

Portfolio effects in green hydrogen production under temporal matching requirements

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ABSTRACT

This article investigates temporal matching requirements between electrolytic hydrogen production and dedicated renewable electricity generation for the hydrogen to qualify as “green”. In contrast to previous studies, which found that a more granular matching increases production costs, we study cost advantages for hourly matching through technological and spatial diversification. To this end, we develop and apply a linear cost-optimization model to quantify the resulting portfolio effects. We identify two types of portfolio effects, “technological” and “locational” ones, and quantify these for different portfolio sizes and types of power generation technologies in Germany. Portfolio effects turn out to be in the range of 3–8% when aggregating two locations, and up to 21 % for a nation-wide portfolio. Finally, we discuss the implications of our findings in terms of discrimination against small players and for the modeling of temporal matching requirements.

1. Introduction

In net-zero energy systems, green hydrogen is expected to play a major role. On the one hand, it can support integrating increasing shares of variable renewable energy (VRE) into the power sector through flexible consumption of surplus electricity and reconversion to electricity when VRE is scarce [1,2]. On the other hand, hydrogen may help decarbonizing hard-to-abate sectors, such as aviation or heavy industries [3]. Against this background, numerous countries have already set ambitious policy targets to expand their hydrogen infrastructure accordingly [4,5]. For example, the EU has set itself the goal of reaching a green hydrogen production capacity of at least 6 GW by 2024 and 40 GW by 2030 [6].

In current energy systems not yet fully decarbonized, however, the ramp-up of hydrogen electrolyzers may actually lead to increasing power sector emissions. This is because additional electricity demand from electrolyzers could trigger increased utilization of fossil-fueled power plants (e.g., Ref. [7]). To avoid such a potential increase in

emissions, the European Commission released a second Renewables Energy Directive (RED II) in 2018, which defines three requirements for hydrogen to be labeled as “green” [8].¹ The first requirement, *additionality*, states that green hydrogen should only be produced from renewable power generation capacities that are either built for this purpose or would otherwise not be in operation. The second requirement concerns the *proximity* between the electrolyzer and any additional renewable energy capacities, which should be as close to each other as possible. The third requirement is the degree of *temporal matching* (or simultaneity) between the production of renewable electricity and hydrogen. These three criteria were further specified by the European Commission in the 2023 Delegated Act on Renewable Fuels of Non-Biological Origin (RFNBOs), which requires electrolyzers and additional power generators to be located in the same bidding zone, and temporal matching to be given on a monthly scale until 2030 and on an hourly scale afterwards [9].

So far, the literature on temporal matching analyzed implications for the levelized cost of hydrogen (LCOH, i.e., the per-unit full costs of

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¹ Note that a similar discussion is currently ongoing in the United States regarding the Inflation Reduction Act Sec. 45V [30,31].

producing hydrogen) and for power sector emissions. In a European and U.S. context, several studies in the literature identify a trade-off between lower costs with less granular temporal matching and lower power sector emissions with a higher time granularity of matching [7,10–14]. As a remedy to this trade-off, Giovanniello et al. [7] argue in favor of a lower granularity in the near term, when the hydrogen industry is still small and power sector implications are modest anyhow, but to introduce hourly matching at a later stage (i.e., similar to the current EU regulation).

One key issue in previous works, which has not yet received the attention it deserves, is whether the analysis is based on a single hydrogen production site or on the aggregation of many sites. Some contributions, namely Schlund and Theile [10] and Ruhnau and Schiele [13], investigate single sites only, whereas Brauer et al. [11], Ricks et al. [12] or Zeyen et al. [14] and Giovanniello et al. [7] analyze hydrogen production after aggregating renewable production profiles across larger areas or whole countries. As we demonstrate below, this significantly changes the variability of renewable electricity generation profiles. However, as diverse assumptions and input parameters can influence the results of such studies in many ways, the effect of aggregation on the results cannot directly be inferred from the existing literature.

The effect of aggregating production profiles of onshore wind energy farms across a region is illustrated in Fig. 1. The figure compares the production time series of a “Germany portfolio”, which is calculated as the average capacity factor of all existing onshore wind farms in Germany for the year 2019 to the production of a “single unit”, which we selected based on a similar number of full-load hours (FLH) to the Germany portfolio. Both the production duration curve (hourly capacity factors sorted in decreasing order) and the production profiles of an exemplary week show that the production of the Germany portfolio is less volatile. This aggregation effect can be referred to as “geographical smoothing” and results from the averaging of diverse weather conditions across Germany.

Having access to a smoother electricity generation profile reduces the costs of hydrogen production under hourly matching requirements, even if the (opportunity) costs of renewable power generation was the same. Conversely, without hourly matching, the shape of the renewable power generation profile would not affect the LCOH, all else being equal. Beyond spatial diversification, technological diversity may also reduce the costs of hourly matching. For example, previous studies already demonstrated that a combination of wind and solar power can produce green hydrogen at lower costs than just one technology [15,16]. We refer to these effects as (locational and technological) “portfolio effects”. Note that these portfolio effects are different from those described by modern portfolio theory [17], which holds that the mean return of a portfolio equals the weighted average mean return of the contained individual assets. By contrast, we will show that diversification under hourly matching requirements reduces the mean of the portfolio’s cash flows below the weighted average of the individual assets’ mean cash flows.

Provided there is an hourly matching requirement for green hydrogen production, such portfolio effects imply that accessing an increasing number of locationally and technologically diverse renewable electricity production units reduces the resulting LCOH. We assume that bigger players – i.e. operators of a larger portfolio – are more likely to be in such a position, either through owning such a diverse portfolio or through signing production purchase agreements (PPAs) with a diverse set of units. Thus, it is relevant to ask whether and to what extent bigger players could gain a competitive advantage over small players through the enforcement of an hourly matching requirement (beyond the usual advantages of scale). This would compromise the energy policy goal of creating a level playing field between actors of different sizes aimed at spurring competition and innovation [18]. Not least, this would also imply high entry barriers, which is a key obstacle to well-functioning markets. While the existence and implications of

portfolio effects are qualitatively intuitive, assessing their relevance requires a thorough quantification of the resulting portfolio effects, which has been lacking in the literature so far.

To address this gap, this article quantifies portfolio effects with green hydrogen production under hourly matching conditions through the comparison of the average LCOH of individual production units to that of an integrated portfolio composed of the same units. To do so, we further develop and apply the cost-optimization model proposed in Ruhnau and Schiele (2023), which has previously been employed to assess the costs and emission intensity of green hydrogen production with a single unit. The model is expanded to account for investment and dispatch decisions at different locations and for different VRE technologies. The model introduced can be applied to individual locations and technologies or a combination of these within a portfolio. Note that the model takes the perspective of an individual firm as a price taker rather than analyzing strategic behavior or system and welfare implications.

By comparing the costs of green hydrogen production through either a single unit or a portfolio of assets, this article makes the following three original contributions to the existing literature: First, the results help assessing to what extent the modeling of hourly matching is influenced by the assumption on whether renewable electricity is provided by individual sites or by a portfolio of assets. This is relevant since both approaches have been adopted in the literature, but without an assessment of the implications of using one or the other. Second, this contribution provides insights into portfolio effects arising in the real world, which is relevant for (potential) green hydrogen producers. Third, the results indicate whether and to what extent bigger players may have competitive advantages over smaller ones. We measure this directly through the portfolio effects, i.e., the share of the LCOH that bigger players can save by having access to more diverse locations and technologies in comparison to smaller players.

The remainder of this paper is structured as follows. Section 2 introduces the method and input data. Section 3 presents the results for portfolios of different sizes, including several sensitivity analyses. Section 4 contains a discussion of the results and concludes with some policy recommendations.

2. Method and data

This section introduces the method and data used for quantifying the portfolio effects. We first present a definition of units and portfolios in Subsection 2.1, continue with the optimization model in Subsection 2.2, and finish with the input data in Subsection 2.3.

2.1. Definition of units and portfolios

In our approach, each “unit” is assumed to be a hydrogen production site consisting of three different components: an electrolyzer, a hydrogen storage unit, and a renewable power generation asset, the latter of which can either be wind turbines, photovoltaic (PV) panels, or a combination of the two. We consider four exemplary locations in the Northeast (NE), Northwest (NW), Southeast (SE) and Southwest (SW) of Germany.² An illustration of the individual units and exemplary portfolios can be found in Figure A.1 in Appendix A.

In this contribution, the term “portfolio” refers to the combined operation of two or more production units. The main advantage expected to be drawn from the operation of a portfolio is that, if hourly matching was enforced, this would only apply on the portfolio level. Since the portfolio consists of units located in different places, it can benefit from the access to different weather conditions, thus minimizing the volatility of renewable electricity production on the portfolio level.

² The names of the specific locations are Grüneplan in Lower-Saxony (NW), Ostrau in Brandenburg (NE), Münchwald in Rhineland-Palatinate (SW), and Wernersreuth in Bavaria (SE).

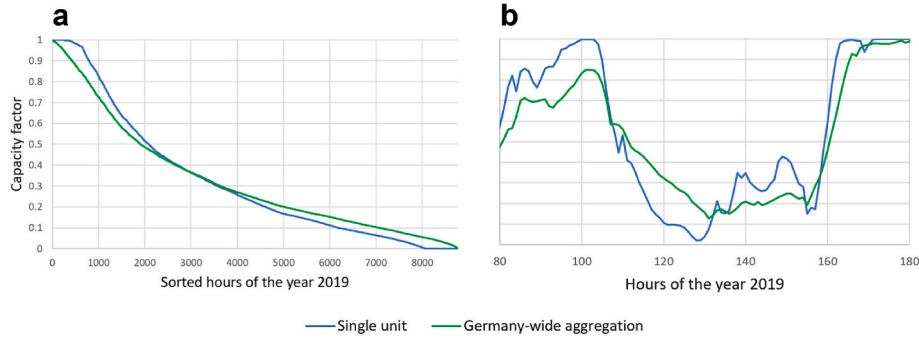


Fig. 1. Comparison between a Germany-wide aggregation and a single unit in terms of electricity production. Smoothing effects of profile aggregation shown for all hours of the year (a) and a narrower time interval (b). Both time series were simulated with the Python package Atlite (see Section 2 for details).

We hence assume that electricity can be transferred between locations via the public grid,³ which would be comparable to contracting a new PPA. According to the current European legislation [9], this is a viable way for green hydrogen production.

2.2. Optimization model

To quantify portfolio effects, we model the perspective of a hydrogen producer who wants to minimize the LCOH of a single unit or across a portfolio of multiple units.⁴ To reach minimal costs, the model finds the optimal investment in the capacity of the different components of each unit (electrolyzer, storage unit, renewable power generators). Additionally, it calculates the optimal volumes of electricity produced and traded, plus the volume of hydrogen produced and stored in each hour of the year and at each location. Technically, it is a linear cost-optimization model with perfect foresight.

Equation (1) calculates the LCOH, which is the objective function of the model. It comprises three components: first, investment costs are calculated as the product of the capacity $CAPA_{tec,i}$ for each technology tec at location i and the corresponding annualized fixed costs $cost_{tec}^{fix}$. Second, variable costs are calculated as the product of the produced electricity $GENE_{t,vre,i}$ and the consumed electricity $CONS_{t,ely,i}$ for each hour t with the corresponding variable costs $cost_{vre}^{var}$ and $cost_{ely}^{var}$ for renewable generators $vre = \{wind, solar\}$ and the hydrogen electrolyzer ely , respectively. The third component are the costs of electricity exchanges between hydrogen production units and the public grid. These are considered by subtracting the revenue of feeding the electricity into the grid, $IN_{t,grid,i}$, from the costs of taking electricity out of the grid, $OUT_{t,grid,i}$. The respective volumes are multiplied with the hourly wholesale market price p_t^{sell} and the buying price p_t^{buy} , which accounts for grid fees and taxes in addition to the wholesale price.⁵

$$LCOH = \sum_{tec,i} CAPA_{tec,i} cost_{tec}^{fix} + \sum_{t,vre,i} GENE_{t,vre,i} cost_{vre}^{var} + \sum_{t,i} CONS_{t,ely,i} cost_{ely}^{var} + \sum_{t,i} (OUT_{t,grid,i} p_t^{buy} - IN_{t,grid,i} p_t^{sell}) \quad (1)$$

Equation (2) represents the hourly electricity balance constraint. It

ensures that the electricity used by the electrolyzer for hydrogen production $CONS_{t,ely,i}$ at a certain location and during a certain hour equals the sum of the electricity generated by the different renewable energy technologies $GENE_{t,vre,i}$ and the electricity taken out of the grid, $OUT_{t,grid,i}$, minus the electricity fed into the grid, $IN_{t,grid,i}$:

$$CONS_{t,ely,i} = \sum_{vre} GENE_{t,vre,i} + OUT_{t,grid,i} - IN_{t,grid,i} \quad \forall t, i \quad (2)$$

We assume a baseload hydrogen offtake, i.e., the delivery of hydrogen is constant over time, which is enforced by Eq. (3). This volume can be produced by the electrolyzer during that same hour, which is considered as the product of the electricity consumption of the electrolyzer $CONS_{t,ely,i}$ and its energy efficiency η_{ely} . The other option for delivering green hydrogen is through a net takeout of hydrogen from the storage unit, i.e., the difference between hydrogen storage discharge $OUT_{t,sto,i}$ and feed-in $IN_{t,sto,i}$.

$$\frac{SHARE_i}{8760} = CONS_{t,ely,i} \eta_{ely} + OUT_{t,sto,i} - IN_{t,sto,i} \quad \forall t, i \quad (3)$$

On the left-hand side of the equation, the hydrogen offtake at every location $SHARE_i$, is evenly distributed across all hours of the year. Across all locations, the hydrogen offtake is normalized to 1 MWh, i.e.

$$1 = \sum_i SHARE_i \quad (4)$$

The constraint for the hydrogen storage level for each hour and location takes the level of the previous hour $LEVEL_{t-1,sto,i}$ as a starting point (Eq. (5)). The volume of hydrogen discharged from the storage, $OUT_{t,sto,i}$, is then subtracted and the hydrogen volume stored, $IN_{t,sto,i}$, is added.

$$LEVEL_{t,sto,i} = LEVEL_{t-1,sto,i} + IN_{t,sto,i} - OUT_{t,sto,i} \quad \forall t, i \quad (5)$$

In the baseline scenario, we assume that the capacity of all renewable power generators needs to be the same across all technologies and locations considered (Eq. (6)). This is useful for two reasons. First, investors often cannot economically optimize the capacities of renewable power generators but are constrained, e.g., by area availability [19]. In that sense, the case that capacities are equal is just an example of exogenously defined capacities. Second, without fixing capacities, the calculation of portfolio effects is not straightforward, as one would need to disentangle the effect of combining technologies and locations in a portfolio from the possibility of shifting capacities to locations or technologies with above-average profitability. In addition, we present the results of sensitivity runs with fixing capacities to a different ratio and without fixing capacities in Subsection 3.3.

$$CAPA = CAPA_{vre,i} \quad \forall vre, i \quad (6)$$

There are three constraints for each technology's capacity $CAPA_{tec,i}$

³ Note that electricity transmission via the public grid may incur grid fee costs, as discussed further below.

⁴ Note that the model builds on the one developed by Ruhnau and Schiele [13], extending it to include multiple locations that can then be combined into various portfolios.

⁵ Note that, when electricity feed-in and take-out occurs at the same time across different units, the net costs of doing so are, by definition, equal to the assumed grid fees and taxes.

Table 1

Cost and lifetime assumptions for the different components.

	Unit	Wind power	Solar power	Hydrogen electrolyzer	Hydrogen storage
Investment cost	€/kW (h)	1120	560	675	15.2
Expected lifetime	a	25	25	20	20
Fixed O&M cost	€/kW/a	14	9	20	0.3
Ann. fixed cost	€/kW/a	93	49	74	1.5
Variable cost	€/MWh	0.23	0	2	0

(Eqs. (7)–(9)). For the electricity generators, their capacity $CAPA_{t,vre,i}$, multiplied with the corresponding availability profile $profile_{t,vre,i}$, is limiting electricity generation $GENE_{t,vre,i}$, but curtailment $CURT_{t,vre,i}$ is possible (i.e. choosing not to produce electricity for economic reasons – during hours where the weather conditions would allow to do so).⁶ For the electrolyzer, the amount of electricity that can be used for hydrogen production $CONS_{t,ely,i}$ is directly limited by its capacity $CAPA_{ely,i}$. Similarly, the hydrogen storage level $LEVEL_{t,sto,i}$ can never exceed its capacity $CAPA_{sto,i}$.

$$GENE_{t,vre,i} = CAPA_{vre,i} \cdot profile_{t,vre,i} - CURT_{t,vre,i} \quad \forall t, vre, i \quad (7)$$

$$CONS_{t,ely,i} \leq CAPA_{ely,i} \quad \forall t, i \quad (8)$$

$$LEVEL_{t,sto,i} \leq CAPA_{sto,i} \quad \forall t, i \quad (9)$$

Depending on the degree of temporal matching considered, one of the following constraints is applied. In the case of yearly matching, the total volume of electricity fed into the grid must exceed the total volume taken out of the grid over a year and across all units, which is enforced by Eq. (10). In the case of hourly matching, electricity feed-in must exceed take-out across all units in every hour (Eq. (11)). Due to the inequality formulation, the model can always choose to sell excess electricity to the grid when this is more economical than using it for green hydrogen production.

$$\sum_{t,i} IN_{t,grid,i} \geq \sum_{t,i} OUT_{t,grid,i} \quad (10)$$

$$\sum_i IN_{t,grid,i} \geq \sum_i OUT_{t,grid,i} \quad \forall t \quad (11)$$

2.3. Input data

Assumptions on costs and lifetimes of the different components are summarized in Table 1. The cost assumptions of the wind and solar power technologies are taken from the “Technology Data” estimates for the year 2020 of the Danish Energy Agency [20]. For the cost assumptions of the hydrogen components (electrolyzer and hydrogen storage), we refer to the 2020 base scenario in a study carried out by Element Energy [21]. More precisely, we consider alkaline electrolyzers and distributed, medium-pressure storage above ground. Moreover, a conversion efficiency of 65 % is assumed for the alkaline electrolyzer and an efficiency of 100 % for the storage units [22]. Finally, we assume a weighted average cost of capital of 5 % for the calculation of the annualized fixed costs.

⁶ Note that we do not consider curtailment because of grid congestion (re-dispatch), as market participants are compensated for foregone revenues under re-dispatch and, therefore, would not change their investment and dispatch decisions.

We use the Python package *Atlite* to generate production profiles of wind and solar power from re-analysis weather data [23].⁷ As discussed below, we use electricity prices from 2019 and hence generate renewable energy profiles for the same weather year. For the wind profiles, we choose a Vestas V112 turbine with a 3 MW rated capacity and 112 m rotor diameter. On average, currently installed turbines are larger both in terms of rated capacity and rotor diameter [24], but data on such modern turbines are unfortunately not available in *Atlite*. However, among the available turbines, the chosen model comes closest to currently installed turbines in terms of specific power, i.e., the rated capacity per rotor area (kW/m²). We finally choose the hub heights such that the wind park fits the average capacity factors for the respective German states [25]. For the solar profiles, we select Copper-Indium-Selenium solar cells.

For the electricity “sell” prices of the respective years, i.e., the revenue from feeding electricity into the grid, we take the historical day-ahead wholesale prices for Germany [26]. For the electricity “buy” prices, i.e. the costs of taking out electricity from the grid, we add a fixed expense of 5.37 €/MWh on top of the “sell” prices. This mark-up accounts for the levies to be paid for green hydrogen production as of the current legislation in Germany: the electricity grid levy (4.17 €/MWh), the levy for switchable loads (0.1 €/MWh), and the concession levy (1.1 €/MWh). We assume that the electrolyzer is exempted from grid fees in our baseline scenario but investigate the effect of varying grid fees in a sensitivity analysis (Appendix B).⁸

3. Results

This section starts with an overview of the LCOH of single technologies and locations (Subsection 3.1). We then investigate technological portfolio effects, locational portfolio effects with two units, the combination of both, and portfolios comprising three and four units for our baseline assumptions (Subsection 3.2). Furthermore, we conduct sensitivity analyses in which we vary and relax the constraint on the capacity ratio of different renewable generators, constrain the location of the electrolyzer, and allow for the buying of electricity during hours of low wholesale market prices (Subsection 3.3). We also investigated the effect of a change in the assumed grid fees, but this did not affect the resulting portfolio effects significantly (see Appendix B). Finally, we estimate a potential maximum portfolio effect based on a portfolio that contains all wind onshore capacities installed in Germany as individually weighted units (Subsection 3.4).

3.1. Costs of the individual units

The LCOH of the individual units for single generation technologies reflect the quality of renewable energy resources (Table 2). In Germany, wind achieves more full-load hours than solar and is especially strong in the North. Furthermore, generation through solar power is less evenly distributed, as solar energy is only available during the day. These factors make it necessary to build between 2.6 and 3 times as much capacity for solar panels than for wind turbines. In addition, since there are fewer hours where hydrogen can be directly produced from solar energy compared to the case of wind, the size of the electrolyzer needs to be increased (by a factor of 1.8–3.3 times). However, in the South the units have an advantage over the ones using wind power due to the higher

⁷ Link to repository: <https://github.com/PyPSA/atlite>.

⁸ In fact, the German Energy Industry Act [32] conveys that electrolyzers are exempted from grid fees if they produce hydrogen for long-term electricity storage, i.e., the hydrogen is subsequently reconverted into electricity. Following this logic, the electrolyzer in our scenario would have to pay grid fees, as we assume that the hydrogen is used for industrial purposes. However, several companies have reported exemptions after consulting with the authorities.

Table 2

LCOH of the individual locations for yearly and hourly matching with wind and solar.

LCOH	Northeast (NE)		Northwest (NW)		Southeast (SE)		Southwest (SW)	
	yearly	hourly	yearly	hourly	yearly	hourly	yearly	hourly
Wind	83	118	83	117	102	193	106	222
Solar	92	238	94	238	88	185	89	199

solar potential in those locations. This results in the storage unit being sized larger for the units using wind. Consequently, wind reaches a lower LCOH than solar in the units located in the North, but not in the South.

Table 2 also illustrates the change in the LCOH between annual and hourly matching. For hourly matching, the LCOH increases by 40–110 % for wind and by 110–160 % for solar. The remainder of this Section focuses on portfolio effects under an hourly matching requirement, as with yearly matching, the average LCOH of individual units and that of the portfolio are the same.

3.2. Baseline scenarios

3.2.1. Technological portfolio effects

Under hourly matching, the combination of individual technologies into a portfolio lowers the portfolio's LCOH below the average of the individual LCOHs. We refer to this reduction in LCOH as “technological portfolio effect”. For the example of the Southwest location, the portfolio effect amounts to 37 % (Fig. 2). Across all locations, the average portfolio effect is 39 %. The portfolio effect results from a smoother generation profile of the combined technologies. In consequence, the capacities of the power generators, of the electrolyzer, and of the storage unit can be reduced by 36–65 %. However, revenues from selling surplus electricity to the market decrease, resulting in net cost savings of 39 % on average. We discuss the underlying mechanism in more detail in the following subsection.

3.2.2. Locational portfolio effects with two units

Similar to the combination of technologies, the combination of individual locations into a portfolio lowers the portfolio's LCOH below the average of the individual LCOHs. We refer to this reduction in LCOH as “locational portfolio effect”. As an example, the portfolio effects for the locations Northwest and Southeast are presented in Fig. 3. We find portfolio effects of 9.4 % and 6.1 % for wind and solar, respectively. This means that a hydrogen producer owning or contracting this portfolio would be able to produce green hydrogen at 9.4 % lower cost when using wind (or 6.1 % lower cost when using solar panels) than the average of other producers that can only take their electricity for hydrogen production from either one of the individual locations.

The mechanism behind the portfolio effect is twofold. On the one

hand, the capacities of all components and corresponding investment costs decrease. On the other hand, the revenues from selling electricity decrease, and some additional costs emanating from grid fees occur when transferring electricity from one location to the other. In fact, only a small amount of electricity is transferred across locations. See Figures A.2 and A.3 in Appendix A for details on installed capacities and cost components for the example of wind energy.

The results for every combination of two individual units as a portfolio are visualized in Fig. 4. The average locational portfolio effects with two units amount to 8 % for wind and 6 % for solar. The different sizes of portfolio effects can be explained by the correlation between the VRE generation profiles and, related to this, the distance between the units. The higher the correlation between VRE profiles, the lower the portfolio effects, which makes sense because a higher correlation reduces the effects of geographical smoothing. The reduced correlation, in turn, is correlated to an increased distance between locations. Hence, a larger distance between different units increases the portfolio effect (see Figure A.4 in Appendix A for an illustration).

3.2.3. Combination of locational and technological portfolio effects

When combining the technological and locational portfolio effects, the LCOH is reduced further. Here, we focus on the locational portfolio effects for units which are already technologically diversified, i.e., which already combine wind and solar power generators. Fig. 5a presents the cost reduction for the exemplary combination of the SE and NW locations, and Fig. 5b provides an overview of the portfolio effects for all possible two-unit combinations (3.3 % on average). We find that the locational portfolio effects for units that already use wind and solar are generally lower than those for units that only use one VRE technology (Subsection 3.3). This can be explained by the technological portfolio effect, which already smoothens generation profiles and reduces the LCOH through smaller necessary installed capacities at each location. After these cost smoothing effects and cost savings have already occurred, the potential for additional cost savings from combining different locations is smaller.

3.2.4. Portfolios with more than two locations

When increasing the size of a portfolio beyond two units, the portfolio effects increase further, but the marginal effect decreases (Fig. 6). The portfolio effects arising from a combination of three units (which allows for four different combinations of the units) are on average 10.2 % for wind and 8 % for solar. Compared to the case with two units, this is a noticeable average increase of 2.2 pp (percentage points) and 2.1 pp, respectively. When further increasing the number of units to four, the portfolio effects increase further, by 2.1 pp for wind and 1.3 pp for solar. The decreasing marginal effect of adding more units can be explained by the portfolio's generation profile already being relatively smooth for three units—i.e., adding another unit does not add much to “geographical smoothing” and to further reducing the LCOH of the portfolio. For the combination of wind and solar, the (average) increase in the portfolio effect is only 0.8 pp when adding the third and 0.4 pp when adding the fourth unit. This is not surprising, since the portfolio effects with technologically diverse units were already relatively small for two-unit portfolios.

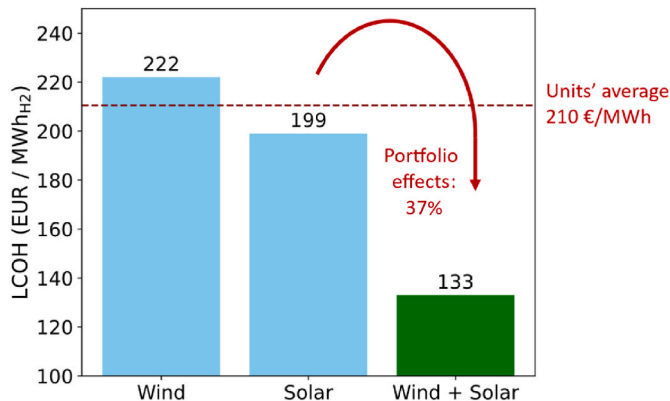


Fig. 2. Visualization of the portfolio effects for the example of location SW.

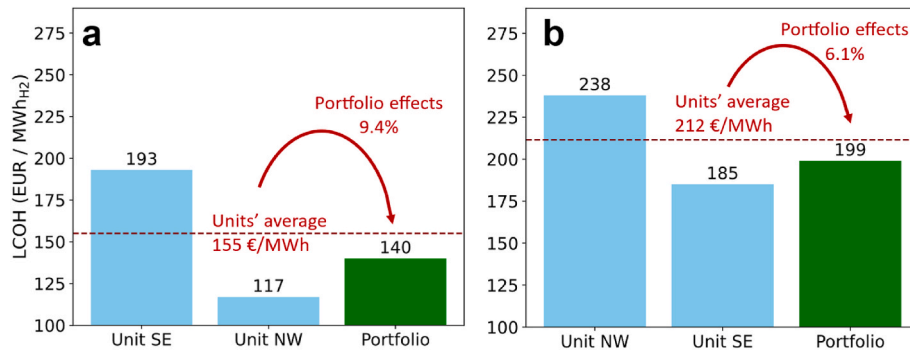


Fig. 3. Portfolio effects when combining either wind (a) or solar (b) across the locations SE and NW.

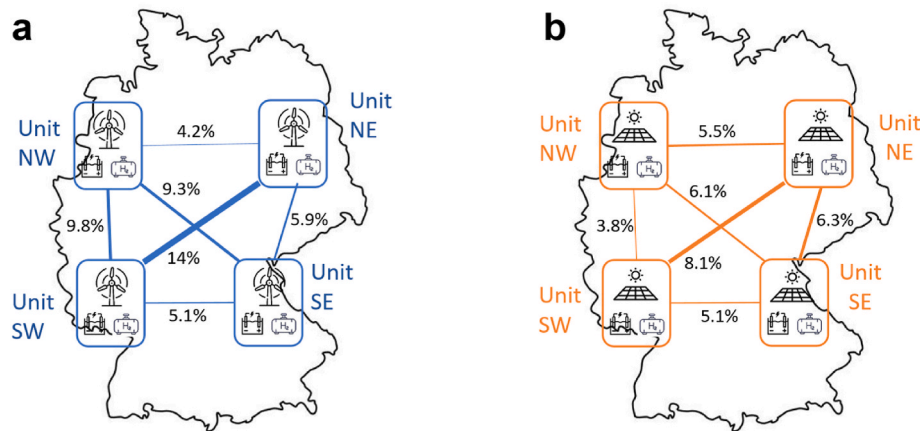


Fig. 4. Portfolio effects for two-unit portfolios for all combinations of wind (a) and solar (b). The thickness of the connections is proportional to the size of the portfolio effects.

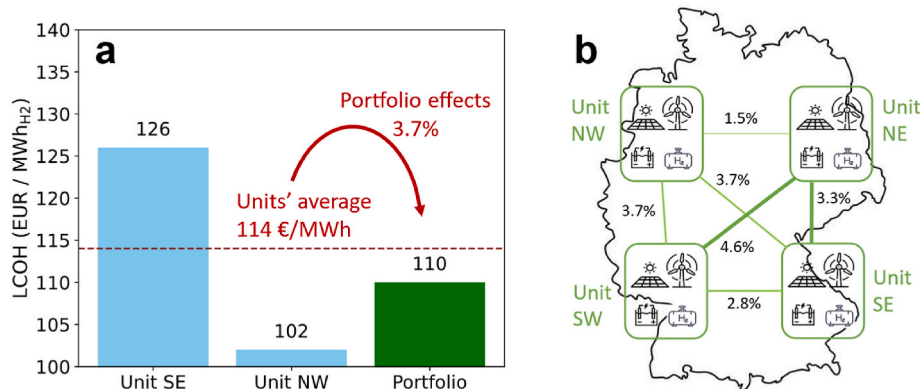


Fig. 5. Portfolio effects for the exemplary portfolio using wind and solar (a) and resulting portfolio effects for two-unit portfolios.

3.3. Sensitivity analyses

3.3.1. Varying the capacity ratio of renewable generators

In our main scenarios, we assumed that the capacities of renewable generators in a portfolio are sized equally across technologies and locations. Here, we investigate the effects that varying the ratio of wind to solar capacity between 4:1 and 1:4 has on the resulting technological portfolio effects. The results for the case of unit NW are visualized in Fig. 7. The results for unit SE can be found in Figure A.5 in Appendix A.

As expected, based on the individual LCOHs at the NW location (see Subsection 3.1), the weighted average of the individual units decreases when more wind energy is used and increases when shifting toward solar

energy. Interestingly, the LCOH of the portfolio hardly changes when varying the capacity ratio, which leads to increasing portfolio effects with the use of solar energy (to up to 46 %). Despite the changing size of the portfolio effect, we conclude from this sensitivity analysis that significant technological portfolio effects occur independently of the capacity ratio of the combined renewable energy technologies.

3.3.2. Relaxing the constraint on the capacity of renewable generators

After analyzing the effect of varying the capacity constraint in the previous sensitivity analysis, we now investigate the effect of completely relaxing this constraint. We conduct this sensitivity analysis for the technological portfolio effects when combining wind and solar at the

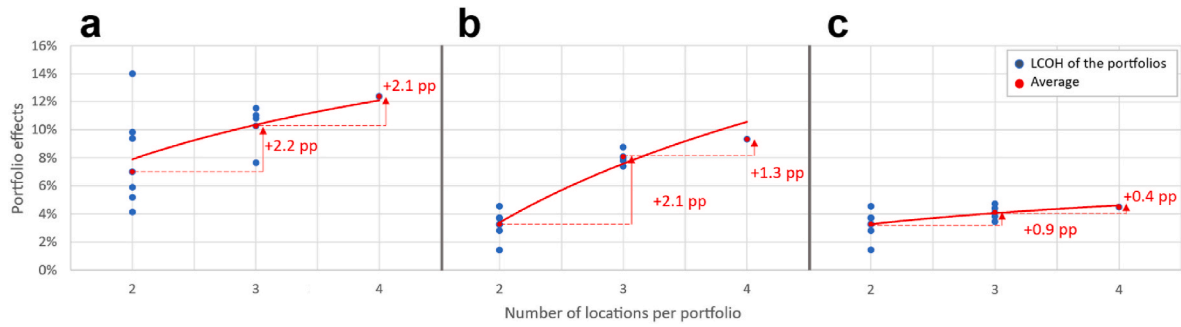


Fig. 6. Final portfolio effect results for the cases of wind (a), solar (b) and the combination of both (c).

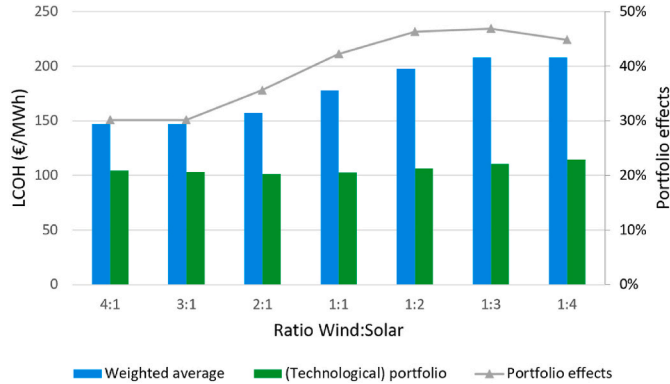


Fig. 7. Results for the sensitivity analysis of varying the capacity constraint. We calculate portfolio effects based on the LCOH of the portfolio and the weighted average of the LCOHs of the individual units (where the weights correspond to the varying capacity ratios).

locations NW and SW and for the locational portfolio effects for the example of combining the locations NW and SE with single technologies or with a mix of wind and solar.

For the combination of technologies at individual locations, the removal of the capacity constraint implies that around 65 % of the total electricity generation capacity is allocated to the most productive generation technology (Table 3). This is wind in the NW and solar in the SW location. However, the LCOH is reduced by only about 1 % compared to the case with the capacity constraint. Compared to the baseline scenario, the portfolio effects diminish from 45 % to 36 % in the NW location and remain roughly constant at 33 % in the SW location.

For the combination of locations with single technologies, removing the capacity constraint reduces the LCOH of the portfolios more significantly than in the previous case of the units (17 % for wind and of 7 % for solar, see Table 4 and Figure A.6 in Appendix A). This is driven by the model's choice of building all capacities only at the location with the best renewable resources (i.e., NW for wind and SE for solar). Hence, these improvements reflect heterogeneity in resource quality, and no portfolio effects arise from combining different locations. This is why we preferred to keep capacities constant for our main results.

Table 3
Results for technological portfolios with and without capacity constraints.

Unit	With capacity constraint		Without capacity constraint		
	Capacity wind & solar	LCOH	Capacity wind	Capacity solar	LCOH
	kW _{el} /MWh _{H2}	€/MWh _{H2}	kW _{el} /MWh _{H2}	kW _{el} /MWh _{H2}	€/MWh _{H2}
NW	0.8	102.5	1.1	0.6	101.3
SE	0.9	126.4	0.8	1.4	125.5

Table 4
Results for locational portfolios with and without capacity constraints.

Unit	With capacity constraint		Without capacity constraint		
	Capacity NW & SE	LCOH	Capacity NW	Capacity SE	LCOH
	kW _{el} /MWh _{H2}	€/MWh _{H2}	kW _{el} /MWh _{H2}	kW _{el} /MWh _{H2}	€/MWh _{H2}
Wind	1.1	140.4	2.44	0.0	116.9
Solar	3.0	198.8	0.0	6.9	185.4
Both	Wind & solar: 0.39	110.1	Wind: 1.1 Solar: 0.2	Wind: 0.0 Solar: 0.4	100.8

For the combination of locations with both technologies, the relaxation of the constraint has the largest impact, as it allows for the free optimization of two technologies across two locations. The cost-optimal result leads to the electrolyzer and storage units being built only in the NW. Furthermore, all wind capacities, which account for 65 % of total electricity generation, are built in the NW. These modifications lead to a resulting LCOH below the best of the two individual units. This is only possible because two types of technology are deployed, creating a synergy that is not present when using only one technology in portfolios. As a result, the portfolio effects increase significantly to around 11 %, compared to 4 % in the baseline scenario.

3.3.3. Constrained electrolyzer location

In our main scenarios, the electrolyzer capacity could be freely allocated across the considered locations. By contrast, in this sensitivity analysis, we constrain the model to build the electrolyzer on the preferred one of the two sites considered. This reflects the potential lack of hydrogen transmission infrastructure in the near term, which would mean that the electrolyzer needs to be built close to the hydrogen consumer. Based on vom Scheidt et al. [27], who estimate the spatial distribution of hydrogen demand in Germany for the year 2030, we select the unit in the Southwest as the electrolyzer location, which is close to the high-demand regions around the Ruhr river and the city of Mannheim. For this sensitivity analysis, we hence consider all portfolios containing the Southwest unit. When calculating the LCOH of the individual units that are not located in the Southwest, we account for electricity grid fees for transmitting the electricity produced from that site to the Southwest, where the electrolyzer is located.

The constraint on the electrolyzer location amplifies the portfolio effects, as depicted in Fig. 8. This effect is small overall, albeit slightly more pronounced for solar than wind. The underlying effect is that the constraint leads to a larger increase in the average LCOH of the individual units than in the LCOH of the portfolio. This, in turn, is driven by the grid fees which the individual units that are not in the SW have to pay.

3.3.4. Buying electricity from the grid during low-price hours

In our main scenario, we assume that electricity generation from

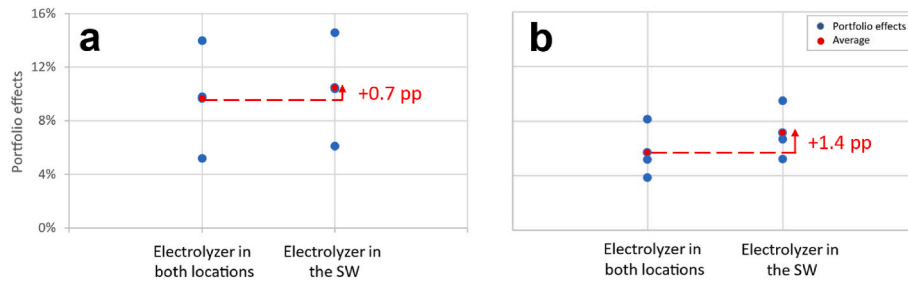


Fig. 8. Effect of placing the electrolyzer on a single site for the chosen cases of wind (a) and solar (b).

renewables and consumption by the electrolyzer must match at an hourly resolution without exception. In this sensitivity analysis, we investigate an exception from hourly matching in the current EU regulation, which allows for buying electricity from the grid when the wholesale electricity prices are low (under 20 €/MWh or 0.36 times the EU ETS price). We investigate the effect of this exception for the main case (units NW and SE) and for all technology combinations.

Overall, this relaxation of temporal matching leads to lower costs in all scenarios (Table 5). The cost reduction is achieved through smaller sizing of the components, which is compensated for by buying electricity from the grid during low-price hours. The effect size depends on the specific case.

For wind and the combination of wind and solar, both units and portfolios achieve only small cost savings in the range of 0 %–1.6 %. The final portfolio effects are thus not significantly altered either. These results align with the findings of Ruhnauf and Schiele [13], where the implications of this exception also remained negligible at current prices in the German electricity market and in the EU ETS. In contrast, the LCOH for solar, of both units and the portfolio, is reduced significantly, viz. between 20 % and 29 %. This larger effect size can be explained by solar being more intermittent, which requires the size of all components to be much larger in the baseline scenario. The low-price exception allows for reducing the capacity considerably. As a result, the portfolio effects are reduced by half (from 6.1 % to 3.3 %). This points towards the intuitive conclusion that relaxing temporal matching gradually reduces portfolio effects.⁹

3.4. Nation-wide aggregation

In this subsection, we investigate an upper bound for the real-world portfolio effect. To do so, we compare the hydrogen production costs resulting from two electricity generation time series: The first one is the resulting generation time series from aggregating all onshore wind (or solar) capacities that are currently available in Germany¹⁰; the second

one is the generation profile of a single site. For the latter time series, we choose locations where the FLH are equivalent to the ones of the respective Germany-wide time series. Notably, we do not simulate the Germany-wide aggregation by running individual capacities as a portfolio. Instead, the aggregated time series already incorporates the inherent smoothing effect. Hence, grid fees for the exchange of electricity within the Germany portfolio are neglected. Note that this approach resembles the modeling in previous system-level studies on hourly matching [7,12,14]

The resulting nationwide portfolio effects amount to 20.6 % for the case of wind and 14.4 % for the case of solar, as illustrated in Fig. 9. These are the relative cost savings that a hydrogen producer with access to the Germany-wide portfolios would benefit from compared to another producer that only has access to the single units. Again, this benefit arises from the geographical smoothing of profiles, which further increases when considering all currently used VRE production sites in Germany, relative to the four exemplary sites considered above. The simplification that we do not consider grid fees will (slightly) upward bias our results (Subsection 3.7). The maximum real-world portfolio effect will thus be somewhat smaller.

4. Discussion

This article quantifies portfolio effects in hydrogen production when requiring hourly temporal matching to label the hydrogen as “green”. These portfolio effects arise from the diversification of electricity production both in terms of technology and location, which smoothens the aggregated VRE production profile and hence eases granular temporal matching. The effect of combining technologies is particularly large: about 39 % of the LCOH can be saved when using wind and solar energy instead of only using either technology. When aggregating pairs of exemplary locations in Germany, we find (average) portfolio effects of 6 % for solar, 8 % for wind, and 3 % for combinations of both. Further sensitivity analyses indicate that the portfolio effects change when exogenously or endogenously varying the capacity ratios of the different renewable generators, but they remain significant as long as at least two technologies or locations are combined. Similarly, constraining the electrolyzer location, allowing to buy electricity during low-price hours, and changing grid fees only modestly changes the estimated portfolio effects. Finally, when aggregating all currently used locations across Germany, we find portfolio effects of 21 % and 14 % for wind and solar, respectively. In the following, we compare our findings to those in the existing literature and discuss the limitations of our study.

Although we are—to the best of our knowledge—the first to analyze portfolio effects related to the definition of green hydrogen, we can compare our results to previous studies in terms of the cost of green hydrogen. Qualitatively, our results align with the existing literature’s finding that temporal flexibility leads to lower costs for green hydrogen. In previous studies, this flexibility came from a relaxation of the temporal matching requirements for green hydrogen or the availability of low-cost hydrogen storage [13,14]. By contrast, we show that technological and spatial diversity helps fulfilling hourly matching requirements with a given hydrogen storage technology at lower costs.

Table 5

Comparison between the results of the baseline scenario and the sensitivity of allowing to buy electricity from the grid during hours of low prices.

	Baseline scenario				Low-price exception			
	LCOH (€/MWh _{H2})			Portfolio effect	LCOH (€/MWh _{H2})			Portfolio effect
	NW	SE	NW + SE		NW	SE	NW + SE	
Wind	117	193	140	9.4 %	116	188	139	8.7 %
Solar	238	185	199	6.1 %	170	149	154	3.3 %
Both	102	126	110	3.7 %	102	124	109	3.5 %

⁹ A similar result can be expected for monthly matching, which is allowed by the EU regulation until 2030.

¹⁰ Again, we use the software *Atlite* for calculating the time series of the Germany portfolio, assuming that the same capacity is built at each site.

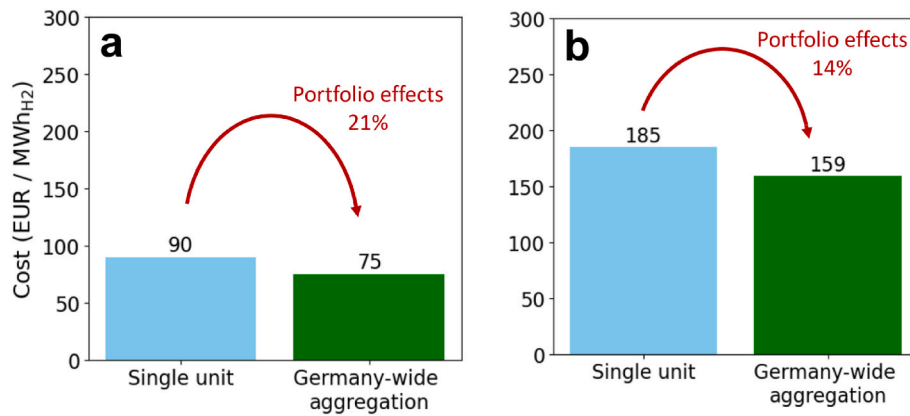


Fig. 9. Resulting portfolio effects from the Germany-wide aggregation for the cases of wind (a) and solar (b).

Notably, many existing studies (implicitly) consider national portfolio effects when analyzing the impact of temporal matching at the national level [7,12,14]. These studies may underestimate the LCOH increase due to matching requirements relative to the real world, in which the size of portfolios is likely to be limited.

Besides costs, previous studies investigated the impact of matching requirements on CO₂ emissions in the power sector. While quantifying emissions is beyond the scope of the present study, we can infer from our finding that portfolio effects allow for reducing VRE capacities that the portfolio will feed in less excess renewable electricity and hence displace less fossil electricity production from the grid. While hourly matching can still be expected to ensure that emissions do not increase due to hydrogen production, operating portfolios may hence lead to a smaller reduction in emissions relative to operating individual units.

We can also compare our results with those from using the more general modern portfolio theory. While that theory holds that the expected return of a portfolio should equal the weighted average return of the contained individual assets, we find that the aggregation of diverse renewable power generation assets into a portfolio can increase expected returns of producing green hydrogen under hourly matching (resulting from the identified decrease in LCOH). This is a result of the hourly matching requirement: if the hourly matching requirements are relaxed, the cost advantage of the portfolio disappears. The portfolio effects that we identify are hence fundamentally different from those obtained using modern portfolio theory. Beyond the expected return, that theory also holds that the variance in returns decreases at the portfolio level. This effect would come on top of the portfolio effects that we quantify here and may be investigated in future research. In particular, a decreasing variance at the portfolio level may help addressing problematic inter-annual variation in optimal system sizing, which was observed in previous studies on hourly matching [13].

There are some limitations to our analysis which we would like to highlight next, and which could be addressed in future research.

First, we consider only a limited set of power generation and energy storage technologies. In the real world, hydrogen producers may also have access to offshore wind farms, geothermal power plants, or other energy storage technologies, such as batteries (through PPAs or within their own portfolio). These options can be expected to increase the technological portfolio effects and decrease the additional benefit from locational diversification relative to our results. Even for the same renewable resource, technological diversification could lead to cost reductions and further synergies.

Furthermore, we have quantified portfolio effects for the example of the German bidding zone, which is relatively large with heterogeneous

weather conditions. By contrast, smaller bidding zones with less heterogeneity can be expected to yield smaller locational portfolio effects.¹¹ Also, the previously discussed exception from hourly matching when electricity prices are low may have a more significant effect in other bidding zones.

Finally, we do not consider potential bottlenecks in the power grid, which could limit the exchange of electricity between the units of a portfolio. Since the volumes traded are relatively low in all scenarios, we assume that this would not make a significant difference. Nevertheless, the role of congestion in the power grid could be an interesting topic for further research as this is relevant for all matching based on PPAs.

5. Conclusions

Based on our results, this section draws some conclusions for hydrogen producers, policy makers, and energy system modelers.

Hydrogen producers can conclude from our study that technological and locational diversification is beneficial when producing green hydrogen under an hourly matching requirement. These portfolio effects go beyond those known from modern mean-variance portfolio theory, as technological and locational diversification under hourly matching requirements does not only reduce the variance but also improves the mean of the resulting cash flows.¹² As a result, investors aiming at reducing their LCOH should consider either investing in (and hence owning) a diverse VRE portfolio or signing PPAs with diverse generation units. Such a diversification strategy is likely easier for large and incumbent firms that either already own such a diverse portfolio or that can afford large PPA liabilities in their balance sheets. By contrast, smaller players may only be able to start their hydrogen business with one or few generation assets and suffer from a relative cost disadvantage and lacking level playing field.

The risk that large players may have a competitive advantage over small players because of hourly matching requirements yields important conclusions for policy makers. If this risk materializes, it implies high entry barriers for new hydrogen producers, which may compromise the functioning of hydrogen markets in general and the ramp-up of hydrogen production in particular. This argument may be considered when deciding on hourly matching requirements, e.g., during the review of the matching requirements that is foreseen by EU regulation by 2028 [9]. If hourly matching requirements were abolished, the portfolio effects identified in the present study in terms of average LCOH, and the

¹¹ Current EU regulation does not allow to match renewables and hydrogen across zones.

¹² The portfolio effects also go beyond other previously known benefits from owning a diverse electricity generation portfolio, such as improved forecasting accuracy.

discrimination risk arising from this, would disappear. Alternatively, if policy makers prefer to maintain the hourly matching requirement, a liquid market for hourly renewable energy certificates that can be used to fulfill hourly matching requirements could address potential discrimination through portfolio effects. This would require the further development of the European system for guarantees of origin [28] to introduce a higher spatial and temporal resolution, similar to a recent proposal by the association of European transmission system operators going beyond the case of green hydrogen [29]. In our context, such a system could unlock the benefits that we identify for the national portfolio and make these benefits accessible to all firms, but only if liquidity is high enough and transaction costs are low, which is unclear ex ante.

Finally, our results can inform existing and future studies that model the impact of hourly matching requirements. Existing studies consider either only one location or portfolios across large areas, both of which imply rather strong assumptions. Given the substantial portfolio effects identified, at least larger firms will likely aggregate generators of different technologies at different sites and achieve lower costs than reported in those studies that only consider one location. Still, it seems unlikely that any firm will come close to the Germany-wide portfolio and even if the market for renewable energy certificates was reformed, liquidity may be limited and transaction costs non-negligible. Hence, studies with national aggregated time series may underestimate the costs of hourly matching.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Appendix A. Supplementary data

Supplementary data to this article can be found online at <https://doi.org/10.1016/j.esr.2024.101580>.

Data availability

Data will be made available upon request.

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