when surplus electricity generation can be sold to the grid.

Keywords: regulation, green hydrogen, electrolysis, decarbonisation, PPA

Context and scale

Highlights

- Annual, monthly and hourly matching of renewable electricity generation to electrolysis operation for green hydrogen production are investigated.
- If electrolyser demand is not matched with additional renewable generation, emissions for hydrogen can be three times as high as grey hydrogen.
- Annual or monthly matching reduces system emissions if the electrolysis operates flexibly or the electricity system is largely decarbonised.
- Annual matching increases electricity prices by up to 43% if electrolysers run constantly and the background electricity system cannot adapt in time to the new electrolyser demand, while hourly matching has no effect on electricity prices and incentivises additional storage.
- Hourly matching with sale of surplus generation has similar cost of hydrogen production to annual matching if electrolysis operates flexibly, otherwise the costs are up to two times higher.

1. Introduction

Governments around the world are seeking to scale up the production of green hydrogen to reduce emissions from sectors of the economy where direct electrification is challenging. In its 2022 REPowerEU strategy [1], the European Commission raised its target for domestic renewable hydrogen production in 2030 to 10 million tonnes per year, with an additional 10 million tonnes per year to be imported. India announced a target in 2022 to produce 5 million tonnes hydrogen per year by 2030 [2]. The 2022 Inflation Reduction Act in the United States established a production tax credit (PTC) of up to 3 $\$/\mathrm{kg}_{\mathrm{H}_2}$ for clean hydrogen. The German government aims to install 10 GW of hydrogen electrolysis capacity by 2030 [3].

To qualify hydrogen for subsidies, quota requirements and to maintain consumer confidence, a transparent system is required to certify that hydrogen is 'green', i.e. produced from renewable electricity. Several definitions for green hydrogen have been suggested. The strictest would be to require that only electricity from newly-built renewable generators directly connected to the electrolyser can be used for producing hydrogen. While this definition is unambiguous, it forces hydrogen production to be located at the site of generation, which may be far from hydrogen demand, and it prevents flexible operation of the assets to

adapt to electricity market prices.

The definition could be relaxed in three major ways based on the additionality of the electricity generation, its location and timing. 'Additionality' means that electricity to supply electrolysis demand must be procured from generators that would not otherwise be operating. The additionality requirement can be met either by building new generators or by providing new business cases for generators about to be retired. Relaxing the additionality requirement implies allowing the existing generation fleet that would be operating anyway to supply hydrogen electrolysis. The strictest location requirement mandates a direct connection of electrolyser and generator. Relaxing the location requirement means permitting the hydrogen production and renewable electricity supply to be spatially separated while still being located in the same region, electricity market bidding zone or continent. The matching of generation and electrolysis in time can be relaxed to match on a sub-hourly, hourly, monthly or annual basis.For example, annual matching means that the electricity generation from renewables summed over the entire year matches the annual demand of electrolysis, but allows mismatch for individual hours.

While requiring additionality and locational matching within the same bidding zone are less controversial, there has been discussion about the need to require temporal matching. Hourly matching would provide a better guarantee that the electricity is truly from renewable sources, but it might be technically difficult to enforce and costly if electrolysers are required to run when wind and solar are scarce. European industry has indicated that hydrogen supply for most industrial processes would need to be continuous and that hydrogen storage is not available in most industrial sectors [4]. An annual matching requirement is technically easier and enables a faster scale-up of hydrogen infrastructure; however, the lack of temporally granular enforcement could mean that electrolysers run for some hours on fossil-fuelled electricity. This could lead to higher emissions for electrolytic hydrogen than for alternatives such as 'blue' hydrogen from reforming natural gas and then capturing and sequestering a large share of the resulting CO_2.

A draft set of rules for green hydrogen production were released by the European Commission in May 2022 in the Delegated Act for the production of renewable liquid and gaseous transport fuels of non-biological origin (DA) [5] specified in the Renewable Energy Directive II [6]. These rules promote locational matching and additionality, with hourly matching phased in by 2027. While the Delegated Act regulates transport fuels, its rules would most likely be extended to hydrogen used in other energy sectors. A counter-proposal in October 2022 by two industry groups, Hydrogen Europe and the Renewable Hydrogen Coalition, suggested a slower phasing in of the rules with only monthly temporal matching [7].

Several academic studies have examined hourly versus annual matching in various contexts. In a study by Ricks et al. [8], a selection of procurement strategies were examined in the United States assuming different offtake prices incentivised by the PTC introduced in the 2022 Inflation Reduction Act [9]. Results showed that hourly matching incurs only small additional costs compared to annual matching while ensuring low embodied emissions unless there is competition for limited high-quality renewable resources. The model setup did not guarantee a steady stream of hydrogen to the consumer but instead set a hydrogen offtake price, which drives the electrolyser utilisation with varying capacity factors. In Brauer et al. [10], various additionality, location and temporal requirements were studied assuming a constant hydrogen demand in Germany for the year 2030. Similar to the US study [8], the authors found that hourly matching has a small cost premium but lowers emissions, both from the perspective of emissions attributed to the electricity consumption and from the impact on system emissions of the hydrogen production. The study by Brauer et al., however, relied on low-cost hydrogen storage from liquid organic hydrogen carriers (LOHC) and did not examine the effect of different hydrogen storage technologies or different background grid systems, which can have a substantial impact on the results. Ruhnau et al. [11] also considered hourly versus annual matching for a baseload hydrogen demand in Germany, but focused on the impact in the existing power system using historical marginal emission factors. They found significantly higher costs for hourly matching, because only hydrogen storage in steel tanks was available. In their study, annual matching slightly reduced system emissions because of the freedom to have renewables feed in when prices and emissions are high. The authors were not able to assess the impact of a large volume of hydrogen or how the impact changes in the future because of the use of historical marginal data.

In this study, we explore hydrogen supply options in a model of two selected countries (Germany and the Netherlands) embedded in the pan-European electricity system for 2025 and 2030. The German system in 2025 is taken as a base scenario. We contrast the case of running an electrolyser of a given capacity using grid electricity only (i.e. no additional procurement of renewable resources) versus additional procurement of wind, utility-scale solar and batteries whose supply is matched on either an annual, monthly or hourly basis. We assume that the hydrogen demand is constant (as required by European industry [4]) but examine several options for hydrogen storage to buffer the hydrogen production, including four scenarios with no storage, (rather expensive) steel tanks, (rather low-cost) underground cavern storage and zero-cost storage. The case of zero-cost storage is equivalent to having a time-flexible hydrogen demand.

Then in several sensitivities, we explore the impact of a monthly matching requirement. We also investigate the impacts of a less clean grid (the Netherlands in 2025, renewable generation share of 35%) and a cleaner grid (Germany in 2030, renewable generation share of 80%) on our

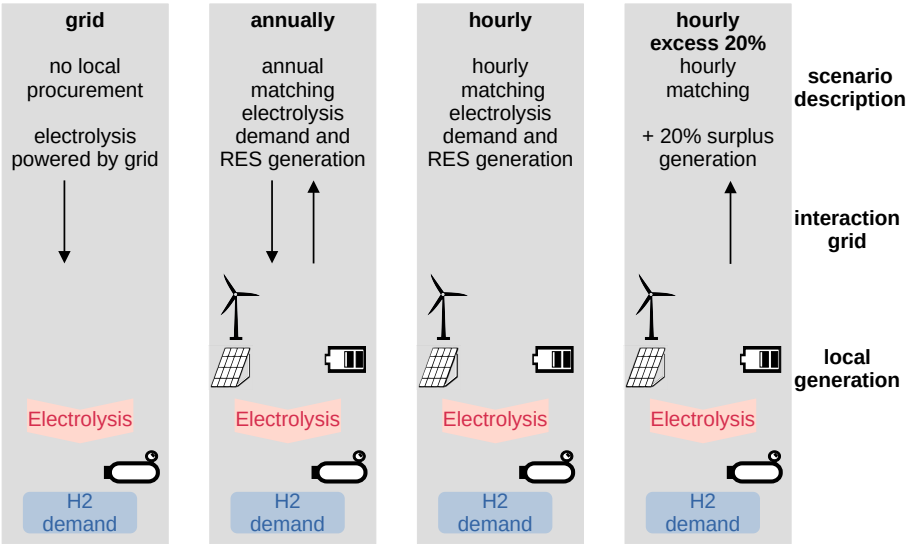


Figure 1: Four different regulatory scenarios are modelled. A (i) grid scenario without any additional renewable generation requirement in which electrolysis is powered by the grid as well as scenarios in which additional renewable energy sources (RES) have to match the electrolysis consumption on an (ii) annual or hourly basis (iii) without and (iv) with allowed excess generation of 20% .

findings. In the Appendix we provide further examples for Poland, the Czech Republic, Portugal and Spain (see Section 11.2.1).

2. Scenarios

We analyse four scenarios of hydrogen production (see Figure 1):

(i) On-grid production (**grid**), where the electrolysis is powered by grid electricity.

(ii) Additional local renewable capacities, whose generation has to match the consumption of the electrolysis annually (**annually**). Grid electricity purchases and sales are allowed as long as this constraint is fullfilled.

(iii) Additional local renewable capacities, whose generation has to match the consumption of the electrolysis hourly (**hourly**).

(iv) Additional local renewable capacities, whose generation has to match the consumption of the electrolysis hourly, while excess generation of 20% of yearly electrolysis demand can be sold to the grid (**hourly excess 20%**).

Green hydrogen production is modelled in two selected European countries (Germany and the Netherlands). In order to account for electricity trade, we model all neighbouring countries in addition to the selected one. In all the modelled countries, renewable generation must meet the political targets as defined in the National Energy and Climate Plans (NECPs) or by more recent national policy targets (such us the Easter package in Germany), see Table 1.

In all scenarios, we assume a fixed hydrogen demand of 28 TWh_{H_2}/a (0.84 million tonnes produced hydrogen per year) in the country. This demand is in line with the German target for 2030. We apply this demand also to the year 2025 since in REPowerEU the European target was raised to 10 million tonnes of produced hydrogen within Europe by 2030. The price of carbon dioxide emission certificates is set to 80 €/t_{CO_2}in 2025 and 130 €/t_{CO_2}in 2030. For comparison, a fourth reference scenario is modelled without any additional local production or hydrogen demand.

The demand for hydrogen is continuous throughout the year, following the needs of European industry [4]. We implement five variations of hydrogen storage for each policy scenario to represent different degrees of flexibility for hydrogen:

(a) zero-cost storage (**flexibledemand**), corresponding to completely flexible hydrogen demand.

(b) storage in underground salt caverns (**underground**), low cost storage, could be accessible via hydrogen pipeline network,

(c) storage in medium pressure steel tanks (**mtank**), medium-cost storage,

(d) storage in high pressure steel tanks (**htank**), relatively expensive storage,

(e) no storage (**nostore**), inflexible hydrogen demand.

In the results, we compare the carbon intensity of electrolytic hydrogen and blue hydrogen. The carbon intensity of blue hydrogen depends on the capture rate and ranges between 1-5 kg_{CO_2e}/ kg_{H_2}[10, 12]. We assume the lowest value of 1 kg_{CO_2e}/ kg_{H_2} similar to Brauer et al. study [10] as a comparison to the carbon intensity of the electrolytic hydrogen.

The modelling is performed in two optimisation steps. In the first step, the capacities and dispatch of power plants and storage facilities in the power sector are optimised without any hydrogen production. In the second step, the optimised capacities of step one are exogenously fixed, and the hydrogen demand and production site are added. The optimisation is rerun allowing capacity expansion of wind, utility-scale solar and battery storage at the hydrogen production site only, as well as any hydrogen storage allowed in the scenario.

Further details of the modelling are provided in Section 10.

3. Results

In the following, we address two aspects of hydrogen production for our different regulatory scenarios. We first highlight the system impacts by analysing the carbon dioxide emissions from hydrogen production for each scenario based on the consequential emissions (Section 3.1), the impact on the electricity prices (Section 3.2) and the capacity factors of electrolysis (Section 3.3). Second, from an accounting perspective, we look at the costs (Section 3.4) and attributional emissions (Section 3.5) of hydrogen production. In a further analysis, we consider the impact of monthly matching (Section 3.6), which is discussed as a compromise solution between annual and hourly matching, and the impact of grid cleanness (Section 3.7).

3.1. Consequential emissions

The consequential emissions indicate the impact on total system emissions of the hydrogen production. Consequential emissions are calculated by the difference of the total system emissions compared to the reference scenario without hydrogen production, divided by the total hydrogen production. The results show that additionality is required to prevent increased emissions. Annual matching in the case of flexible demand and hourly matching in all cases with allowed sales of surplus generation reduce emissions.

Without the additionality requirement, up to 31 kg_{CO_2} are emitted per produced kg_{H_2} (see Figure 2). This corresponds to more than three times the CO_2 intensity of grey hydrogen produced via steam methane reforming (10 kg_{CO_2}/ kg_{H_2}).

The impact of annual matching on emissions can be subtle. Annual matching increases demand in some hours when the electrolyser is running and RES are scarce, while it decreases demand for conventional generation in hours with plentiful RES. If the increase in demand is met with coal while gas is displaced at other times, emissions will increase. On the other hand, if the increase is met by nuclear and otherwise-curtailed renewables while coal is displaced, emissions will sink. The exact effect depends on the background system mix.

Annual matching has emission up to 2 kg_{CO_2}/ kg_{H_2} if the hydrogen demand is completely inflexible. In absolute numbers, this leads to an increase in CO_2 emissions from the German power sector of 2 million tonnes of CO_2, which corresponds to about 1% of power sector emissions in Germany in 2021. However, emissions are reduced if storage is available, to the point that annual matching can even lower total system emissions in the case of flexible demand by -8 kg_{CO_2}/ kg_{H_2}. This is because having flexible electrolyser demand and variable generation, only constrained by the annual matching, provides many degrees of freedom. On the one hand, electrolysers can consume not just procured renewable electricity, but also excess renewable electricity from the grid. On the other hand, the procured renewable electricity has the freedom to feed in when electricity prices are high and the emissions intensity of the grid is high. These freedoms are constrained in the scenarios with costly storage. In these cases, constant demand of the electrolysis is met by additional fossil generation which increases emissions.

Hourly matching without the option to sale excess electricity to the grid has no impact on total emissions since the electrolysis demand is met with renewable generation in every hour. The strongest reduction in total system emissions of up to -10 kg_{CO_2}/ kg_{H_2}occurs in hourly matching scenarios with possible sale of surplus generation. This corresponds to a total reduction in system emissions of 8.5 million tonnes CO_2. In this case, the additional renewable generation sold to the grid reduces the operation of coal fired plants and therefore decreases system emissions. In contrast to annual matching, in scenarios with hourly matching with excess generation emissions are reduced for each scenario of hydrogen storage.

3.2. Electricity prices

The electricity prices are a result from the optimisation. They are derived from the dual variables of the nodal balance constraint in each region. An infinitely small relaxation of the constraint, i.e., one unit of load less to be met, returns the marginal costs of providing that unit, which can be used as the electricity price indicator in a competitive market. It should be noted that capacities of conventional generators are fixed in the first optimisation step (without hydrogen demand) and therefore cannot adapt to the new additional demand for hydrogen. Prices

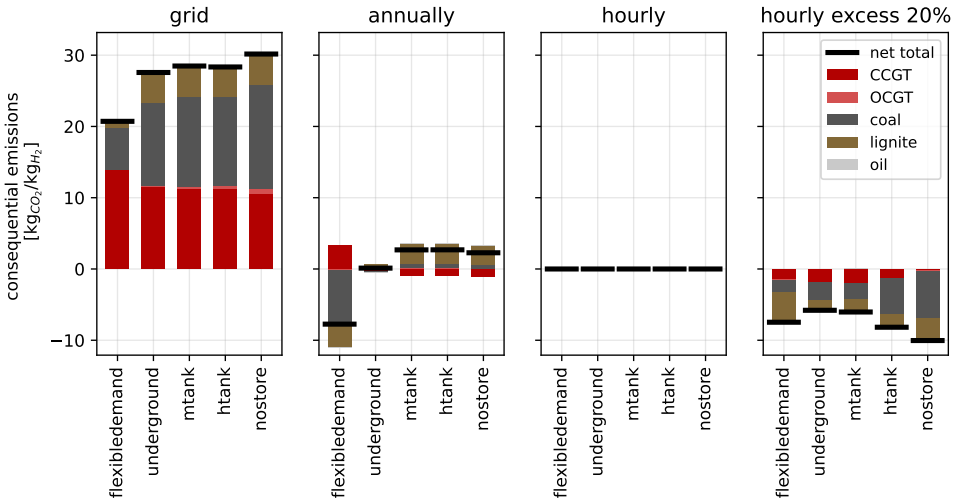


Figure 2: Consequential emissions of hydrogen, calculated as the difference in total system emissions per produced kg_{H_2} compared to a reference scenario without any hydrogen production. See Section 3.1 for further information.

would be lower if power plant capacities can adjust to the higher electricity demand. Assuming no adjustment represents the situation that permitting procedures and construction of additional power plants require longer periods of time.

Electricity prices increase both in the grid and in the annually matching scenario if only expensive or no storage options are available. The hourly matching has no effect on electricity prices. In the grid scenario, which has no additional local procurement, demand cannot be met every hour without hydrogen storage and prices become very high in this case. In scenarios with annual matching, electricity prices increase by 43% if the electrolysis is operated inflexibly. The price increase is due to the fact that hours with low feed-in from renewable generation are not bridged with storage, but electricity is purchased from the grid. This additional demand causes more coal-fired power plants to run and leads to a price rise.

In the DA, it is planned that hours with electricity prices below a threshold of 36% of the EU carbon price, which currently corresponds to 27 €/MWh, count as green. We have not included this option in our model. In our results, about 2% of the hours (160 hours per year) have prices below 27 €/MWh in scenarios with hourly matching. Since grid and annual matching increase electricity prices, there are only 80-90 hours below the threshold in these scenarios. The system offers enough flexibility options, for example in the form of storage or transmission, that even with a very high share of renewable generation, prices are not zero. For example with 100% renewable generation (defined without the demand for hydrogen production), hours per year below the threshold are 18% in the hourly case and 11-15% in the grid and annually matching scenario.

3.3. Capacity factor

The capacity factors are defined as the actual hydrogen output divided by its maximal capacity. The capacity factors increase with higher costs of hydrogen storage (see Figure 4). Low costs of hydrogen storage or a flexible demand allow the producer to buffer periods of low variable feed-in of the renewable generation, leading to lower capacity factors of the electrolysis since they operate when electricity prices are low. If the demand is inflexible, electrolysis runs at full capacity around the clock to meet the demand. Running the electrolysis at full capacity every hour leads either to increased emissions and higher electricity prices in the case of annual matching or to high costs of hydrogen production in the case of hourly matching.

The grid scenario and the annual matching have higher capacity factors, since in these scenarios there is flexibility to purchase grid electricity when directly procured generation is not available. In the case of annual matching, electrolysis with purchased grid electricity can run at a higher capacity factors of e.g. 58% with flexible demand compared to 45% with hourly matching, even with low feed-in from the additional renewable generation. Hourly matching with allowed excess results in higher capacity factors of 51% in case of flexible demand. The higher utilisation of electrolysis in case of allowed excess generation results from larger cost-optimal capacities of local procurement and smaller electrolysis capacities. Without excess, it is cost-optimal to build larger electrolysis capacities in order to curtail as little renewable energy as possible. With excess, the electrolysis capacity is adapted more closely to the demand and surplus electricity is sold to the grid.

3.4. Cost of hydrogen production

The cost of hydrogen production is defined as a sum of annualised capital costs and variable operating costs of all new assets contracted by the hydrogen producer, plus

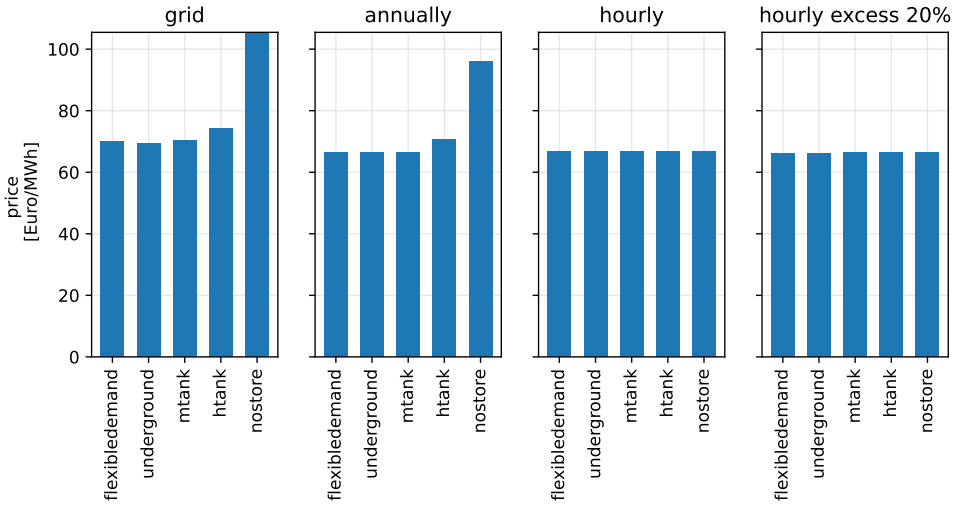


Figure 3: Electricity prices of grid, annually and hourly matching without and with allowed excess for Germany 2025. Annual matching can increase electricity prices by up to 43% in case of inflexible operation of the electrolysis. Note that the background electricity system has fixed capacities and is not able to adapt to the new electrolysis demand. If capacities can adapt then the price rise could be lower.

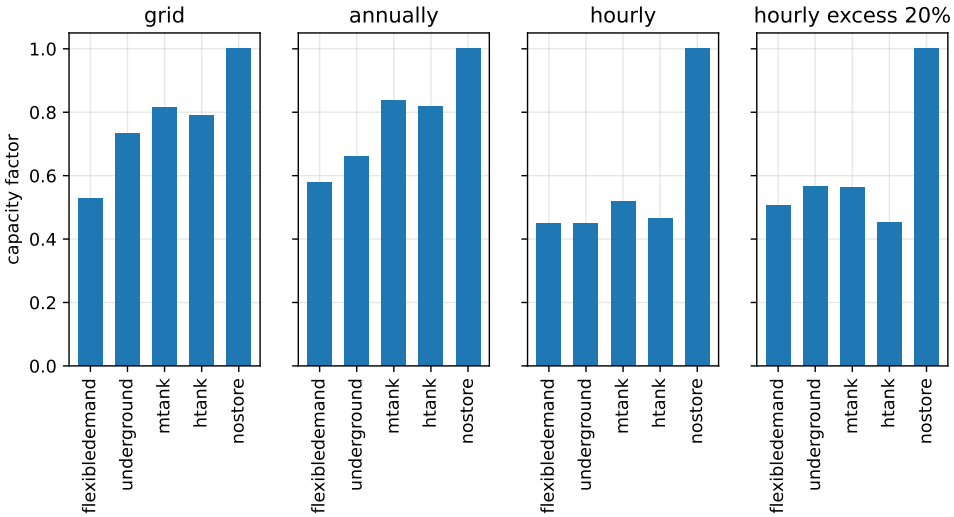


Figure 4: Capacity factors of electrolysis for different policies and different storage types. Higher capacity factors are associated with higher costs for hydrogen storage. With completely inflexible demand, electrolysis runs at full capacity for all hours. This results in either higher emissions and higher electricity prices in case of the grid and annually scenario or in high costs in case of the hourly matching. See Section 3.3 for further information.

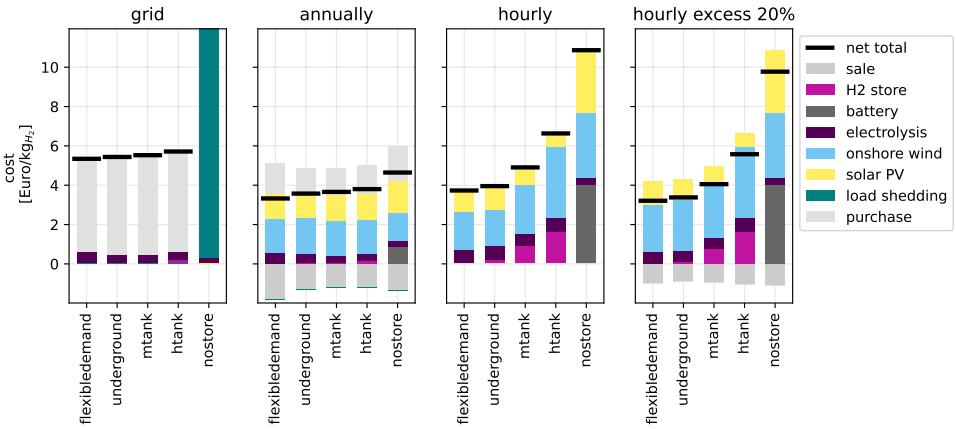


Figure 5: Cost of hydrogen production. See Section 3.4 for further information.

costs of electricity purchases from the grid, minus revenue from selling the excess electricity to the grid (if allowed by scenario) per MWh$_{H_2}$ of hydrogen demand (see further information in the Appendix 10.4). The costs for the production of hydrogen are lowest independently of the storage options in the case of annual matching, with cost ranging between 3.33-4.64 €/kg$_{H_2}$(see Figure 5). They are below the costs of the grid scenario because additional renewable capacity is built, which lowers the electricity prices. The costs for hourly matching compared to annual matching are only 11–12% higher if demand is flexible or low-cost storage in the form of salt caverns is available. In the case of inflexible demand, hydrogen production costs with hourly matching are 10.86 €/kg$_{H_2}$ and therefore 2.3 times higher than the production costs with annual matching. These high costs result from transforming variable renewable electricity generation profiles into constant electrolyser output. This transformation is partly provided by battery storage (37% of production costs) and partly by overbuilding renewable capacities, which are then partially curtailed (see Figure 14 in Appendix). Since no additional capacities are built in the grid scenario, the inflexible demand cannot be met at all hours, which is illustrated in Figure 5 by the costs of load shedding for the unmet demand.

The cost of hourly matching with allowed excess is 3.21 €/kg$_{H_2}$, which is slightly below the cost of annual matching in the case of flexible demand. This is caused by the additional profit that can be made by selling electricity in hours of high feed-in of renewable generation. As in the hourly case without excess, the cost increases sharply up to 9.77 €/kg$_{H_2}$in the case of inflexible operation of electrolysis, which is two times the cost of annual matching.

3.5. Attributional emissions

The attributional emissions of hydrogen are calculated based on the average emissions when the electrolysis uses grid electricity, taking into account imports and exports to the bidding zone. Attributional emissions are only guaranteed to be zero with hourly matching since in every hour,

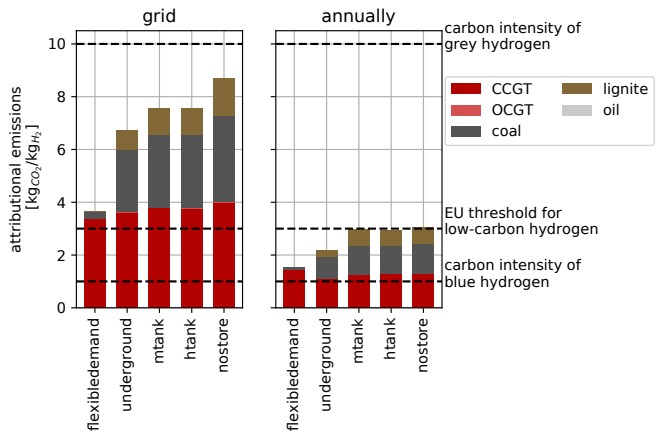


Figure 6: Attributional emissions of hydrogen, based on the mix of used electricity. The carbon intensity of the hydrogen if the electrolysis is powered by the grid without an additionality requirement (**grid**) is above the EU threshold for low-carbon gas. Annual matching has a carbon intensity higher than blue hydrogen, but emissions are below the EU threshold. Hourly matching has no attributional emissions, since the renewable generation has to match the demand of the electrolysis in every hour. See Section 3.5 for further information.

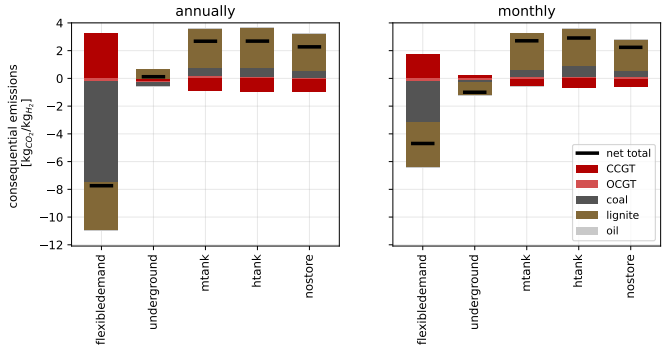


Figure 7: Consequential emissions annual and monthly matching.

the demand of the electrolysis has to be met by additional renewable generation. The carbon intensity of hydrogen is highest in the case where the electrolysis is directly connected to the grid without any additionality requirement (**grid**), followed by the annual matching (see Figure 6). These attributional emissions are caused by the fact that electrolysis also runs during hours when fossil fuels contribute to the generation.

The carbon intensity rises as the cost of hydrogen storage increases. If hydrogen demand is flexible or low-cost storage is available, electrolysis can run when the feed-in of renewable generation is high and electricity prices are low. If no hydrogen or only expensive storage is available, the variable feed-in of renewable generation cannot be bridged. In this case, the electrolysis is powered with a higher proportion of electricity from coal generation which causes higher attributional emissions (see the generation mixes in Figure 9 in the Appendix).

In the grid scenario, in which the electrolysis is directly connected to the grid without additional renewable generation, the attributional emissions range between 3.5–8.5 kg_{CO_2}/ kg_{H_2}, which is above the EU limit for low-carbon hydrogen of 3 kg_{CO_2e}/ kg_{H_2}[13]. The attributional emissions of electrolytic hydrogen are even higher than those from the production of grey hydrogen from methane via steam methane reforming (10 kg_{CO_2e}/ kg_{H_2}) if the grid is less clean (see carbon intensity in the Netherlands 2025 in Figure 28).

Annual matching leads to attributional emissions below the EU threshold for low-carbon hydrogen but above the emissions of blue hydrogen (1 kg_{CO_2}/ kg_{H_2}). If hydrogen storage is expensive or the demand is not flexible, emissions increase. The attributional emissions depend on the cleanness of the grid and can be therefore higher in countries with a higher share of fossils in the generation mix (see carbon intensity in the Netherlands 2025 in Figure 28).

3.6. Monthly matching

In the monthly matching scenario, the electricity generation from additional renewable generation must equal the electricity consumption of electrolysis every month. This is often discussed as a compromise between annual and hourly matching and is proposed as a transitional solution in the Delegated Act draft until 2027 [5]. Looking at the consequential emissions, the results do not change significantly compared to annual matching. When electrolysis can be operated flexibly, the consequential emissions are negative, otherwise total system emissions increase due to hydrogen production (see Figure 7). The costs for hydrogen production with monthly matching range between 3.43-4.88 €/kg_{H_2} and are thus 3–5% higher than with annual matching. Similar to annual matching, electricity prices increase by up to 45% if demand is inflexible (see Figure 20). The higher electricity prices arise because electricity is also purchased at times when there is a high demand for electricity and a low feed-in of renewables.

3.7. Cleanness of the grid

The emissions and costs of hydrogen production are related to the electricity generation mix of the respective country. To investigate the influence of the generating fleet on our results, we consider a grid with a higher share of fossil fuels (Netherlands 2025) and a cleaner grid (Germany 2030 with coal power plants being phased out). The country-specific shares of renewable generation are applied for the respective years (see Table 1 in the Appendix). An overview of the shares of the individual technologies in electricity generation for the respective year and country is in the Appendix (see Figure 23). Hydrogen demand is assumed constant at 28 TWh_{H_2}/a to keep the results comparable.

Progress in the decarbonisation of the power sector has a major impact on hydrogen production emissions for the grid and annual scenarios. In the case of hourly matching the emissions are zero or negative in case of allowed excess and we therefore discuss in the following only the grid and annual matching scenarios. If the renewable share in the overall electricity mix is low, as in the case of the Netherlands in 2025 with a share of 35%, the consequential emissions of hydrogen production in the grid scenario of more than 32 kg_{CO_2}/ $kg_{H_2}$for each storage option are significantly higher than the carbon intensity of grey hydrogen production (10 kg_{CO_2}/ kg_{H_2}). Annually matching results in a reduction of emissions in scenarios with low cost storage or flexible demand since the generation of coal power plants is reduced by sales from the local procurement. Otherwise emissions increase by up to 5 kg_{CO_2}/ kg_{H_2}since electrolysis runs at hours with a higher share of coal generation. Electricity prices increase by 26% in scenarios with annual matching and constant operation of the electrolysis.

In the case of a higher share of 80% renewable generation, as in our scenarios for Germany 2030, scenarios without additional local procurement lead to an increase in system emissions. Since coal power plants are decommissioned, additional emissions arise from increased generation from gas power plants. The consequential emissions are negative with annual matching for every storage

type, i.e. total system emissions are further reduced by hydrogen production. The reduction in emissions results from the fact that the purchased grid electricity has only a small share of fossil energy sources and the sold electricity contributes more to the decarbonisation of the grid. A share of 80% renewable is below the currently envisaged threshold of 90% in the DA [5] yet our results show that even with inflexible demand, total emissions decrease with annual matching. The electricity prices rise in case of annual matching without any storage option by 15% which is below the rise of 43% of our scenarios in Germany 2025. Overall the scenario with a cleaner grid illustrates that with increasing decarbonisation, the regulation of hydrogen production certificates plays a minor role.

3.8. Further sensitivities

In the Appendix, we provide further sensitivity analyses regarding various parameters of hydrogen production and the background energy systems to analyse the impacts of key assumptions and generalise our findings:

1. We analyse hydrogen production in four additional countries. Two without a planned coal phase-out by 2030 (Czech Republic and Poland) plus two with a higher share of solar generation (Spain and Portugal), see Section 11.2.1. Annual matching leads to an increase in total emissions with a low share of renewable generation (Czech Republic, Poland) except when hydrogen demand is flexible. Hydrogen production in countries with a high share of solar generation (Spain, Portugal) leads to a decrease in emissions for annual matching already in 2025 except when electrolyser run constantly.

2. The effect of the size of hydrogen demand is explored in Section 11.2.2. It does not have a large impact on the emissions or production costs.

3. Allowed sales of excess electricity to the grid for annual (Section 11.2.3) and hourly matching (Section 11.2.4) are considered. Annual and hourly matching with higher excess electricity sale volumes lead to a stronger decrease of system emissions. For hourly matching allowing excess electricity of up to 30% of electrolysis demand to be sold to the grid reduces costs of hydrogen production by up to 18% in case the hydrogen demand is inflexible.

4. We vary the share of renewable generation in the background system in Germany to analyse the effect if political targets are not fulfilled or higher renewable generation shares are achieved (Section 11.2.5). Low generation of coal power plants and high feed-in of renewable generation are required to avoid increases in total system emissions with annual matching.

4. Discussion

The rules for green hydrogen must balance the impact of production on carbon emissions with the additional cost burden on producers. Our results indicate three possible pathways to low emissions without a cost premium:

1. Additional, locational and hourly matched renewable electricity combined with either flexible demand or low-cost hydrogen storage, so that the electrolysers can adapt to variable wind and solar production.

2. Additional, locational and annually matched generation if the hydrogen demand is flexible with a capacity factor below 60%. This operation mode could also be achieved without any temporal matching requirements, by simply allowing hydrogen production to be counted as green when electricity market prices are below a certain threshold (as planned in the DA [5]).

3. Additional, locational and annually matched generation if the background grid is largely decarbonised (such as the Germany 2030 case with 80% renewable electricity and a phase-out of coal).

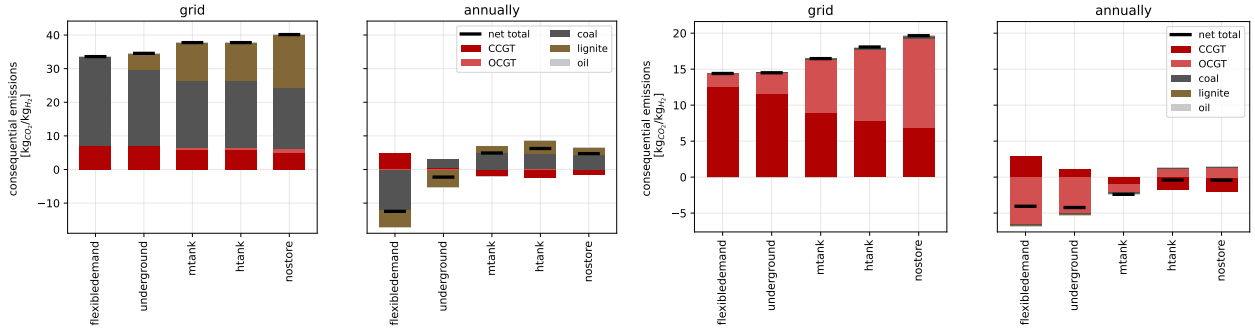
In the first two cases, electrolysers have capacity factors in the range 45–60%, so they can adapt to hours of high wind and solar production. This flexibility is made possible either by flexible hydrogen demand or low-cost hydrogen storage in underground caverns to buffer the variable hydrogen production.

We show that electrolysis production running at high capacity factors either causes high emissions (in the case of annual matching) or comes at high costs (in the case of hourly matching).

Examples where flexible hydrogen demand is possible in industry include ammonia production via the Haber–Bosch process or methane production via the Sabatier process. Both of these processes can be made flexible with must-run part loads down to 30–50%.

Low-cost hydrogen storage in salt caverns relies on the availability of suitable geological salt deposits. Fortunately, there are abundant salt layers and domes in Europe [14]. These salt deposits are mostly concentrated around the North Sea, where there is also abundant wind power resources available. Outside these areas, hydrogen storage is possible in steel tanks, but this has a significant cost penalty on the hydrogen. Storing the hydrogen in liquid organic carriers (LOHC) may alleviate this cost penalty [10]. Our results show that in the case of inflexible hydrogen demand, hydrogen production systems will rather be run with steel tank storage than without any storage. Steel tanks can easily be deployed at hydrogen production or industrial sites, and result in lower average production costs than no storage. A hydrogen pipeline network could also make underground storage accessible to a wider area.

Hourly matching is the only matching scheme that provides strong incentives for demand flexibility and storage,



(a) Netherlands 2025

(b) Germany 2030

Figure 8: Consequential emissions for two selected cases representing a less clean system, Netherlands 2025 (*left panel*), and a cleaner system, Germany 2030 (*right panel*), than the reference case of Germany 2025.

since the cost differences between constant and flexible electrolyser operation are so high. For annual matching the differences are much smaller. Incentives for flexible electrolyser operational are desirable since flexible operation is seen in top-down system cost optimising studies [15]. The difference between the emissions of annually and hourly matched green hydrogen reduces if the background electricity system is cleaner (see the change in German emissions from 2025 to 2030 in Figures 6, 8). However, hourly matching always results in low-emissions, regardless of the background system, and provides a hedge against the case where ambitious targets for the expansion of renewable electricity are not met.

It is sometimes asked why strict rules are applied to hydrogen, but not other new electricity consumers such as electric vehicles or heat pumps. One reason is that rules are required only for producers seeking to get the label 'green' and associated subsidies. Another reason is that it is easier to regulate hydrogen production because it is done centrally at large scale. This study shows a third reason: if hydrogen is produced without additionality or locational and temporal matching, its carbon emissions impact can be worse than that of grey hydrogen. For electric vehicles and heat pumps, numerous studies have shown that they reduce emissions compared to fossil-based alternatives even with today's electricity mix [16–19].

It has also been argued that additionality requirements cannot affect system emissions in a system like Europe where an emissions cap applies in the form of an Emissions Trading System (ETS) [20]. We argue that the large volume of planned hydrogen production planned in Europe by 2030, 10 million tonnes of hydrogen per year, means that additionality is a useful precaution to ensure that renewable production keeps pace with electrolysis demand. Without this safeguard, emission certificate prices could rise to politically unsustainable levels and endanger the entire ETS. It would also lead to higher electricity prices, affecting all consumers.

The European Commission is considering competitive tendering as a support mechanism for hydrogen uptake and a switch from natural gas-based to renewable hydrogen production for industrial processes [21]. Financial subsidies received through such competitive tendering (e.g., via Contracts-for-Difference (CfDs)) can enable hydrogen producers to stabilise their electricity procurement cost at a certain level (*the Strike Price*) for the duration of the contract. These subsidies will naturally have an effect on green hydrogen production profiles, and consequently, on the energy system impacts of hydrogen production. The impacts will largely depend on the design of tendering procedures and contracts. For example, an important feature of the CfDs is the *Reference Price*. In the absence of a functioning market for hydrogen, different indexation options are being considered, such as the electricity price, grey hydrogen cost, available commercial cost indexes, among others [22]. If the hourly electricity price is used as a reference point of a CfD, this would incentivise baseload operation of hydrogen producers by providing compensation against high electricity prices. In the context of our analysis, this would imply high attributional emissions (unless an hourly matching requirement is imposed). If a CfD is based on a time-fixed index, then the subsidy would function like an offtake price. The latter can also facilitate a constant operation if the subsidy level is high compared to the market electricity prices. Taken together, the envisaged support for hydrogen projects makes the baseload operation scenario in our study even more relevant.

We now compare our results to other studies in the literature. In [8], annual and hourly matching rules were compared in the United States in a setup with a high offtake price and a fixed electrolyser capacity but no fixed profile of hydrogen delivery to the customer. In the annually matched case, the high offtake price incentivises running the electrolyser even when electricity prices are high, leading the electrolyser to run when fossil generators are dispatched. This scenario results in high capacity factors and high emissions. This finding and the lower emissions impact of hourly matching agree with our study. However, the small cost premium for hourly matching in [8], even without storage, is not seen in our study. This difference arises because, in [8], the model does not need to provide a constant stream of hydrogen and can choose to turn off the

electrolyser if the cost of production in that hour is higher than the offtake price. Hydrogen storage is not considered in [8].

The study design in Brauer et al. [10] is similar to ours in that they model a baseload hydrogen demand rather than using a fixed offtake price like [8]. Brauer et al. also see a small cost premium for hourly versus annual matching because the model uses hydrogen storage in the form of liquid organic hydrogen carriers (LOHC), which have a low cost for energy storage similar to the underground cavern storage in our study. We complement the study of [10] by exploring the availability of different storage options, in the case that LOHC or cavern storage is not available. We also explore the impact on the electrolysis capacity factors, varying hydrogen demand volumes and different background grids with varying levels of cleanness. Thereby we show in contrast to the study of Brauer et al. that annual matching reduces system emissions if the background grid is largely decarbonised or capacity factors of electrolysis are below 60%.

Ruhnau et al. [11] investigated the impacts of hourly versus annual matching in Germany in the existing power system using historical marginal emission factors. The hydrogen demand profile was continuous and hydrogen storage was available in steel tanks. They found similar costs for hourly and annually matched hydrogen to our study in 2025 with steel tanks. Like our study, they found that system emissions are slightly lowered by annual matching when electrolysis operates flexibly and more pronounced by hourly matching when excess electricity can be sold to the grid. In contrast to our study they assess the emissions impact using marginal emissions factors, and therefore cannot see the non-linear effects of a large volume of hydrogen demand (such as higher-emission power plants being required in some hours for large volumes than are historically on the margin). They are also restricted to a historical system, whereas we expect the grid to be considerably cleaner in 2030 and therefore see also larger emission reduction for annual matching. There are further differences in that [11] only considers wind power and no solar PV nor additional batteries for local procurement, and that other hydrogen storage options were not explored.

5. Limitations

Our study has several limitations that should be highlighted.

We have limited the suite of procured technologies to utility photovoltaics, onshore wind and lithium-ion batteries as these are the technologies commonly considered for green hydrogen. Broadening the generators to include new hydroelectric or geothermal plants could reduce costs, particularly for hourly matching with expensive hydrogen storage. Allowing long-duration electricity storage, however, is unlikely to provide any additional benefit given that we have already made hydrogen storage available to the system.

As mentioned in the Discussion section, not all regions have suitable salt deposits available for underground hydrogen storage. In these cases, hydrogen producers are forced to use steel tanks or explore other options with more expensive conversion, such as liquid hydrogen storage.

We have not included that hydrogen could be considered green if electrolysis runs when electricity prices are low. This would reduce the cost of hourly matching. This is planned in the DA[5] with a price threshold of 20 €/MWh or 36% of the EU carbon price (which currently corresponds to a price of 27 €/MWh with 75 €/t_{CO_2}[23]). Based on our results, prices are not low enough for enough of the year to make a substantial impact on our results.

There may be additional costs in wear-and-tear as well as efficiency losses from operating the electrolysers at low capacity factors. We have not considered these effects because we assume they are small compared to other costs in the system.

When we calculate the average emissions of the electricity system, we do not subtract renewable electricity procured with power purchase agreements (PPAs). The guarantees of origin for this electricity may already have been cancelled. Ideally, therefore, renewable energy from power purchase agreements should not also be used for green hydrogen. Using the residual mix, after subtraction of PPAs, would increase the attributional emissions of annually matched and grid electricity. However, since the volume of PPAs in Europe is currently low, this impact is expected to be small.

Competition for high-quality renewable sites between renewable projects built under subsidy schemes for regular electricity demand and renewables built for hydrogen production with electrolysis has not been modelled. In our model, all renewable generators see the same quality resources. Competition could lead to a higher impact of green hydrogen production, since it could use up good sites that would otherwise be used for decarbonising the electricity sector [8].

We have only matched renewable supply to electrolysis demand within each bidding zone. For large bidding zones like Germany there could be congestion inside the bidding zone that prevents the transport of the electricity. For example, if wind generation is procured in North Germany for electrolysers in South Germany, grid bottlenecks in Central Germany may prevent the transfer of electricity. Redispatch measures, whereby conventional generators are fired up to compensate missing production in South Germany, could worsen the emissions balance in this case.

6. Conclusion

Dozens of countries have set targets for clean hydrogen production to drive the decarbonisation of hard-to-electrify sectors and reduce dependence on fossil fuels. These hydrogen production targets require a set of regulations to ensure that the hydrogen produced contributes to decarbonisation and does not increase emissions.

In this work, we investigated different ways of regulating green hydrogen production. We analysed scenarios in which the electrolysis operates directly with grid electricity without additional renewable generation, as well as scenarios with additional local procurement. The local procurement matches the demand of the electrolysis either annually, monthly or hourly.

Our results show three possible sets of rules that enable the production of hydrogen with both low emissions and low costs. Additional local renewable generation is necessary in all three cases to avoid increased emissions from hydrogen production. The first option is hourly matching with flexible demand or low-cost storage, which allows to smooth out the variable feed-in of renewable generation. The second option is annual matching either with flexible demand such that electrolysis capacity factors are limited to around 60% or an upper limit on the electricity price when the electrolyser is allowed to operate. The third option is annual matching if the grid already has a high share of renewable generation and coal is phased out. In our scenarios, a share of 80% of renewable generation is sufficient to provide for negative consequential emissions with annual matching. All three options are already provided in some form or another by the proposed legislation from the European Union [5]. However, the order of implementation of annual matching (transitional phase) and hourly matching (up to 2027) in the proposed legislation is not consistent with our results. Our findings advocate a stricter regulation in the form of hourly matching or annual matching with additional limits on the capacity factors of electrolysis until policy targets are met for renewables and the phase-out of coal. Alternatively, one could apply a regulation with annual matching for the initial scale-up of electrolysis with the disadvantage of additional emissions until the policy targets for 2030 are reached.

Hourly matching provides several benefits not seen with annual matching. Hourly matching has significantly lower attributional emissions based on the average grid mix when electricity is consumed for electrolysis. Hourly matching is the only scenario which provides incentives for demand flexibility and storage, which are typically found to be optimal in top-down capacity expansion models. It also prevents electricity prices rising in the case that hydrogen demand rises faster than the conventional power plant fleet can adapt. For the case that policy targets are not met, hourly matching provides a useful hedge by guaranteeing low emissions even in this case.

Monthly matching has been suggested as a compromise between annual and hourly matching, but it shows few benefits over annual matching. In order to ensure that monthly matching does not lead to an increase in emissions, the same additional conditions would have to apply as for annual matching, such as a restriction on full load hours of electrolysis or electricity prices at which electrolysis is allowed to run, or an already high share of renewable generation in the electricity mix.

The regulation of green hydrogen production is often described as a trade-off between strict rules with higher costs or looser rules with potentially higher emissions. In this work, we show that regulations with low emissions and a small cost premium are possible.

7. Acknowledgements

The code for this investigation was adapted from open-source code for exploring 24/7 carbon-free electricity procurement written by Iegor Riepin and supported by funding from Google. This investigation on hydrogen was not funded by Google. All authors thank the following people for fruitful discussions on green hydrogen procurement: Falko Ueckerdt, Johannes Hampp, Christoph Tries, Wilson Ricks, Qingyu Xu, Jesse Jenkins, Killian Daly and Devon Swezey.

8. Declaration of interests

9. Authors contributions

10. Experimental procedures

The modelling workflow and data behind this study are open. The entire project is available in a public repository under MIT license and all the output data in a Zenodo repository.

10.1. General information

The analysis for this study is done with a modified version of the European energy system model PyPSA-Eur-Sec [24], which is based on the open-source framework PyPSA [25] maintained by the Department of Digital Transformation of Energy Systems at TU Berlin. Both the PyPSA-Eur(-Sec) suite of models and PyPSA framework are open-source, have online documentation [26, 27], and a broad community of users.

We narrow our modelling scope to the power sector of the European energy system. The scoped model performs a optimisation of the electricity system configuration (including investment and dispatch decisions) by minimising the annualised system costs in a given year. The annual system costs comprise the capital costs of investments as well as the variable operating costs for generator dispatch. In the process of optimisation, power generation and storage capacities are optimised assuming perfect foresight and perfectly competitive market operation. The optimisation is done under the set of relevant engineering constraints (such as demand-supply balance at every node or asset's capacity limits) and policy constraints (such as National energy and climate plans (NECPs)). Both the objective function and a set of constraints are linear, resulting in a convex linear optimisation problem.

The geographical scope of the model is set to Germany and its neighbouring countries. Countries with several bidding zones are split to individual nodes, such as Denmark-West and Denmark-East. The high-voltage transmission system of the ENTSO-E area is clustered to a representative system for this study using a methodology discussed in detail in [28].

The temporal scope of the model is set to 2920 representative 3-hourly snapshots, such that their total duration adds up to one year. We focus on the medium-term planning horizon, modelling two individual years of 2025 to 2030. The years differ in technology cost assumptions, existing fleet of legacy power plants in a system, NECP additions, etc. Generally, 2025 and 2030 are selected to represent the German electricity system in two sufficiently different states of decarbonisation.

10.2. Modelling annual, monthly and hourly matching requirements

Electrolysis production is co-optimised with the electricity system. In addition to purchasing grid electricity to run the electrolyser, the hydrogen producer can procure new renewable generators and battery storage located in the local market zone to meet any imposed policy requirement on temporal matching. The optimisation seeks for a cost-optimal portfolio of onshore wind, utility solar and battery storage supplying hydrogen production.

More formally, the hourly electricity demand of electrolyser d_t for hour t can be met by a combination of the dispatch $g_{r,t}$ of procured renewable generators $r \in R$, the dispatch $\bar{g}_{s,t}$ of procured storage technologies $s \in S$ (requires charge $\underline{g}_{s,t}$), the purchases from the local grid im_t and sales to the local grid ex_t. The hydrogen production pattern and cost-optimal combination of electiricity supply options depends on the (i) policy requirement on temporal matching, (ii) cleannes of the background grid, and (iii) technology costs/performance assumptions that change from 2025 to 2030.

We implement a set of additional constraints to the PyPSA-Eur-Sec model to encode policy requirements on temporal matching for the hydrogen production.

Scenario 1: On-grid production

No state policy on temporal matching is imposed. The hydrogen producer buys electricity from the grid. No procurement of additional renewable resources.

Thus, the hourly purchases from the grid im_t must cover the hourly electricity demand for electrolysis production d_t:

$$im_t = d_t \tag{1}$$

Scenario 2: Annual matching requirement

The 100% annual matching with renewable energy is modelled with a constraint (2), which requires hydrogen producer to purchase enough renewable electricity from the local bidding zone to completely offset its annual consumption.

Thus, the sum of all dispatch $g_{r,t}$ for contracted renewable generators $r \in R$ over the year $t \in T$ is equal to the annual electricity demand d_t of electrolysis:

$$\sum_{r \in R, t \in T} g_{r,t} = \sum_{t \in T} d_t \tag{2}$$

The contracted renewable generators must be new (i.e. additional to the system) and must be sited in the local market zone. Purchases from the grid allow covering electrolysis demand when in times with low renewable generation. Sales to the grid allow selling excess generation in times when generation from procured renewable resources exceeds hourly electrolysis demand. Both grid purchases and sales come at cost/revenue of hourly price at the local market defined below.

Scenario 2b: Monthly matching requirement

In section 3.6 of the manuscript, we discuss results for the monthly matching scenario, which is discussed as a compromise between the annual and hourly matching requirements. From the modelling perspective, 100% monthly matching with renewable energy requirement is implemented similar to the constraint (2), with a shorter time scope. Thus, a hydrogen producer is required to purchase enough renewable electricity from the local bidding zone to completely offset its *monthly* consumption.

Scenario 3: Hourly matching requirement

The hourly matching requirement is modelled with a constraint (3), enforcing the hydrogen producer to match electricity consumption with clean electricity on an hourly basis.

Thus, the hourly generation from the procured renewable resources $r \in R$ and the discharge and charge from the procured battery storage $s \in S$, minus hourly sales to the grid ex_t must be equal to the hourly electricity demand of electrolysis:

$$\sum_{r \in R} g_{r,t} + \sum_{s \in S} \left(\bar{g}_{s,t} - \underline{g}_{s,t} \right) - ex_t = d_t \tag{3}$$

The excess hourly generation from the procured renewable resources can be sold to the grid or curtailed. Note that for the base scenario discussed in the main part of the manuscript, the excess (after the curtailment) is set to zero. In the Appendix, we show sensitivity runs where the excess is allowed and limited to 20% and 30% of the annual electricity demand of the electrolyser. Note that purchases from the grid im_t are not allowed in this scenario.

Hourly price estimates in the local market

The hourly price estimates in the local market are derived from the dual variable of each zone's energy balance constraint. An infinitely small relaxation of the constraint,

i.e., one unit of load less to be met, returns the marginal costs of providing that unit, which can be used as the electricity price indicator in a competitive market.

10.3. Model input data

Model inputs, including regional demand profiles, existing fossil and renewable power plants, technology cost assumptions, technology performance data, renewable potentials and time-series availability data, are compiled using PyPSA-Eur-Sec model [26] that is based on the ecosystem of PyPSA data tool-sets [29]. The original data sources as well as the tool-sets for downloading, cleaning, standardising and combining energy system data are described in greater detail in [28, 30–32].

10.4. Cost of hydrogen production

The cost of hydrogen production [Eur/kg$_{\mathrm{H_2}}$] presented in Figure 5 is defined as a sum of annualised capital costs C_a and variable operating costs $O_{a,t}$ of all new assets A contracted by the hydrogen producer, plus costs of electricity purchases from the grid, minus revenue from selling the excess electricity to the grid (if allowed by scenario) per MWh$_{\mathrm{H_2}}$ of hydrogen demand $d_{\mathrm{H_2}}$:

$$C_{\mathrm{H_2}} = \frac{\sum_{a\in A} C_a + \sum_{a,t} O_{a,t} + \sum_t P_t \cdot (im_t - ex_t)}{d_{\mathrm{H_2}}} \quad (4)$$

Electricity price P_t for every timesep t is estimated based on the marginal price of the local zone, as discussed above.

References

[1] EU Commission, REPowerEU: A plan to rapidly reduce dependence on Russian fossil fuels and fast forward the green transition (2022).
URL https://ec.europa.eu/commission/presscorner/detail/en/IP_22_3131

[2] Arunabha Ghosh, Tulika Gupta, Shuva Raha, Hemant Mallya, Deepak Yadav, and Nandini Harihar , Rules for an Energy-Secure Global Green Hydrogen Economy (2022).
URL https://globalchallenges.org/wp-content/uploads/2022/11/CEEW-Rules-for-an-Energy-Secure-Global-Green-Hydrogen-Economy-Web-09Nov22.pdf

[3] Bundesregierung, Nationale Wasserstoffstrategie - Wasserstoff – Energieträger der Zukunft (2022).
URL https://www.bundesregierung.de/breg-de/themen/klimaschutz/wasserstoff-technologie-1732248#:~:text=In%20diesen%20L%C3%A4ndern%20eignen%20sich,von%20mindestens%20zehn%20Gigawatt%20aufbauen.

[4] Hydrogen Europe et al , Joint statement of the EU industry: Pragmatic regulatory framework necessary for hydrogen market (2022).
URL https://hydrogeneurope.eu/wp-content/uploads/2022/07/2022.07_Joint-Letter-by-18-Industry-Associations-on-REDII-DA.pdf

[5] EU Commission, Production of renewable transport fuels – share of renewable electricity (requirements) (2022).
URL https://ec.europa.eu/info/law/better-regulation/have-your-say/initiatives/7046068-Production-of-renewable-transport-fuels-share-of-renewable-electricity-requirements-_en

[6] EU Parliament and EU council, Directive (EU) 2018/2001 of the European Parliament and of the Council of 11 December 2018 on the promotion of the use of energy from renewable sources (recast). L328/82 (2018).
URL https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=uriserv:OJ.L_.2018.328.01.0082.01.ENG&toc=OJ:L:2018:328:TOC

[7] Hydrogen Europe, Renewable Hydrogen Coalition, Joint Letter on urgent need to adopt DA on additionality (2022).
URL https://usercontent.one/wp/hydrogeneurope.eu/wp-content/uploads/2022/10/2022.10.6_Industry-letter-on-RFNBO-DA.pdf?media=1668170528

[8] W. Ricks, Q. Xu, J. D. Jenkins, Enabling grid-based hydrogen production with low embodied emissions in the united states, Tech. rep. (2022).
URL https://zenodo.org/record/7183516#.Y1f5N9JByrw

[9] 117th Congress (2021-2022), H.R.5376 - Inflation Reduction Act of 2022 (2022).
URL https://www.congress.gov/bill/117th-congress/house-bill/5376/text

[10] J. Brauer, M. Villavicencio, J. Trüby, Green hydrogen: How grey can it be?, Tech. rep. (2022).
URL https://fsr.eui.eu/publications/?handle=1814/74850

[11] O. Ruhnau, J. Schiele, Flexible green hydrogen: Economic benefits without increasing power sector emissions, Tech. rep., Kiel, Hamburg, older version: http://hdl.handle.net/10419/253267 (2022).
URL http://hdl.handle.net/10419/258999

[12] H. Council, Hydrogen decarbonization pathways, A life-cycle assessment (2021).
URL https://hydrogencouncil.com/wp-content/uploads/2021/04/Hydrogen-Council-Report_Decarbonization-Pathways_Part-1-Lifecycle-Assessment.pdf

[13] European Commission, Annex 1 to the Commission Delegated Regulation (EU), Taxonomy Regulation Delegated Act 2021 2800 (2021).
URL https://ec.europa.eu/finance/docs/level-2-measures/taxonomy-regulation-delegated-act-2021-2800-annex-1_en.pdf

[14] D. G. Caglayan, N. Weber, H. U. Heinrichs, J. Linßen, M. Robinius, P. A. Kukla, D. Stolten, Technical potential of salt caverns for hydrogen storage in europe, International Journal of Hydrogen Energy 45 (11) (2020) 6793–6805. doi:10.1016/j.ijhydene.2019.12.161.
URL https://doi.org/10.1016/j.ijhydene.2019.12.161

[15] T. Brown, D. Schlachtberger, A. Kies, S. Schramm, M. Greiner, Synergies of sector coupling and transmission reinforcement in a cost-optimised, highly renewable European energy system, Energy 160 (2018) 720–739. doi:10.1016/j.energy.2018.06.222.
URL https://doi.org/10.1016/j.energy.2018.06.222

[16] Georg Bieker, A global comparison of the life-cycle greenhouse gas emissions of combustion engine and electric passenger cars, updated version 11.11.22 (2021).
URL https://theicct.org/wp-content/uploads/2021/07/Global-Vehicle-LCA-White-Paper-A4-revised-v2.pdf

[17] Agora Verkehrswende, Klimabilanz von strombasierten Antrieben und Kraftstoffen (2019).
URL https://www.agora-verkehrswende.de/veroeffentlichungen/klimabilanz-von-strombasierten-antrieben-und-kraftstoffen-1/#:~:text=In%20der%20Klimabilanz%20eines%20Fahrzeugs,des%20Batteriefahrzeugs%20mit%2035%20kWh.

[18] F. Knobloch, S. V. Hanssen, A. Lam, H. Pollitt, P. Salas, U. Chewpreecha, M. A. J. Huijbregts, J.-F. Mercure, Net emission reductions from electric cars and heat pumps in 59 world regions over time, Nature Sustainability 16 (2020) 437–447. doi:10.1038/s41893-020-0488-7.
URL https://doi.org/10.1038/s41893-020-0488-7

[19] P. Bayer, D. Saner, S. Bolay, L. Rybach, P. Blum, Greenhouse gas emission savings of ground source heat pump systems in europe: A review, Renewable and Sustainable Energy Reviews 16 (2) (2012) 1256–1267. doi:10.1016/j.rser.2011.09.027.

URL https://doi.org/10.1016/j.rser.2011.09.027
[20] K. Bruninx, J. A. Moncada, M. Ovaere, Electrolytic hydrogen has to show its true colors, Joule 6 (11) (2022) 2437–2440. doi:10.1016/j.joule.2022.09.007.
URL https://doi.org/10.1016/j.joule.2022.09.007
[21] DG Clima, European Commission, Designing competitive bidding mechanisms under the Innovation Fund.
URL https://ercst.org/wp-content/uploads/2022/10/20221128-ERCST-CCfD-Workshop65-copy.pdf
[22] Antonio A. Fernández, (Carbon) Contracts for Difference: Priorities and Red Lines for the EU Scheme.
URL https://ercst.org/event/carbon-contracts-for-difference-priorities-and-red-lines-for-the-eu-scheme/
[23] Trading Exonomicy, EU Carbon Permits, last accessed 22.11.22,.
URL https://tradingeconomics.com/commodity/carbon
[24] PyPSA-Eur-Sec Github.
URL https://github.com/PyPSA/pypsa-eur-sec
[25] PyPSA Github.
URL https://github.com/PyPSA/pypsa
[26] Tom Brown, Marta Victoria, Elisabeth Zeyen, Fabian Neumann, PyPSA-Eur-Sec: A Sector-Coupled Open Optimisation Model of the European Energy System documentation.
URL https://pypsa-eur-sec.readthedocs.io/en/latest/
[27] PyPSA Documentation.
URL https://pypsa.readthedocs.io/en/latest/
[28] PyPSA-Eur Documentation.
URL https://pypsa-eur.readthedocs.io/en/latest/
[29] PyPSA Webpage.
URL https://pypsa.org/
[30] Github repository Technology Data.
URL https://github.com/PyPSA/technology-data
[31] Github repository Powerplantmatching.
URL https://github.com/PyPSA/powerplantmatching
[32] Github repository Atlite.
URL https://github.com/PyPSA/atlite
[33] Bundestag, Osterpaket zum Ausbau erneuerbarer Energien beschlossen (2022).
URL https://www.bundestag.de/dokumente/textarchiv/2022/kw27-de-energie-902620
[34] European Commission, National energy and climate plans (NECPs) (2019).
URL https://energy.ec.europa.eu/topics/energy-strategy/national-energy-and-climate-plans-necps_en
[35] National Climate Agreement Netherlands (2019).
URL https://climate-laws.org/geographies/netherlands/policies/national-climate-agreement
[36] Wind Europe, Austria aims to have 100 percent renewable electricity by 2030 (2021).
URL https://windeurope.org/newsroom/news/austria-aims-to-have-100-renewable-electricity-by-2030/
[37] Sarah George, Energy Security Strategy: UK targets 95will increase oil and gas production (2022).
URL https://www.edie.net/energy-security-strategy-uk-targets-95-low-carbon-electricity-mix-by-2030-but-will-increase-oil-and-gas-production/
[38] The Danish Energy Agency, Catalogue of technology data for energy technologies.
URL https://ens.dk/en/our-services/projections-and-models/technology-data

Acronyms

CAPEX Capital expenditures

CfD Contract for Difference

DA Draft Delegated Act for the production of renewable liquid and gaseous transport fuels of non-biological origin

ENTSO-E European network for transmission system operators electricity

ETS Emissions Trading System

EU European Union

FOM Fixed operation and maintenance costs

LOHC Liquid organic hydrogen carriers

NECP National energy climate plan

PPA Power Purchase Agreement

PTC Production Tax Credit

RES Renewable energy sources

VOM Variable operation and maintenance costs

11. Appendix

In the Appendix we first provide an overview of the assumed renewable shares of electricity generation in Table 1, as well as the cost assumptions in Table 2. Second, further graphs on our main results in the manuscript are given in Section 11.1. In this section we show the electricity generation mix when the electrolysis is running (see Figure 9), the installed capacities at the industrial site (renewable capacities Figure 10, electrolysis capacities Figure 11, storage capacities Figure 12), the duration curve of the electrolysis (Figure 13), the curtailment of the renewable generation (Figure 14), the amount of sold and purchased electricity (Figure 15), one example week in March for annual and hourly matching with flexible demand and without any storage options (Figures 16, 17, 18, 19).

Further plots of the monthly matching scenarios are given for the electricity prices (Figure 20), the hydrogen production costs (Figure 21) and attributional emissions (Figure 22). The generation mix of Germany 2025, Germany 2030 and Netherlands 2025 is given in Figure 23, capacity factors of electrolysis in Netherlands 2025 (Figure 24) and Germany 2030 (Figure 25), hydrogen production cost in Netherlands 2025 (Figure 26) and Germany 2030 (Figure 27), attributional emissions in Netherlands 2025 (Figure 28) and Germany 2030 (Figure 29).

We explore further sensitivity analyses in the last section. In these, we

1. explore hydrogen production in four further countries, namely Czech Republic (Figure 30, Figure 31), Poland (Figure 32, Figure 33), Spain (Figure 34, Figure 35) and Portugal (Figure 36, Figure 37),
2. vary the size of hydrogen production to examine the impact on the results with smaller or larger demand (Figure 38, Figure 39)
3. vary the size of hydrogen production to examine the impact on the results with smaller or larger demand (Figure 38, Figure 39)
4. vary the share of renewable electricity generation to examine the impact of missing policy targets or exceeding set targets. We alter the shares of RES generation in
   (a) Germany 2025 (consequential emissions of grid scenarions Figure 42 and annual matching Figure 43, capacity factors of grid scenario 44 and annual matching 45, cost breakdown of grid scenario in Figure 46 and annual matching in Figure 47,
   (b) Germany 2030 with a coal phase out as planned by the current government (consequential emissions of annual matching in Figure 48),
   (c) Germany 2030 without a coal phase out (consequential emissions of annual matching in Figure 49).

Country	Renewable Constraint 2025 Share of renewable generation from total load	Renewable Constraint 2030 Share of renewable generation from total load
Germany	55.0% [1]	80.0% [33]
Denmark	90.0% [1]	110.0% [34]
Netherlands	35.0% [1]	50.0% [35]
Ireland	47.0% [1]	70.0% [34]
Austria	90.0% [1]	100.0% [36]
Belgium	33.5% [1]	40.4% [34]
Czech Republic	14.0% [1]	17.0% [34]
France	32.0% [1]	40.0% [34]
Great Britain	68.5% [1]	95.0% [37]
Poland	24.5% [1]	32.0% [34]
Spain	58.8% [1]	74.0% [34]
Portugal	69.0% [34]	80.0% [34]
Others	50% capacity increase compared to 2021	400% capacity increase compared to 2021

[1]Linear interpolated from 2020 renewable generation share to 2030 target.

Table 1: Renewable generation target by country for 2025 and 2030. Since most countries do not have a target for 2025, a linear increase from renewable generation in 2020 to 2030 target is assumed.

Year	Technology	CAPEX (overnight cost)	FOM (%/year)	VOM (€/MWh)	Efficiency (per unit)	Lifetime (years)
2025	utility solar	612 €/kW	1.7	0.01	-	37.5
2025	onshore wind	1077 €/kW	1.2	0.015	-	28.5
2025	battery storage	187 €/kWh	-	-	-	22.5
2025	battery inverter	215 €/kW	0.3	-	0.96	10
2025	hydrogen storage (salt caverns)	2.5 €/kWh	0	0	-	100
2025	hydrogen storage (steel tanks)	51 €/kWh	1.08	0	-	27.5
2025	electrolysis	550 €/kW_{el}	2.0	-	0.67	27.5
2030	utility solar	492 €/kW	2.0	0.01	-	40
2030	onshore wind	1035 €/kW	1.2	0.015	-	30
2030	battery storage	142 €/kWh	-	-	-	25
2030	battery inverter	160 €/kW	0.3	-	0.96	10
2030	hydrogen storage (salt caverns)	2.0 €/kWh	0	0	-	100
2030	hydrogen storage (steel tanks)	44.9 €/kWh	1.11	0	-	30
2030	electrolysis	450 €/kW_{el}	2.0	-	0.68	30

Table 2: Technology costs assumptions for 2025 and 2030. Data is originally retrieved from the Danish Energy Agency's catalogues of technology data for energy technologies [38].

11.1. Further plots of the main results

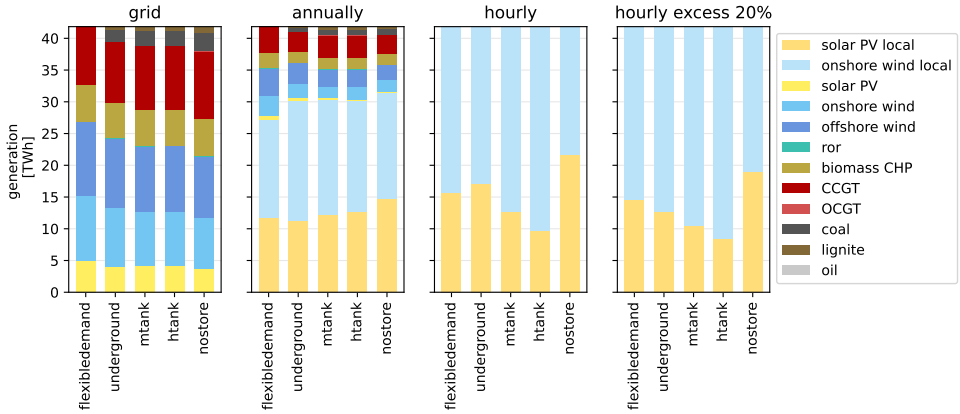


Figure 9: Mix of electricity generation in Germany 2025 when electrolysis is running.

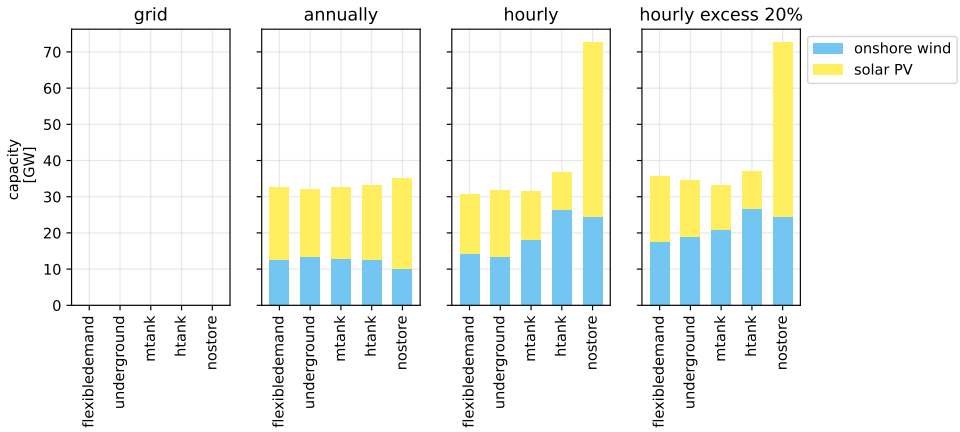


Figure 10: Installed renewable capacities at industrial node for Germany 2025. With annual matching solar is favoured. With hourly matching solar and onshore wind are built.

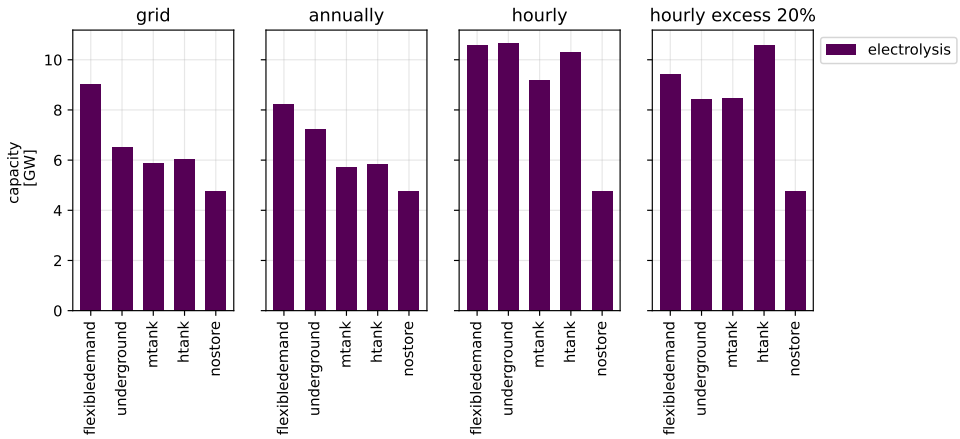


Figure 11: Installed electrolysis capacities at industrial node for Germany 2025.

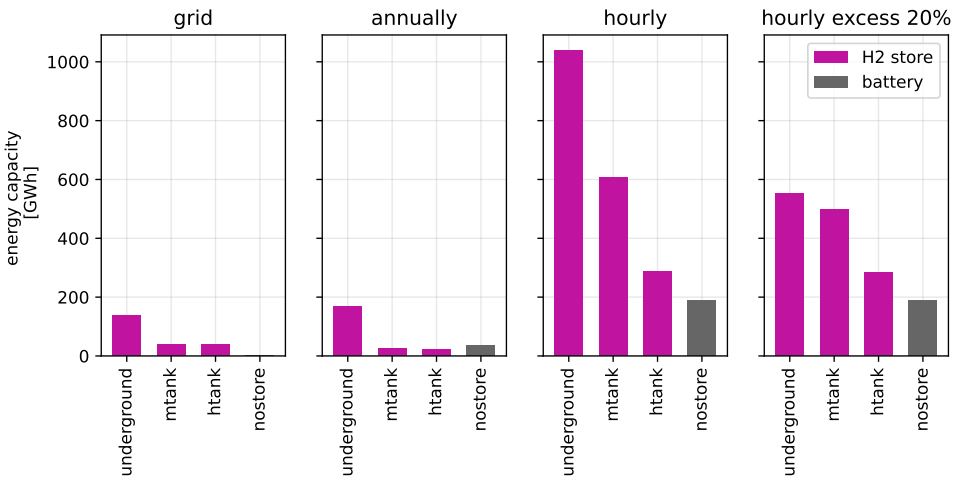


Figure 12: Energy storage capacities for Germany 2025.

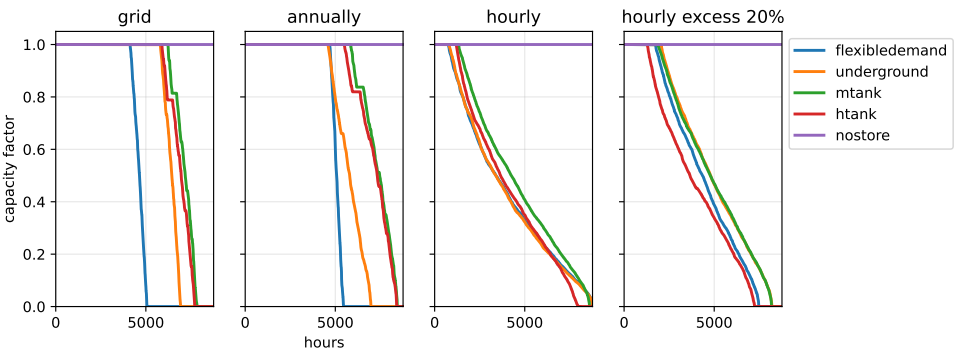
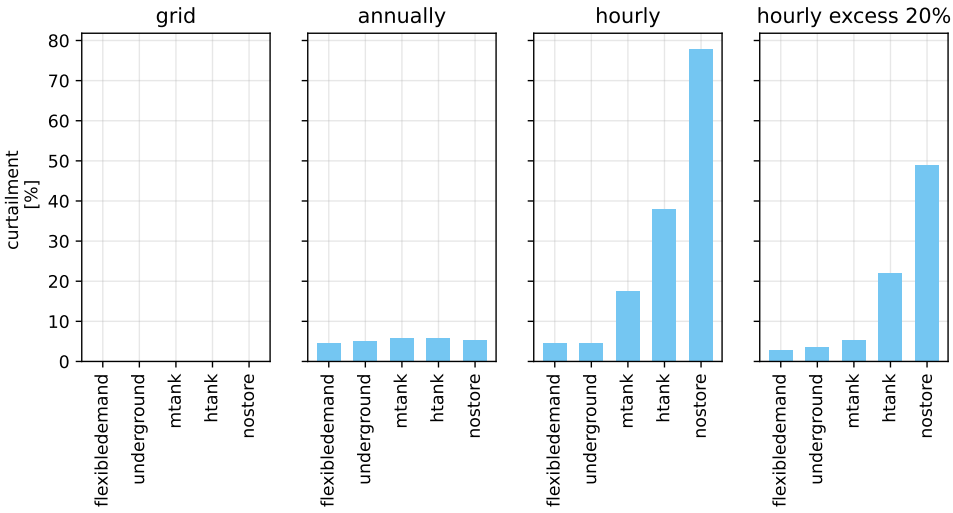
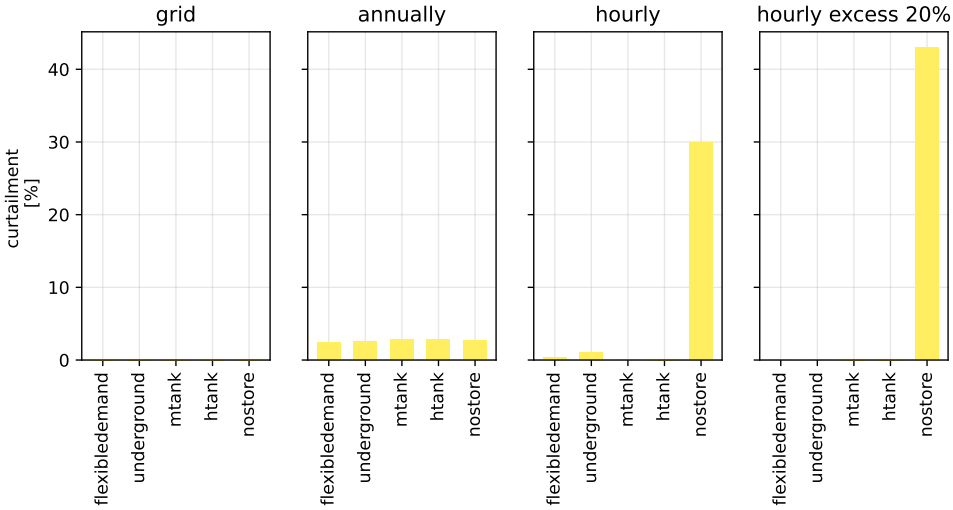


Figure 13: Duration curve of electrolysis for Germany 2025.



(a) Curtailment local onshore wind



(b) Curtailment local solar PV

Figure 14: Curtailment of renewable generation at local node for Germany 2025.

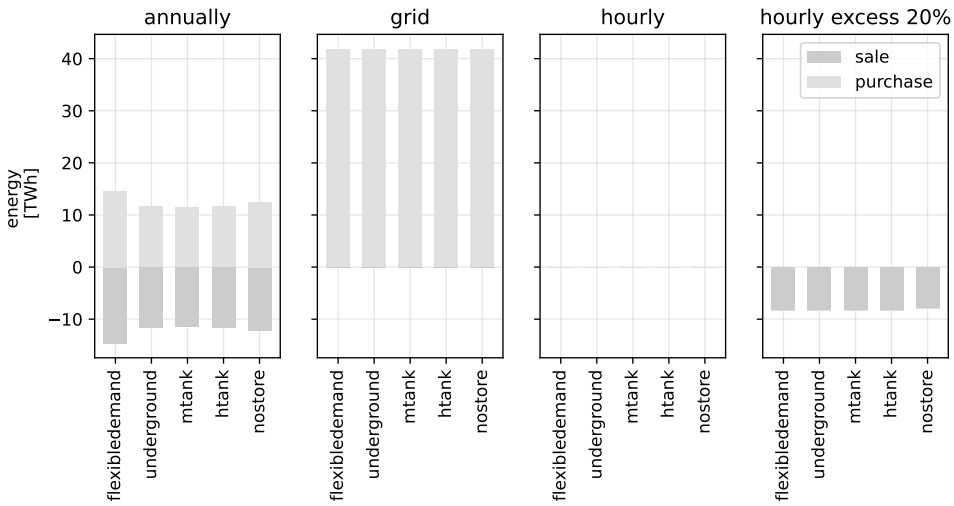


Figure 15: Sale and purchase from the local production to the background grid for Germany 2025.

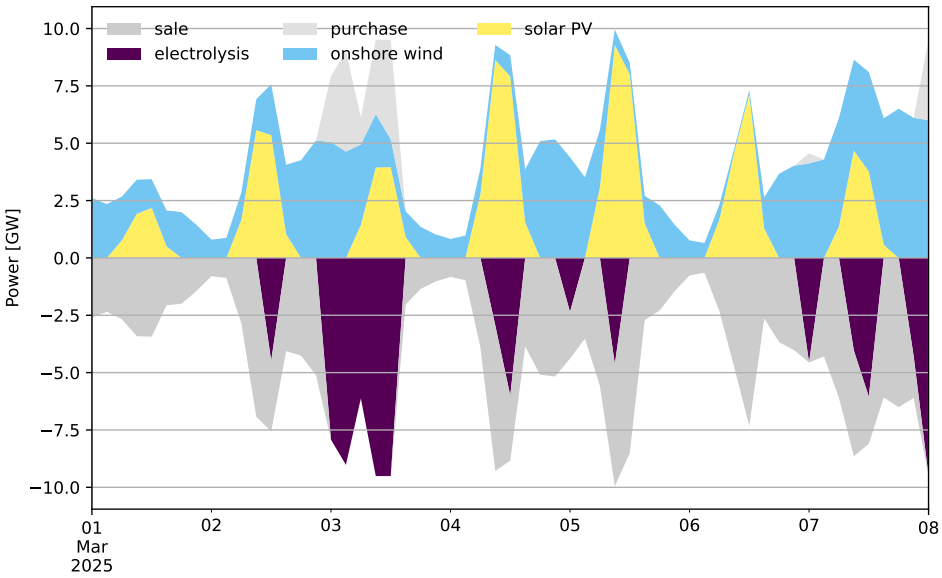


Figure 16: Representative week for annual matching and flexible demand in Germany 2025. Electrolysis runs flexibly depending on price for purchasing electricity and local renewable generation. At hours with high feed-in of local renewable generation electricity is sold to the grid.

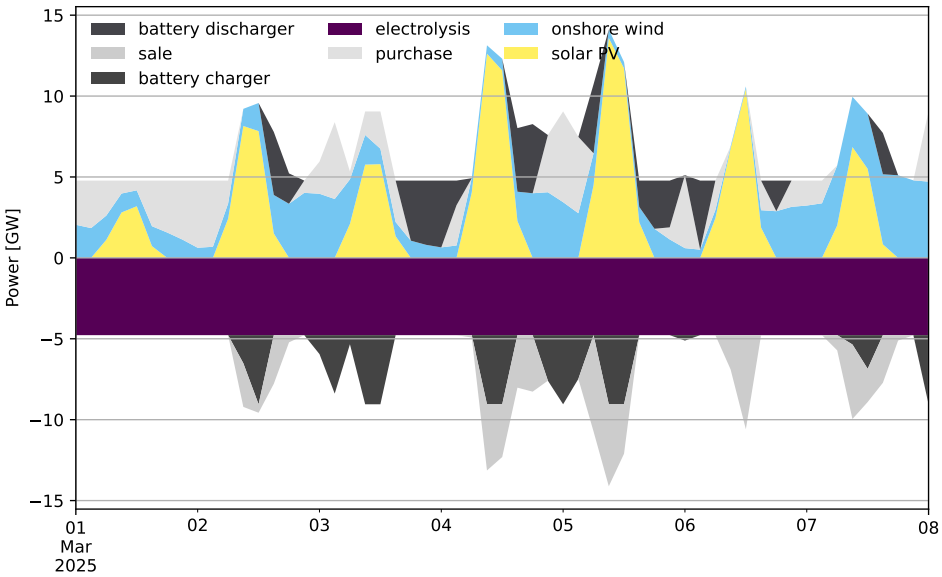


Figure 17: Representative week for annual matching and no hydrogen storage options in Germany 2025. Electrolysis runs constantly. Hours with low feed-in of renewable generation are bridged with battery storage and purchase of electricity.

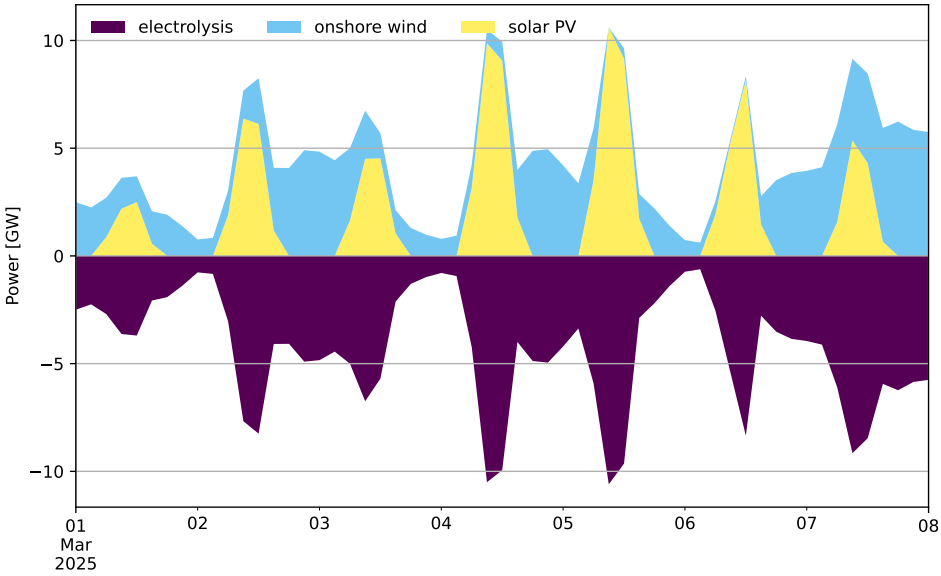


Figure 18: Representative week for hourly matching and flexible demand in Germany 2025. Electrolysis operation follows the feed-in of the local generation.

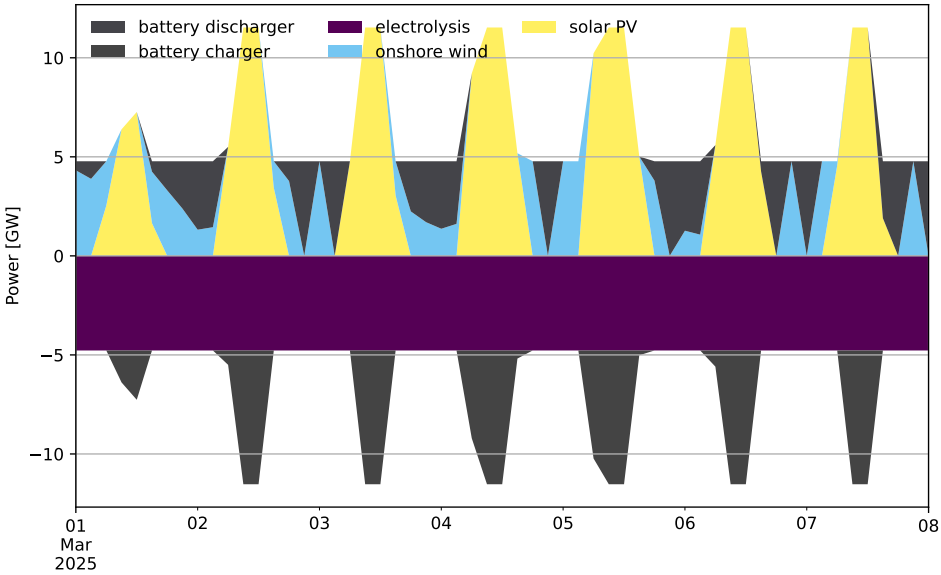


Figure 19: Representative week for hourly matching and no hydrogen storage options in Germany 2025. Electrolysis runs constantly. Hours with low feed-in of renewable generation are bridged with battery storage.

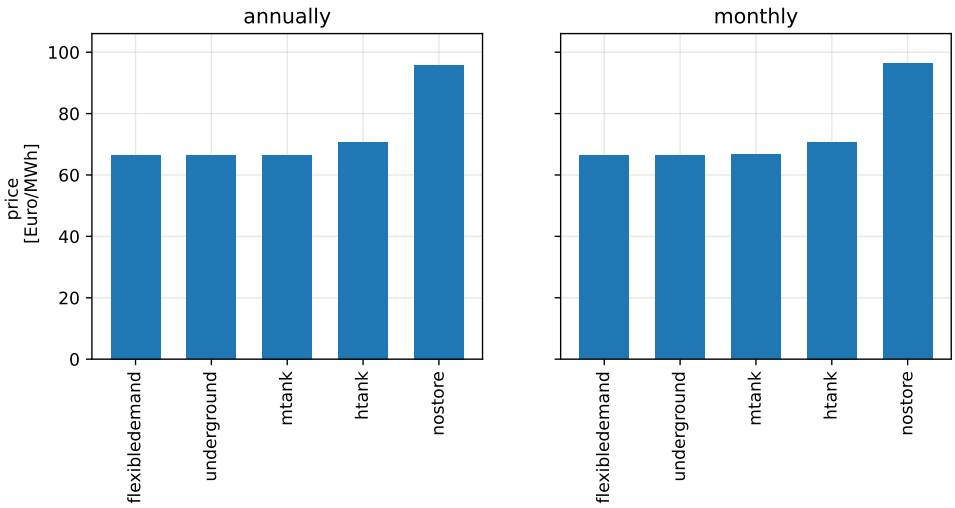


Figure 20: Load weighted electricity prices for annual and monthly matching for Germany 2025. Annually and monthly matching increases electricity prices in case of expensive storage or complete inflexible demand. Note that the background electricity system has fixed capacities and is not able to adapt to the new electrolysis demand. If capacities can adapt then the price rise could be lower.

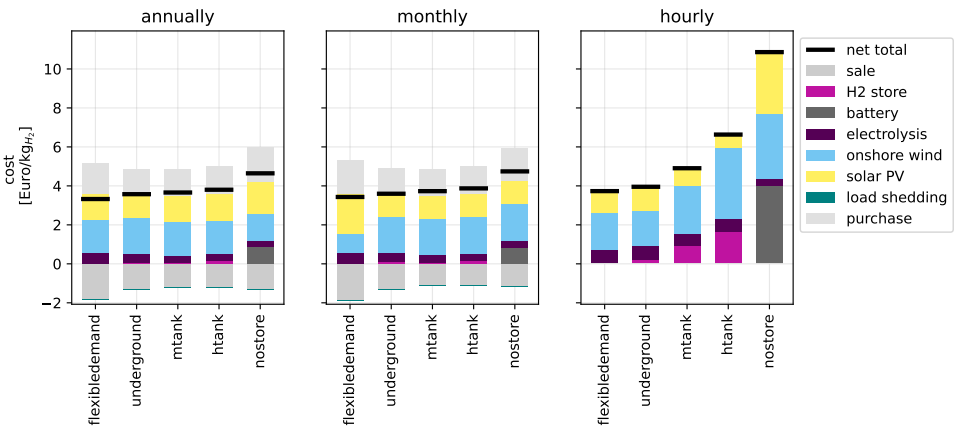


Figure 21: Cost breakdown monthly matching Germany 2025.

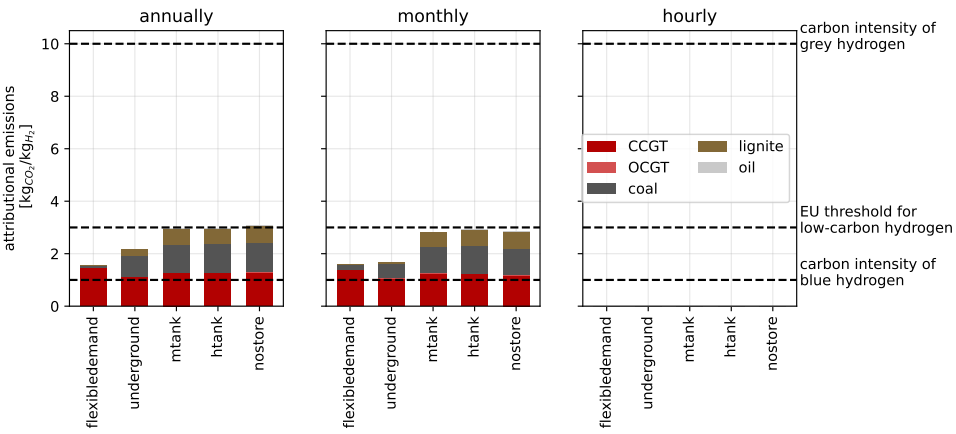


Figure 22: Attributional emissions with monthly matching in Germany 2025.

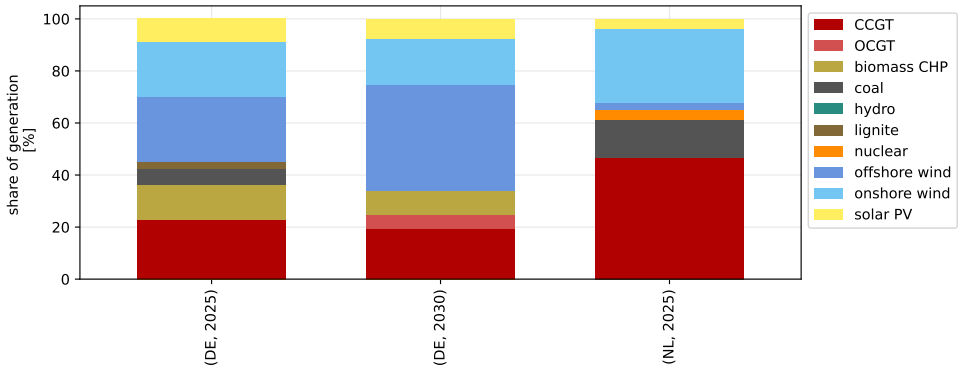


Figure 23: Electricity generation share of different carriers for Germany in 2025 (DE, 2025) and 2030 (DE, 2030) and Netherlands 2025 (NL, 2025).

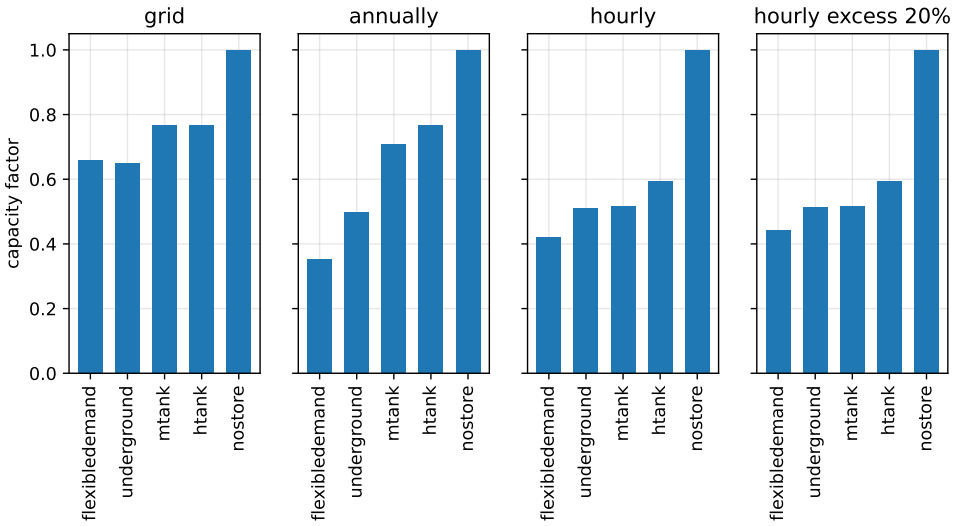


Figure 24: Capacitiy factors of electrolysis for local production in Netherlands 2025.

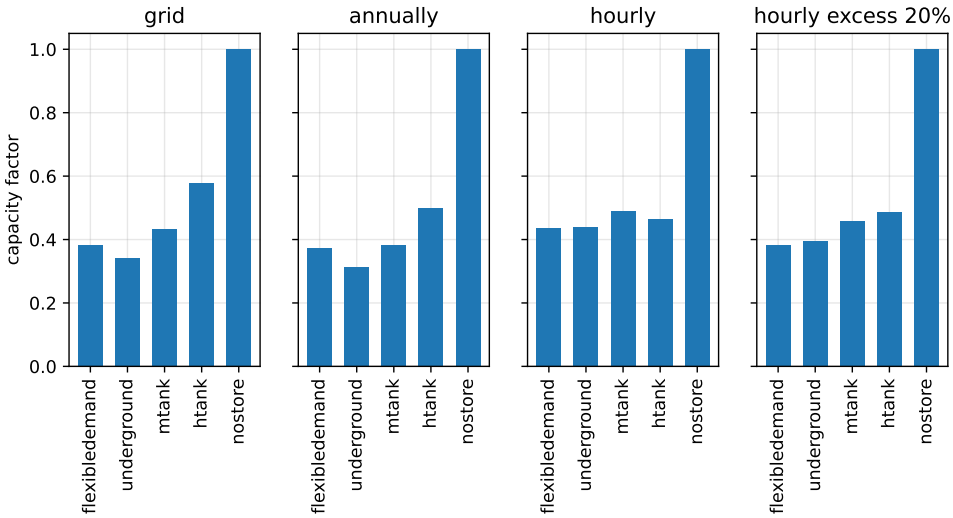


Figure 25: Capacitiy factors of electrolysis for local production in Germany 2030.

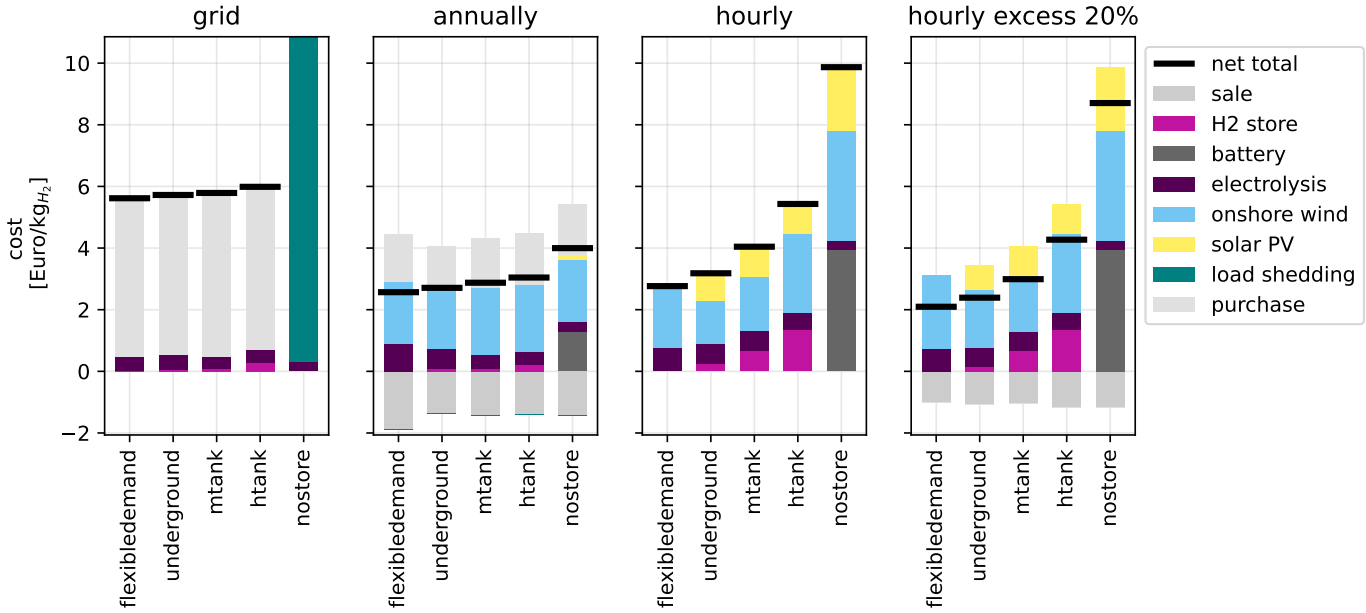


Figure 26: Cost breakdown of hydrogen production Netherlands 2025. In the grid scenario no additional generation capacity can be built. Without any hydrogen storage there are hours in which the hydrogen demand cannot be met.

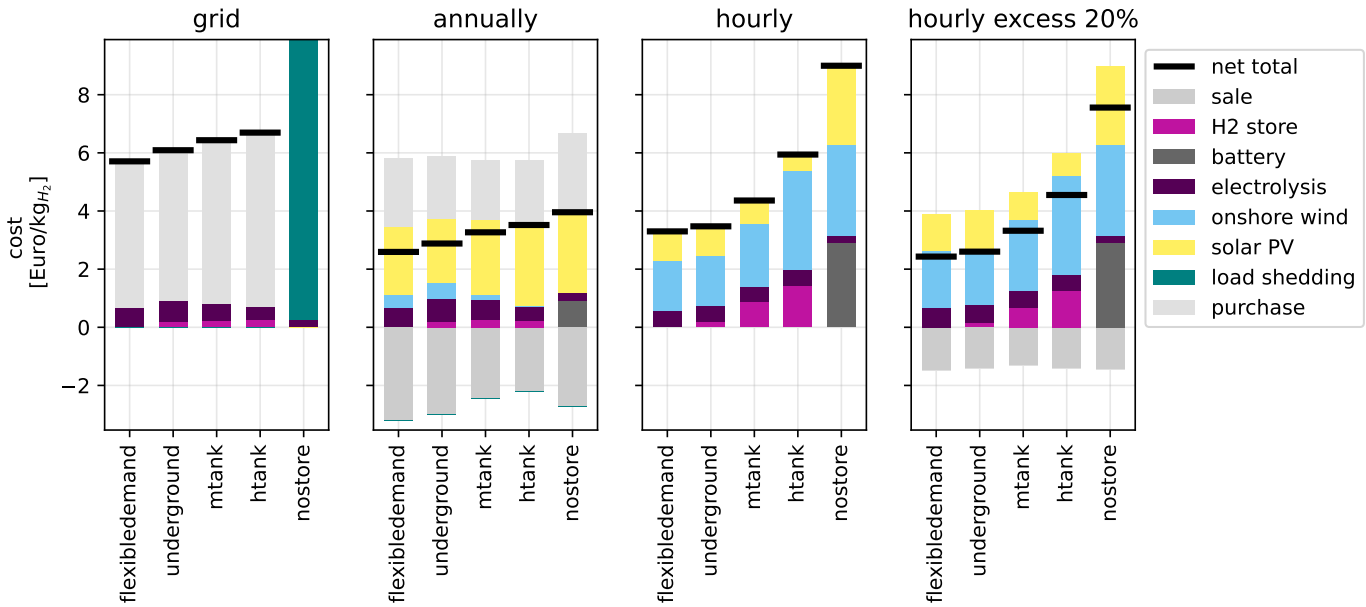


Figure 27: Cost breakdown of hydrogen production Germany 2030. In the grid scenario no additional generation capacity can be built. Without any hydrogen storage there are hours in which the hydrogen demand cannot be met.

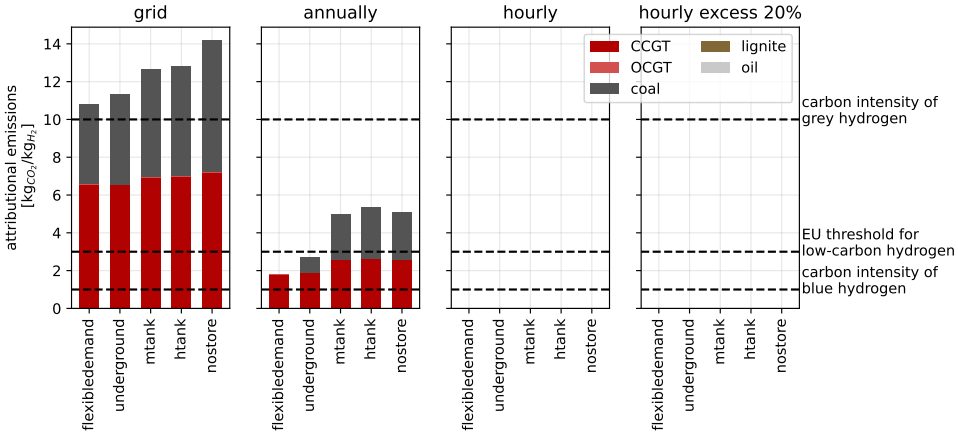


Figure 28: Attributional emissions of hydrogen for local production in Netherlands 2025.

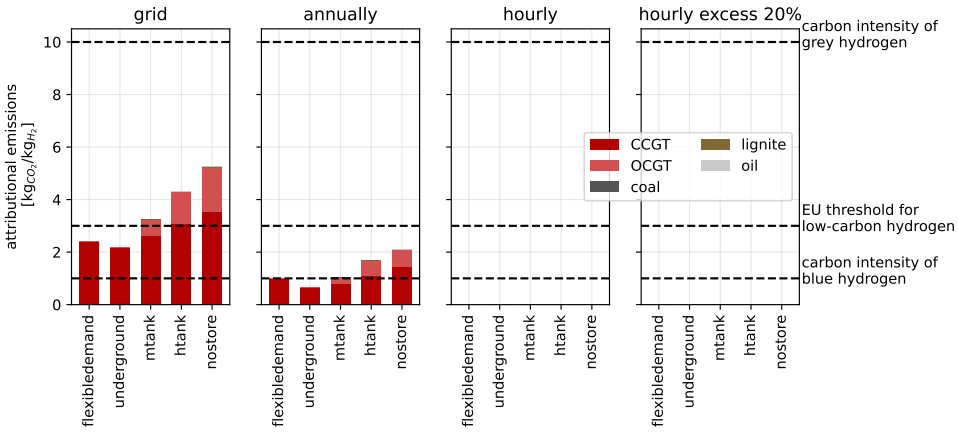


Figure 29: Attributional emissions of hydrogen for local production in Germany 2030.

11.2. Further sensitivities

11.2.1. Further countries: Czech Republic, Poland, Spain, Portugal

11.2.2. Volume of hydrogen demand

11.2.3. Allowing excess for annual matching

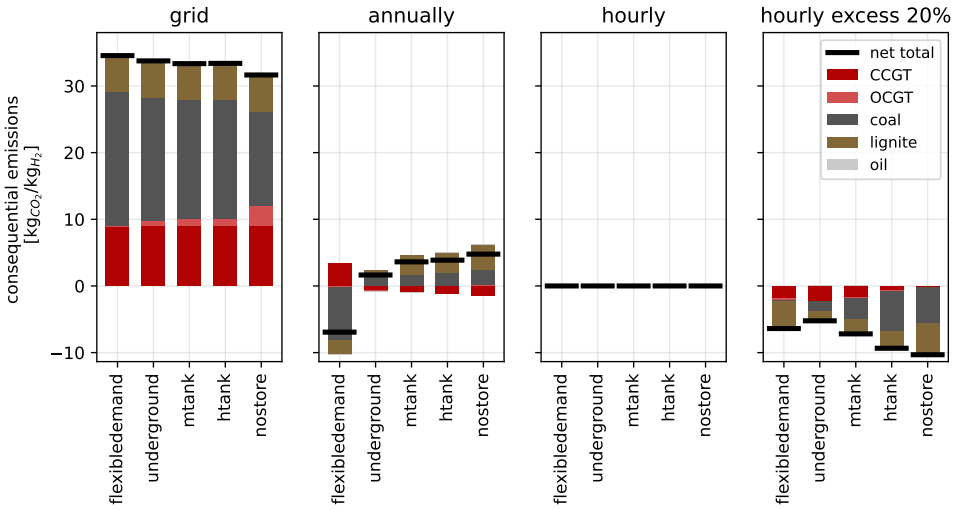


Figure 30: Consequential emission Czech Republic 2025 renewable generation share 14%.

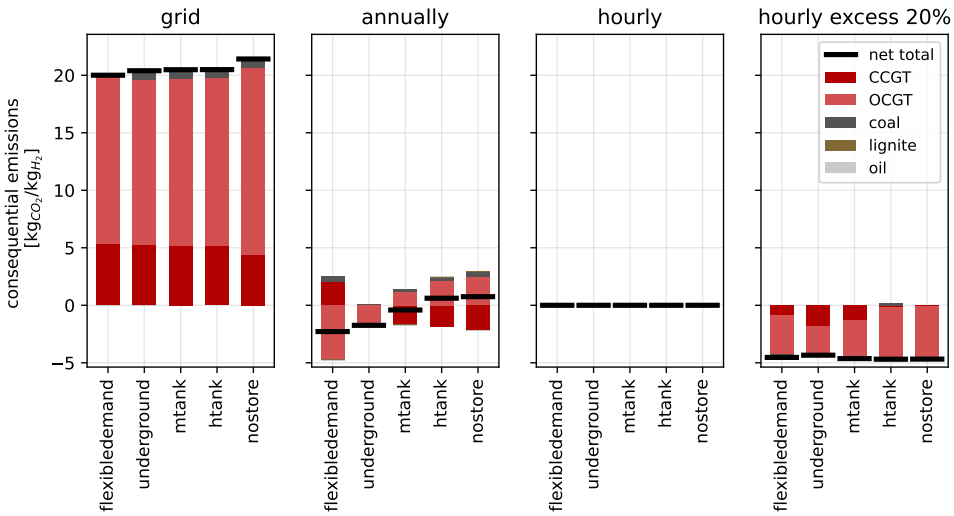


Figure 31: Consequential emission Czech Republic 2030 renewable generation share 17%.

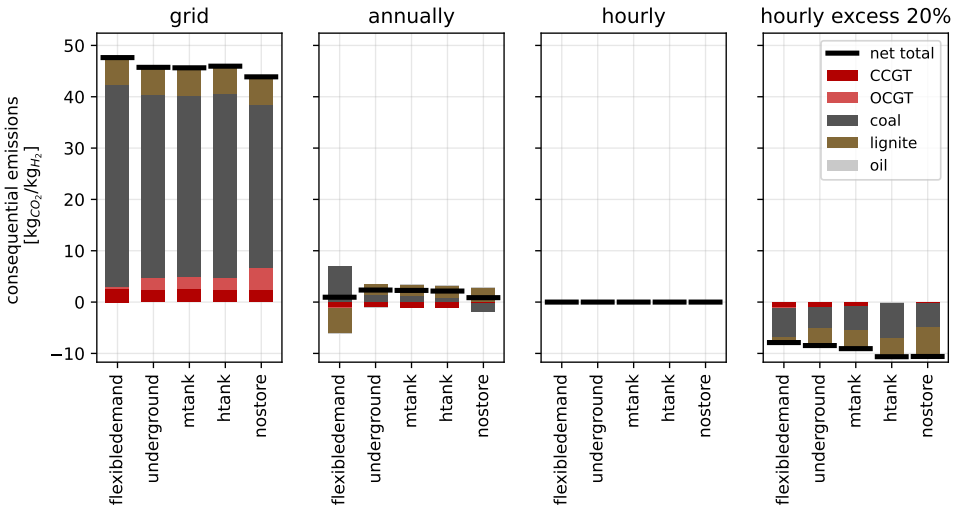


Figure 32: Consequential emission Poland 2025 renewable generation share 24.5%.

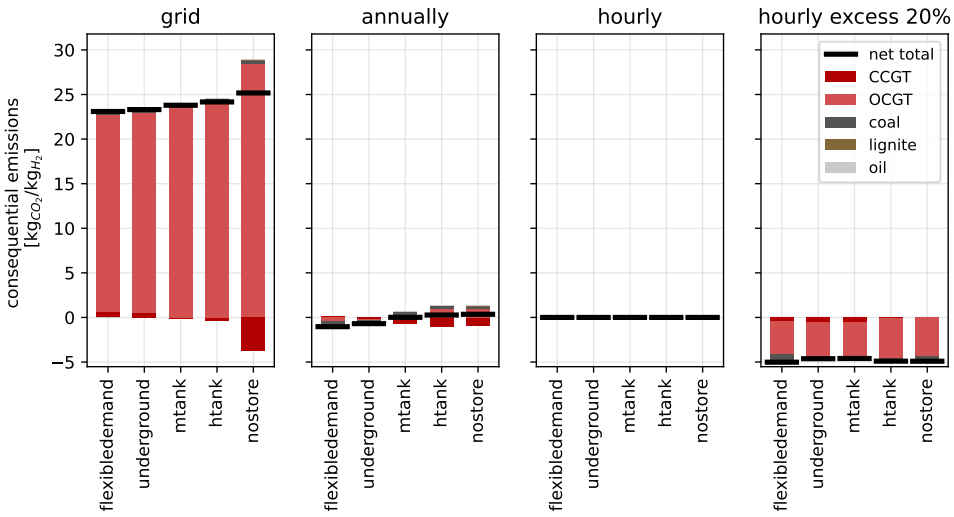


Figure 33: Consequential emission Poland 2030 renewable generation share 32%.

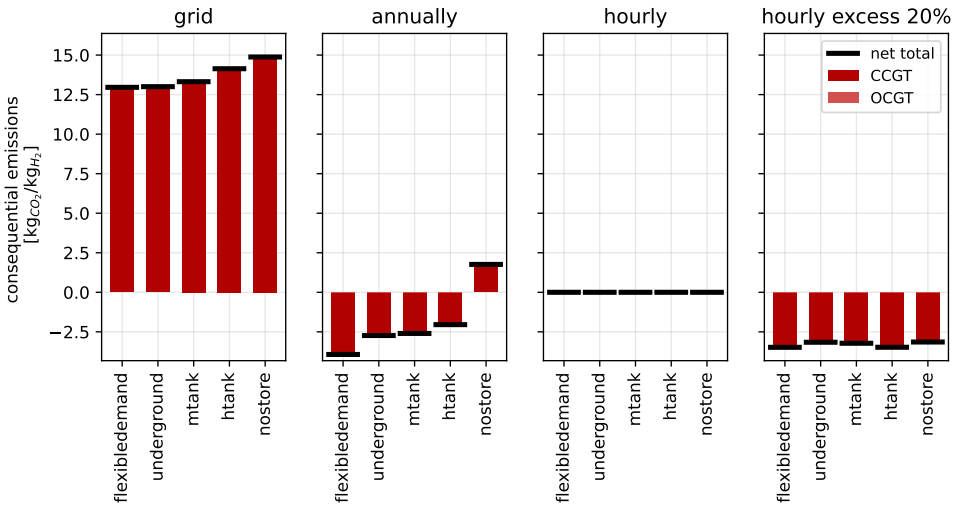


Figure 34: Consequential emission Spain 2025 renewable generation share 58.5%.

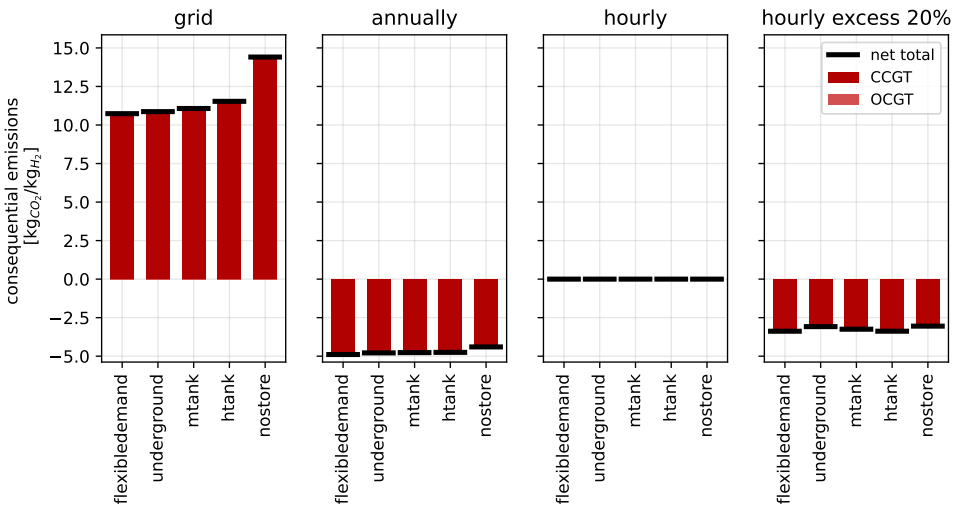


Figure 35: Consequential emission Spain 2030 renewable generation share 74%.

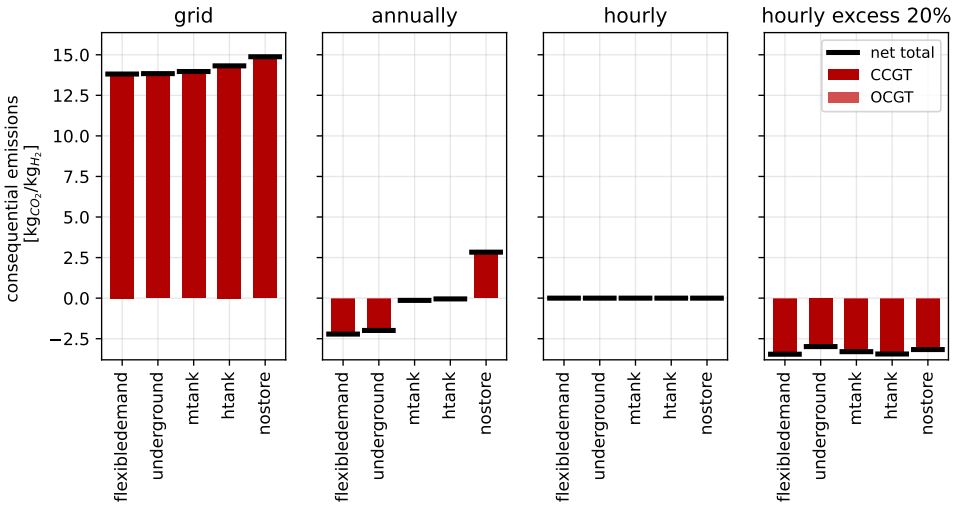


Figure 36: Consequential emission Portugal 2025 renewable generation share 69%.

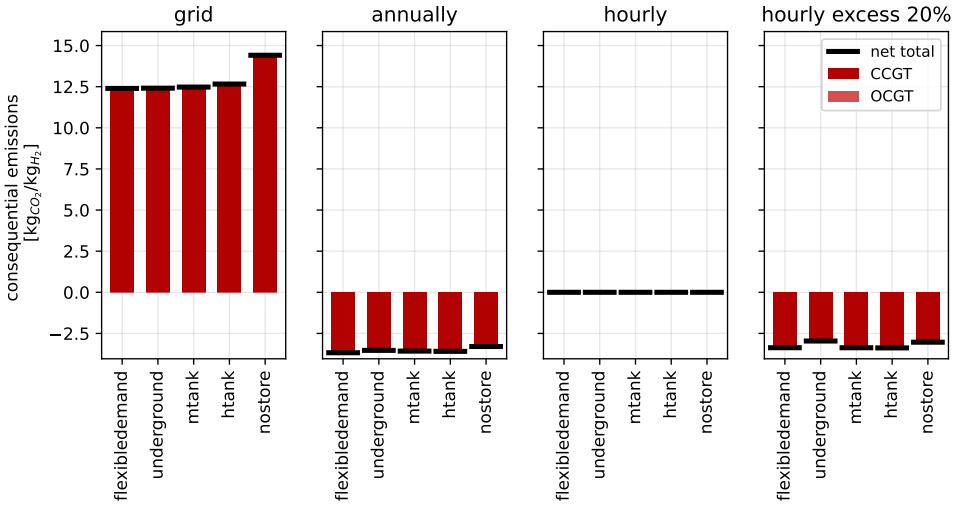
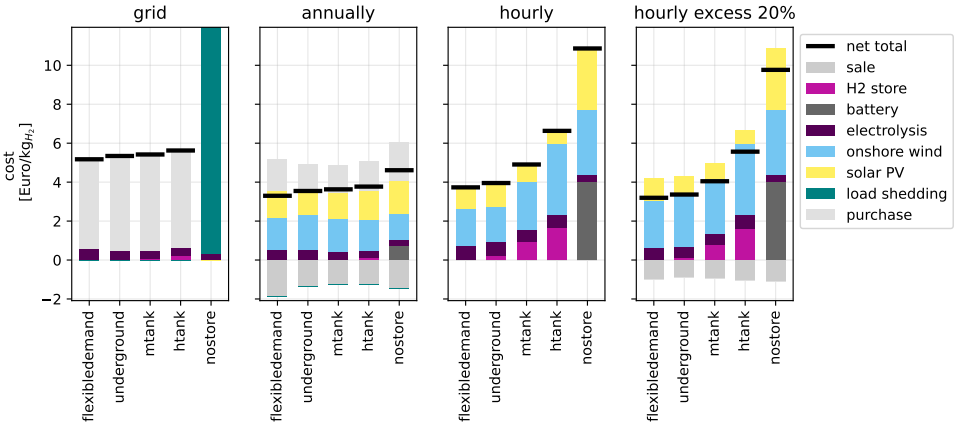
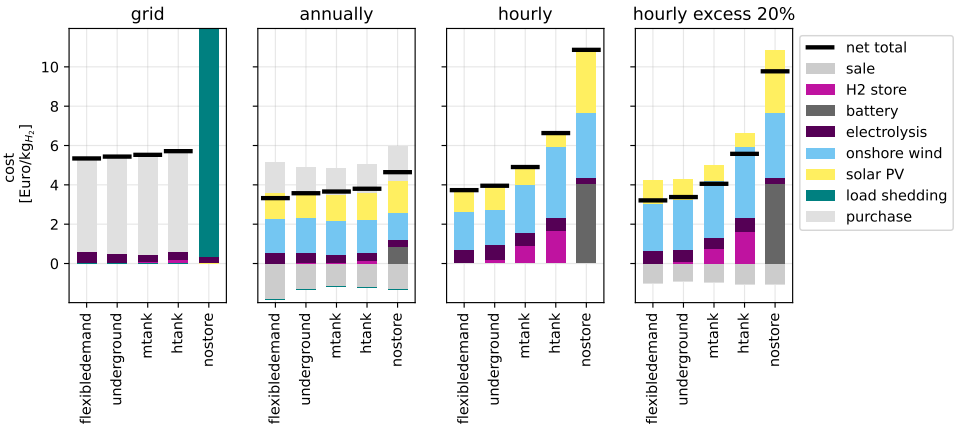


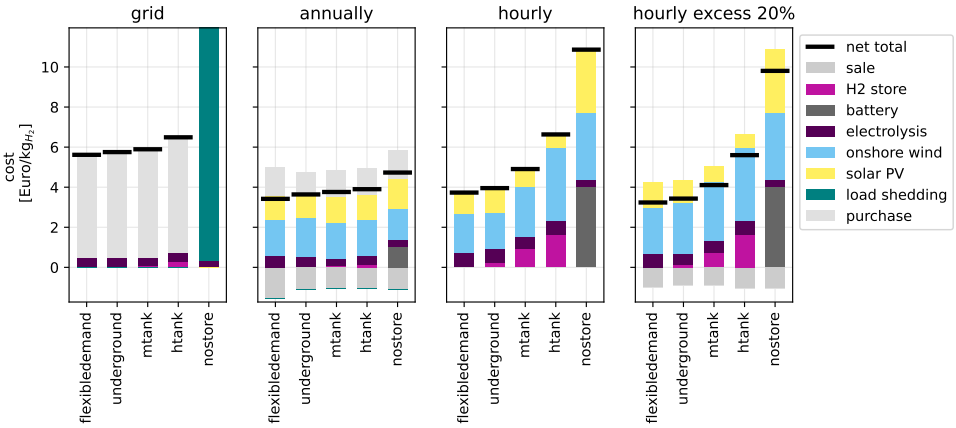
Figure 37: Consequential emission Portugal 2030 renewable generation share 80%.



(a) 20 $\mathrm{TWh_{H_2}/a}$ (0.6 $\mathrm{Mt_{H_2}/a}$)

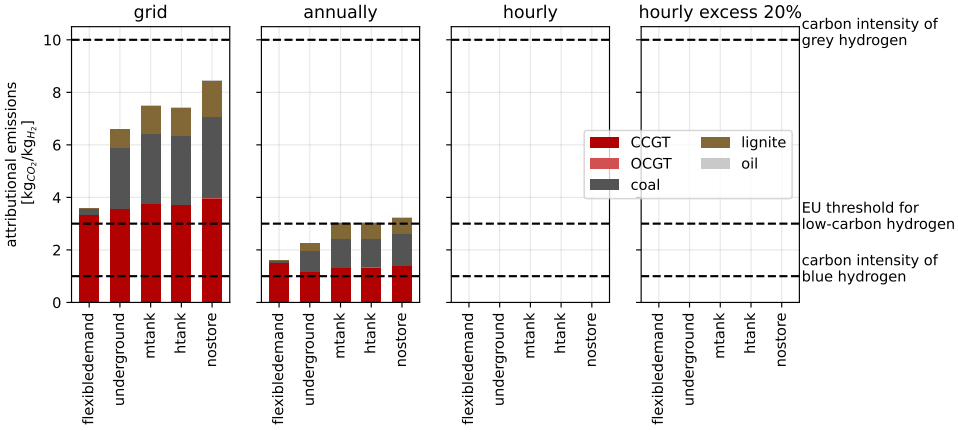


(b) 28 $\mathrm{TWh_{H_2}/a}$ (0.84 $\mathrm{Mt_{H_2}/a}$, base assumptions)

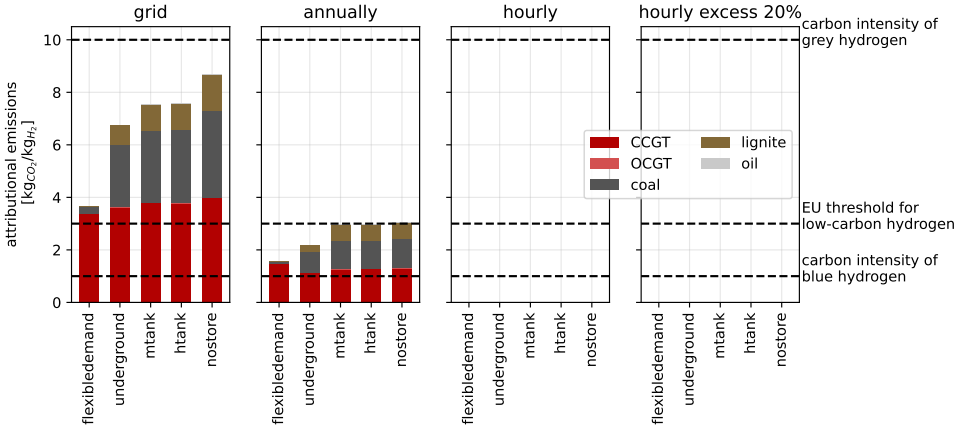


(c) 59 $\mathrm{TWh_{H_2}/a}$ (1.76 $\mathrm{Mt_{H_2}/a}$)

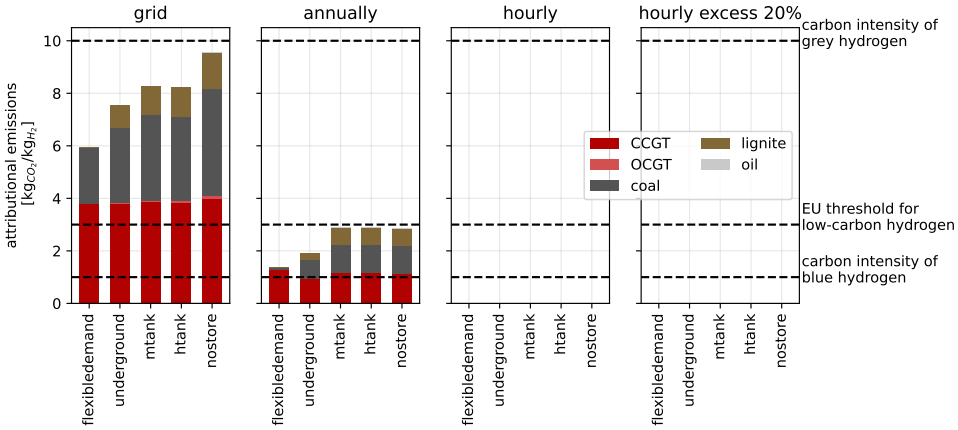
Figure 38: Cost breakdown for different hydrogen demands for Germany 2025. The volume of hydrogen demand does not have a strong impact on the hydrogen cost. In the grid scenario no additional generation capacity can be built. Without any hydrogen storage there are hours in which the hydrogen demand cannot be met.



(a) 20 $\mathrm{TWh_{H_2}/a}$

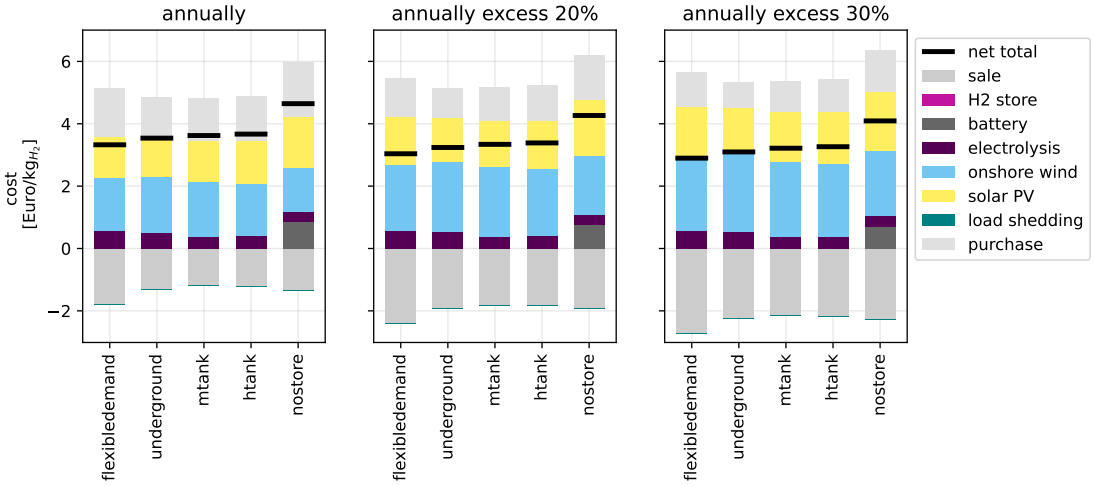


(b) 28 $\mathrm{TWh_{H_2}/a}$, base assumptions

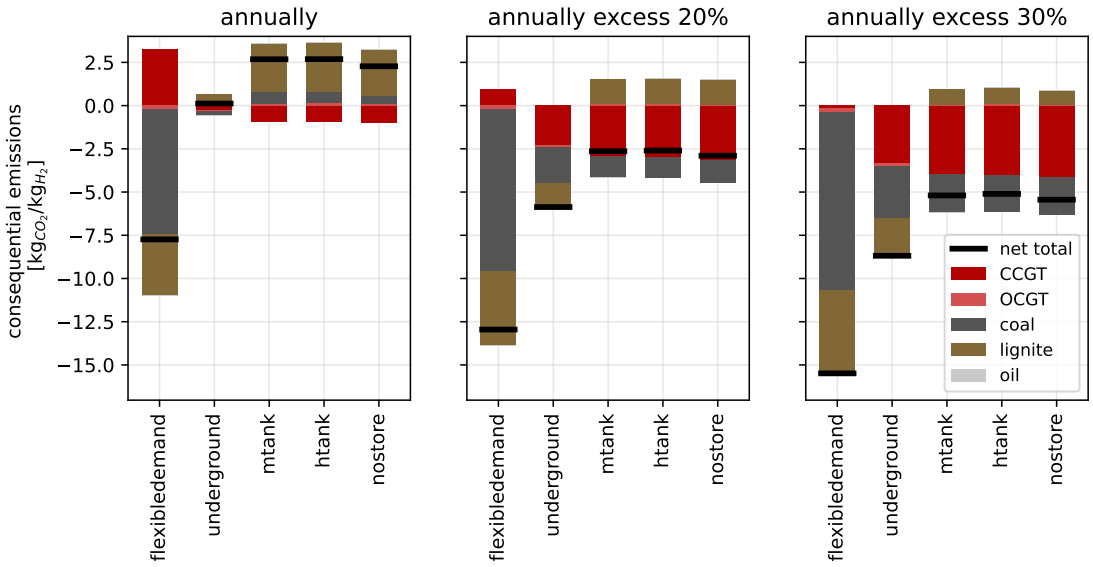


(c) 59 $\mathrm{TWh_{H_2}/a}$

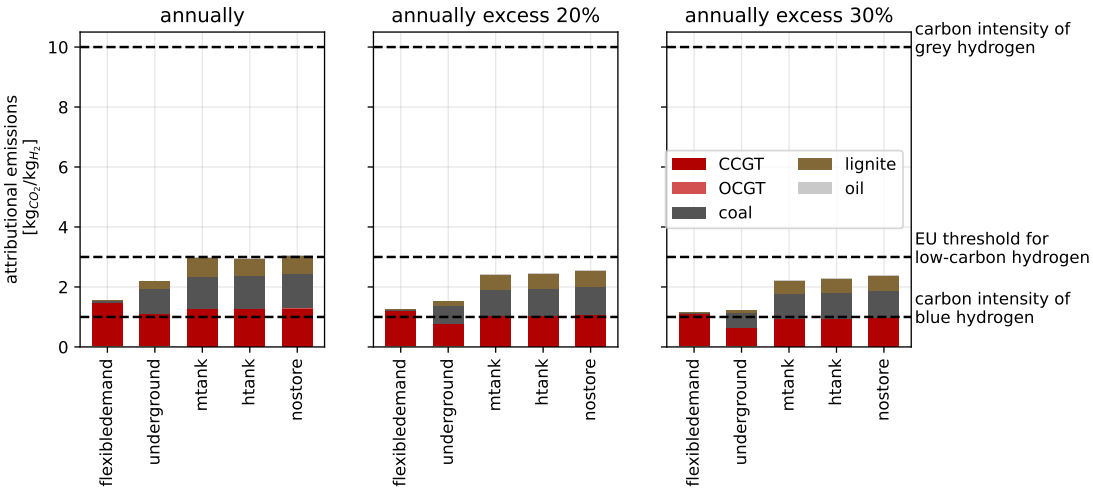
Figure 39: Attributional emissions for different hydrogen demands for Germany 2025. Attributional emissions without additionality requirement (**grid**) are increasing with increasing demand. Attributional emissions from annual matching are decreasing.



(a) Cost breakdown for annual matching with different allowed excess rates for Germany 2025.



(b) Consequential emissions.



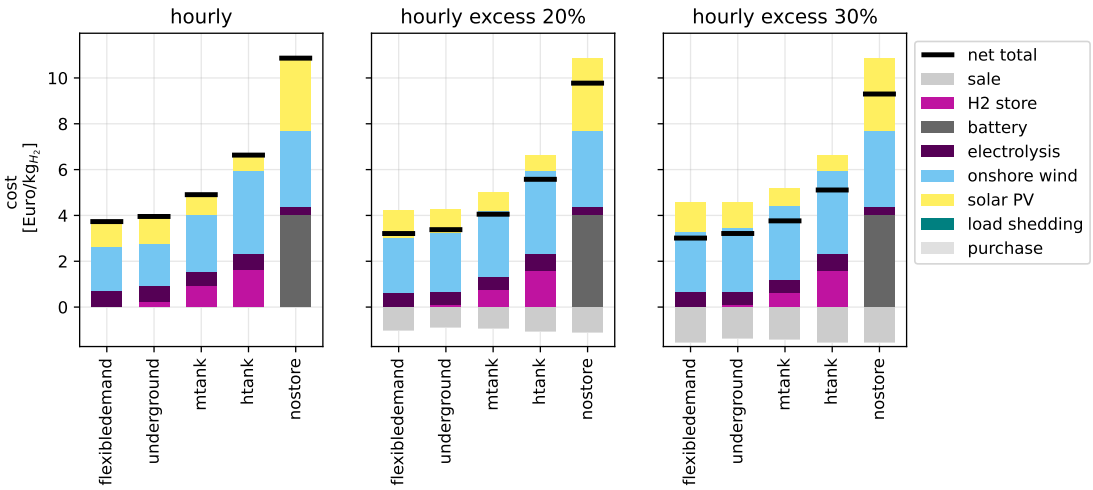
(c) Attributional emissions.

Figure 40: Scenarios with annual matching and different allowed excess to the grid for Germany 2025.

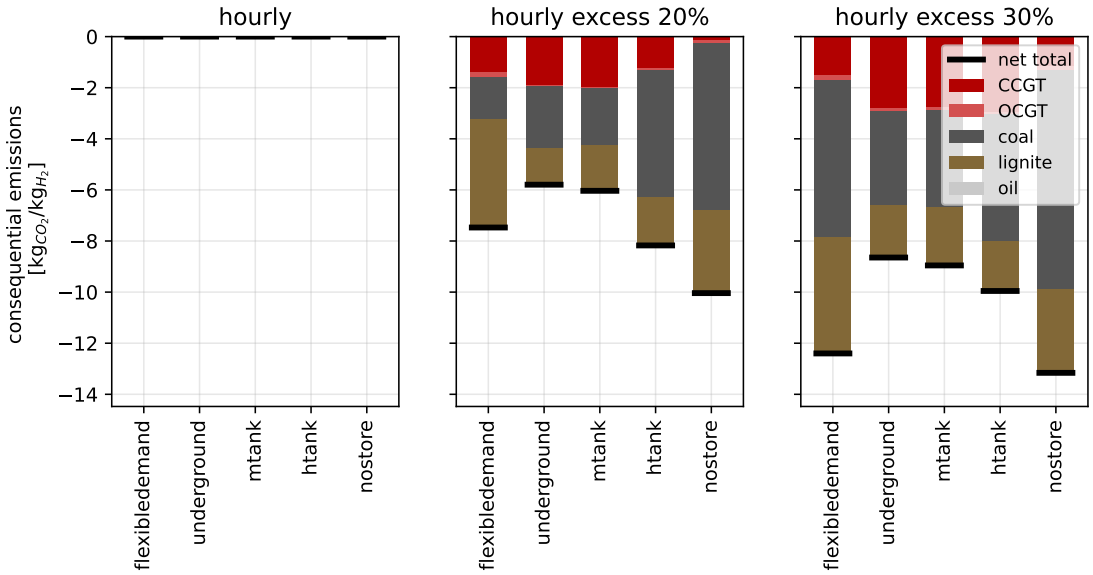
11.2.4. Allowing excess for hourly matching

11.2.5. Share of renewable generation

In the following, we consider the impact of the share of renewable generation on (i) consequential emissions, (ii) capacity factors of the electrolysis and (iii) costs of hydrogen production. We increase the renewable generation share in Germany from our base assumptions of 55% in 2025 to a share of 100%. The renewable generation share in the neighbouring countries is kept on the 2025 target. Since only the grid and annually matching scenarios are in exchange with the rest of the system, only these two regulatory options for hydrogen production are considered. The share of renewable generation is a constraint in optimisation part one, where only the electric system is modelled without hydrogen demand. Therefore, even with a share of 100% renewable generation in the first optimisation step, the additional hydrogen demand which is added in the second optimisation run may result in the use of conventional power plants with associated emissions.



(a) Cost breakdown for different allowed volumes of electricity sales to the grid with hourly matching.



(b) Consequential emissions.

Figure 41: Scenarios with hourly matching and different allowed excess to the grid Germany 2025.

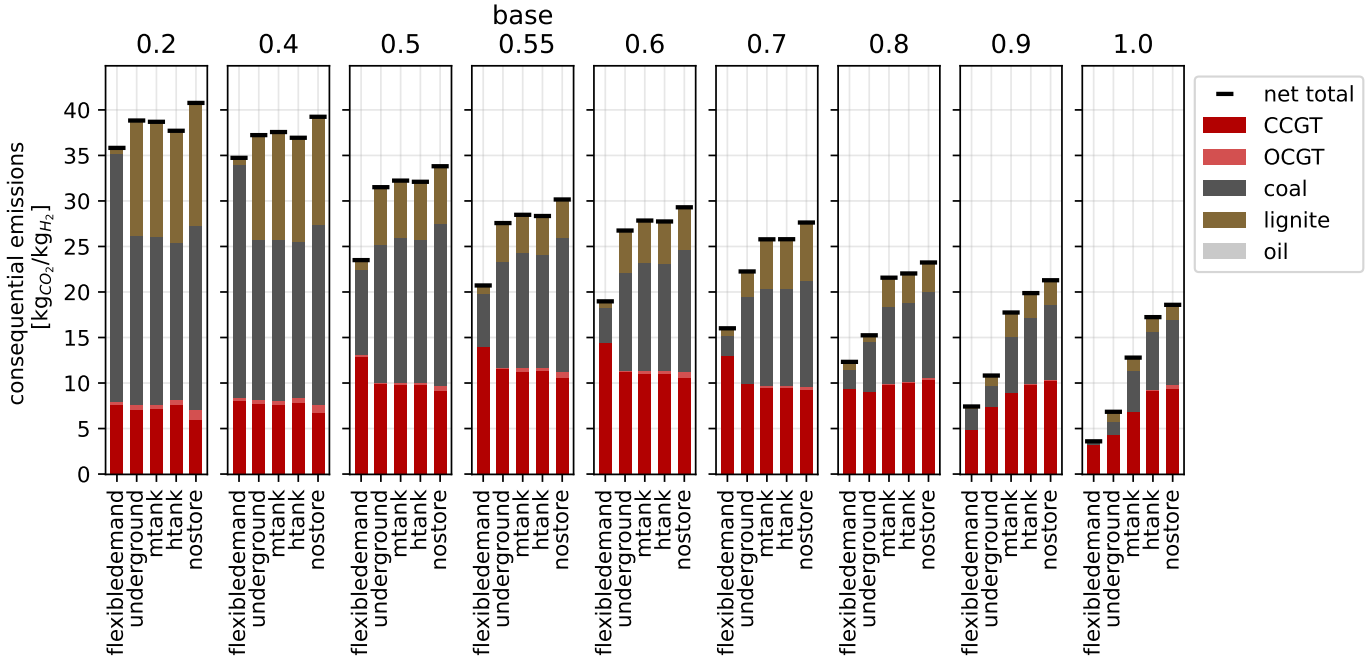


Figure 42: Consequential emissions for the **grid** scenario in Germany 2025 with increasing share of renewable generation from 20% to 100% renewable generation. Our base assumptions are 55% renewable gernation share in 2025. The renewable targets of the neighbouring countries are fixed to 2025. Coal power plants are still part of the generation mix in Germany. Since the renewable generation constraint only applies to the electricity demand before the hydrogen production there can be consequential emissions even with a 100% renewable generation.

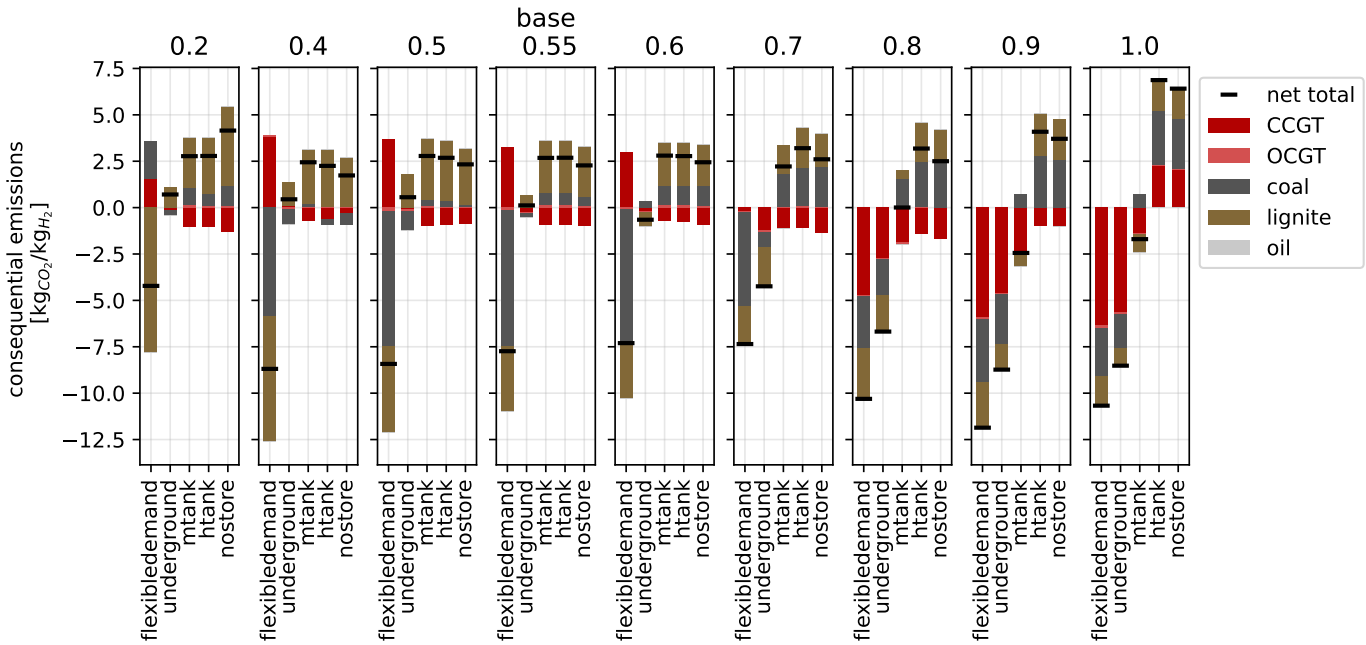


Figure 43: Consequential emissions for the **annually** scenario in Germany 2025 with increasing share of renewable generation from 20% to 100% renewable generation. Our base assumptions are 55% renewable gernation share in 2025. The renewable targets of the neighbouring countries are fixed to 2025. Coal power plants are still part of the generation mix in Germany. Since the renewable generation constraint only applies to the electricity demand before the hydrogen production there can be consequential emissions even with a 100% renewable generation.

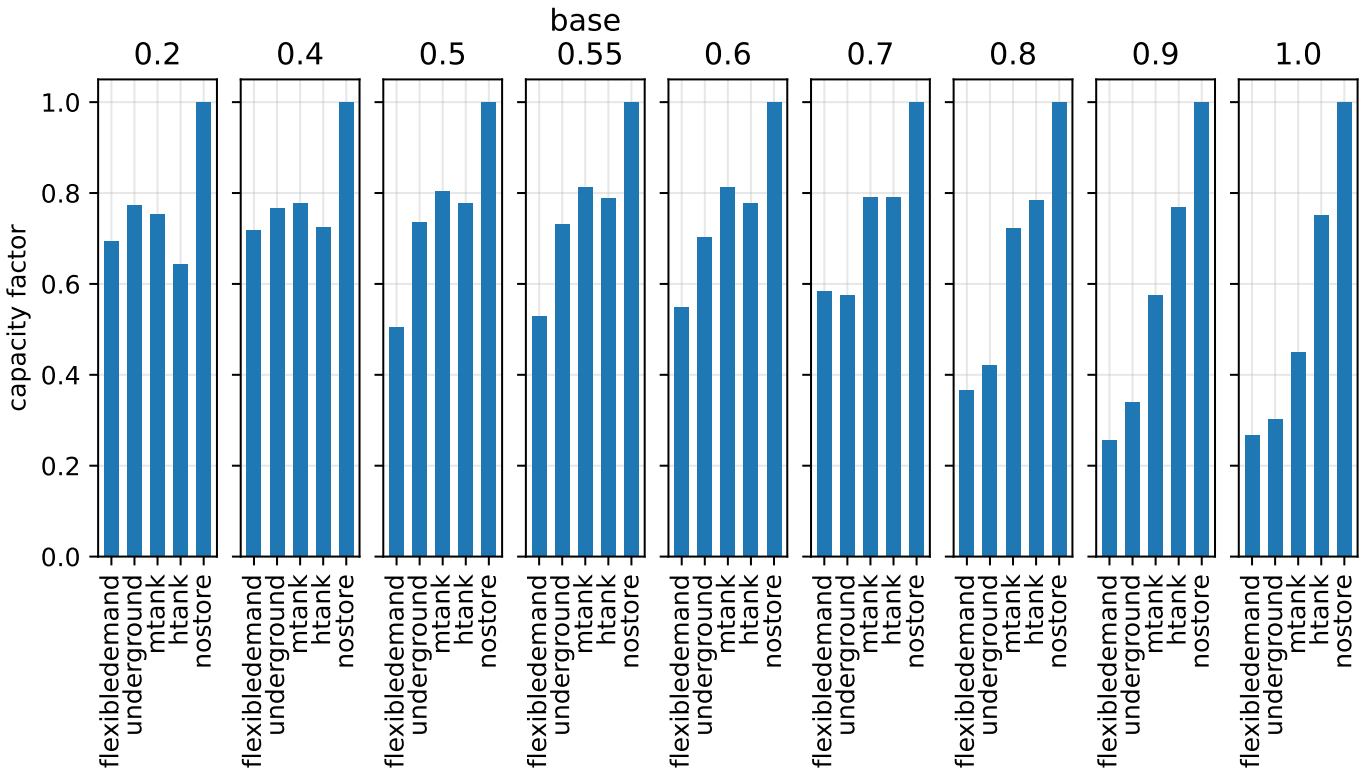


Figure 44: Capacity factors of the electrolysis for the **grid** scenario in Germany 2025 with increasing share of renewable generation from 20% to 100% renewable generation. With an increasing share of renewable generation the capacity factors are decreasing.

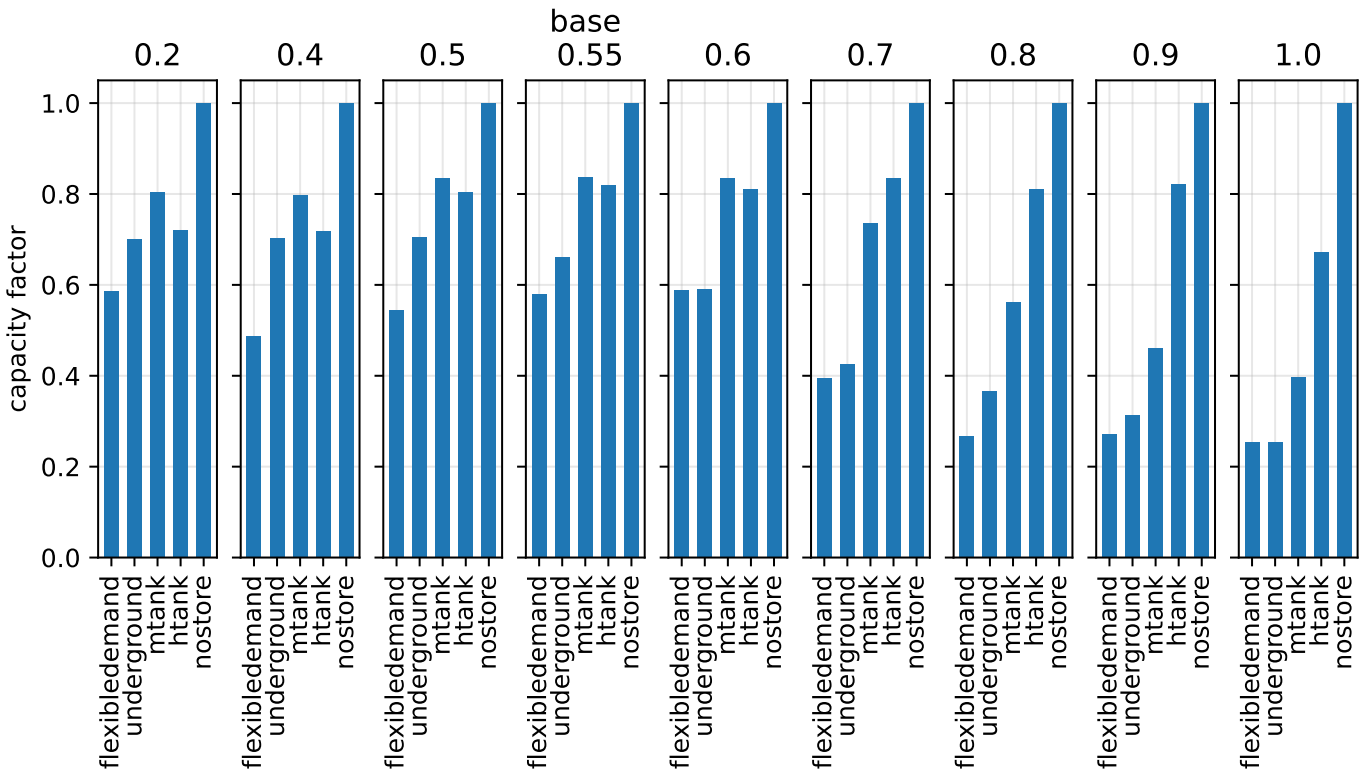


Figure 45: Capacity factors of the electrolysis for the **annually** matching scenario in Germany 2025 with increasing share of renewable generation from 20% to 100% renewable generation. With an increasing share of renewable generation the capacity factors are decreasing.

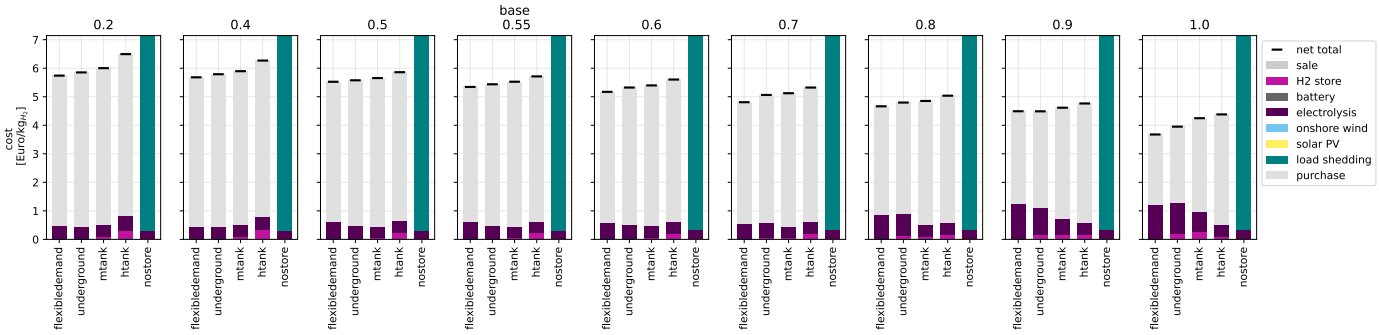


Figure 46: Cost breakdown of hydrogen production for the **grid** scenario in Germany with increasing share of renewable generation from 20% to 100% renewable generation.

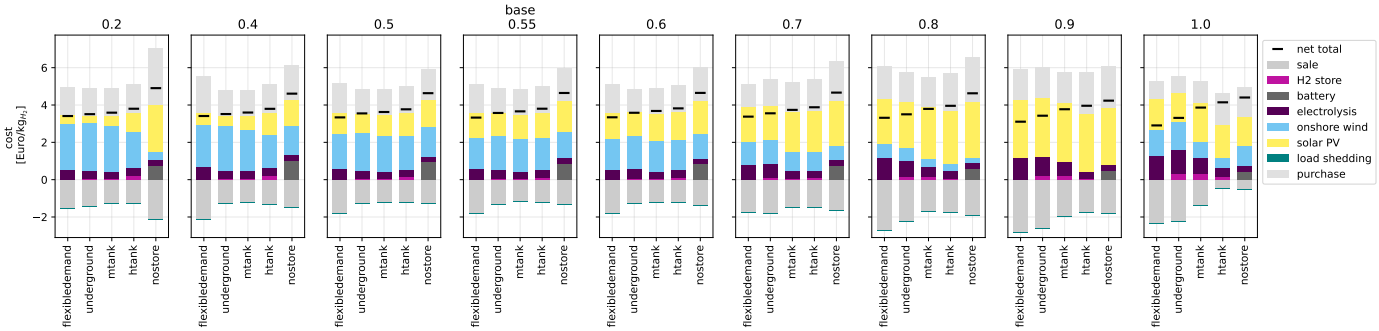


Figure 47: Cost breakdown of hydrogen production for the **annually** matching scenario in Germany with increasing share of renewable generation from 20% to 100% renewable generation.

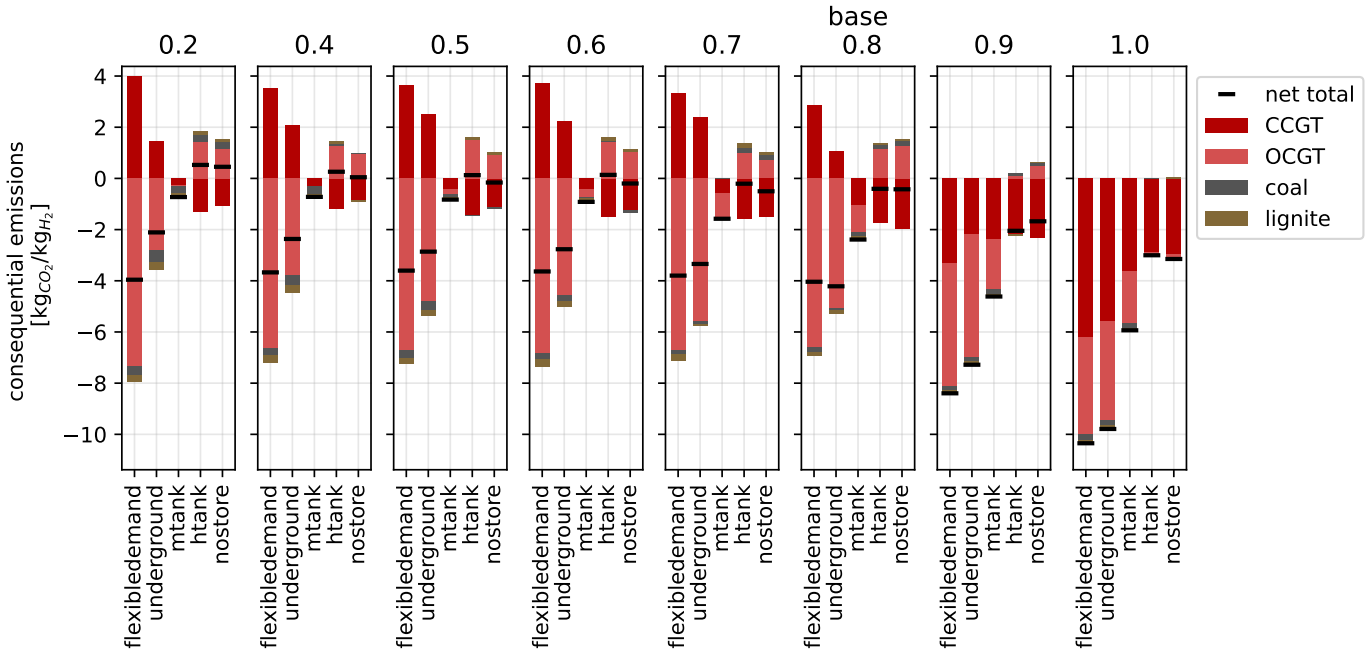


Figure 48: Consequential emissions for the **annually** matching scenario in Germany 2030 with increasing share of renewable generation from 20% to 100% renewable generation. Our base assumptions are 80% renewable generation share in 2030. The renewable targets of the neighbouring countries are fixed to 2030. Coal power plants are phased-out in Germany as planned from the current coalition. Since the renewable generation constraint only applies to the electricity demand before the hydrogen production there can be consequential emissions even with a 100% renewable generation.

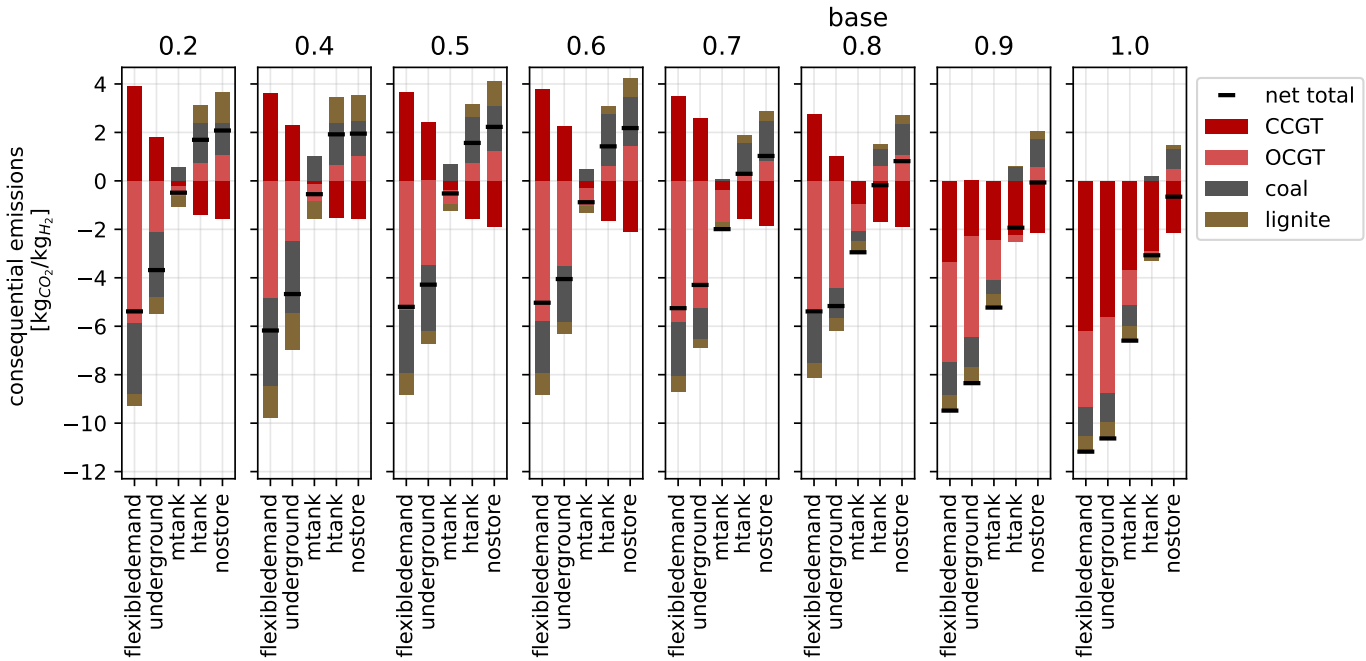


Figure 49: Consequential emissions for the **annually** matching scenario in Germany 2030 **without coal phase** out with increasing share of renewable generation from 20% to 100% renewable generation. Our base assumptions are 80% renewable generation share in 2030. The renewable targets of the neighbouring countries are fixed to 2030. Since the renewable generation constraint only applies to the electricity demand before the hydrogen production there can be consequential emissions even with a 100% renewable generation