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Abstract

Climate-neutral hydrogen is set to play a crucial role in decarbonizing Europe by 2050. Yet, assumptions on hydrogen imports vary widely across existing studies — ranging from fully flexible to fixed import volumes — often neglecting the modalities of future hydrogen trade such as long-term contracts (LTC). This paper addresses this gap by investigating the implications of Take-or-Pay (TOP) rates in hydrogen LTCs on a decarbonized European energy system. We employ a numerical model that optimizes generation capacity, storage and infrastructure investment, and dispatch decisions for the European power and hydrogen sector in 2050, explicitly incorporating TOP obligations in hydrogen LTCs. Our findings show that varying TOP-rates induce significant shifts in cost-minimal infrastructure requirements of the energy system. These shifts underscore the necessity to account for the degree of import flexibility in planning assessments for future energy systems relying on hydrogen imports. Additionally, we show that reduced import flexibility imposed by high TOP rates is balanced predominantly by increased hydrogen storage and withdrawal capacity while import capacity decreases. By simulating dispatch decisions for 35 weather years for the energy systems planned with representative weather, we find that systems planned with high TOP-rates exhibit a lower reliability when weather characteristics during operation differ from the planning stage.

Keywords: Energy System Modeling, Hydrogen Infrastructure, Hydrogen Storage, Hydrogen Long-Term-Contracts, Hydrogen and Electricity Markets
JEL classification: C61, F10, Q27, Q40, Q41, Q48.

1. Introduction

The goal of achieving climate neutrality in the EU and other European countries by 2050 calls for fundamental changes to the energy system infrastructure across the continent. Clean hydrogen is set to become one of the key pillars of a decarbonized energy system, which is underlined by major energy system studies pointing out the future role of hydrogen (IEA, 2023; IRENA, 2023; Tarvydas, 2022). Besides using hydrogen and its derivatives in selected end-use applications or as a feedstock in industrial processes, its physical properties favor using it as a storage medium, balancing intermittent renewable energy sources

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(RES) over days, weeks, or months. To become an essential part of the future European energy system, infrastructure facilities such as storage and transmission grids will be required. In light of the ambitions to phase out the use of fossil gas (EC, 2021), a promising and cost-saving approach is the partial reconversion of existing infrastructure. Studies have already started investigating the emergence of a European hydrogen grid from existing, reconverted natural gas pipelines (van Rossum et al., 2022; Frischmuth et al., 2022; Schlund, 2023) and exploring the technical potential of storage facilities (Caglayan et al., 2020). However, the research on cost-efficient sizing, especially for storage and potential import terminals, remains limited. Their size is of central relevance not only in terms of energy balance, but also in terms of short-term power balance to guarantee security of supply in both the electricity and hydrogen sectors.

The production of hydrogen can be based on numerous primary energy carriers, but the most promising method in a decarbonized European energy system is clean electricity powering electrolyzers to split water into oxygen and hydrogen (EC, 2023). In light of the limited techno-economic potential of alternative emission-free generation technologies, wind and solar PV are set to be the primary electricity generation technologies. However, cost-efficient renewable energy potentials in the EU are limited, and a rapid ramp-up is essential. In other regions, full-load hours for wind and solar PV, as well as land availability, can be significantly higher than in Europe. Thus, hydrogen production from renewable electricity in other world regions and subsequent transport to Europe could pose an economically favorable case (Moritz et al., 2023). With the publication of the REPowerEU plan, the EU is aiming for global trade in derivatives of renewable hydrogen, whereby half of the hydrogen consumed in the EU should originate from imports by 2030 (EC, 2022). Until now, an international market and a trade framework have not emerged. Current research suggests that hydrogen is likely to be traded via long-term contracts (LTCs) (Antweiler and Schlund, 2023; IEA, 2022) ensuring the refinancing of investments for both exporter and importer. This is especially true for the initial market ramp-up given high upfront investment costs linked to long amortization periods of the infrastructure required.

In the context of LTCs, offtake agreements serve as an instrument of risk sharing between buyer and seller and provide security for financial contracts. They can reduce the variability of cash flow and thus reduce the upfront risk of the investment associated with an LTC (Creti and Villeneuve, 2004; Bento, 2008). The minimum offtake of the contracted volume, which can be processed with physical delivery or financial compensation, is called the Take-or-Pay rate (TOP rate). Today, TOP rates find application in LTCs for trading natural gas via pipeline or liquefied natural gas (LNG). Besides these minimum offtake quantities, LTCs contain agreements on the destination of gas deliveries. In the past, LTCs were tied to specific destinations or terminals, a practice deemed by the European Commission to violate European competition law (Creti and Villeneuve, 2004; Ason, 2022). However, LTCs are now increasingly characterized by greater destination flexibility - enabling LNG cargoes to be diversified and redirected within Europe (Talus, 2023). The fact that natural gas and hydrogen transport infrastructure have similar characteristics suggests that TOP rates will remain pertinent in future hydrogen LTCs. At the same time, most studies examining hydrogen infrastructure overlook the restrictions associated with TOP, instead rather assuming either fully flexible or fixed hydrogen imports. For example, while ENTSOE and ENTSOG (2022) presumes inflexible imports at predefined volumes, EWI (2021) assumes complete import flexibility, and other studies, such as van Rossum et al. (2022), lack transparency in their methodological assumptions. Our study aims to shed light on the bias resulting from simplifying assumptions on hydrogen imports from previous studies. In addition, destination flexibility in LTCs to diversify energy imports across markets is becoming increasingly important in light of the advancing energy transition - allowing flexible imports across Europe to be assumed for future hydrogen LTCs (Talus, 2023). However, implementing TOP rates in LTCs may pose challenges to the importer. A high TOP rate imposes inflexibility on the demand side, as importers are obliged to physically import hydrogen or pay financial compensation, even when imports are not required due to abundant domestic supply. The availability of domestic hydrogen supply and its trade-off with imports are significantly linked to the availability of RES and, in turn, to weather variability. Moreover, the demand side for both hydrogen and electricity in a decarbonized European energy system will be affected by weather characteristics, underscoring the need to investigate the interplay of weather variability and flexibility of hydrogen imports.

To the best of our knowledge, no research analyzes the impact of TOP rates in hydrogen LTCs on a decarbonized European energy system. Against this background, this paper aims to answer the following research questions: i) How do TOP rates in hydrogen LTCs affect the system costs of a decarbonized European energy system? ii) How do TOP rates affect the optimal configuration of the European energy system infrastructure? iii) How reliable are energy systems planned with representative weather and different TOP rates regarding weather variability?

To answer these questions, we develop a partial equilibrium model named HYEBRID, which optimizes investment and dispatch decisions for the European power and hydrogen sectors for the climate-neutral target year 2050. We set up a two-step approach. First, we determine investment decisions based on a representative weather year for six equidistant TOP rates. Subsequently, we calculate the dispatch decisions for each of these six energy systems given a set of 35 weather years in a high temporal resolution. The model comprises a holistic representation of an integrated hydrogen sector by accounting for endogenous investment in electrolysis, storage, and import facilities while considering exogenous cross-border hydrogen transport capacity from converted natural gas pipelines. In contrast to most existing models, we explicitly model capacity requirements of daily storage injection and withdrawal as well as hydrogen import terminal capacity requirements. Moreover, we account for the technical potential of reconverted natural gas storage and the theoretical potential of newly constructed hydrogen storage by salt caverns. We apply the concept of TOP rates to potential hydrogen LTCs including destination flexibility within Europe and analyze their effect on the configuration of the European energy system. Further, we conduct the planning of infrastructure based on a representative weather year and run a stress test of the infrastructure by dispatching a set of 35 weather years. Doing so, we seek to analyze the operational inflexibility imposed by TOP rates in the context of weather variability. This research framework can as well be interpreted as analyzing the impact of unexpected short-term conditions deviating from the planning stage.

This work contributes to the existing research by firstly incorporating TOP obligations in hydrogen imports in a newly developed investment and dispatch model for power and hydrogen. Assuming a fixed price for hydrogen imports, we show that higher TOP rates only marginally increase total system costs, but induce significant shifts in cost-minimal infrastructure requirements. This underscores the importance of taking TOP rates into consideration in today's research and planning assessments of stakeholders and institutions responsible for energy infrastructure. We find that rising inflexibility with high TOP-rates leads to an increase in H2 storage and withdrawal capacity, while capacity of H2 terminals decreases, reducing surplus imports. We extend the scarce research on European hydrogen storage requirements by calculating a range between 63 TWh and 81 TWh and discuss key determinants for the sizing of storage. Lastly, we conduct a stress test to the energy systems planned with representative weather and show that the energy systems restricted with a higher TOP-rate generally show a lower reliability.

The remainder of this paper is organized as follows: Section 2 reviews recent literature along two coherent literature streams. In Section 3, we introduce the model framework and define the underlying assumptions and data. Section 4 shows the results on system costs, the energy system infrastructure, and the effect of weather variability. We critically discuss the key findings concerning central assumptions and limitations of the model framework in Section 5 and give an outlook for future research. Lastly, Section 6 concludes this work.

2. Literature

Our research ties into existing work in European energy system optimization with a representation of the hydrogen sector. We categorize existing publications into two streams of literature. The first consists of energy system modeling for investigating the development of hydrogen infrastructure, extended by analyzing the impact of weather variability on energy systems. The second deals with the effects of TOP rates and LTCs in natural gas and hydrogen markets.

While many modeling approaches have researched the emergence of hydrogen infrastructure on a national level (e.g., Germany (Peterssen et al., 2022; Schöb et al., 2023; Schmitz et al., 2024), France (Tlili et al., 2019), or Great Britain (Samsatli et al., 2016), a representation on a European scale remains limited.

Neumann et al. (2023) investigate the benefits of building a hydrogen network and expanding electricity transmission capacity in Europe with a linear optimization model. Their model considers a high spatial resolution with a total of 181 regions, improving the granularity of infrastructure development within countries but lacking a representation of hydrogen imports from outside Europe. Related research is done by Schlund (2023), who conducts a scenario-based approach analyzing critical dependencies between system elements for a ramp-up of hydrogen infrastructure with an integrated representation of the natural gas sector while accounting for hydrogen storage and import options. Depending on the scenario, hydrogen import capacities range between 58 TWhpa and 561 TWhpa. However, the analysis does not consider electricity markets.

The Ten-Year Network Development Plan (TYNDP) is a non-academic joint report by the ENTSO-E and ENTSOG and conducts detailed bottom-up modeling of the EU's energy system up to 2050. They endogenously model investment[1] and dispatch decisions for an integrated electricity and hydrogen sector and aim to find cost-efficient infrastructure requirements for three scenario settings. The analysis accounts for hydrogen imports from non-EU countries only via retrofitted gas pipelines, i.e., excluding the possibility for imports via ship, and finds viable hydrogen imports between 358 TWh and 901 TWh to EU27 in 2050 (ENTSOE and ENTSOG, 2022). These relatively high import volumes are caused mainly by their explicit assumption to set the import price marginally lower than the price of domestically generated hydrogen. Further research has been done by Sasanpour et al. (2021), who test the effect of policy targets and constraints on system costs and infrastructure requirements in a climate-neutral European energy

[1]Their approach does not consider the endogenous investment of some technologies, e.g., thermal power plants or hydrogen storage capacity.

system with the linear optimization model REMix. Among others, they find that doubling the price for hydrogen imports compared to a reference case of 120 EUR/MWh increases system costs by 2% without specifying the quantity of imports.

The long-term scenarios 3 (Sensfuß et al., 2024), commissioned by the Federal Ministry for Economic Affairs and Climate Protection in Germany, investigate pathways to achieve climate neutrality by 2045 by identifying robust developments from various scenarios through computational modeling. The study allows for hydrogen imports from non-EU countries, underground hydrogen storage in salt caverns and intra-European hydrogen transport in repurposed and newly built pipelines. They find hydrogen imports in Europe between 60 TWh and 79 TWh, while domestic hydrogen production ranges between 994 TWh and 1193 TWh. The resulting European hydrogen storage requirements vary between 223 TWh and 240 TWh and entails a seasonal profile with two full-cycles for 2045.

However, research regarding the role of hydrogen storage in a future energy system remains limited. For the case of Germany, Lux et al. (2022) determine a requirement for hydrogen storage between 42 TWh and 102 TWh, while Robinius et al. (2020) find a requirement of up to 69 TWh given an integrated modeling approach and Kondziella et al. (2023) find a capacity between 14 TWh and 67 TWh to be optimal. Moreover, the latter analysis finds a seasonal characteristic of storage cycles. Schlund (2023) observes a similar characteristic, identifying a total capacity between 87 TWh and 197 TWh for Europe. Moser et al. (2020) finds the lowest value for hydrogen storage capacity in Europe, showing a requirement of 45 TWh, albeit focusing on the effect of grid extension. However, the underlying assumptions, e.g., temporal resolution, weather characteristics, cost levels, and the research frameworks broadly differ across the literature reviewed. With an exogenous assumption on the conversion rate for current salt cavern storage, ENTSOE and ENTSOG (2022) defines an underground storage capacity of about 102 TWh.

In the context of energy system modeling, existing research points out the importance of accounting for weather variability driving backup capacity and storage requirements. By processing a cost optimization model for Germany given 35 years of weather data with hourly resolution, Ruhnau and Qvist (2022) find that relying on single weather years or short-duration weather events can lead to an underestimation of storage requirements and costs. Similar findings with a regional scope of single countries result from Zeyringer et al. (2018) and Abdin et al. (2018). Caglayan et al. (2021) incorporate the effect of weather variability on a European level by deriving a robust design of a climate-neutral energy system considering the hydrogen sector. Their iterative approach of single linear model runs ensures a robust solution to 38 weather years. Nonetheless, this approach does not guarantee optimality and relies on a low temporal resolution while neglecting the option for hydrogen imports. They conclude that considering multiple weather years instead of single ones can lead to an increase in system costs of up to 25%.
Summarizing the first literature stream shows that previous modeling approaches provide valuable insights into the emergence of a hydrogen sector and the interplay with the electricity sector in Europe. Our paper contributes to the existing literature body with an explicit representation of endogenous hydrogen terminal capacity for imports and hydrogen storage injection and withdrawal capacity, considering a distinction between repurposed and newly constructed underground cavern storage. We acknowledge existing research pointing out a potential underestimation of capacity requirements when relying on single weather years for investment decision making. However, the aim of our approach is not to derive highly robust systems with respect to weather variability, but to investigate and the operational reliability of a system planned

with weather that might deviate from future weather. We do so by simulating dispatch decisions of energy systems with varying TOP rates for 35 weather years, including weather effects on the demand and supply side.

The second stream of literature regards the role of TOP rates as a contractual part of LTCs, which are prevalent in global energy markets, particularly natural gas markets. Historically, for natural gas delivered via pipelines, typical TOP rates range between 70% and 90% (IEA, 2020), while LTCs for LNG may reach TOP rates of nearly 100% depending on the region (Ason, 2022). Creti and Villeneuve (2004) point out that TOP clauses, setting a minimum offtake volume sold under LTCs, are intended to introduce risk sharing between producers and buyers. Such agreements bind both parties under predefined conditions, e.g., for natural gas pipeline contracts with a term of 20 to 30 years. By committing to buy on a long-term basis, the buyer accepts part of the risk, which arises from long lead times in investment planning and high capital intensity. Ruester (2015) analyzes 26 liquefied natural gas (LNG) projects to investigate the determinants of debt ratios in project finance. The author shows that long-term offtake agreements such as TOP clauses secure project financing and reduce cash flow variability over LNG contract periods of 15 to 25 years. Thus, the debt ratios and therefore, financial power of those projects increase. Conversely, LTCs can also pose caveats, e.g., creating lock-in effects for the contracting parties, depending on the specifics of the LTC (Talus, 2023). Antweiler and Schlund (2023) summarize the necessary conditions for the emergence of LTCs and find that most are fulfilled for international hydrogen trade. By investigating the history of natural gas markets using an analytical framework, Dejonghe et al. (2023) suggest that the development of hydrogen trade routes may differ from natural gas. Their analysis indicates that seaborne (derivatives) shipments could take precedence over pipeline deliveries due to less concentrated global hydrogen production than today's existing natural gas reserves. The existing research shows initial investigations on potential forms of an emerging hydrogen trade, potentially via LTCs and ship-based transportation. The articles discuss similarities to existing natural gas trading via LTCs, including take-or-pay agreements, and their benefits to developing a well-functioning and reliable European market. However, no studies have numerically investigated the effects of LTCs or TOP rates on a decarbonized European energy system. This work contributes to the extant literature by explicitly incorporating six equidistant TOP rates between 0% and 100% for the maritime import of hydrogen to Europe. We analyze the impact of varying TOP rates on system costs and the configuration and operation of a decarbonized European energy system.

3. Methodology

This chapter describes the model used in this paper and provides a general intuition for the economic rationale of hydrogen imports with TOP rates within our model framework. Lastly, this chapter presents central assumptions and input data.

3.1. Model framework

To answer our research questions, we developed a new linear optimization model named HYEBRID (Hydrogen and Electricity market model with broad representation of weather variability and Import Decisions). The partial equilibrium model optimizes European electricity and hydrogen investment and dispatch decisions. It minimizes the net present value of energy system costs, comprising fixed capacity-based and variable generation costs. The model assumes complete markets and no transaction costs. Therefore, the competition of profit-maximizing symmetric firms is the dual formulation of a central planner's cost minimization. Contrasting to many existing modeling approaches, HYEBRID accounts for all key entities in a possible future hydrogen sector and its interrelations with the power sector. This includes domestic (European) generation by electrolysis, storage in underground salt caverns, non-European imports using ammonia import terminals, intra-European transmission by converted natural gas pipelines, and hydrogen consumption in the power sector and end-use sectors. The technologies used in our model framework and the interrelations between the power and hydrogen sector are shown in Figure 1.

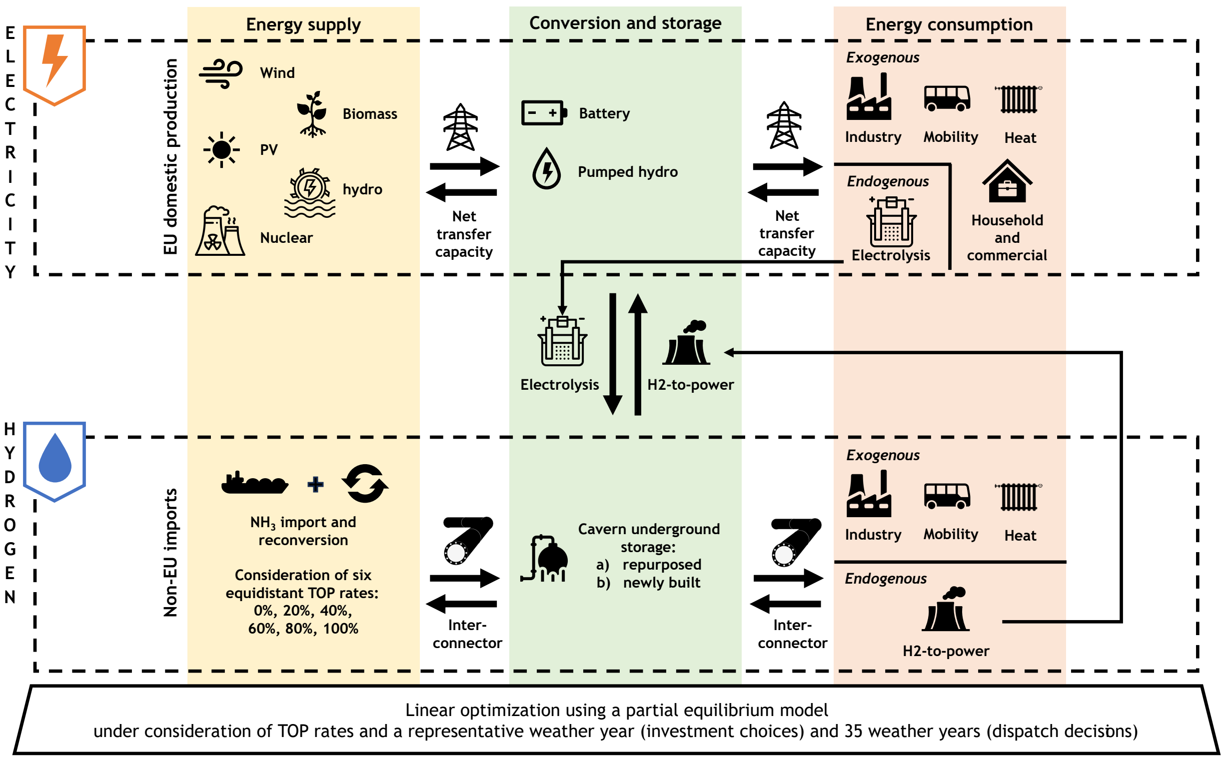

Figure (1) Conceptional scheme and scope of the model

Another key feature of the model is the representation of weather variability. We choose a two-stage modeling approach, as illustrated in Figure 2. In the first step, we run our model based on a representative weather year to determine the investment decisions for future infrastructure from the central planner's perspective. In the second step, we compute dispatch decisions for 35 weather years to capture the volatile nature of renewable availability and temperature-dependent demand influencing both the power and hydrogen sectors. Thus, considering a set of weather years enables a stress test of systems planned without inter-annual weather variability. Regarding our research question, we are able to analyze the role of flexibility in hydrogen imports to balance weather vagaries during operation.

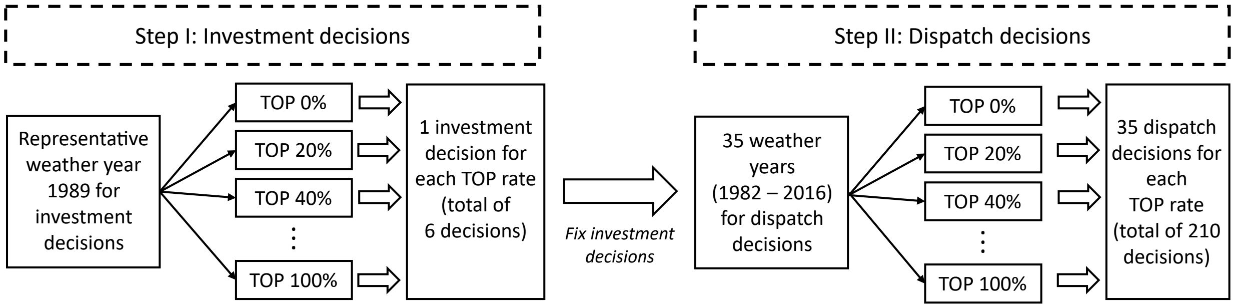

Figure (2) Fundamental two-stage modeling approach

Selection of the representative weather year

Investments in infrastructure require extensive development and construction periods and must be planned for the long term due to the associated lifespan and high capital intensity. From the central planner's perspective, this requires making decisions today about the energy system of the future. Therefore, assumptions have to be made about future events, such as weather conditions. Ideally, energy system modeling would account for a large set of potential weather phenomena with high spatio-temporal resolution and even account for changing weather patterns owing to climate change. To keep the computational complexity in means, our modeling approach considers a reference weather year to determine investments in the European energy system. Since no accurate definition of representative weather exists, we select what we refer to as the representative weather year, the year which exhibits the median total system costs. With a low temporal resolution, we run investment decisions for each of the 35 historic weather years considered and for a TOP rate of 0% and 100%, capturing the extremes in hydrogen import flexibility. The results on system costs show 1989 to be the median weather year for both TOP rates. Therefore, subsequent investment decisions with higher resolution are made based on the weather year 1989. Against this background, our approach does not aim to derive an energy system that is robust to a large set of weather phenomena. Instead, we seek to investigate how different degrees of hydrogen import flexibility (TOP rates) alter the dispatch decisions of energy systems planned with representative weather. This can be interpreted as a stress test regarding weather variability.

The model formulation poses challenges to computational complexity. Therefore, our model exhibits several limitations: We run the model only for the climate-neutral target year 2050. Therefore, we do not account for dynamic investment decisions but consider annualized investments. Further, the model abstracts from uncertainty and assumes perfect foresight, i.e., parameters such as the availability of RES and the level of demand are known ex ante. The demand for electricity and hydrogen from end-use sectors is assumed to be inelastic, i.e., not price-responsive. On the supply side, we abstract from ramping and minimum load constraints of combined heat and power units to avoid a mixed-integer optimization.

In the following, we present the key equations of HYEBRID. All sets, parameters, variables and indicies related to the model are summarized in Table A1 in the Appendix. The model employs total costs TC as the objective function, which is minimized by applying linear optimization. As Equation 1 depicts, total costs TC are a sum over each day d and hour h in the target year, node n, and technology $tech$ of the variable costs $OPEX$, fixed operating and maintenance costs FOM, annualized[2] capital costs $CAPEX$, and hydrogen import costs for IC.

$$min\ TC = \sum_{d,h,n,tech} OPEX_{d,h,n,tech} + \sum_{n,tech} FOM_{n,tech} + CAPEX_{n,tech} + \sum_{d,n} IC_{d,n} \tag{1}$$

The equilibrium equation for electricity (Equation 2) ensures that in each hour electricity supply $\mathrm{S^{EL}}_{\mathrm{d,h,n,tech}}$ from technology $tech$ to node n minus injection to electrical storage $\mathrm{S^{EL}}_{\mathrm{d,h,tech,n}}$ covers the exogenous electricity demand from end-use sectors $\mathrm{d^{EL,exo}}$, the endogenous electricity demand from hydrogen production $D^{EL,H2}$, and the net trade balance for electricity $\mathrm{TRADEBAL^{EL}}$ (Equation 3), which depicts the trade flows from other nodes under consideration of transmission losses δ^{EL}. Depending on the specification of the model, we allow for uncovered demand L^{EL}.

$$\sum_{tech}(S^{EL}_{d,h,n,tech} - S^{EL}_{d,h,tech,n}) = d^{EL,exo}_{d,h,n} + D^{EL,H2}_{d,n} - TRADEBAL^{EL}_{d,h,n} - L^{EL}_{d,h,n}\ \forall d,h,n \tag{2}$$

$$TRADEBAL^{EL}_{d,h,n} = \sum_{m}[(1-\delta^{EL}_{m,n}) * TRADE^{EL}_{d,h,m,n} - TRADE^{EL}_{d,h,n,m}]\ \forall d,h,n \neq m \tag{3}$$

The equilibrium equation for hydrogen (Equation 4) is formulated such that hydrogen supply $\mathrm{S^{H2}}_{\mathrm{d,n,tech}}$ by electrolysis or storage withdrawal and non-European hydrogen imports dedicated for consumption $\mathrm{I^{H2,consumption}}$ minus storage injection $\mathrm{S^{H2}}_{\mathrm{d,tech,n}}$ cover the hydrogen demand from end-use sectors $d^{H2,exo}$, the hydrogen demand for re-conversion into electricity $D^{H2,EL}$, and the net trade balance for hydrogen $\mathrm{TRADEBAL^{H2}}$, which is formulated just as the net trade balance for electricity.

$$\sum_{tech}(S^{H2}_{d,n,tech} - S^{H2}_{d,tech,n}) + I^{H2,consumption}_{d,n} = d^{H2,exo}_{d,n} + D^{H2,EL}_{d,n} - TRADEBAL^{H2}_{d,n}\ \forall d,n \tag{4}$$

Daily hydrogen generation within Europe is limited by electrolysis capacity $C^{H2,ELY}$ according to Equation 5.

$$S^{H2}_{d,n,tech} \leq C^{H2,ELY}_{n}\ \forall d,n,tech \in Tech^{\mathrm{H2,ELY}} \tag{5}$$

The energy balance describing the electricity input to electrolysis is formulated in Equation 6.

$$\sum_{h} D^{H2,EL}_{d,h,n} * \eta^{H2}_{tech} = S^{H2}_{d,n,tech}\ \forall d,n,tech \in Tech^{\mathrm{H2,ELY}} \tag{6}$$

In our model setting, we assume that hydrogen imports can be physically imported and consumed instantaneously ($\mathrm{I^{H2,consumption}}$), or be stored ($\mathrm{I^{H2,STOR}}$), or, if the underlying TOP rate forces additional imports, which are not required physically, financial compensation applies to fulfill the contractual agreement on the TOP condition ($\mathrm{I^{H2,financial}}$). The aggregate volumes equal the total amount of non-European hydrogen imports (cf. Equation 7).

[2] Annuities are computed with a discount rate of 8%.

$$I_{d,n}^{H2} = I_{d,n}^{H2,consumption} + I_{d,n}^{H2,STOR} + I_{d,n}^{H2,financial} \ \forall d, n \tag{7}$$

Hydrogen imports I^{H2} are represented by seaborne hydrogen derivatives [3], which are landed via import terminals, including re-conversion to hydrogen. As Equation 8 reveals, the import quantity of hydrogen in each day is limited by the import capacity $C^{H2,IMP}$.

$$I_{d,n}^{H2} \leq C_{n}^{H2,IMP} \ \forall d, n \tag{8}$$

Storing hydrogen is described in Equation 9. The storage volume ST^{H2} of the time step $d+1$ must always equal the quantity of the previous time step d under consideration of injected hydrogen into the storage $S^{H2}{}_{t,tech,n}$, withdrawals from storage $S^{H2}{}_{t,n,tech}$ in accordance with the injection and withdrawal losses $\delta^{H2,STOR}$, and imports fed into the storage $I^{H2,STOR}$.

$$ST_{d+1,n}^{H2} = ST_{d,n}^{H2} + \delta_{tech}^{H2,STOR} * (S_{d,tech,n}^{H2} - S_{d,n,tech}^{H2} + I_{d,n}^{H2,STOR}) \ \forall d, n, tech \in Tech^{\mathrm{H2,STOR}} \tag{9}$$

In our model setting, we assume all European import terminals to be under LTCs. Thus, a direct dependency exists between European terminal capacity and the underlying TOP rate in LTCs. We define the TOP rate *top* as a share of the maximum imports possible occurring under full utilization of import terminals, i.e., $C^{H2,IMP} * \#d$ with the latter being the number of days in a year. Therefore, the terminal capacity determines the minimal quantity of hydrogen imports, as described in Equation 10. By summation over all nodes, we ensure the destination clause is formulated with respect to Europe, i.e., the TOP rate is valid for the aggregate of European countries but not for individual countries or terminals. By this definition, the following profiles for H2 imports result: The higher the TOP rate, the lower the flexibility for importing hydrogen during the year. Consequently, at a TOP rate of 100%, a constant import of hydrogen results for each day of the year.

$$\sum_{d,n} I_{d,n}^{H2} \geq \sum_{n} C_{n}^{H2,IMP} * \#d * top \tag{10}$$

We calculate the costs for hydrogen imports IC by multiplying the quantity of imports I^{H2} with the assumed price $p^{H2,IMP}$ as formulated in Equation 11.

$$IC_{d,n} = I_{d,n}^{H2} * p^{H2,IMP} \ \forall d, n \tag{11}$$

In case the model is not run in full temporal resolution, the variable costs $OPEX$, the costs for hydrogen imports IC and storage injection and withdrawal quantities are scaled with the weight of representative days. Further equations, not explicitly mentioned above, include the restriction of hydrogen and electricity flows between nodes, renewable space restrictions per node, electric capacity restrictions from electrolysis, and volume restrictions for storage.

[3] This analysis assumes that ammonia serves as imported hydrogen derivative. Further explanations can be found in Section 3.3.

3.2. *The economic rationale for hydrogen imports with TOP rates*

This section serves to explain the intuition behind the model outcomes for varying TOP rates in hydrogen LTCs and describes the interrelation between import capacity, import quantity and TOP rate. From the central planner's perspective, an increase in the TOP rate can reduce the flexibility of non-European hydrogen imports, which in turn can change the optimal energy system configuration and the cost-efficient amount of non-European hydrogen imports and terminal capacities. In theory, we can differentiate between two states of solutions to the cost optimization, depending on the TOP rate. The first case refers to an equilibrium in which the cost-optimal utilization of European hydrogen import terminals U^* turns out equal to or higher than the assumed TOP rate. As a result, the TOP condition does not pose additional costs for hydrogen imports that might deviate from the optimum. Thus, a variation of the TOP rate does not affect the European energy system if the first case holds true. From the model's perspective, the restriction imposed by the TOP rate is non-binding. In the second case, the cost-minimal utilization rate of European import terminals is lower than stated by the TOP rate, i.e., the restriction stemming from the TOP rate is binding and forces aggregate terminals to be utilized at least with the TOP rate. Here, the social planner adjusts the energy system configuration to find a new cost-minimal equilibrium, deviating from the first case, as the TOP condition implies a reduced flexibility of non-European hydrogen imports. In the following, we refer to these cases as benchmark and individual solutions (cf. Equation 12 and Figure 3).

$$U^* \begin{cases} \geq top, & \text{benchmark solution} \\ < top, & \text{individual solution} \end{cases} \tag{12}$$

In the case of an individual solution, the social planner is confronted with a trade-off compared to the benchmark solution between i) additional costs imposed by additional non-European hydrogen imports or ii) additional costs imposed by additional assets within Europe to balance a reduction in non-European hydrogen imports in terms of both energy and capacity. We point out that this trade-off is highly complex, as the cost function of the European hydrogen supply is dependent on all other endogenous energy system variables and thus requires computational modeling. Moreover, the possibility of storing hydrogen adds another layer of complexity through intertemporal linkage.

3.3. *Assumptions and data*

The regional scope of the model is the EU27, the United Kingdom, Norway, and Switzerland, excluding Cyprus, Malta, Bulgaria, and Greece. The temporal scope of the model is the year 2050, which is the climate-neutral target year aimed at by the EU. Thus, a zero-emission power and hydrogen sector is a central condition for our model framework. The intra-annual resolution varies between the power and hydrogen sectors. We compute the power sector hourly, whereas hydrogen is modeled in a daily resolution to implicitly account for flexibility through the inert pipeline network. For the investment stage, we use 122 representative days, not allowing for lost load, whereas dispatch decisions are computed with full resolution and the possibility of load shedding. Since the value of lost load varies across regions and sectors and is subject to uncertainty (ACER, 2018, 2022), we assume it to be significantly higher than the highest marginal costs of any technology considered. Consequently, it is treated as the last resort to satisfy the equilibrium constraint.

The technological scope of the model is summarized in Figure 1. Table B1 in the Appendix summarizes the techno-economic assumptions for the technologies considered in this analysis. For comparability, all cost-related data are converted to €$_{2019}$. All calorific units are based on the lower heating value. For the power sector, we initialize the model with capacities for the supply, conversion, and storage of electricity for 2022. These capacities can generally be expanded using the model, making it a brownfield investment model, although nuclear and hydro capacities are assumed to maintain current levels. For the hydrogen sector, hydrogen can be produced domestically by electrolysis or imported from non-European countries by ammonia shipping and import at European terminals, including the reconversion to hydrogen. Assumptions on import terminal costs and hydrogen import costs are based on Moritz et al. (2023). We assume a hydrogen import price of 75 EUR/MWh, corresponding to the average levelized supply costs of the 20 most cost-efficient export countries in the optimistic scenario of Moritz et al. (2023). This fixed price assumption, irrespective of the underlying TOP rate, also assumes a fixed supply curve of the exporters. Indeed, accounting for the flexibility of exporters could influence the hydrogen supply costs. Further, transaction costs and security margins could drive hydrogen import prices higher than supply cost levels. We point out that the emergence of a spot market for hydrogen imports and a subsequent indexation of LTCs to spot prices remains speculative and is not considered in this work. In addition, we assume a fixed price for hydrogen imports irrespective of the underlying TOP rate. In reality, a higher TOP rate could be associated with lower risk for the exporters' investment and lead to a lower price for hydrogen or higher margins. Due to difficulties and uncertainty in quantification, we abstract from this relation and discuss this assumption in Section 5.
Storing hydrogen is considered by repurposed or newly built salt caverns, currently representing the most promising and cost-effective type of long-duration underground hydrogen storage (Caglayan et al., 2020). In the model, storing hydrogen in cavern sides is enabled only in countries[4] with existing and operating caverns for natural gas. Moreover, we differentiate between storage volume, injection capacity, and withdrawal capacity, as the volume-to-capacity ratio in a climate-neutral energy system may deviate from the current ratios of natural gas storage. We prescribe the filling level of storage at the end of the year to be equal to the start of the year. Electricity transmission between countries is represented by net transfer capacities (NTC), which are assumed to develop according to the TYNDP 2022 (ENTSOE and ENTSOG, 2022). For hydrogen transmission, we utilize hydrogen interconnectors in our model by repurposed natural gas pipelines based on ENTSOG (2023). A repurpose rate of 50% and a conversion factor of 75% of the initial natural gas capacity based on Galyas et al. (2023) is assumed.

The representation of annual electricity demand from end-use sectors is based on TYNDP's Global Ambition scenario for 2050 (ENTSOE and ENTSOG, 2022). To capture the weather-dependent nature of electricity demand for both inter-annual and intra-annual variations, we use the hourly demand time series from the European Resource Adequacy Assessment 2022 (ENTSO-E, 2022). These time series capture the weather-dependent nature of electricity demand for 35 weather years, i.e., 1982 to 2016. We combine the two sources by multiplying the ERAA demand time series with the total demand from TYNDP for 2050 for every country and dividing the product by the average total demand across the 35 weather years. Likewise, the representation of hydrogen demand follows TYNDP's Global Ambition scenario for 2050 (ENTSOE and

[4]These countries are FR, DE, DK, NL, PL, PT, and GB, following current data from Gas Infrastructure Europe (GIE, 2021).

ENTSOG, 2022), assuming a flat demand from the end-use sectors of industry and mobility. The degree to which hydrogen will be used in heating applications is highly uncertain. For our model, we assume that 25% of heating demand, met by natural gas today, will be met by hydrogen in 2050, introducing a degree of seasonality in hydrogen demand. To capture the intra-annual temperature dependence of future hydrogen demand for heating, we compute a linear regression of daily heating demand with temperature as the independent variable based on data from Ruhnau and Muessel (2023), which is based on Ruhnau et al. (2019). This function is applied to the daily temperature observed in the weather years 1982 to 2016. The hydrogen required for re-conversion to electricity is determined endogenously. On the supply side, we feed our model with data on the hourly availability for solar PV, wind onshore, and wind offshore for all 35 weather years based on ENTSO-E (2022). Run-of-river flows, storage volumes of pumped-hydro units, and weekly hydro reservoir levels are based on the ENTSO-E (2022) as well.

4. Results

This section presents findings of varying six equidistant TOP rates between 0% and 100% for the import of hydrogen on the cost-minimal configuration of the European energy system. First, we show the implications of TOP rates on system costs, investment decisions, and subsequently dispatch decisions given a representative weather year. Based on the resulting energy system configurations, we then conduct dispatch simulations for a set of 35 weather years, analyzing how the energy system configurations planned with a representative weather year and varying TOP rates respond to weather variability.

4.1. System costs

In our model setting, the effect of TOP rates on system costs is unidirectional. From the central planner's perspective, an increase in TOP rates can reduce the flexibility of non-European hydrogen imports, leading to an increase in system costs. As shown in Equation 10, the TOP rate forces European import terminals to be utilized at least at the level of this TOP rate. Based on equation 12, we can state that all benchmark solutions exhibit equal system costs. As soon as the TOP rate forces the utilization of import terminals to exceed the utilization of the benchmark solutions, the social planner is confronted with additional costs due to the obligation of the TOP rate. Thus, all individual solutions exhibit higher system costs than the benchmark solutions. The relation between the benchmark and the individual solution is illustrated in Figure 3. Further, we can state the following: The higher the TOP rate deviates from the benchmark terminal utilization, the higher the resulting additional system costs. Figure 3 depicts the relative change in total system costs at a specific TOP rate compared to a TOP rate of 0%.

The benchmark solution is evident up to a TOP rate of at least 57%. Although we only conduct a scanning on TOP rates in steps of 20%, we can derive the precise point of change from the benchmark to individual solutions based on the average utilization rate of European hydrogen terminals. In this range up to 57%, no TOP rate leads to an increase in system costs. Beyond this TOP rate, the results exhibit an increase in system costs, implying that the TOP rate imposes additional restrictions on the optimization.
The shape of the individual solution curve is convex, meaning that marginal system costs increase with higher TOP rates. The maximum system costs can be located at a TOP rate of 100%, resulting in a markup of 0.77% compared to the benchmark results. Despite the relative increase in system costs being small, the cost increase in absolute terms can be substantial, considering the level of European energy system costs.

Further, changes in system costs not only cause additional capacity requirements for a single technology but also change the equilibrium of cost-optimal technology shares along the electricity and hydrogen systems, which we analyze in the subsequent Section 4.2.

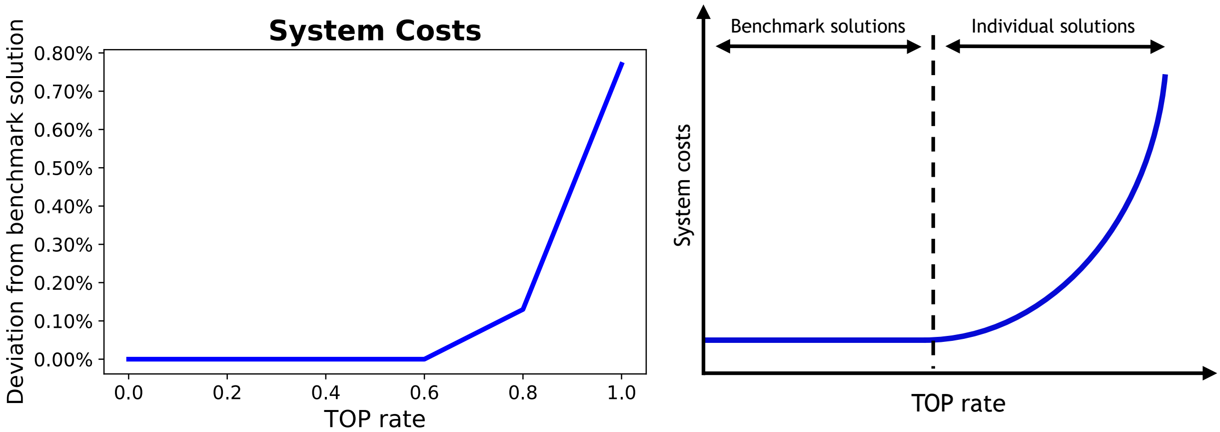

Figure (3) Total system costs as a function of TOP rates for the representative weather year (left) and schematic illustration (right)

The finding of convex curves for total system costs points to the importance of negotiating the lowest TOP rate possible in a potential LTC, given a fixed price for imports. However, real-world import prices may differ for varying TOP rates, as TOP rates influence the financial reliability of a project. The influence of TOP rates on LTC prices is very difficult to determine. We approach the topic by quantifying a theoretical willingness to pay a price premium on hydrogen imports at lower TOP rates from the central planner's perspective.

This premium describes the maximum additional costs per MWh of imported hydrogen that the central planner would agree to ensure a lower TOP rate. We quantify the maximum price premium by dividing the additional system costs, an increase from a lower TOP rate to a TOP rate of 100% implies, by the corresponding quantity of imported hydrogen at lower TOP rates. Therefore, the price premium shown in Figure 4 indicates the maximum willingness to pay for a shift away from a TOP rate of 100% to a lower TOP rate. To reach a state of full import flexibility (benchmark solution), the willingness to pay a price premium amounts to almost 12 EUR/MWh, or 16% of the assumed hydrogen import price. We point out that assuming a price premium at lower TOP rates may alter

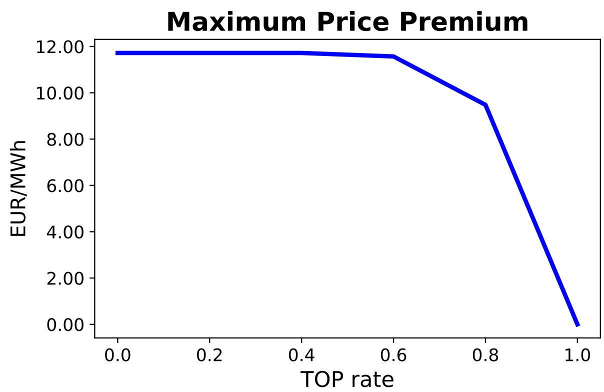

Figure (4) Maximum price premium as a function of TOP rates the equilibrium, potentially adjusting capacities to the increased import price. Therefore, the premium should be interpreted as a conservative estimate or upper bound.

4.2. Investment decisions under representative weather year

To receive a holistic overview of the effect of varying TOP rates on the European energy system, we consider eight technology categories, which are optimized for each TOP rate based on the representative weather year 1989. In the following, we refer to H2 terminal capacity as the installed capacity of aggregated European hydrogen import terminals. H2 storage capacity measures aggregate repurposed and newly built hydrogen storage volumes. H2 storage injection and withdrawal capacities describe the maximum daily inflows and outflows from hydrogen storage. Electrolysis capacity measures the installed electric capacity to produce hydrogen, whereas battery capacity measures the discharge power from batteries, and H2-to-power capacity summarizes the electric capacity of all hydrogen-fired power plants. To account for the aggregate capacity of volatile renewable energy sources, we define available wind and PV electricity as the annually available electricity from wind and solar PV before curtailment. We show the results for each technology decision as a relative change to the solution with a TOP rate of 0% in Figure 5.

With TOP rates exceeding 57%, investment decisions and thus capacities, start to deviate from the benchmark solution. This deviation can be interpreted as adjusting infrastructure investments to the restrictions imposed by the TOP rate. As all investment decisions are interdependent, all capacities change simultaneously. However, the magnitude and direction of change differ across technologies. Further, most technologies exhibit a non-linear relationship to a change in the TOP rate. Except for battery capacity and H2-to-power capacity, the technologies show a strictly increasing or decreasing slope across the TOP rates. At a TOP rate of 100%, the highest deviation compared to the benchmark solution is shown by H2 terminal capacity (- 31%), H2 storage capacity (+ 28%) and H2 injection capacity (+ 25%). Conversely, the H2-to-power capacity (+ 1.5%), available wind and PV electricity (- 1.0%), and battery capacity (+ 0.5%) exhibit the lowest relative changes at 100% TOP rate. Absolute values of investment decisions are shown in their respective units in Table C2 in the Appendix.

In a non-benchmark solution, a direct link exists between H2 terminal capacity and imported quantity via the TOP rate, as the TOP rate determines the utilization of European import terminals. We generally observe a strictly decreasing H2 terminal capacity, as the reduction of inflexible imports at higher TOP rates seems beneficial to the cost optimization. If the terminal capacity were to stay high at high TOP rates, this could cause excess imports that cannot be utilized by the European energy system or would pose significant additional storage requirements. The reduced terminal capacity (-533 GWh/d) is primarily offset by an increase in H2 storage withdrawal capacity (+485 GWh/d), whose graph shows the opposite slope of the terminal capacity.

The restricted flexibility of hydrogen imports at higher TOP rates can be partially offset by additional H2 storage volume. In this context, hydrogen storage can provide flexibility in two ways. First, with continuously high imports or high quantities of domestic hydrogen production, storage facilities absorb hydrogen in periods of excess supply. This enables a temporal shift in structuring the hydrogen import profile and can reduce the amount of otherwise curtailed electricity in periods with high RES yields. Second, hydrogen storage supports the supply side in periods with low RES yields or restricted hydrogen imports and high demand for hydrogen. As a result, H2 storage capacity increases with increasing TOP rates.

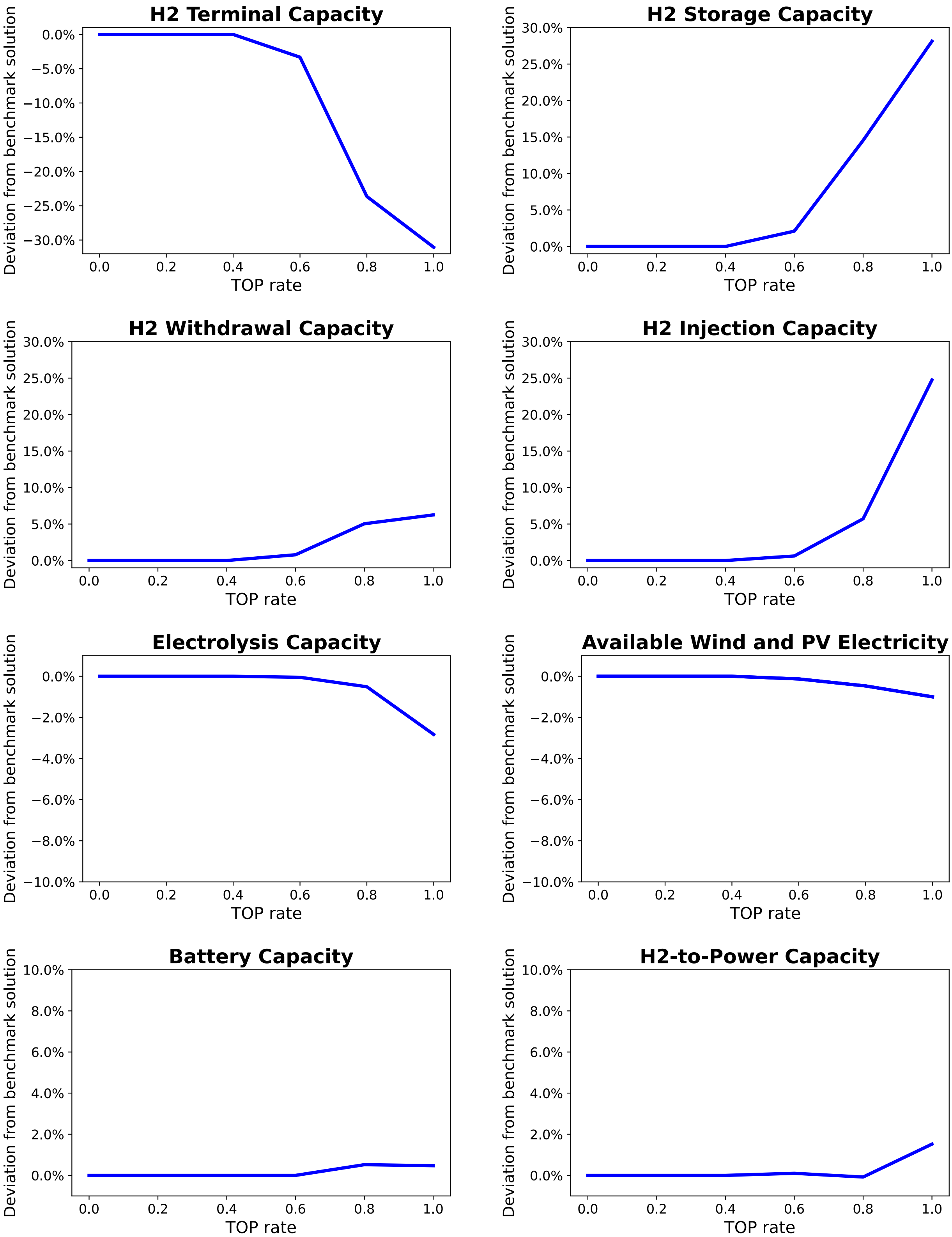

Figure (5) Relative change in investment decisions as a function of TOP rates

Despite a decrease in H2 terminal capacity, the imported quantity of hydrogen increases with higher TOP rates, as the obligation on terminal utilization outweighs the decrease in terminal capacity. As a result, there is a lower need for European hydrogen generation via electrolysis and volatile renewable energy sources. Consequently, the electrolysis capacity and available wind and PV electricity slightly decrease with rising TOP rates. Concluding, in our model setting, H2 storage serves as an instrument to integrate more (inflexible) imported hydrogen at higher TOP rates.

To test the robustness of our findings, we computed investment decisions based on an alternative representative weather year. We find the year 2005 to be representative in terms of median residual load, which has been calculated with current levels of renewable capacity. The results show similar effects for varying TOP rates compared to the results under the representative weather year 1989. Whereas terminal capacity decreases for high TOP rates down to -40%, H2 storage capacity grows by almost 60% and withdrawal capacity by 15%. Shifts in the electricity sector are ambiguous, but the magnitude of shifts is marginal compared to those in the hydrogen sector.

4.3. Regional insights from investment decisions

In addition to the changes in investment decisions on an aggregated European level, the following analysis reveals insights into regional shifts in investment decisions initiated by varying TOP rates. In this analysis, we compare the relative shift imposed by a TOP rate of 100% compared to a TOP rate that does not impose additional restrictions (benchmark solutions). These shifts are shown for 26 European countries in Figure 6.

Investment decisions in European countries respond to the restriction of inflexible hydrogen imports (TOP 100%) in a way that generally leads to reduced H2 terminal capacities. The regions may expand storage capacities or rely on increased hydrogen flows via pipelines from neighboring countries. Therefore, countries with limited access to the European hydrogen grid respond strongly to declining import capacities. This is the case for the Iberian Peninsula, located in Southwestern Europe and consisting of Spain and Portugal. The shift to a TOP rate of 100% results in a 100% decline in H2 terminal capacity. The region is only connected to the European hydrogen grid via limited capacity to France. Consequently, domestic hydrogen production and subsequent storage capacities significantly increase to serve the largely self-sustaining regional energy system. Similar patterns can be observed in other poorly connected regions to the European hydrogen grid. Romania uses additional storage capacities to compensate for inflexible hydrogen imports. In Finland, expanded battery capacity is an instrument for balancing short-term fluctuations as the flexibility of H2 terminals is reduced. Central European countries, without H2 terminal capacity but high connectivity to the hydrogen grid, expand storage and injection capacities to absorb inflexible hydrogen imports from neighboring countries. These countries are mainly the Netherlands, France, and the United Kingdom. Besides, landlocked countries react to changed investment decisions in neighboring countries. For example, a more import-oriented investment at TOP 100% in Germany with increased H2 terminal capacity, higher H2 imports and less domestic H2 production capacity also leads to decreased hydrogen production in the Czech Republic and Austria. These countries are well-connected to the German hydrogen grid and therefore increase hydrogen imports from Germany. Similar behavior can be observed between Hungary and its neighbors. The regional energy system adjustments highlight the importance of closely interconnected European countries and well-functioning European domestic trade. A broadly developed European hydrogen grid enables the cross-border use of infrastructures such as high underground storage potential for hydrogen in Northwestern Europe in countries without storage facilities. Simultaneously, landlocked countries without

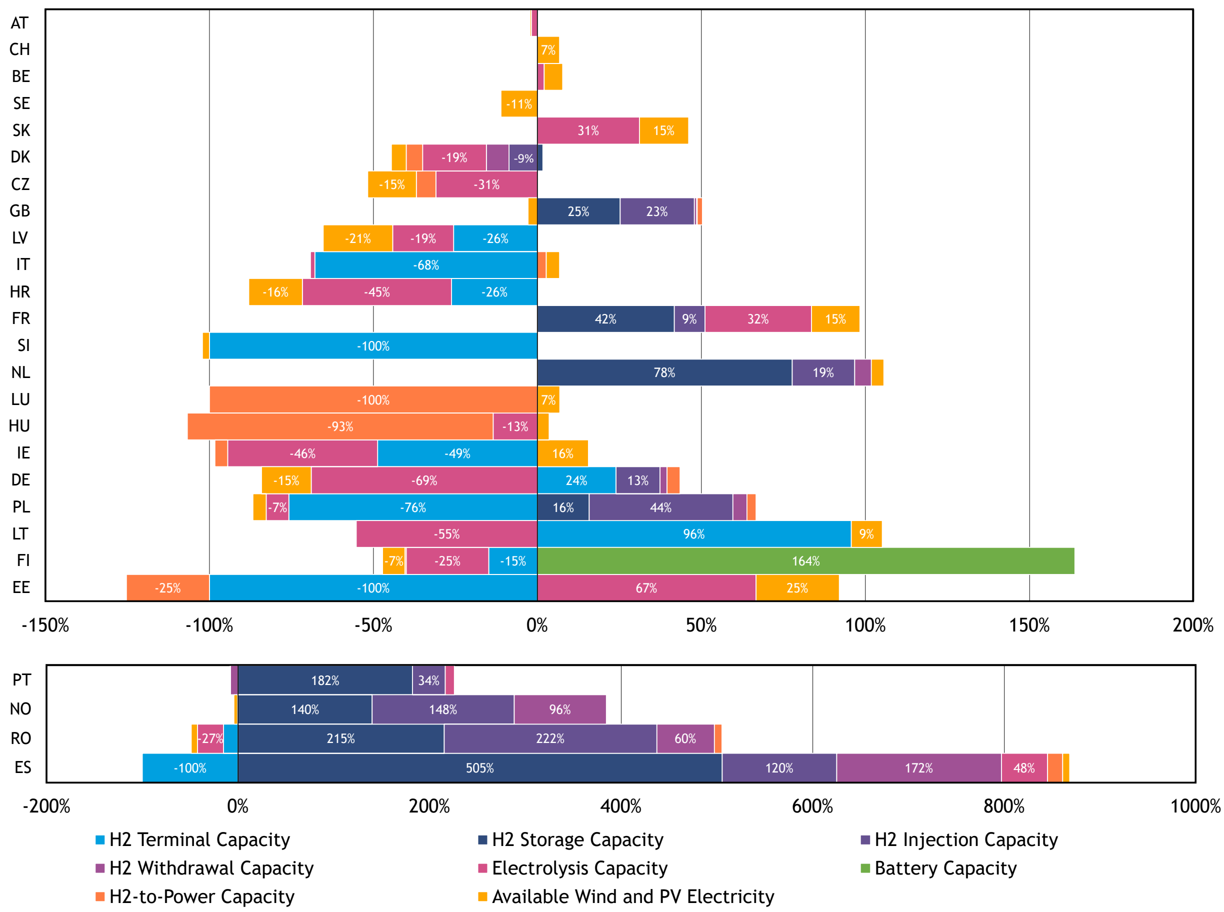

Figure (6) Regional shifts in investment decisions from 0% to 100% TOP rate the possibility of importing hydrogen via ship are not independent of a shift in the TOP rate. To limit future system costs in these cases, our findings can be relevant to hydrogen infrastructure planning and investment authorities.

4.4. Dispatch decisions under reference weather year

In this section, we analyze the dispatch decisions for the energy systems derived in Section 4.2 under higher temporal resolution, i.e., each day in the case of the hydrogen sector and each hour in the case of the power sector for the representative weather year.

Lost load is the quantity of electricity demand disrupted by the model due to capacity constraints. Since the combined investment and dispatch decision have been computed with a lower temporal resolution, the lost load in the dispatch simulation with a high temporal resolution indicates the methodological error of the temporal resolution. Given any TOP rate, the lost load resulting from the dispatch decision is smaller than 0.13 TWh across Europe implying a rather small methodological error via temporal resolution. However, we find small differences between the TOP rates: Assuming no TOP obligation, we observe a lost load of 0.10 TWh across Europe, while it increases up to 0.13 TWh due to limited flexibility in cases of very high TOP rates.

The quantity of imported hydrogen from non-European countries directly results from terminal capacity and the assumption of the TOP rate in the individual solutions. In benchmark solutions (TOP rates below 57%), the TOP rate is not restrictive, and the imported quantity always amounts to 346 TWh. Despite a constant decrease in European H2 terminal capacity for higher TOP rates, the imported quantity increases. This comes as the relative decline in capacity is not as steep as the underlying increase in the TOP rate. More generally, optimization faces a trade-off between the value of flexibility and energy imports. Although a TOP rate of 100% implies no flexibility from H2 terminals, the imported hydrogen rises by 86 TWh (+ 25%).

The operation of H2 storage sites yields insights into how the limited flexibility in cases of high TOP rates is balanced. We show above that a decrease in the flexibility of hydrogen imports imposed by higher TOP rates is partially balanced by an increase in storage capacity. However, the storage cycle, i.e., when to inject or withdraw hydrogen, is only marginally affected by a variation in the TOP rate. This cycle characteristic can be observed not only for the reference weather year 1989 but for all weather years considered for the dispatch decisions. To illustrate an exemplary hydrogen storage cycle, Figure 7 depicts the aggregate daily hydrogen storage level for the reference weather year 1989, considering a TOP rate of 0% and 100%, respectively, as well as the corresponding daily demand and supply of hydrogen. Concerning the profile of non-European hydrogen imports, the graph with 100% TOP rate (right) highlights the inflexibility of the offtake agreement. Conversely, without this obligation (left), imports are reduced whenever electrolysis via renewables is abundant.

Irrespective of the underlying TOP rate, we can derive a characteristic for the operation of hydrogen storage in a climate-neutral European energy system. Unlike today's natural gas storage, our results do not show a strong seasonality in the operation of hydrogen storage. Considering an aggregated European H2 storage capacity of 81 TWh in case of a 100% TOP rate, a total of 350 TWh of hydrogen is injected and withdrawn from storage facilities in Europe during the year. This corresponds to a number of 4.3 full cycles within the investigated year, compared to approximately one full cycle, which is typically observed for

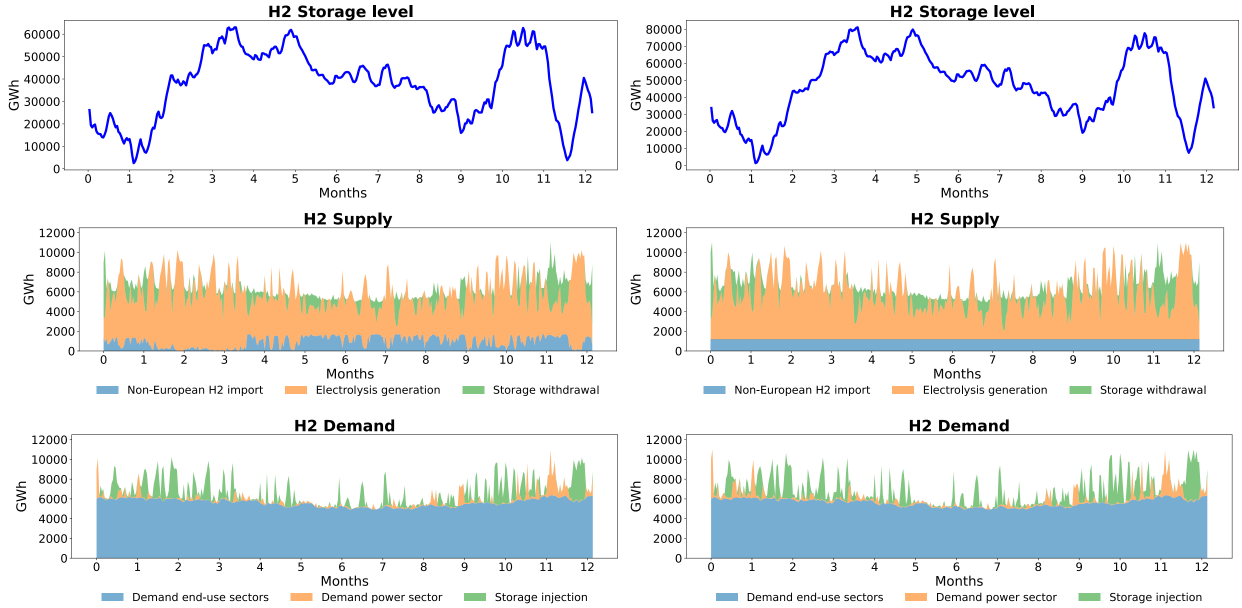

Figure (7) Aggregated European storage levels and H2 demand and supply profiles for the reference weather year 1989 and TOP rates of 0% (left) and 100% (right)

today's natural gas storage facilities. Therefore, our results indicate a more dynamic operation of the storage facilities, which do cover seasonal imbalances stemming from heating and serve to cover short-durational supply shortages stemming from the availability of renewable energies. This is underlined by high withdrawal ramps, e.g., in November. Here, the low availability of renewables leads to significant hydrogen demand from the power sector, which is covered primarily by storage withdrawal. To cover this load ramp, the withdrawal capacity is sized accordingly. In the case of a 100% TOP rate, up to 10% of the total storage capacity can be withdrawn within one day. In contrast, the dynamic operation of storage facilities also results from absorbing hydrogen in periods of excess electricity supply from renewable energies utilized by electrolysis. This can be observed by high injection ramps, e.g., in February, March, and December. The findings of non-seasonal storage cycles could be relevant for future hydrogen grid operators and storage operators to consider in their asset requirements.

4.5. Dispatch decisions under 35 weather years

In this section, we analyze the robustness of the energy systems planned under a representative weather year against weather variability. We compute the dispatch decisions for each of the energy systems planned with TOP rates between 0% and 100% for a set of 35 weather years and summarize key results in Figure 8. Here, each box plot represents the distribution, spread, and skewness of annual dispatch volumes across all weather years considered [5].

[5]The box plots include the middle 50% of annual dispatch volumes across all weather years in a box to represent the interquartile range between the upper and lower quartile, the median marked with a horizontal line, and the averages marked with a cross. Outside the box, the upper and lower whiskers mark the maximum and minimum dispatch volumes if no outliers (marked by points outside the whiskers) exist. Otherwise, they represent the highest and lowest values within the distance of 1.5 times the interquartile range from the upper or lower quartile.

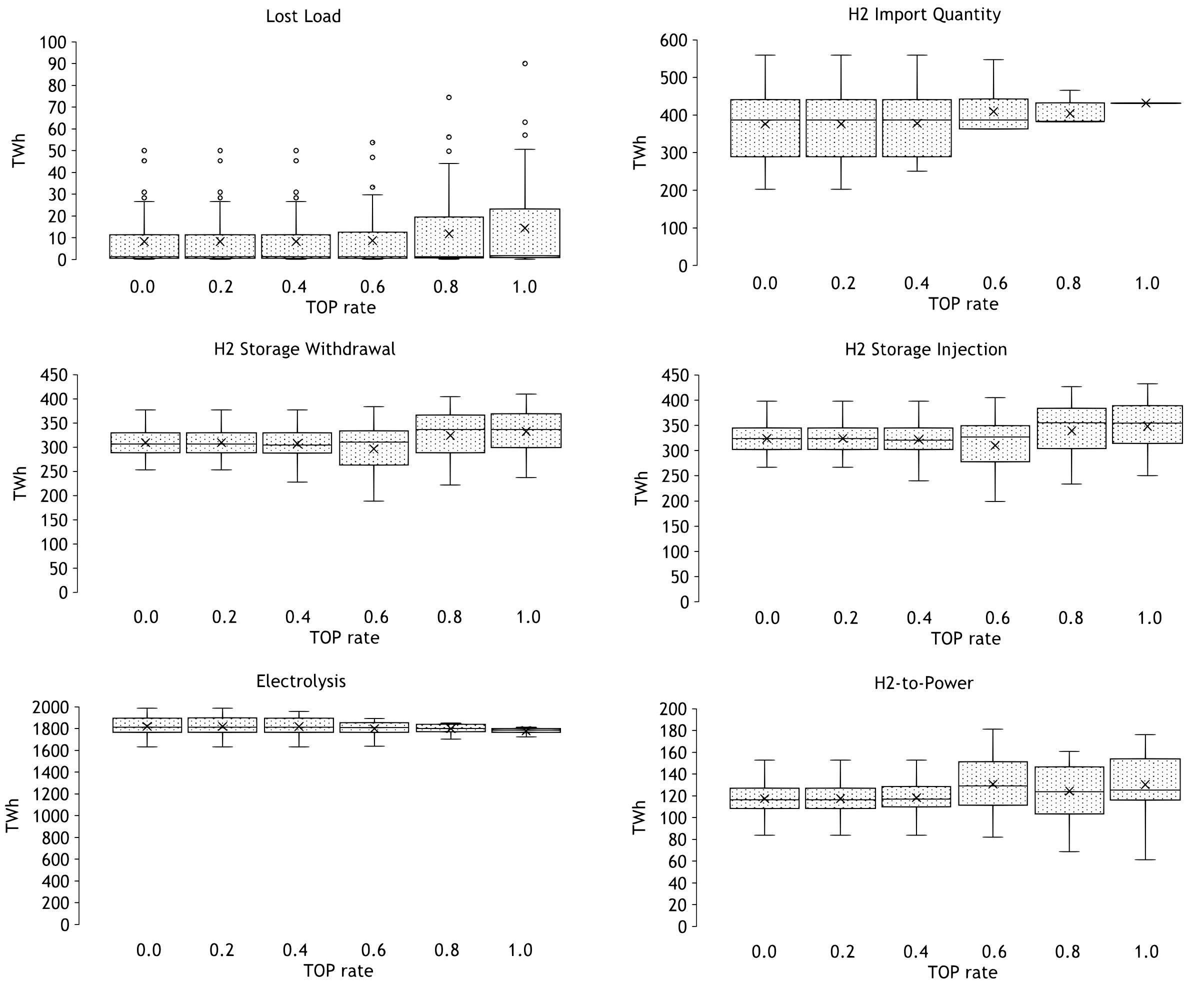

Figure (8) System response to variability of 35 weather years

The lost load we observe in certain weather years occurs since the energy system was planned under a representative weather year, which does not incorporate extreme events such as cold dark lulls. The lost load in benchmark solutions amounts to 8 TWh on average across the 35 weather years and 50 TWh in the most critical weather year 2010 [6]. Notably, the reliability of energy systems decreases with increasing TOP rates, as aggregated lost load rises to a maximum of 90 TWh (2010) and an average of 14 TWh in the case of a 100% TOP rate. Despite higher storage capacity, the reduced flexibility of H2 terminal capacity at high TOP rates prevents an adjustment of the corresponding energy system to weather variability. High

[6]In multiple months, 2010 is characterized by below-average full-load hours for onshore and offshore wind across many European countries. In January, February, and December 2010, wind onshore and offshore utilization were up to 40% below the long-term average of all investigated weather years in Central and Northern European countries. Simultaneously, PV exhibits an availability below average compared to the long-term average during the summer months across Europe, exceptionally sharp in May (-27% on a monthly average). Further, the weather year 2010 shows a four-week cold spell starting at the end of January, with temperatures dropping ten degrees Celsius below the continent-wide average, increasing hydrogen demand. Electricity demand from end-use sectors in the weather year 2010 turns out to be almost 2% higher than the annual average of weather years under investigation.

costs associated with lost load cause the system with the highest TOP rate to also imply the highest total dispatch costs. Together with the elevated investment costs (cf. Section 4.2), this again underlines the importance of accounting for the degree of flexibility in hydrogen imports.

Considering a TOP rate of 0%, the average H2 import quantity is 376 TWh, while the spread resulting from all weather years considered amounts to 356 TWh. For low TOP rates, the inherent flexibility provided by H2 terminals is used to adjust to weather vagaries. Notably, the results for a TOP rate of 40% already start to deviate from the benchmark solutions. This implies that an average utilization of European terminals below the previously determined 57% seems favorable in some weather years. With TOP rates exceeding 40%, H2 import quantities significantly narrow up to a TOP rate of 100% without any flexibility remaining. Here, the imported quantity in every weather year amounts to 432 TWh, implying that mainly European storage facilities are posed to balance inter-annual weather variability.

As a result, the spreads for annual storage withdrawal volumes are generally higher for higher TOP rates. While the difference between minimum and maximum annual storage withdrawal is 123 TWh for a TOP rate of 0%, it grows to around 172 TWh in the case of a 100% TOP rate. In line with the slightly higher withdrawal capacity for a TOP rate of 100%, the average annual withdrawal volume (332 TWh) is slightly higher than in the benchmark solutions (310 TWh). For storage injection, the spreads of annual injected hydrogen volumes show characteristics over all TOP rates similar to storage withdrawal.

Conversely, average annual hydrogen production via electrolysis decreases with increasing TOP rates, as its underlying capacity has decreased in the investment decision. Moreover, its utilization shows a higher variance for benchmark solutions than in the case of high TOP rates. Among other reasons, this originates from altered RES capacities for higher TOP rates implying lower inter-annual variability in surplus electricity, which can be utilized by electrolysis.

Lastly, increasing TOP rates impact the annual hydrogen quantity provided to the electricity system by H2-to-power plants. On average, the hydrogen used for H2-to-power increases slightly between the benchmark solution (117 TWh) and a 100% TOP rate (130 TWh). Among others, this results from increased hydrogen import volumes at higher TOP rates, also utilized for reconversion in the electricity system. Considering minimum and maximum H2-to-power quantities among 35 weather years, the spread increases significantly from 69 TWh at 0% TOP rate to 130 TWh at 100% TOP rate.

Besides the annual dispatch volumes across all weather years, our results also reveal insights into how flexibility is provided throughout the year for the energy system under varying TOP rates. We illustrate this in Figure 9 by showing sorted utilization curves of H2 terminal capacity for selected TOP rates. With increasing TOP rates, the installed terminal capacity is fully utilized more frequently compared to the utilization of the benchmark solutions. Consequently, a TOP rate of 100%, characterized by a constant, non-flexible import of hydrogen, results in fully utilized import capacities throughout the year under all weather years. Conversely, the highest flexibility can be exploited at low TOP rates, i.e., in the range of the cost-optimal benchmark solutions. Here, the operation of H2 terminals adjusts to weather variability, resulting in significant inter-annual deviations in utilization and thus, import quantities. Despite this flexibility inhibits a higher system value, it may pose challenges to the economic operation of H2 terminals since asset owners typically strive for non-volatile cash flows.

According to our results above, the reduced flexibility of hydrogen imports imposed by higher TOP rates is mainly compensated by adjusted capacity levels of the investment decisions (cf. Section 4.2). Hydrogen

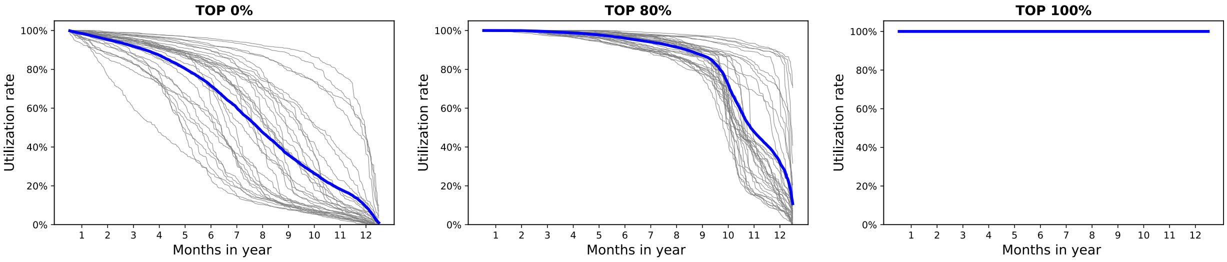

Figure (9) Sorted H2 terminal utilization for selected TOP rates on average (blue) and for all underlying weather years (grey)

storage facilities, as the most important flexibility alternative to H2 terminals, exhibit similar utilization curves at all TOP rates, with utilization increasing or decreasing slightly depending on the weather conditions as the TOP rate increases. Additionally, decreasing flexibility from hydrogen imports is partially substituted with increasing utilization of the European hydrogen grid, represented in this study through repurposed gas interconnector capacities (cf. Section 3.). The average hydrogen grid utilization for the benchmark solutions is 45%. With decreasing flexibility from H2 terminal capacity, intra-European hydrogen transport via pipelines increases, on average, by 2.5% at a TOP rate of 100%. Although this is not a particularly large increase on average, grid utilization deviates by up to +15% or -14% at a TOP rate of 100% depending on the weather year. Despite the exogenous representation of transmission capacity in our model, the flexibility of hydrogen imports, has an impact on the utilization of the European hydrogen grid. Therefore, further research with endogenous determination of transmission capacities may be required for the economic planning of a future European hydrogen grid.

5. Discussion

The following section summarizes and discusses the key findings of this work. Further, we reflect upon central limitations of the modeling, and suggest opportunities for future research.

5.1. Key findings and implications

We investigate the effect of TOP rate clauses as part of hydrogen LTCs on a future decarbonized European energy system under weather variability. The analysis is conducted with the integrated hydrogen and electricity market model HYEBRID. Using a representative weather year for investment decisions, we employ six equidistant TOP rates between 0% and 100% to analyze the impact of hydrogen import flexibility on the European asset configuration. Subsequently, we conduct a 'stress test', simulating dispatch decisions for 35 weather years for each of the six energy systems. This enables investigating the operational aspects of TOP rates under weather variability. To our knowledge, this is the first publication with an explicit representation of TOP rates in hydrogen LTCs.

Our results show that changing the underlying TOP rate significantly impacts the optimal configuration of the European energy system. With higher TOP rates, total system costs increase, as high TOP rates impose inflexibility on the import of hydrogen. This is balanced by an alternative configuration of other technologies, primarily hydrogen storage. For investment decisions based on the reference weather year 1989, we observe a convex cost curve, indicating the importance of avoiding very high TOP rates for importers given a fixed price for hydrogen. At a TOP rate of 100%, system costs increase by 0.77%, representing a substantial absolute contribution to the energy system costs. Conversely, TOP rates up to 57% do not impose further restrictions, and therefore no additional system costs occur. By calculating a theoretical maximum willingness to pay a price premium for hydrogen import flexibility, we provide an indication for the system value of the flexibility implied by lower TOP rates. We find a price premium of 12 EUR/MWh for LTCs without minimum offtake obligation to be indifferent from LTCs without price premium and total inflexibility in imports. Based on our analysis, future research could improve calculating the value of hydrogen import flexibility, which could provide Europe with guidance and orientation when negotiating LTCs with exporters.

A further important finding is that varying TOP rates induce significant shifts in cost-minimal infrastructure requirements of the energy system. The equilibrium resulting from each TOP rate provides insights into how reduced flexibility from hydrogen imports can be balanced cost-efficiently. A prominent example is more hydrogen storage and withdrawal capacity and less terminal capacity at high TOP rates. These changes highlight the critical need to address the flexibility of hydrogen imports when planning the future energy system. Moreover, this finding suggests existing publications could be biased by neglecting this issue.

This work also contributes to the existing body of literature by calculating European hydrogen storage requirements under consideration of imports. Our results exhibit a hydrogen storage capacity between 63 TWh and 81 TWh depending on the TOP rate. Comparing our results to the literature, which exhibits a range of required hydrogen storage capacity between 45 TWh and 240 TWh, our results can be assigned to the lower range of this spectrum, although some publications showing high storage capacities do not allow for hydrogen imports. Unlike other publications, we model hydrogen storage injection withdrawal capacity independent of storage volume, showing that their capacity requirements are linked to the hydrogen demand from the power sector and supply from domestic hydrogen production. This representation enables a cost-efficient trade-off between hydrogen supply from storage, import and electrolysis. Another key distinction to existing studies is the assumed costs of storage. While the Long-term scenarios 3 (Sensfuß et al., 2024) adopts a value of 550 EUR/MWh for newly built storage, this work assumes 1454 EUR/MWh. Lastly, the underlying weather characteristics play a central role in the investment decision. Our analysis is based on a representative weather year, whereas Long-term scenarios 3 assumes the weather year of 2010, which we characterize as an extreme year with a cold dark lull in the dispatch analysis.

In addition, we calculate hydrogen import volumes between 203 TWh and 559 TWh, which can be assigned to the middle range of existing research. Similar to hydrogen storage, the determination of import quantities relies on underlying costs, weather and research framework.

Irrespective of the underlying TOP rates, our findings reveal that the operational characteristics of future hydrogen storage may differ from today's natural gas storage. Instead of a definite seasonal profile, hydrogen storage is also used for short- to midterm balancing with multiple full cycles a year, particularly to bridge hydrogen demand peaks from the power sector and to absorb excess hydrogen from domestic production in periods of excess electricity supply from renewables. The characteristic of high withdrawal and injection ramps, which we observe for all 35 weather years, can yield valuable insights into the requirements of future hydrogen storage operations. However, the finding differs from existing publications such as Kondziella et al. (2023), Schlund (2023) and Sensfuß et al. (2024), which use a different model framework and mostly find a seasonal profile for hydrogen storage use. In contrast to our approach, Kondziella et al. (2023) assumes exogenous RES implicitly imposing a seasonality in electricity generation, and Schlund (2023) lacks a representation of an integrated hydrogen and electricity market. Sensfuß et al. (2024) only find non-seasonal storage requirements during earlier stages of the hydrogen market ramp-up, while seasonal profiles result under increased storage costs as the energy system approaches climate neutrality. The most similar to our finding is Junge et al. (2022), who found a partially non-seasonal operation of hydrogen storage. Nonetheless, we point out that the degree of hydrogen use for heating may alter the operational characteristic.

The response of the six energy systems planned under representative weather year to weather variability shows significant inter-annual spreads. As extreme events are not considered in the planning stage, the results reveal significant quantities of lost load in the electricity sector. We observe a rise in the maximum lost load from about 50 TWh in the case of low TOP rates up to 90 TWh if a TOP rate of 100% applies. Although our approach does not consider weather variability in the planning stage, our analysis highlights that reserve requirements are generally higher when flexibility from hydrogen imports is absent and future weather is unknown. If, different from our approach, future LTCs do not include TOP rates, or hydrogen is imported via a potentially emerging spot market, we point out the significance of inter-annual variance in import quantities, which should be considered in the economic assessment of H2 terminals.

Beyond that, a regional analysis reveals insights into adjustments at a national level. Countries with limited access to the European hydrogen grid show a rather self-sustaining regional system at high TOP rates, while well-connected countries gain benefits from the cross-border use of infrastructure such as neighboring storage facilities. In addition, landlocked countries react indirectly to varying TOP rates by adapting their energy systems to the shifts in neighboring countries. The findings point to the relevance of establishing a European hydrogen grid, similar to suggestions by Schlund (2023), to facilitate intra-European hydrogen trading, utilize regional infrastructure potential across borders and thus increase security of supply and limit additional costs for infrastructure investments. Since higher TOP rates indicate an increased need for regional transport capacities in a European hydrogen grid, further research could focus on the endogenous determination of regional transport capacities, taking import flexibility into account.

5.2. Limitations and future research

Our work contains certain limitations that should be interpreted in light of important assumptions and limitations of the model framework. General assumptions include perfect foresight, complete markets, and inelastic demand. The future degree of price responsiveness for both electricity and hydrogen demand could affect the degree to which flexibility must be provided on the supply side to ensure a reliable energy system.

Another important assumption is the cost level for infrastructure investment and the price level for hydrogen imports. Due to the model formulation, cost assumptions are not linked to the capacities resulting from the model, i.e., there is no representation for effects such as technological learning like in Seck et al. (2022). A change in the cost assumption could alter the configuration of the energy system. Nevertheless, the overall effect of varying flexibility of hydrogen imports via TOP rates would not change fundamentally. The fixed price assumption for hydrogen imports, irrespective of the underlying TOP rate, as stated in Section 3, may not hold in reality due to the lower risk for the exporter's investment at higher TOP rates. The degree to which the import price might change for different TOP rates is subject to the risk profile and risk aversion of the exporter and is difficult to quantify. Indeed, a TOP rate-dependent import price would alter the system costs curve, making it a relevant topic for future research. With our analysis of the maximum willingness to pay for import flexibility, we take a first step in this direction. Apart from this, we do not account for a potentially emerging spot market for seaborne hydrogen. Further, the assumption of a fixed import price could be affected by assuming an elastic supply curve for hydrogen imports and by taking into account short- and long-term fluctuations in hydrogen supply, e.g. due to weather variability in the exporting region, leaving room for further research.

In addition, our approach does not consider technologies such as thermal power plants with carbon capture and storage (CCS) or direct air capture (DAC). The political ambiguity surrounding CCS and the underlying cost assumptions for DAC induce uncertainty. However, a representation of these could alter the demand for hydrogen and renewable generation capacity but the effect of TOP rates on the energy system is not set to change fundamentally. In addition, we abstract from non-European import via pipeline and focus on seaborne imports instead. Despite cost levels largely differ between H2 terminals and pipelines, the concept of TOP rates is transferable to pipelines. Again, the overall effect of import flexibility should not change.

Lastly, an important limitation is the representation of weather and weather variability. We exclusively consider historical weather patterns. However, future weather can differ from historical characteristics due to climate change and impact infrastructure requirements (cf. Peter (2019)). Regarding the methodology, our approach assumes a single weather year in the investment stage without allowing for lost load. Subsequently, we analyze the implications of weather variability in the dispatch stage, allowing for electric lost load. A more adequate planning approach should account for weather variability already in the investment stage, which results in more robust energy system configurations. Despite this limitation, our two-step approach highlights the following: If the assumption on future weather is not precise, i.e., real weather differs from assumed weather, the energy system with a higher TOP rate turns out to be less reliable. Nonetheless, future research could investigate the effect of TOP rates using advanced methods such as multi-year models (cf. Ruhnau and Qvist (2022)), stochastic models or heuristic methods similar to Grochowicz et al. (2023). Depending on the model, researchers could also investigate the implications of risk-averse investment decisions, since our results indicate a link between the quantity of lost load and the underlying TOP rate.

6. Conclusion

Hydrogen is set to become a central commodity in a future decarbonized European energy system. Yet, a European hydrogen market, fed by domestic production and non-European imports, is still in its very early stages. To accelerate the market ramp-up, a cost-efficient implementation of hydrogen infrastructure is required, which is closely linked to the development of the power sector. Moreover, research on seaborne hydrogen impacting the European energy system is minimal, and the effect of minimum offtake agreements in LTCs on the design and operation of such infrastructure requirements still needs to be investigated.

Thus, this work seeks to shed light on the implications of TOP rates in hydrogen import LTCs on the European energy system. To answer our research questions, we developed a new integrated electricity and hydrogen market model named HYEBRID. The partial equilibrium model optimizes European electricity and hydrogen investment and dispatch decisions while accounting for hydrogen imports, domestic production, underground storage, and pipeline transport. We compute the model for six equidistant TOP rates and optimize the investment decisions of the European energy system based on a representative weather year.

To analyze the system responses to weather variability, we simulate cost-minimal dispatch decisions for a set of 35 weather years.

Our findings reveal that high TOP rates significantly impact the energy system configuration and increase total system costs. To avoid excess imports and counteract a lack of flexibility, hydrogen import terminal capacity at 100% TOP rate is 31% lower compared to a case without TOP obligation, while hydrogen storage capacity is 28% higher, respectively. In this context, hydrogen storage provides flexibility by absorbing hydrogen in periods of surplus hydrogen stemming from inflexible imports and supplying hydrogen in periods of low RES production or insufficient hydrogen imports. Despite a decrease in terminal capacity, more hydrogen imports and less domestic production follows from the increased utilization of terminals with higher TOP rates. A regional analysis of the modeling region highlights the importance of interconnected areas to a European hydrogen grid at varying TOP rates for efficient cross-border use of infrastructure such as underground storage. The energy system configuration, planned under representative weather, exhibits significant variations in dispatch quantities when being exposed to the characteristics of 35 weather years. While a system with no or low TOP rate is mostly able to adjust to weather variability, the reliability of the energy system decreases with higher TOP rates resulting in higher dispatch costs[7].

Apart from the numerical results, our analysis provides multiple real-world implications to stakeholders. The convex system costs curve underlines the importance of flexibility in hydrogen imports and advises importers to pay attention to the TOP rate in negotiations with exporters. Despite we do not differentiate import prices for varying TOP rates, we indicate the willingness to pay a premium for flexibility, which may guide stakeholders in negotiations. Nonetheless, if future seaborne suppliers insist on high TOP rates, we show that the diversity in the European technology landscape, especially hydrogen storage facilities, can offset inflexibility of imports to some degree. Given the technological shifts induced by varying TOP rates, our findings highlight the importance of accounting for the degree of import flexibility in energy system studies and suggest that most existing publications may be biased by neglecting this. With the regional analysis, we highlight the advantages of cross-border trade for higher TOP rates. Thus, European transmission system operators should explicitly address the degree of hydrogen import flexibility in their planning. Lastly, in light of the revived discussions in some European countries about capacity markets and resource adequacy in general, our findings on the altered system reliability depending on the TOP rate, is something to consider when designing future mechanisms fostering security of supply.

The presented modeling approach is the first to explicitly represent TOP obligations in hydrogen imports. However, limitations such as the deterministic nature of weather variability, a fixed price for hydrogen imports at all TOP rates, exogenous hydrogen transmission capacity, or inflexible demand leave room for further research.

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[7] The exact value for dispatch costs depends strongly on the underlying assumption for the value of lost load and is not explicitly evaluated.

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Appendix A. Appendices

A. Model sets, parameters, variables and indices

Table (A1) Model sets, parameters, variables and indices

Name	Unit	Definition
Sets		
$d \in D$		Representative days
$h \in H$		Hours
$n, m \in N$		Nodes
$tech \in Tech$		Technologies
Parameters		
η	%	Efficiency
δ	%	Losses
p	-	Price
$timesteps$	-	Number of representative days
top	%	Minimum annual utilization of aggregate European H2 terminals
Variables		
TC	tEUR	Total system costs
$OPEX$	tEUR	Variable cost
FOM	tEUR	Fixed operating and maintenance cost
$CAPEX$	tEUR	Annualized capital cost
IC	tEUR	Import cost
S	GWh	Supply
D	GWh	Demand
$TRADEBAL$	GWh	Net trade balance
I	GWh	Imports
C	GW	Capacity
ST	GWh	Storage volume
L	GWh	Uncovered demand
Indices		
IMP		Import
$STOR$		Storage
ELY		Electrolysis
EL		Electricity
$H2$		Hydrogen

B. Assumptions and inputs for energy system modeling

Table (B1) Techno-economic assumptions as inputs for energy system model

Technology	Parameter	Unit	Value	Reference
H2 storage capacity	CAPEX - New	tEUR/GWh	1,454	[1,2,3,4,5]
	CAPEX - Retrofit	tEUR/GWh	727	[1,2,3,4,5,6]
	OPEX	tEUR/GWh	6.03	[1,2,5,7,8]
	FOM	% of CAPEX/a	4	[1,8]
	Conversion factor H2/CH4	%	20	[9,10]
	Round-trip efficiency	%	90	[11]
	Lifetime	a	33	[12]
H2 storage injection & withdrawal capacity	CAPEX - New	tEUR/GWh/d	3,841	[1]
H2 pipeline	Conversion factor H2/CH4	%	75	[13]
	Losses	%	1	
H2 import terminal	CAPEX - New	tEUR/GWh/d	14,447	[14]
	OPEX	tEUR/GWh/d	included in IC	[14]
	FOM	% of CAPEX/a	2.5	[14]
	Lifetime	a	33	Assumption
Electrolysis	CAPEX	tEUR/GW	392,243	[15]
	FOM	tEUR/GW	10,000	[6]
	Efficiency	%	74	
	Lifetime	a	25	
Battery	CAPEX	tEUR/GW	384,626	[15]
	FOM	tEUR/GW	13,100	[6]
	Efficiency	%	90	
	Lifetime	a	10	
Wind onshore	CAPEX	tEUR/GW	1,117,000	[6]
	FOM	tEUR/GW	13,140	[6]
	Efficiency	%	100	
	Lifetime	a	25	
Wind offshore	CAPEX	tEUR/GW	2,036,000	[6]
	FOM	tEUR/GW	26,280	[6]
	Efficiency	%	100	
	Lifetime	a	25	

Table (B1) Techno-economic assumptions as inputs for energy system model

Technology	Parameter	Unit	Value	Reference
Photovoltaics	CAPEX	tEUR/GW	682,000	[6]
	FOM	tEUR/GW	9,330	[6]
	Efficiency	%	100	
	Lifetime	a	25	
H2-to-power CCGT	CAPEX	tEUR/GW	762,000	[6]
	FOM	tEUR/GW	26,000	[6]
	Efficiency	%	60	
	Lifetime	a	30	
H2-to-power OCGT	CAPEX	tEUR/GW	412,000	[6]
	FOM	tEUR/GW	7,400	[6]
	Efficiency	%	40	
	Lifetime	a	30	

Table references:

[1] van Gessel and Hajibeygi (2023), [2] for Energy. et al. (2021), [3] Bünger et al. (2016), [4] Lord et al. (2014), [5] DEA (2022), [6] ENTSOE and ENTSOG (2022), [7], Yousefi et al. (2023), [8] Noack et al. (2015), [9] Bültemeier et al. (2022), [10] NWR (2021), [11] Tsiklios et al. (2023), [12] Schlund (2023), [13] Galyas et al. (2023), [14] Moritz et al. (2023), [15] IEA (2023)

Table (C2) Investments decisions under varying TOP rates for the reference weather year 1989

Technology category	Unit	TOP 0%	TOP 20%	TOP 40%	TOP 60%	TOP 80%	TOP 100%
H2 Terminal Capacity	GWh/d	1716	1716	1716	1659	1310	1183
H2 Storage Capacity	TWh	63.4	63.4	63.4	64.7	72.6	81.2
H2 Withdrawal Capacity	GWh/d	7758	7758	7758	7819	8149	8243
H2 Injection Capacity	GWh/d	4284	4284	4284	4311	4529	5344
Electrolysis Capacity	GW	617	617	617	617	614	600
Available Wind and PV Electricity	TWh	5577	5577	5577	5570	5551	5521
Battery Capacity	GW	43.7	43.7	43.7	43.7	43.9	43.9
H2-to-Power Capacity	GW	188	188	188	188	187	190