Pan-European Wholesale Electricity Market

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Executive Summary

The present deliverable was developed as part of the research activities of the TradeRES project **Task 5.4 – Performance assessment of current and new market designs and trading mechanisms for Pan-European electricity Markets**. This report present the final version of deliverable 5.4, which provides an assessment of the performance of the future electricity market under different scenario assumptions and market design bundles developed in the project's work packages 2 and 3. The assessment is performed quantitatively using market performance indicators (MPIs) to address specific research questions of the project, all identified within work package 5. The analyses were conducted using the optimization framework Backbone, implemented in the workflow and scenario manager Spine Toolbox – tools that were advanced within work package 4 of this project.

The focus of the Pan-European case study is to identify drivers of **market prices and profitability** of variable renewables (vREs) in different scenarios of the future Pan-European short-term electricity wholesale market. Particularly, the study explores characteristics of fully decarbonized European electricity markets resulting from the optimization of four main scenarios that vary in terms of three scenario dimensions: (i) the degree of coupling of the hydrogen and power sector, (ii) the level of demand-side flexibility of the personal traffic and building heat sector, and (iii) the market penetration of vREs. The main scenarios range from a **conservative** scenario representing a vision of the future power system with moderate levels of vRE market penetration, demand-side flexibility and hydrogen sector-coupling to a **radical** vision with high levels of these three characteristics. To identify the impact of each scenario dimension on market dynamics and price formation as well as profits and costs of different market actors, further scenarios are optimized that vary each scenario dimension in an isolated manner. Furthermore, the impact of varying levels of cross-border transmission capacities are studied.

The key findings indicate that opposed to common belief, prices in future electricity markets frequently exceed variable renewables' low variable costs. Particularly, electricity prices are shown to continue to rely on fuel prices. In contrast to today's markets, their impact can also result from cross-sectoral demand setting the price at the level of opportunity costs from electricity consumption. Particularly, electrolyzers can become a major price-setting technology in future electricity markets. Other flexible demand from the building heat and personal transport sector is shown to reduce curtailment and load shedding. However, prices vary substantially across scenarios. While flexible demand can mitigate price risks, investors in variable renewables and inflexible consumers of electricity are found to be exposed to significant price risks.

Therefore, this study also examines a mechanism to mitigate these price risks. Particularly, different design options of governmental **Contracts for Difference (CfDs)** are evaluated in scenarios of a fully decarbonized European electricity market. The government is assumed to issue CfDs to wind onshore power plants that stipulate payments between the contract parties defined by the difference in an ex ante determined strike price and an ex post realized reference market price. The considered design options of CfDs differ in terms of the definition of the reference price, its unit (kW or kWh) and the allowed direction of payments.

This case study's findings indicate that the different incentives set by these design options affect curtailment, electrolyzer activity and market prices in the future electricity market. Consequently, ex post realized CfD payments differ from ex ante expectations used to define strike prices. Therefore, the results also highlight that wind onshore power plants subject to CfDs do not necessarily recover exactly 100% of their costs. The studied cases suggest that CfD designs that include more market-oriented elements expose investors to a higher risk of not recovering their costs.

Overall, the results of the Pan-European case study shows that the current electricity market design is generally suitable for the future electricity market as it can result in efficient price signals. However, this only holds true under certain conditions, i.e. perfectly competitive markets for all energy carriers with a perfectly integrated flexible demand-side. While resulting price levels exceed variable renewables' low cost in a substantial number of hours, exact levels are uncertain and depend on the realization of these conditions. Consequently, market actors are exposed to significant price risks and are likely to require instruments to mitigate these risks. Contracts for Difference constitute such an instrument. Their design should be chosen carefully as it has important implications for market outcomes and investor risks.

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1 Introduction

1.1 Description of the work package and deliverable

[WP5]: *In this work package, the models and simulation tools developed in WP4 will be used to assess the performance of the new market designs and products obtained in WP3. The test cases will emulate the future power systems of European countries that were selected for their physical differences. The test cases will also encompass different system scales and typologies. The energy mix and characteristics that result from WP2 will be used as a benchmark. This work package will show the strengths and weaknesses of the proposed market designs. This information will be fed back to WP3, where the designs will be improved, until the market performance is close enough to the benchmark. This work package will also provide an indication of the price levels in different countries and different scenarios.*

[D5.4]: *Performance assessment of current and new market designs and trading mechanisms for a Pan-European wholesale electricity market (Case Study E)*

In this report, the performance of a reference Pan-European wholesale electricity will be presented and deeply analysed, as well as its performance in light of the new market designs.

1.2 Structure of the deliverable

The present deliverable's main goal is to evaluate the market performance of the TradeRES scenarios developed in work package 2 and market designs proposed in work package 3 for the pan-European scale using the tools developed in work package 4. First, this deliverable analyzes drivers of market prices, profits and costs in scenarios of fully decarbonized European electricity markets. Second, different design options of Contracts for Difference (CfDs) are evaluated in scenarios of future electricity markets.

This deliverable is structured as follows: Section 2 describes the research questions of this case study and lays out the approach pursued to answer these questions. It describes scenarios, our modelling infrastructure and the indicators applied to evaluate the market designs' performances. In Section 3, we present and discuss our results. Section 4 concludes.

2 Research questions and methodology

This section first outlines the research questions addressed by this case study. Second, the applied methodology is presented. Particularly, we describe the applied energy system model, our scenarios and the market performance indicators used to evaluate model outcomes.

2.1 Research Questions

The TradeRES project addresses a wide range of market design topics. The current European electricity market design and its challenges with regards to decarbonization were laid out in this project's work package 3, which this work package builds upon. Within the overall work package 5, specific research questions to be addressed by the TradeRES' case studies and models were clustered and identified. In total, seven main themes were identified by the project:

1. Improvement of short-term markets
2. Incentivizing distributed flexibility and local markets
3. Incentivizing demand response and sector coupling
4. System design and adequacy
5. Investment incentives for renewables (RES) and for secure capacities
6. Investment incentives for renewables
7. Investment incentives for secure capacities

Table 1 presents the research questions covered by the Pan-European case study.

Table 1. TradeRES research questions covered by this case study

Cluster	Research question to be addressed by TradeRES models and simulations	Perspective / Time frame
system design and adequacy	What are the drivers of future electricity market prices?	system perspective / long and short term
system design and adequacy	What is the impact of thermal capacity on the power market?	system and investor perspective / long and short term
incentivizing demand response and sector coupling	What is the impact of sector-coupling and flexible players on the demand-side on the power market?	system and investor perspective / long and short term
system design and adequacy	What is the impact of different levels of transmission capacity on the power market? What are the implications for further European market harmonization?	system perspective / long and short term
investment incentives for renewables	Are RES remuneration schemes needed and if so, how should they be designed?	RES investors / long term and short term

2.2 Method

This case study applies an optimization model of a fully decarbonized European power system that is coupled with the industrial hydrogen, personal road traffic and building heat sector. First, the model's geographical and technological scope is outlined. Second, optimization workflow and the scenarios are described. Finally, the market performance indicators used to evaluate model results are presented.

2.2.1 Geographical and technological scope

The model's geographical scope comprises all EU27-countries except for Malta, but including Great Britain, Switzerland and Norway. It includes one bidding zone per country or aggregated countries, i.e., Luxembourg and Germany, the Baltics (covering Lithuania, Latvia and Estonia) and Balkans (covering Hungary, Romania, Bulgaria, Slovakia, Slovenia, Greece, Cyprus and Croatia) resulting in a total of 19 considered bidding zones (cf. Figure 1). In the following, the terms "bidding zone" and "countries" are used interchangeably.

The model represents a power system coupled to the industrial hydrogen (H_2), the personal road traffic and building heat sector. On the **power supply** side, it allows the implementation of a policy target for a certain share of annual electricity demand to be covered by variable, non-thermal renewables. These include onshore and offshore wind, utility-scale and rooftop solar photovoltaics (PV), concentrating solar power (CSP), run-of-river (ROR) hydro and storage injections by batteries, reservoir and pumped hydro[1]. Remaining electricity demand is supplied by carbon-free thermal power plants, namely, biofuel, waste, nuclear or H_2 combined cycle or open cycle gas turbines (named CCGTs or OCGTs, respectively).

The **industrial H_2 sector** consist of a substantial amount of exogenous hydrogen demand. There exist two options to cover this demand: (i) endogenously built electrolysers that are able to store H_2 in newly invested long-term storages or (ii) imports for a constant price from outside Europe. **Personal road traffic** is represented by consumption and charging station connectivity time series of electric vehicle units. The data originates from the open-source tool ChaProEV [1] and is based on Europe's current car fleet [2]. While a fraction of electric vehicles' demand is represented by a static electricity load profile, another fraction is charged flexibly in the model. Particularly, this fraction is charged at lowest electricity prices within their limited storage and charging capacities. Similarly, a fraction of **heating and cooling demands for buildings** follow static electricity load profiles, while another fraction is modelled endogenously using the building model by Rasku [3] with data from the EU building stock observatory [4]. The model ensures cost-minimal operation of these flexible electric heat pumps with exogenous capacities and temperature-dependent coefficients of performance (COPs), while keeping temperatures in buildings within acceptable limits. Heat can be stored by using the building envelope's thermal storage capability and domestic hot water tanks. Furthermore, the model has the option to meet heat demand with fuel boilers

[1] Following [24], the constraint includes storage electricity charge in annual electricity demand used to calculate the enforced generation share of variable, non-thermal renewables in order to avoid storage cycling. Furthermore, existing thermal power generation capacities are reduced by 25% to make room for additional vRE capacities in the scenarios with this share exceeding 95% by constraint.

using synthetic methane for a price of 200 €/MWh during hours with high electricity prices. The model also includes load shedding of industrial electricity demand as well as involuntary load shedding at the European market's current maximum price of 4000 €/MWh [5]. All technologies represented in our model as well as its structure are depicted on the left side of Figure 1, where a “grid” refers to a group of bidding zones of the same energy carrier or sector. Bidding zones within the H_2 and power grid are connected via exogenous transmission lines that are presented on the right side of Figure 1. In contrast, bidding zones within the electric vehicle (EV) and heat grid are not connected. A more detailed description of the model scope can be found in Johanndeiter et al. [6].

As a result, the model covers a wide geographical, technological scope allowing to analyze dynamics in a future sector-coupled European power market in absence of CO_2-emitting technologies. Particularly, it enables to assess price formation in future power markets and consequences for the profitability of investments in variable renewables and electrolyzers. Furthermore, costs of energy consumption in different sectors can be calculated, which provides important insights for the design of the future power market. However, this case study does not use the model to assess security of supply in the future power market. Hence, the result of this case study cannot be used to draw conclusion on market designs targeting security of supply.

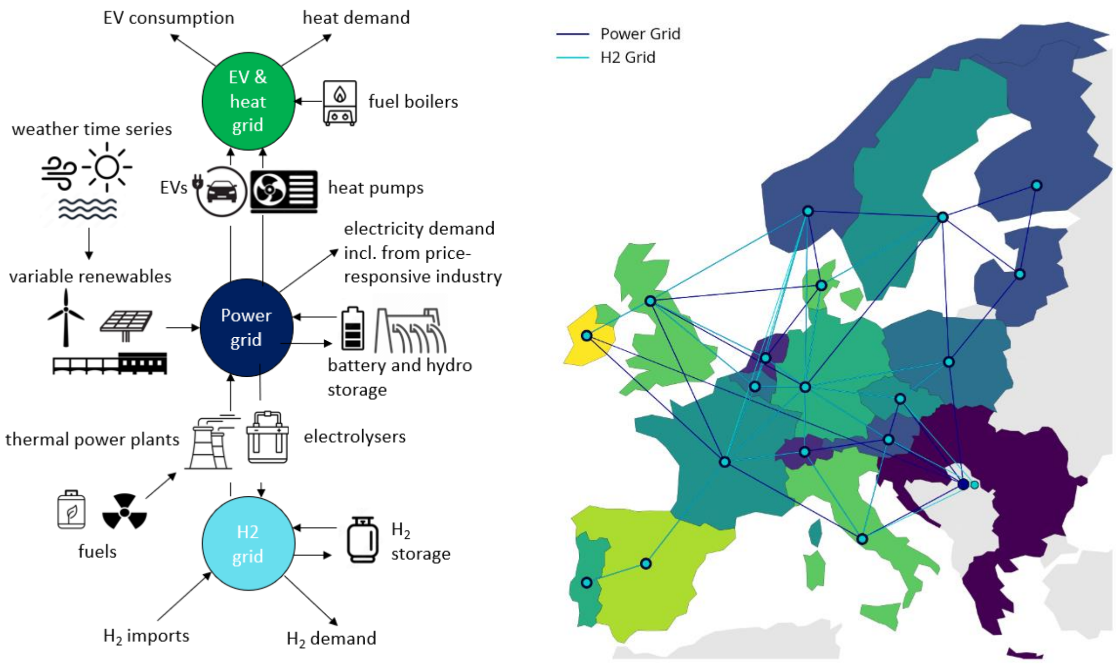

Figure 1. Technological and geographical scope of our energy system model.

2.2.2 Energy system model and workflow

The scenarios in this case study are optimized using the modelling framework Backbone. Backbone is a generic bottom-up energy system optimization tool. It can be used to optimize both investment and dispatch and is highly adaptable in different temporal, spatial and technological dimensions. Backbone minimizes an objective function that sums investment and operational costs over the model horizon and is formulated as a mixed-integer linear program. A detailed description of Backbone can be found in Deliverable 2.2 and Helistö et al. [7].

The workflow applied to transform TradeRES scenario data into Backbone input data was integrated into the open-source workflow and scenario manager Spine Toolbox[2] [8]. Furthermore, we implemented a soft-linking methodology of a cost-minimizing investment optimization followed by an operational optimization in linear programming (LP) mode. The investment optimization is conducted using samples of five typical and three extreme weeks used to represent a full year and under the constraint that a certain share of variable, non-thermal electricity generation covers electricity demand. The operation of exogenous brownfield and new capacities resulting from the investment phase is optimized for a full year applying a rolling horizon approach. It sequentially optimizes 24-hour-long blocks in hourly resolution with the remaining 364 days modelled at an increasingly coarser. The applied workflow is represented in Figure 2. Soft-linking methodology. and described in more detail in Helistö et al. [9].

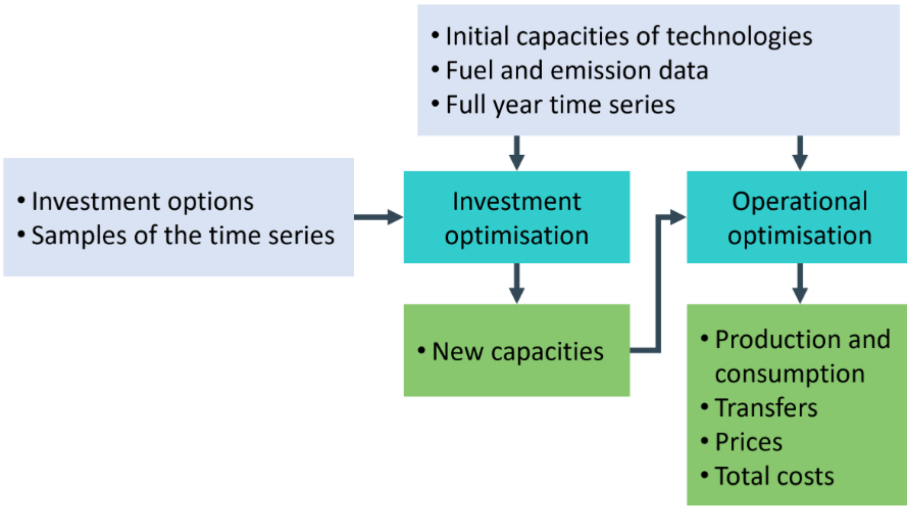

Figure 2. Soft-linking methodology. Adapted from [9].

Assuming our model to represent a perfectly competitive short-term market, we interpret the dual variables of the operational optimization's energy balance constraint as short-term market prices. Due to our soft-linking methodology, they differ from dual variables resulting from the investment phase. By construction, the operational optimization does not account for investment costs, it does not consider a constraint on electricity demand to be covered by certain technologies and it optimizes the full year with a rolling-horizon approach. Consequently, unlike in standard perfect foresight linear programming cost minimization problems (cf. [10]), new capacities within this approach do not necessarily generate exactly zero profits. Besides computational advantages, this method reflects a short-term equilibrium in a competitive electricity market with policy targets and imperfect foresight. Particularly, the

[2] Spine Toolbox public repository: https://github.com/spine-tools/Spine-Toolbox}{https://github.com/spine-tools/Spine-Toolbox, TradeRES-Backbone-Project public repository: https://github.com/TradeRES/TradeRES-Backbone-demo}{https://github.com/TradeRES/TradeRES-Backbone-demo

rolling-horizon approach represents more realistic operational conditions, especially for long-term storage.

2.2.3 Scenarios

The model is used to optimize several scenarios of a carbon-free, sector-coupled European power system. “Scenario” within TradeRES refers to a structured input data collection that characterizes the properties of the underlying future power system. The complete input dataset used in this case study originates from the TradeRES database, whose full set of assumptions and sources are publicly available as Deliverable 2.1 (D2.1)3. All considered scenarios start from a brownfield energy system, scenario S0, representing an intermediate power system on the path to decarbonization (cf. Figure 3). It considers exogenous electricity generation capacities based on 2030 national estimates and plans. They congruently assume all fossil power plants to be decommissioned and allow for endogenous investments in additional carbon-free electricity generation capacities[4] to meet 2050 demand projections of all modelled sectors. Investments are limited according to natural potentials and cost projections reflect the year 2050. All load and capacity factor time series reflect the weather year 2019.

TradeRES scenarios vary three key factors that are particularly interesting from a market design perspective as they are likely to influence market prices: (i) the share of variable, non-thermal electricity generation relative to annual electricity demand, (ii) the degree of coupling between the hydrogen (H_2) and power sectors, and (iii) the level of price responsiveness in electric vehicle and building heat demand. The first dimension is implemented by enforcing a certain share of non-thermal variable renewables to cover annual electricity demand by constraint. The degree of sector-coupling is varied by means of an assumption of the import price of H_2 from outside Europe. A higher price makes domestic H_2 production more attractive and hence, increases the degree of coupling between the power and H_2 sector. Demand-side flexibility is implemented by varying the fraction of electric vehicles and heat pumps that can respond to market prices. As a result, final energy demand is constant across all scenarios, while it differs in terms of its degree of flexibility (of electric vehicles and heat pumps) and substitutability (of heat and H_2).

2.2.3.1 Main TradeRES scenarios

First, this case study analyses TradeRES’ four main scenarios, abbreviated with S1, S2, S3 and S4 (cf. Figure 4). The first scenario (**S1**) is a **conservative** scenario, characterized by moderate levels of sector-coupling and flexibility of the demand-side and a moderate level of variability of the supply-side. This is ensured by allowing only ~50% electric vehicles (EVs) to be applied in a flexible manner and by assuming a rather low price of 45 €/MWh for non-European hydrogen imports. On the supply-side, variability is moderate as we allow only 85% of electricity demand to be covered by variable, non-thermal electricity generation, such that 15% are covered by dispatchable thermal power plants. In a **flexible** scenario (**S2**), the demand-side also becomes more flexible by modelling all electric vehicles to be

[3] 10.5281/zenodo.10692697

[4] Cost projections reflect the year 2050 and all monetary values are expressed in 2020€.

operated in a price-responsive manner. Additionally, heat pumps (HPs) are complemented by fuel boilers and the H_2 import price is raised to 117 €/MWh. In contrast, demand-side flexibility and sector-coupling are kept moderate in a scenario **S3**, which is called **variable**, as it is driven by the variability of the supply-side. Particularly, the share of variable, non-thermal electricity generation of annual demand is enforced to exceed 95% by constraint. Finally, this variable electricity supply meets a high degree of demand-side flexibility and sector-coupling in a **radical** scenario (**S4**) representing the most fundamental changes of today's power system. Furthermore, for S1 and S4, sensitivities of power transmission capacities are considered. Particularly, scenarios denoted **transfer-** reduce all cross-border capacities by 50%, while scenarios denoted **transfer+** increases them by 50%. Results of these scenarios are discussed in Section 3.1.

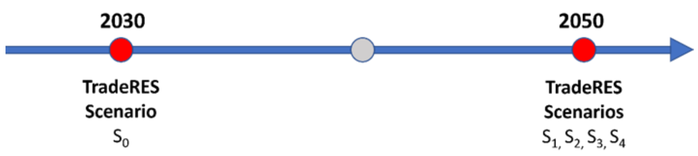

Figure 3. Allocation of TradeRES main scenarios on the timeline

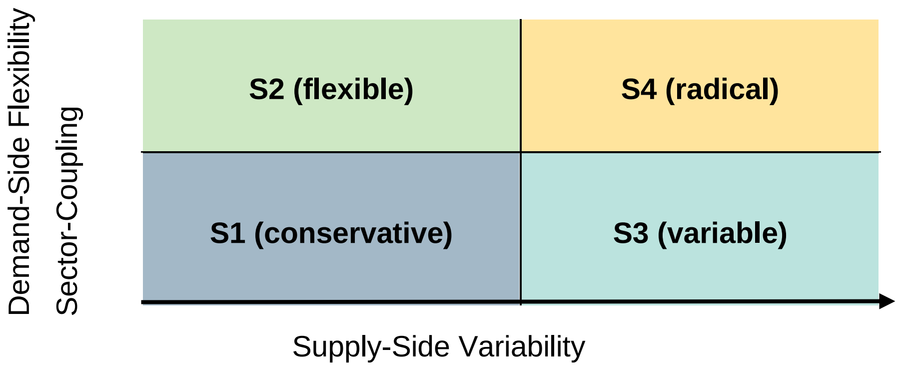

Figure 4. TradeRES main scenarios

Table 2: Overview of varying assumptions of TradeRES main scenarios including sensitivities

	con-servative (S1)	flexible (S2)	variable (S3)	radical (S4)	S1 transfer-	S1 transfer+	S4 transfer-	S4 transfer+
vRE Share	85%	85%	≥95%	≥95%	85%	85%	≥95%	≥95%
EVs	50% flexible	100% flexible	50% flexible	100% flexible	50% flexible	50% flexible	100% flexible	100% flexible
HPs	100% flexible	100% flexible + fuel boilers	100% flexible	100% flexible + fuel boilers	100% flexible	100% flexible	100% flexible + fuel boilers	100% flexible + fuel boilers
H_2 Price	45 €/MWh	117 €/MWh	45 €/MWh	117 €/MWh	45 €/MWh	45 €/MWh	117 €/MWh	117 €/MWh
Transmission capacities	2050 assumptions	2050 assumptions	2050 assumptions	2050 assumptions	-50% per line	+50% per line	-50% per line	+50% per line

2.2.3.2 Isolated changes of scenarios

Second, further variations of the three scenario dimensions are analyzed to identify drivers of market prices and intersectoral distributional effects in future power markets. Particularly, each of the three dimensions is varied separately to capture its effect in an isolated manner. The analysis starts from a **Base** scenario, which reflects a particularly variable and inflexible scenario. It resembles the variable scenario **S3**, but with an even lower demand-side flexibility as all electric vehicles (EV) and heat pumps (HP) are assumed to be inflexible. We define three further scenarios, each varying one dimension of the Base scenario: In a scenario named **vRE↓**, the enforced variable, non-thermal share of electricity generation (vRE share) is decreased to study the impact of thermal power supply. In a scenario **H2Price↑**, the H_2 import price is increased to assess the impact of sector-coupling in an isolated manner. Finally, the impact of demand-side flexibility can be evaluated by enabling all EVs and HPs to be deployed in a flexible manner in a scenario named Flex. Table 3 provides an overview of the scenarios, whose results are discussed in Section 3.2.

2.2.3.3 Contracts for Difference for wind onshore

Third, this case study analyzes different market design bundles. Particularly, we evaluate the impact of four different design options of Contracts for Difference (cf. Deliverable 3.5.)

for wind onshore power plants in the future European power market. Particularly, we consider another variation of the variable scenario S3, which for this analysis is called **target** scenario. In contrast to S3, all electric vehicles are flexible, while all heat pumps are inflexible. Importantly, the scenario distinguishes two types of wind onshore power plants per bidding zone (cf. Table 3). They are distinct in terms of their capacity factor time series, which can relate to the location or hub height of a wind power plants – variables that have been shown to be influenced by support schemes ([11], [12], [13], [14]). Particularly interesting for the analysis of CfD design is to contrast one wind type per bidding zone named *High FLH* that is characterized by relatively high full load hours, but a relatively low market value, while another type, named *High MV,* has the opposite characteristics. We assume costs to be uniform for all new wind power plants, such that wind type *High FLH* incurs lower LCOE than type *High MV*. In contrast, *High MV*'s higher market value indicates this type to be more system-friendly as it is more correlated to residual load [15]. First, investment and dispatch in this **target** scenario are optimized. Second, subsidy payments under four different types of CfDs are introduced to the model.

Table 3: Overview of varying assumptions of TradeRES scenarios to study isolated scenario changes and CfDs

	Base	**vRE↓**	**H_2Price↑**	**Flex**	**target**
vRE share	≥95%	85%	≥95%	≥95%	≥95%
EVs	static	static	static	100% flexible	100% flexible
HPs	static	static	static	100% flexible + fuel boilers	static
H_2 Price	45 €/MWh	45 €/MWh	117 €/MWh	45 €/MWh	45 €/MWh
Wind onshore type	1 per bidding zone (BZ)	1 per BZ	1 per BZ	1 per BZ	2 per BZ

Generally, CfDs specify payments from the government to a generator of renewable electricity. Different types of CfDs are distinguished by the definition of these payments. For our analysis, we formally define annual profits, $\Pi_{i,n}$ of a power plant of technology $i \in \{1,2,\ldots,I\}$ in bidding zone $n \in N$ under a CfD as

$$\Pi_{i,n} = \sum_{t=1}^{T} (q_{t,i,n} p_{t,n}) - C_{i,n} + P_{i,n}^{\text{type}},$$

with $q_{t,i,n}$ denoting power sold by power plant i in hour $t \in 1,2,\ldots,T$ with T =8760 for price $p_{t,n}$ in bidding zone n's wholesale electricity market and annual costs, $C_{i,n}$. The latter include variable costs c and investment costs M per installed capacity $Q_{i,n}$ and are annualized with annuity factor A, such that $C_{i,n} = \sum_{t=1}^{T} cq_{t,i,n} + A \cdot M \cdot Q_{i,n}$. $\mathrm{P}_{\mathrm{I,n}}^{\mathrm{type}}$ denote annual net payments with $\mathrm{type} \in \{\mathrm{basic,1way,2way,fin}\}$, representing the four types of CfDs considered by our analysis and the contracts' durations assumed to be equal to the power plant's economic lifetime D.

Payments are generally defined by the difference of a power-plant-individual strike price, $S_{i,n}^{\text{type}}$ and a reference market price, $p_n^{\mathrm{R,type}}$, which is uniform in each bidding zone n. The reference market price is determined ex post, whereas the strike price is agreed upon ex ante. We consider three volume-based CfDs, i.e. payments depend on the electricity sold in the wholesale market. We define a **basic** CfD as a CfD type with the reference price being equal to the hourly market price, i.e.,$p_n^{\mathrm{R,basic}} = p_{t,n}$, such that payments are given by

$$P_{i,n}^{\text{basic}} = \sum_{t=1}^{T} q_{t,i,n} \left(S_{i,n}^{\text{basic}} - p_{t,n} \right).$$

In contrast, reference prices of the volume-based **1way** and **2way** CfD are defined by the market value v_n, of all new wind onshore power plants in bidding zone n, i.e.,

$$p_n^{\mathrm{R,1way}} = p_n^{\mathrm{R,2way}} = v_n \equiv \frac{\sum_{t=1}^{T} \sum_{i=1}^{I} q_{t,i,n} \; p_{t,n}}{\sum_{t=1}^{T} \sum_{i=1}^{I} q_{t,i,n}}.$$

We name a CfD with this reference price **2way** CfD, if it stipulates both positive and negative net payments, such that

$$P_{i,n}^{\mathrm{2way}} = \sum_{t=1}^{T} q_{t,i,n} \left(S_{i,n}^{\mathrm{2way}} - v_n \right).$$

We denominate it *1way* CfD, if only positive net payments are allowed:

$$P_{i,n}^{\mathrm{1way}} = \sum_{t=1}^{T} q_{t,i,n} \max\{0, S_{i,n}^{\mathrm{1way}} - v_n\}.$$

Finally, we consider the *financial* CfD as proposed by Schlecht et al. [16], where net payments are independent of a power plant's volume produced. Specifically, the authors suggest a fixed hourly payment, $S_{i,n}^{\mathrm{fin}}$, in exchange for paying the revenues of a reference power plant, r_n. We define r_n as total market revenues of new wind power plants in a bidding zone and normalize them by installed capacity, i.e.,

$$r_n = \frac{\sum_{t=1}^{T} \sum_{i=1}^{I} q_{t,i,n} \; p_{t,n}}{\sum_{i=1}^{I} Q_{i,n}}.$$

Accordingly, we define the strike price by installed capacity instead of electricity sold, such that payment are given by

$$P_{i,n}^{\mathrm{fin}} = Q_{i,n} \left(S_{i,n}^{\mathrm{fin}} - r_n^{\mathrm{fin}} \right).$$

Finally, CfD payments of all types are not limited to hours with non-negative wholesale market prices.

We assume all CfDs to be awarded to a target level of new wind onshore capacity within zonal pay-as-bid auctions for the CfDs' underlying strike price. We derive optimal strike prices $S_{i,n}^{\mathrm{type}}$ for power plant i for each $\mathrm{type} \in \{\mathrm{basic,1way,2way,fin}\}$ under the following simplifying assumptions:

- The auction is perfectly competitive.
- Investors are rational, risk-neutral and have perfect foresight.

- They expect hourly prices $p_{t,n}$, and power sales, $q_{t,i,n}$ to equal to the target scenario results in each year of $D > 0$ years of economic lifetime, which equals the contract duration.

Hence, investors choose strike prices, such that their profits are equal to zero.

Under the **basic** CfD and with $\sum_{t=1}^{T} q_{t,i,n}$>0, the optimal strike price $S_{i,n}^{\text{basic}}$ is given by

$$D \cdot \Pi_{i,n} = D \cdot \sum_{t=1}^{T} \left(q_{t,i,n}\, p_{t,n} + q_{t,i,n} \left(S_{i,n}^{\text{basic}} - p_{t,n} \right) \right) - D \cdot C_{i,n} = 0$$

$$\Leftrightarrow S_{i,n}^{\text{basic}} = \frac{C_{i,n}}{\sum_{t=1}^{T} q_{t,i,n}} \equiv \mathrm{lcoe}_{i,n}$$

This implies that under a **basic** CfD a power plant's revenues eventually equal the strike price times its power sales, such that the resulting optimal strike price is equal to power-plant-specific levelized cost of electricity (LCOE) as it ensures cost-recovery over lifetime. Consequently, within the auction, **basic** CfDs are typically awarded to power plants with the lowest LCOE. Under our assumptions these are power plants with a high number of full load hours, i.e. type *High FLH*. However, power plants with higher market values, i.e. type *High MV,* typically induce lower system integration costs [15]. The market value, $v_{i,n}$, of power plant i in bidding zone n is defined as its generation-weighted average market revenue (cf. [17]):

$$v_{i,n} = \frac{\sum_{t=1}^{T} q_{t,i,n}\, p_{t,n}}{\sum_{t=1}^{T} q_{t,i,n}}.$$

By design, individual market values are not considered by power plants that are subject to a **basic** CfD, while they matter under **1way** and **2way** CfDs according to our definition. This can be seen when deriving optimal strike prices under these types of CfDs, $S_{i,n}^{\text{2way}} = S_{i,n}^{\text{1way}} \equiv S_{i,n}^{\text{way}}$:

$$D \cdot \Pi_{i,n} = D \cdot \sum_{t=1}^{T} \left(q_{t,i,n} p_{t,n} + q_{t,i,n} \left(S_{i,n}^{\text{way}} - v_n \right) \right) - D \cdot C_{i,n} = 0$$

$$\Leftrightarrow S_{i,n}^{\text{way}} = \frac{C_{i,n}}{\sum_{t=1}^{T} q_{t,i,n}} + v_n - \frac{\sum_{t=1}^{T} q_{t,i,n}\, p_{t,n}}{\sum_{t=1}^{T} q_{t,i,n}} = \mathrm{lcoe}_{i,n} + v_n - v_{i,n}$$

The equation shows that those investors that expect their own market value $v_{i,n}$ to be above the bidding zone's average, v_n, which is also the reference price, accept a strike price lower than their LCOE and vice versa. Similarly, the **financial** CfD allows investors to keep individual market revenues above those of the reference power plant – yet, both are defined by capacity and not volume. Therefore, their optimal strike price $S_{i,n}^{\text{fin}}$, defined by installed capacity $Q_{i,n}$, which is assumed to be strictly positive, is given by:

$$D \cdot \Pi_{i,n} = D \cdot \sum_{t=1}^{T} (q_{t,i,n} p_{t,n}) + D \cdot (Q_{i,n}(S_{i,n}^{\text{fin}} - r_n) - C_{i,n}) = 0 \Leftrightarrow S_{i,n}^{\text{fin}}$$

$$= \frac{C_{i,n}}{Q_{i,n}} + r_n - \frac{\sum_{t=1}^{T} q_{t,i,n} p_{t,n}}{Q_{i,n}} = \frac{C_{i,n}}{Q_{i,n}} + r_n - r_{i,n}$$

with power plant i, n's market revenues by installed capacity defined as

$$r_{i,n} = \frac{\sum_{t=1}^{T} q_{t,i,n}\, p_{t,n}}{Q_{i,n}}.$$

Therefore, in theory, the **1way**, **2way** and **financial** CfD lead to more system-friendly investments than the **basic** CfD. Additionally, the definition of CfD payments also has implications for their dispatch decisions. Particularly, volume-based CfDs have been shown to distort dispatch decisions. **Basic** CfDs set the incentive to `produce and forget', i.e. to maximize power generation regardless of current market prices. Conversely, power plants under power plants subject to the other three types of CfDs only dispatch if market prices are above their short-term variable costs. For the **financial** CfD they merely reflect operation and maintenance costs, such that dispatch under this type of CfD is efficient. However, under a **1way** and **2way** CfD, short-term variable costs artificially depend on expected payments per electricity sold, constituting so-called virtual variable costs. Therefore, in theory, only the **financial** CfD is subject to neither investment nor dispatch distortions [16]. Under the assumption that investors expect market outcomes according to the target scenario, we calculate expected CfD payments. Particularly, we use the **target** scenario results to determine power-plant-specific parameters required to calculate the above-derived strike prices. Furthermore, we add a uniform risk premium ρ to the strike price to account for the possibility that ex post resulting payments deviate from ex ante expectations used to calculate the strike price. As a result, expected annual net payments for a wind onshore power plant of technology $i \in \{\text{High FLH}, \text{High MV}\}$ in n by type of CfDs are given by with target scenario outcomes denoted by superscript *:

- Basic CfD: $\sum_{t=1}^{T} q_{t,i,n}^{*}\left(S_{i,n}^{\text{basic}}\rho - p_{t,n}^{*}\right) = \sum_{t=1}^{T} q_{t,i,n}^{*}\left(\text{lcoe}_{i,n}^{*}\rho - p_{t,n}^{*}\right)$
- 2way CfD: $\sum_{t=1}^{T} q_{t,i,n}^{*}\left(S_{i,n}^{\text{way}}\rho - v_{n}\right) = \sum_{t=1}^{T} q_{t,i,n}^{*}(\text{lcoe}_{i,n}^{*} + v_{n}^{*} - v_{i,n}^{*})\rho - v_{n}^{*})$
- 1way CfD: $\sum_{t=1}^{T} q_{t,i,n}^{*} max\{S_{i,n}^{\text{way}}\rho - v_{n}^{*}, 0\} = \sum_{t=1}^{T} q_{t,i,n}^{*}(max\{\text{lcoe}_{i,n}^{*} + v_{n}^{*} - v_{i,n}^{*}, 0\}\rho - v_{n}^{*})$
- Financial CfD: $Q_{i,n}^{*}(S_{i,n}^{\text{fin}}\rho - r_{n}^{*}) = Q_{i,n}^{*}((\frac{C_{t,i,n}}{Q_{i,n}^{*}} + r_{n}^{*} - r_{i,n}^{*})\rho - r_{n}^{*})$

We use these expected payments to implement CfDs in our model. Particularly, expected volume-based net payments, are deducted from (added to if negative) the technical variable costs of wind onshore for the **1way** and **2way** CfD. To mimic the `produce and forget' strategy for the **basic** CfD scenario, we set variable costs to the minimum market price in this scenario, which is equal to 0. For the **basic** and **financial** CfD, we manipulate investment costs according to their expected net payments per capacity installed.

We implement the capacity target of the auction by restricting the sum of new wind onshore capacities in each bidding zone to **target** scenario results for capacities. Furthermore, we remove the constraint on the vRE generation share and fix solar and wind offshore capacities to target scenario capacities. Results of this analysis are presented in Section 3.3. Further details on theoretical considerations and our modelling approach can be found in a publication that is currently under review [18].

2.2.4 Market performance indicators

For all scenarios, this case study compares the installed electricity generation and electrolyzer capacities, the resulting generation and consumption mix by bidding zone. The results are also compared in terms of a selection of TradeRES market performance indicators (cf. Table 4) that are defined Deliverable 5.1. Furthermore, we calculate load cost factors of different technologies and average cost of final energy consumption by sector as defined in [6].

Table 4: List of TradeRES Market Performance Indicators covered in this case study

MPI number	MPI description
8	Load Shedding
17	Annual curtailment of market-based energy of vRES
26	Total system costs
27	Total costs for dispatch
29	Annual volume-weighted average of hourly day-ahead market price
31	vRES support schemes costs
32	Market-based cost recovery
33	Yearly price convergence between market zones
41	Volatility of electricity prices

3 Results

The optimization results of all scenarios considered by this case study are first characterized in terms of their composition and level of electricity supply and demand. Second, economic market performance indicators are analysed to draw conclusions on possible future market dynamics. The optimization results are interpreted as market outcomes. Realized investments are assumed to represent investor decisions made based on expectations that reflect the scenario assumptions. Hence, they not only represent investor expectations on fuel prices, technology costs, demand levels and weather conditions, but also their expectations on policies targeting the relevance of thermal power and demand-side flexibilities.

3.1 Main scenarios (S1-S4)

This section characterises the modelling results of TradeRES' four main scenarios of carbon-free, sector-coupled future European power systems, S1-S4.

3.1.1 System characterization

All four scenarios are dominated by electricity generation from variable renewables, i.e., solar and wind power, complemented by batteries, hydro power and thermal renewables. Figure 5 depicts installed electricity generation capacities aggregated over all bidding zones by scenario and contrasts them with initial brownfield capacities of S0. Figure 6, Figure 7 and Figure 8 show corresponding electricity generation, consumption and curtailment, respectively. Table 5 shows total electricity traded aggregated over Europe. Generally, the differences in results reflect the scenario variations:

- **S1:** Amounting to less than 3,000 GW, total electricity generation capacities are lowest in the **conservative** scenario due to two main reasons. One the one hand, with 5,500 TWh, electricity consumption is lowest in this scenario, since a large share of energy consumption, namely industrial H_2 consumption, is covered by non-European imports (cf. Figure 35). On the other hand, there is a moderate expansion of variable renewable and battery capacities due to the enforced high share of thermal power. Thermal power is mainly provided by gas turbines fuelled with low-cost H_2 imports, followed by biofuel and waste.
- **S2:** While higher demand-side flexibility in the **flexible** scenario significantly decreases battery capacities, total installed electricity generation capacities increase to approximately 4,800 GW. This result is mainly driven by the higher H_2 import price, which causes an increase in H_2 production by electrolysers using European electricity generation, predominantly from low-variable-cost variable renewables. The higher fuel price for H_2 turbines additionally causes nuclear to become the dominant source of thermal power. Furthermore, the induced demand-side flexibility causes load shedding and total transmitted electricity to decrease in this scenario.
- **S3:** By constraint, there are more variable renewable electricity generation capacities in the **variable** scenario. The lower share of thermal power is substituted by a significant increase in battery capacities. However, absolute curtailment (in TWh) significantly increases in this scenario due to a relatively low demand-side flexibility.

- **S4:** The **radical** scenario requires the largest amount of capacity expansion due to the high degree of sector-coupling combined with a higher share of variable, non-thermal renewables. Despite the significant amount of electrolyser capacities and demand-side flexibility, absolute curtailment (in TWh) increases in this scenario. Yet, required battery capacities and transmitted electricity are lower than in S3.

The isolated effects of each varying scenario dimension are discussed in detail in Section 3.2.

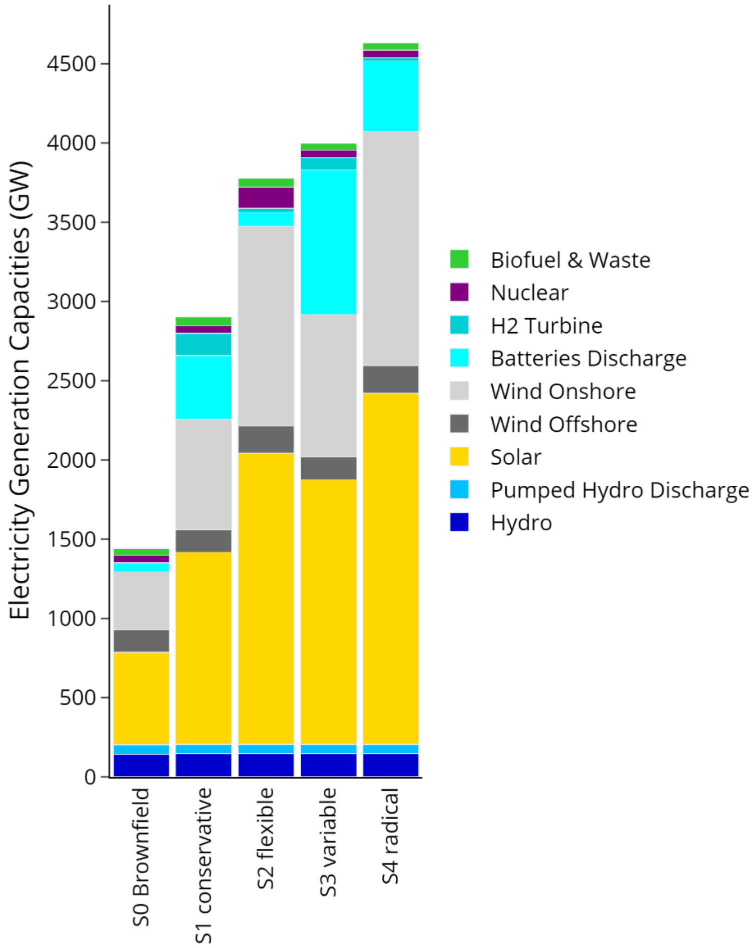

Figure 5. Total installed electricity generation capacities by technology and scenario aggregated over all bidding zones

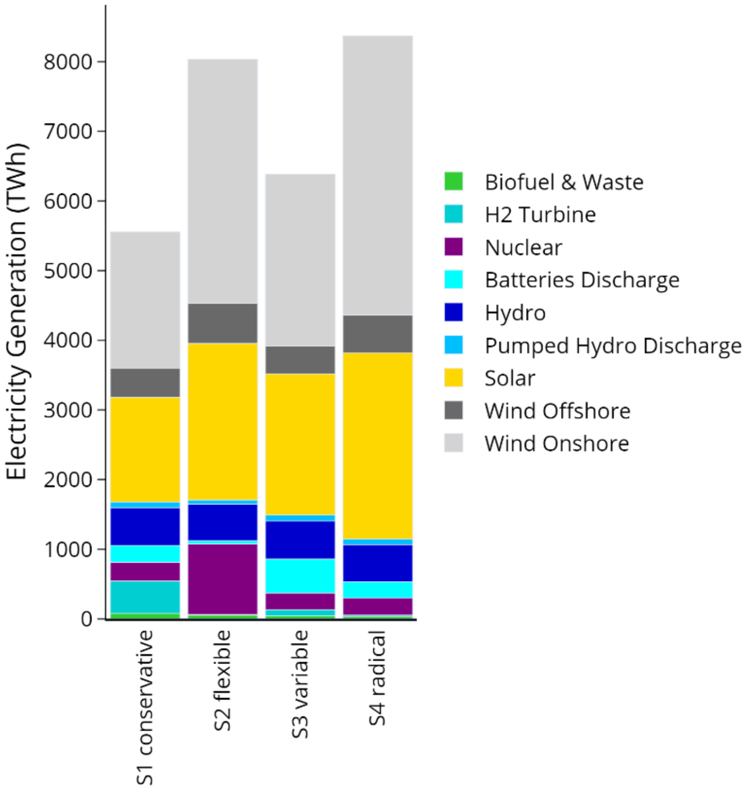

Figure 6. Total electricity generation by technology and scenario aggregated over all bidding zones

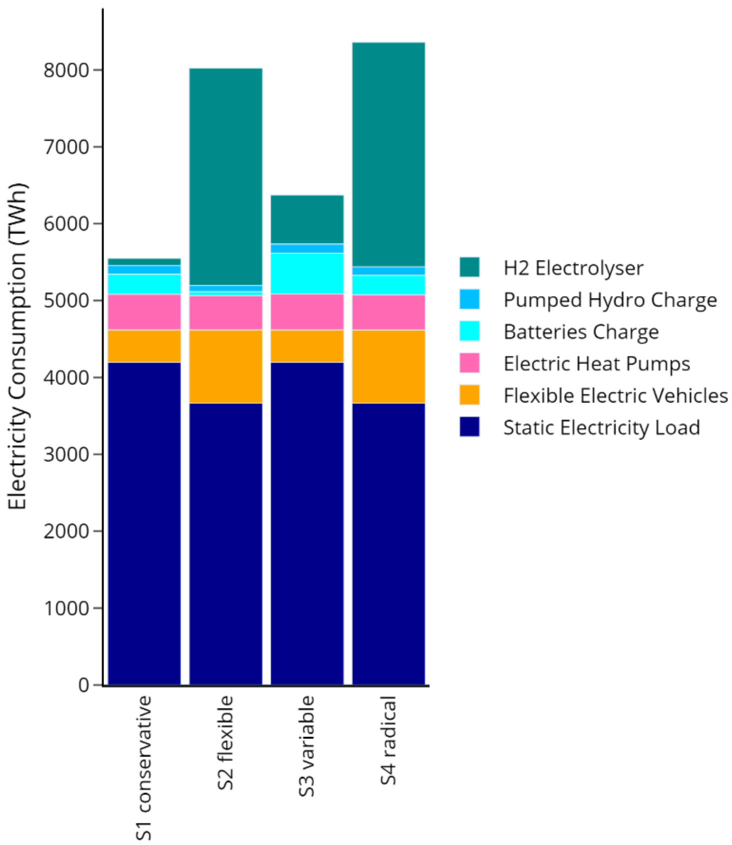

Figure 7. Total electricity consumption by sector and scenario aggregated over all bidding zones

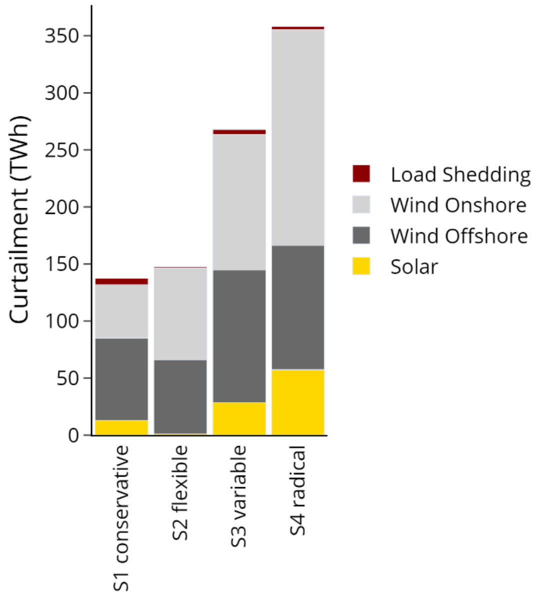

Figure 8. MPI#8 and MPI #17: Total involuntary load shedding and curtailment of potential electricity generation by technology and scenario aggregated over all bidding zones

Table 5: Total electricity transmitted between bidding zones aggregated over all bidding zones

Scenario	Total electricity traded (TWh)
S1 conservative	743.4
S2 flexible	647.6
S3 variable	744.7
S4 radical	692.8

Further characteristics of the scenario results, such as the composition of H_2 demand and supply or inter-European electricity and H_2 net exports can be found in Annex.

3.1.2 Economic parameters

Figure 9 shows total annual system costs resulting from our scenarios, which vary between almost 200 Bn. € in the **variable** scenario S3 and 240 Bn. € in the **flexible** scenario S2. While system costs resulting from scenarios with a high degree of sector-coupling, i.e. S2 and S4, mainly consist of investments costs, built to domestically cover a large share of energy demand, S1 and S3 are dominated by H_2 import costs. Since the H_2 import price differs between the scenarios, total system costs are not directly comparable. Importantly, it should be noted that investment costs of exogeneous capacities are not included in the system costs, i.e. capital costs of transmission lines, heat pumps, fuel boilers, electric vehicles and all brownfield capacities.

Yet, the scenario comparison provides important insights. First, the optimization results correspond to investment decisions made based on expectations that reflect our scenario assumptions. Hence, the optimization results for scenarios S1 and S3 resemble decisions made based on expectations on low H_2 import prices. In that sense, they illustrate that a future energy system built based on such predictions, could expose European energy consumers to substantial cost risks.

Second, the effect of a higher share of non-thermal renewables becomes evident when comparing S1 to S3 and S2 to S4, respectively. It corresponds to slightly lower operating costs, lower total system costs, but higher costs of load shedding indicating that a system with a 95% share of variable, non-thermal power incurs lower costs than a system with only 85%. Furthermore, the results indicate that an increase in demand-side flexibility increases security of supply, as load shedding costs are lower when comparing S1 to S2 and S3 to S4, respectively. However, this result highly depends on our assumptions on investment costs and the value of lost load (VOLL) at the level of the European maximum wholesale market price of 4000 €/MWh. If the true VOLL exceeds this value, the lower level of security of supply in S3 and S4 could result in higher system costs. As described in Section 2.2.1, the model does not incorporate market designs targeted at increasing the level of security of supply.

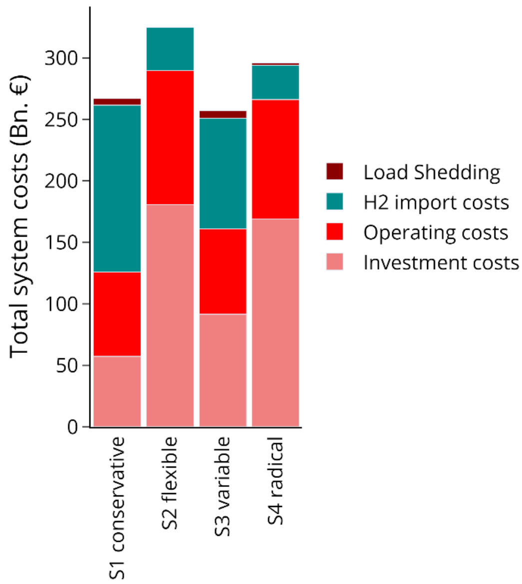

Figure 9. MPI #26: Total system costs distinguished by investment costs, operating costs (MPI #27), H_2 import costs and load shedding costs by scenario aggregated over all bidding zones

Figure 10 depicts electricity price duration curves in all 19 bidding zones and the four scenarios. The price plateaus observed in each bidding zone generally reflect our assumptions on the existing technologies' marginal cost of electricity generation and consumption, which are presented in Table 6 and Table 7, respectively. The lowest prices in all scenarios can be observed at the level of variable renewables' (solar and wind's) and nuclear power's low variable costs below 10 €/MWh. The second lowest price level is observed at levels around 31.27 €/MWh in the **variable** scenario S3. This value reflects the marginal value of electricity consumption of electrolyzers, i.e. the electricity price, up to which it is more cost-efficient to cover H_2 demand from electrolysis than importing it from outside Europe at the assumed price of 45.07 €/MWh. With an electricity-to-hydrogen-efficiency of 70.5% and variable costs of 0.5 €/MWh, producing H_2 with for 31.27 €/MWh exactly matches import cost assumptions of 45.07 €/MWh (cf. [19], [20], [21], [22]). In the **flexible** scenario S2 and the **radical** scenario S4, where the H_2 import price is assumed to be 116.9 € /MWh, this value shifts to 81.91 €/MWh.

Other price levels reflect thermal power plants' marginal costs of electricity production at 79.37 €/MWh or 199.1 €/MWh (H_2 CCGTs), 99.62 €/MWh or 276.1 €/MWh (H_2 OCGTs), 109.37 €/MWh (waste) and 170.23 €/MWh (biofuel). Not depicted in the figure are prices above 300€/MWh reflecting industrial load shedding at country-specific levels up to 617 €/MWh and involuntary load shedding at the level of 4000 €/MWh. Furthermore, in S2 and S4, some prices reflect opportunity costs of heat to be provided by fuel boilers instead of heat pumps. These opportunity costs depend on the price of synthetic gas (235 €/MWh), fuel boiler efficiency (85%) and vary with temperature-dependent COPs (η_t). As a result, they range from approximately 200 €/MWh to more than 3000 €/MWh. Finally, some price levels cannot be assigned to the marginal costs of specific technologies as they reflect varying opportunity costs of storages, electric vehicles and heat pumps to shift load between time steps.

Overall, all scenarios show that future electricity prices continue to rely on fuel prices. Yet, in contrast to today's markets, their impact can also result from opportunity costs of cross-sectoral demand. Section 3.2 provides further insights into factors that determine if the supply- or the demand-side becomes price-setting. Moreover, the isolated impact of each of the three scenario dimensions on prices is identified.

Table 6: Marginal costs of electricity generation

Technology	Variable operating costs (€/MWh)	Fuel-to-electricity efficiency (%)	Fuel price (€/MWh)	Marginal costs (€/MWh)	Scenarios
Solar	0.5	-	-	0.5	All
Wind Onshore	1.3 – 1.44	-	-	1.3 – 1.44	All
Wind Offshore	3.25 – 3.89	-	-	3.25 – 3.89	All
Nuclear	3.5	33	1.69	8.62	All
H_2 CCGT	4.25	60	45.07	79.37	S1, S3
Waste	28.2	21	15	99.63	All
H_2 OCGT	4.79	43	45.07	109.37	S1, S3
Biofuel	2.6	30	50.29	170.23	All
H_2 CCGT	4.25	60	116.9	199.1	S2, S4
H_2 OCGT	4.79	43	116.9	276.1	S2, S4

Table 7: Marginal value of electricity consumption

Technology	Variable operating costs (€/MWh)	Electricity-to-fuel efficiency in time step *t* (%)	Opportunity costs (€/MWh)	Marginal value (€/MWh)	Scenario
Electrolyzer	0.5	70.5	45.07	31.27	S1, S3
Electrolyzer	0.5	70.5	116.9	81.91	S2, S4
Heat Pump	0	η_t	119.75	119.75 η_t	S2, S4

Resulting annual volume-weighted averages of hourly day-ahead market prices are shown in Figure 11 and range from 28 €/MWh (in Spain and Portugal in the **variable** scenario S3) to 182 €/MWh (in the Balkans in the **conservative** scenario S1). The volume-weighted European average price gradually decreases from the **conservative** scenario S1 to the **radical** scenario S4. On the one hand, the average price decreases with increased demand-side flexibility that reduces load shedding. On the other hand, it also decreases with a higher share of non-thermal, variable renewables due to their low variable costs. Notably, average prices also decrease from S2 to S1 and S4 to S3 despite a higher H_2 import price. This finding suggests that the large expansion of low-variable-cost variable renewables corresponding to higher domestic H_2 production outweighs the higher import price on average. Average prices in individual bidding zones largely follow the same pattern. Yet, higher H_2 import price causes higher average electricity prices in several countries, where electrolyzers are setting the price in a high number of hours (e.g. Norway, Sweden, Spain or Portugal). Overall, the results illustrate the uncertainty of the level of future electricity prices, as, in each bidding zone, their average varies by at least 25 €/MWh between scenarios. More detailed dynamics of price formation in the future electricity market are discussed in Section 3.2.

Hourly price convergence seems to follow a similar pattern as yearly average prices. Price convergence is defined as the weighted hourly day-ahead price differentials across interconnected European borders (MPI #33). The differentials are either weighted by the number of hours in a year, yielding the average hourly price differential for each cross-border pair (hereafter referred to as 'Average Price Convergence'), or price convergence is defined as the median of the hourly day-ahead price differentials (hereafter referred to as 'Median Price Convergence'). Furthermore, we define *low* price convergence for differentials of more than 10 €/MWh, *moderate* price convergence for differentials between 1 €/MWh and 10 €/MWh and *full* convergence for price differentials below 1 €/MWh (see also Table 8).

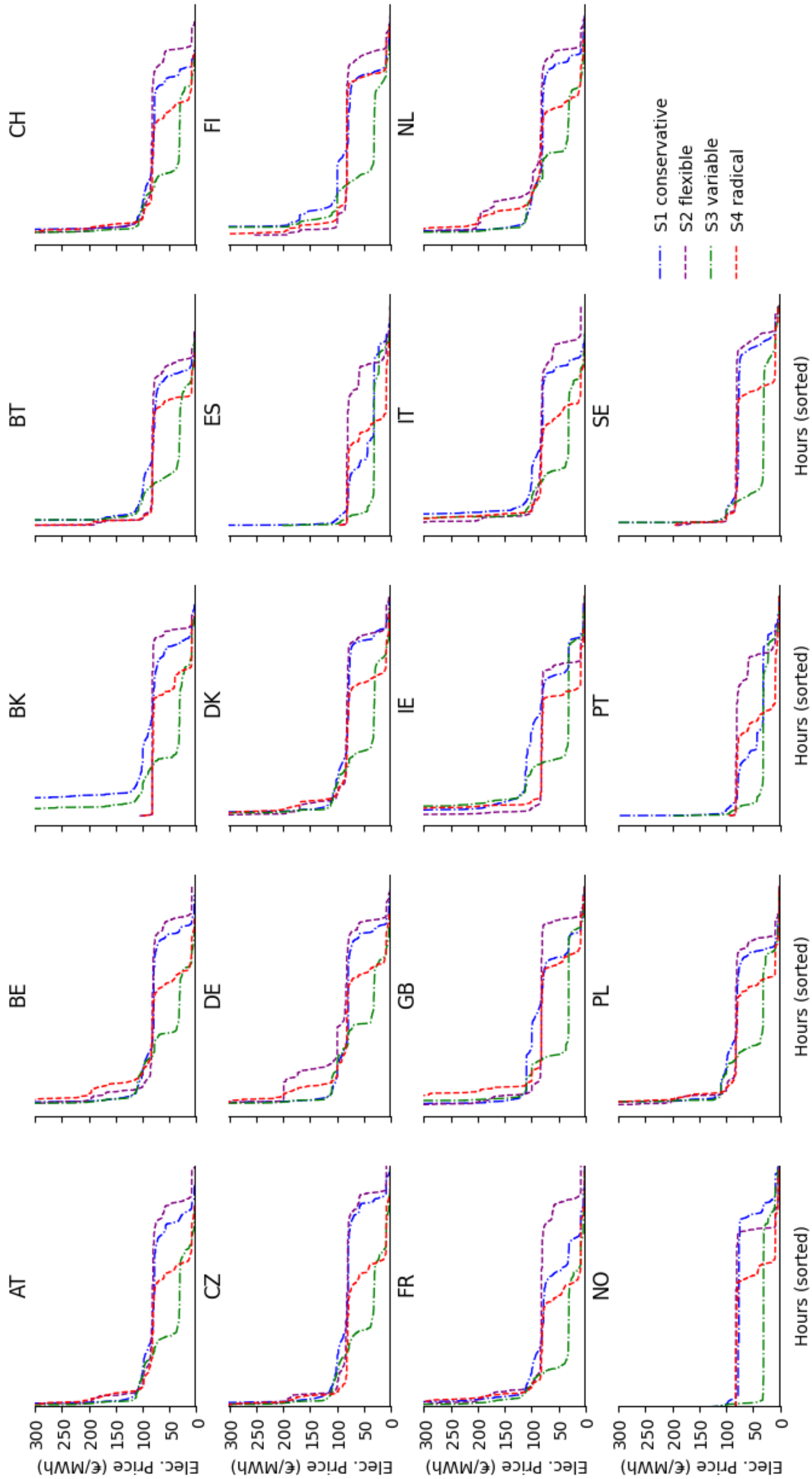

Figure 10. Electricity price duration curves by bidding zone and scenario, truncated at 300€/MWh.

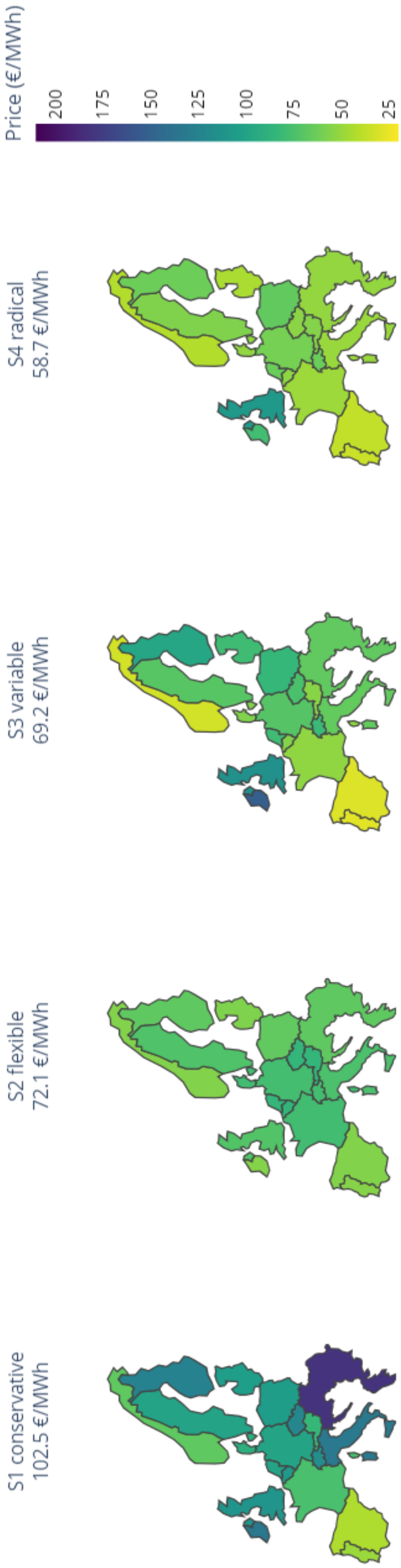

Figure 11. MPI #29: Annual volume-weighted average of hourly day-ahead market price by scenario by bidding zone with the European average depicted above each map

Table 8: Level of price convergence derived from average/median price differentials X

Level of price convergence	Definition
Low	X > 10 €/MWh
Moderate	1 €/MWh < X ≤ 10 €/MWh
Full	X ≤ 1 €/MWh

Figure 12 shows the percentage of cross-border pairs with low, moderate and full price convergence in each scenario. As displayed in Panel B (Average Price Convergence), all scenarios have a high percentage of border pairs with low price convergence. However, Panel A (Median Price Convergence) indicates that average price differentials are largely driven by high prices due to a right-skewed price distribution. In the following, we will therefore focus on the interpretation of the concept of median price convergence to avoid distortion.

The share of cross-border pairs with moderate hourly price convergence is highest in the **flexible** and **radical** scenarios S2 and S4, respectively. Both scenarios are characterized by a high price responsiveness of the demand-side and a high degree of sector-coupling as induced by a high H_2 import price, with S4 additionally incurring a high share of variable, non-thermal electricity supply. Given that trading volumes are lowest in S2 (cf. Table 5 in Section 3.1.1), the number of cross-border pairs with full and moderate price convergence is reduced compared to S4.

Conversely, the share of cross-border pairs with full price convergence is highest in the scenario with the highest trading volumes, i.e. the **variable** scenario S3 (cf. Table 5 in Section 3.1.1). On the one hand, this causes prices to converge more strongly across borders. On the other hand, prices diverge, when the cross-border transmission capacity limit is reached as a result of these high trading volumes. In conjunction with the low flexibility on the demand-side, which prevents prices from being smoothed, this explains the high share of low price convergence in S3.

A similar reasoning applies to the **conservative** scenario S1, where the share of cross-border pairs with low price convergence equals to the share of S3. In contrast to S3, only a small number of cross-border pairs exhibits full price convergence in scenario S1 that is characterized by a lower share of renewable electricity generation. While the marginal costs of various types of vRE are relatively homogeneous, they substantially differ among different thermal power plant technologies (cf. Table 6). Since prices are more frequently determined by vREs' marginal costs in S3 compared to S1, market prices in neighboring markets with correlated vRE generation profiles can be similar regardless of cross-border trade. Consequently, the share of full price convergence is higher in S3 than in S1.

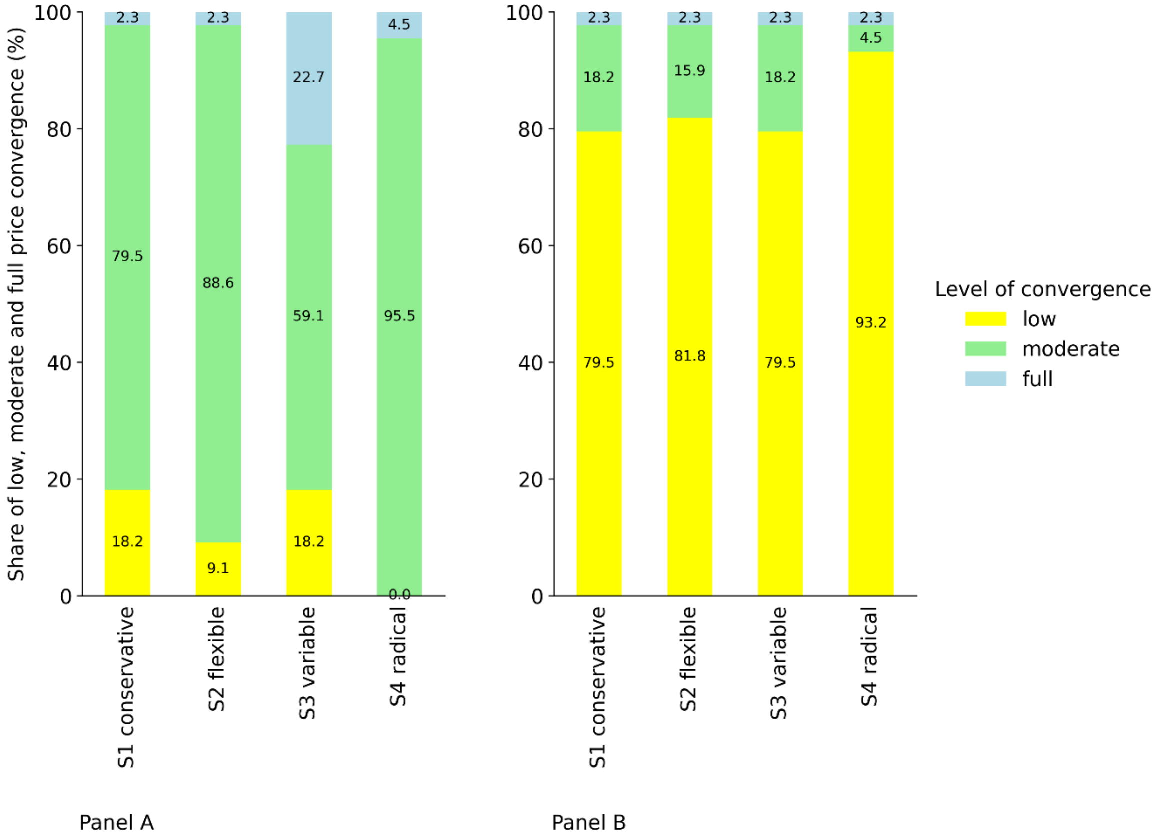

Figure 12. MPI #33: Price Convergence across scenarios. Panel A shows Median Price Convergence, defined as the median of hourly day-ahead price differentials across European borders. Panel B depicts Average Price Convergence, measured by the yearly average of hourly day-ahead price differentials across European borders.

Figure 13 shows the volatility of electricity prices, defined as the standard deviation of the average daily price differences on two consecutive trading days. Across bidding zones, the lowest level of price volatility can be observed in the **flexible** and **radical** scenarios S2 and S4, where demand-side flexibility is high. This result indicates that the price-responsiveness of electricity consumers effectively contributes to decreasing daily price fluctuations by reducing consumption in times of high prices and by increasing consumption in times of low prices. Consequently, extreme prices are smoothened and become intertemporally more aligned, such that volatility is reduced. Since in most bidding zones, price volatility is lower in S2 than in S4, a higher share of thermal power appears to additionally reduce price volatility. Due to the stochasticity and relatively high simultaneity of variable renewable electricity supply, periods of price spikes and low prices occur more frequently in S4, where the share of vRE is higher than in S2. Indeed, across bidding zones, the volatility of prices in the **variable** scenario S3 is around twice the size of the volatility in S2 and S4. Yet, the role of demand-side flexibility appears to be more important, since the **conservative** scenario S1 with is characterized by a low share of vRE exhibits a similarly high level price volatility as S3.

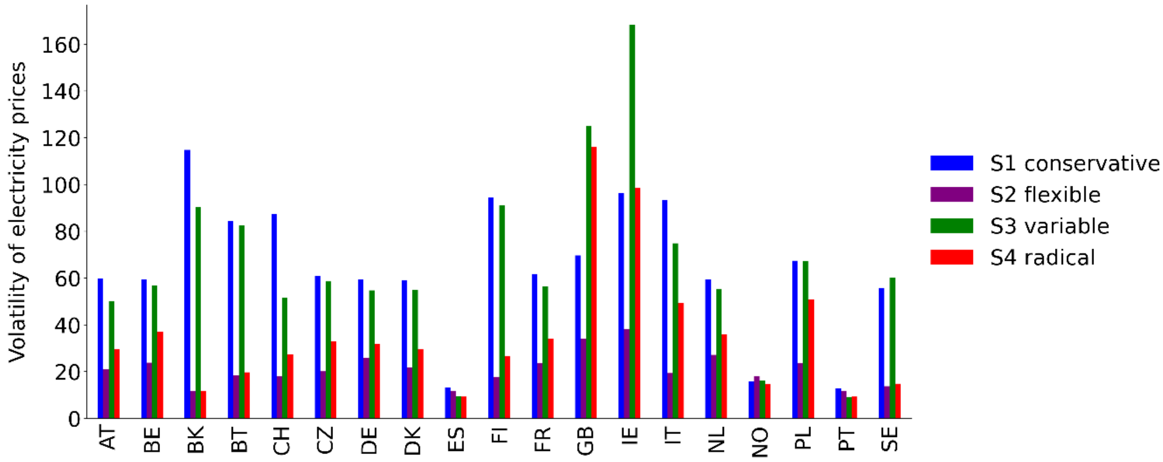

Figure 13. MPI #41: Volatility of electricity prices defined by the standard deviation of the difference between the daily average prices on two consecutive trading days in a particular market

Finally, Figure 14 illustrates the rate, to which market revenues cover annual costs (MPI #31). Each dot represents one bidding zone, while technologies, i.e. utility-scale solar PV, wind onshore and electrolyzers, are distinguished by color. The figure shows that the rate of cost-recovery of electrolyzers is relatively homogenous across bidding zones in scenarios with a higher share of thermal power, i.e. the **conservative** scenario S1 and the **flexible** scenario S2. Conversely, it slightly diverges in the **variable** and **radical** scenarios, where it is more dependent on the availability of low-cost renewable electricity in a bidding zone. While most electrolyzers are profitable, their rate of cost recovery benefits from a higher H_2 import price.

Due to the lifting effect of demand-side flexibility and sector-coupling on electricity prices (cf. Figure 10), vRE are more profitable in our future market scenarios than commonly believed. Especially wind onshore is profitable across all scenarios and bidding zones except for France and Norway in the **variable** scenario S3. Wind onshore expansion is particularly high in these bidding zones and therefore, subject to cannibalization. Solar PV appears to be exposed to cannibalization to a larger degree, particularly in S3 and the **radical** scenario S4. Generally, flexibility either on the supply- or demand-side appears to increase the profitability of vRE. Hence, the results illustrate that investors in vRE can generate substantial profits in future power systems that – alike TradeRES' main scenarios – are characterized by at least a moderate level of flexibility either on the supply- or demand-side. However, revenues are highly volatile and particularly solar PV is exposed to cannibalization risks.

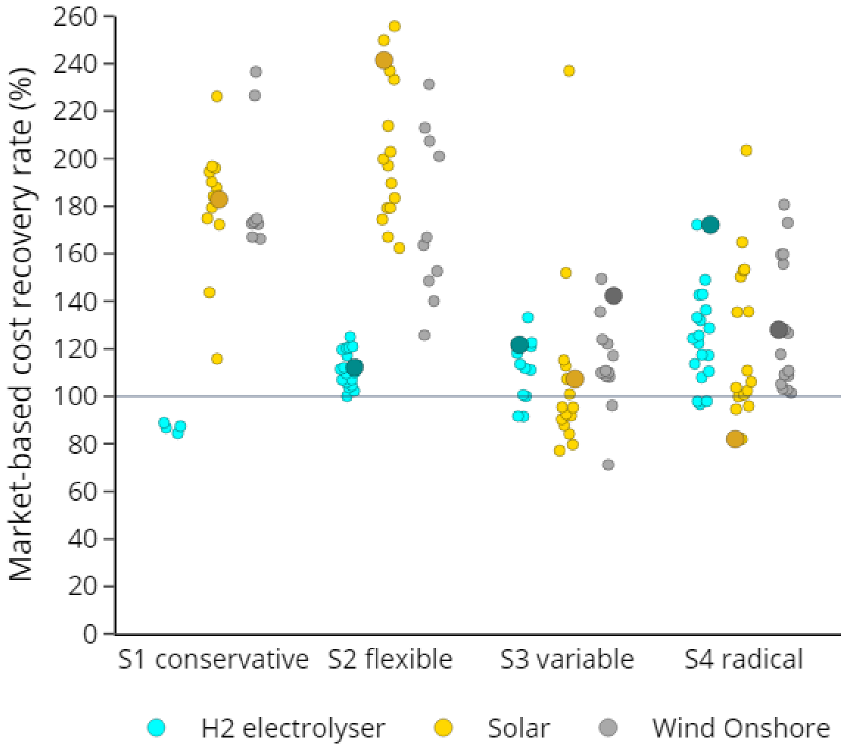

Figure 14. MPI #32: Market-based cost recovery rate by technology and scenario. Each dot represents a bidding zone with Italy highlighted as an example.

3.1.3 Transmission capacity sensitivity analysis

As a sensitivity, we varied transmission capacities in the **conservative** scenario S1 and the **radical** scenario S4. Expectedly, installed electricity generation capacities decrease in scenarios with higher transmission capacities (**transfer+**), since they allow weather-dependent supply of vRE to balance across bidding zones and vice versa for scenarios with lower transmission capacities (**transfer-**) (Figure 15). Particularly, higher transmission capacity allows a reduction in absolute curtailment (in TWh) (Figure 16). Figure 17 depicts the impact on electricity market prices. It shows that the volume-weighted average European electricity price generally increase in the **transfer-** scenario with fewer transmission capacities, where thermal power or load shedding are increasingly used in hours with low local wind and solar supply. This effect is particularly pronounced for the **radical** scenario S4, where electricity generation is dominated by weather-dependent renewables. Accordingly, the average price decreases with higher transmission capacities in **S4 transfer+**, where cross-border trade allows to balance weather-dependent fluctuations across Europe. This result also holds true for all individual bidding zones' average electricity prices in S4 and its variations. For the **conservative** scenario S1, however, volume-weighted average prices increase in several countries with increasing transmission capacities. On the one hand, exports of thermal power increase in this scenario. On the other hand, the decrease in curtailment also causes renewables to become price-setting in fewer hours.

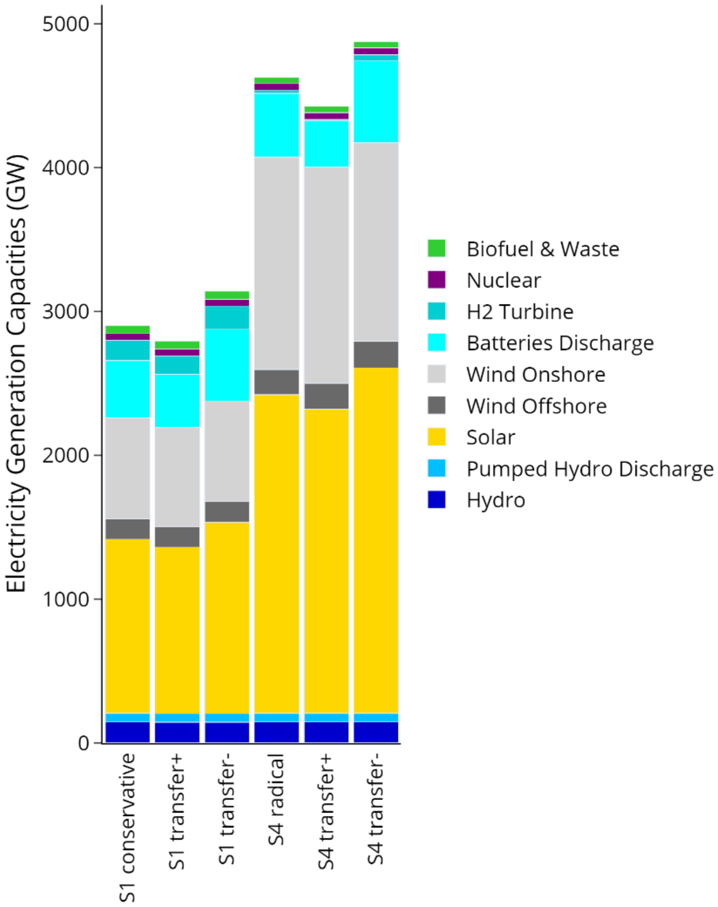

Figure 15. Total installed electricity generation capacities by technology and scenario aggregated over all bidding zones

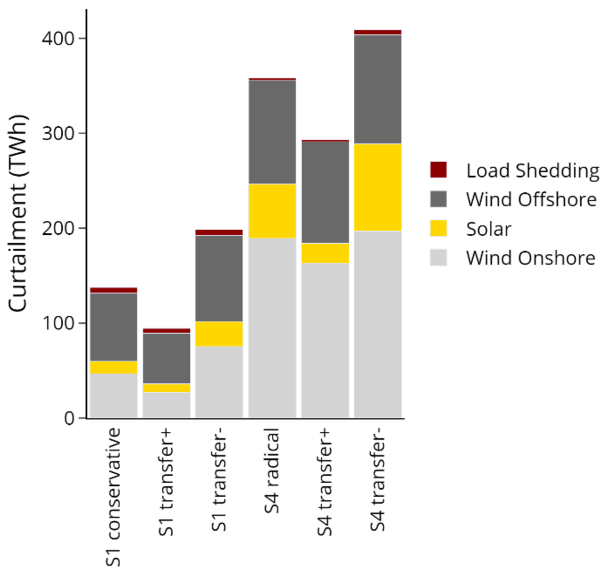

Figure 16. MPI #8 and #17: Total involuntary load shedding and curtailment of potential electricity generation by technology and scenario aggregated over all bidding zones

Figure 17. MPI #29: Annual volume-weighted average of hourly day-ahead market price by scenario and bidding zone with the European average depicted above each map

While the impact of transmission capacities is more pronounced within the **radical** scenario S4 compared to the **conservative** scenario S1, the rate of cost-recovery of utility-scale solar PV and wind onshore power plants is more affected in S1. Particularly, the reduction in curtailment in the **transfer+** scenarios tends to increase wind onshore and solar PV cost recovery rates due to a decrease in cannibalization. In S4 with a higher dominance of variable renewables, this effect is smaller, yet still visible.

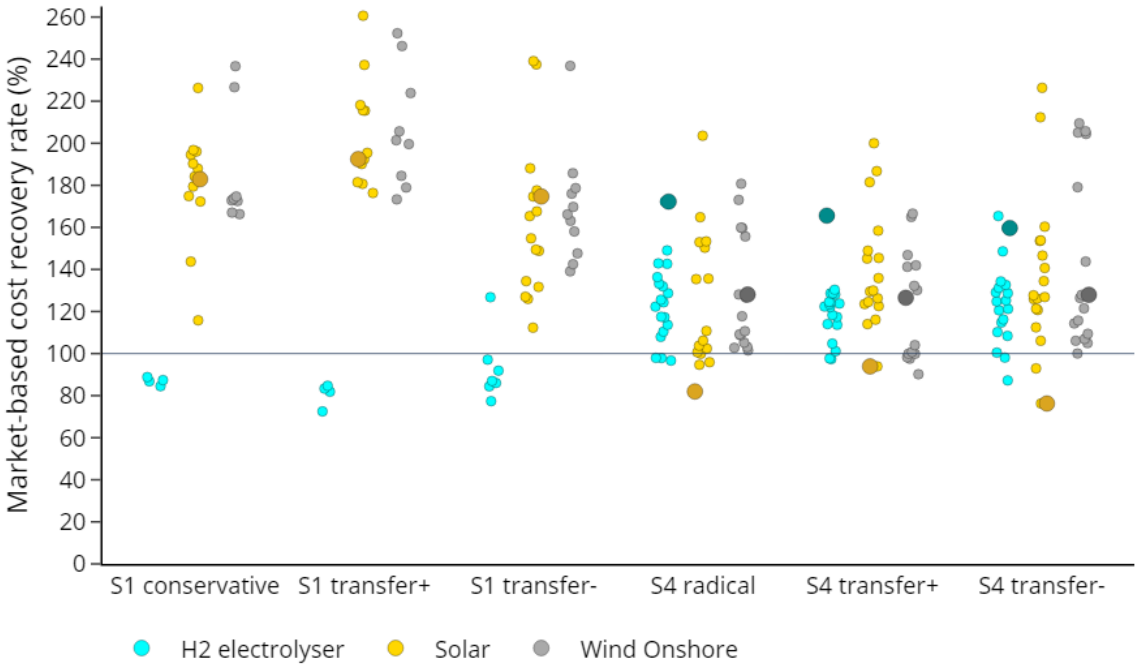

Figure 18. MPI #32: Market-based cost recovery rate by technology and scenario truncated at 260% excluding 7 observations in total. Each dot represents a bidding zone with Italy highlighted as an example.

3.2 Price formation and intersectoral distributional effects

This section characterizes the modelling results of additional TradeRES scenarios that examine each scenario dimension in an isolated manner. The analyses allow to study drivers of prices in future electricity markets as well as costs of final energy consumption in different sectors.

3.2.1 System characterization

Figure 19 compares total installed capacities in the **Base** scenario, which corresponds to the **variable** scenario S3 with a completely inflexible demand-side, to three scenarios: (i) a **Flex** scenario, where all electric vehicles and heat pumps become flexible, (ii) a scenario with a higher H_2 import price (**H2Price↑**) and (iii) a scenario, where only the share of flexible, thermal electricity supply is increased (**vRE↓**) (cf. Section 0 for a detailed scenario description). Comparing the **Flex** and **vRE↓** scenario to the **Base** scenario highlights how introducing demand-side flexibility or thermal supply-side flexibility in an isolated manner significantly reduces total installed capacities by more than 1000 GW. On the one hand, flexible electric vehicles and heat pumps substitute battery capacities, while thermal capacities replace additional variable renewable capacities. On the other hand, both absolute and relative curtailment are reduced in both scenarios (cf. Figure 22). Conversely, increasing the H_2 import price causes an increase in capacities of approximately 1000 GW, particularly in solar, wind onshore and battery capacities. For the results described in Section 3.1.1, this analysis allows to conclude that the increase in capacities in the **flexible** and **radical** scenarios S2 and S4 mainly results from the increasing degree of sector-coupling through higher electrolyzer deployment and is reduced by the increase in demand-side flexibility. Figure 20 depicts corresponding electricity generation, which reflects the installed capacities. Notably, differences in the level of electricity generation mainly correspond to different levels of battery and electrolyzer deployment (cf. Figure 21).

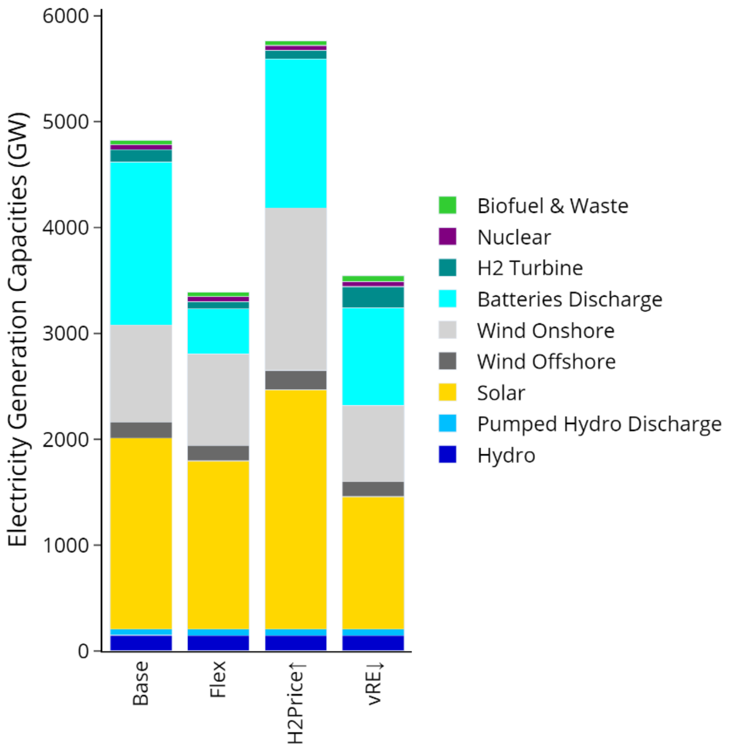

Figure 19. Total installed electricity generation capacities by technology and scenario aggregated over all bidding zones

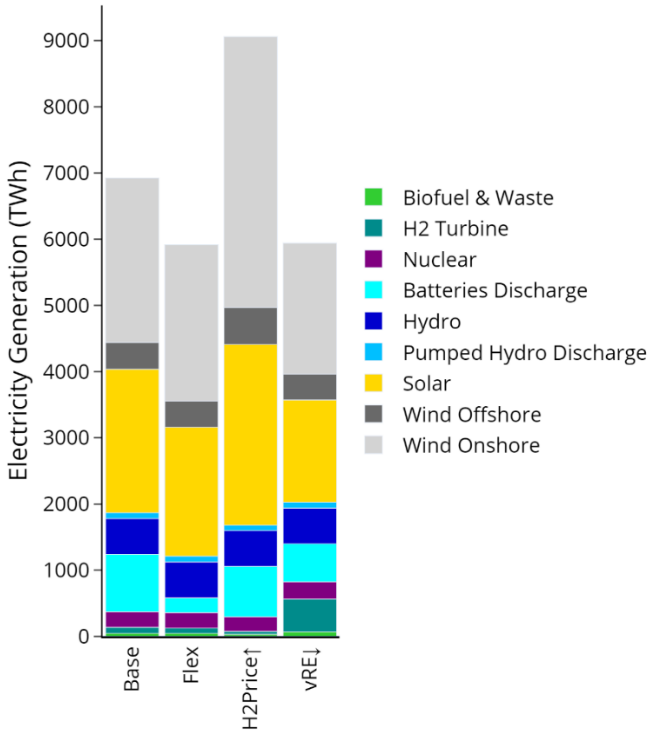

Figure 20. Total electricity generation by technology and scenario aggregated over all bidding zones

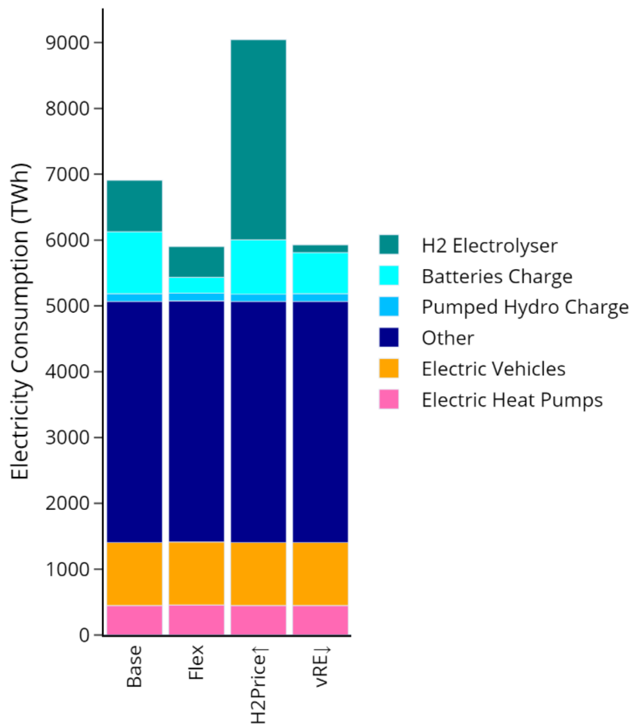

Figure 21. Total electricity consumption by sector aggregated over all bidding zones by scenario

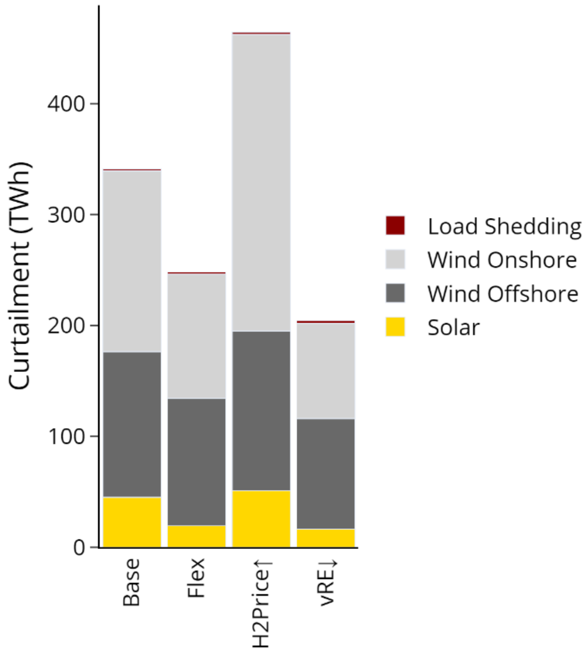

Figure 22. MPI #8 and #17: Total unvoluntary load shedding and curtailment of potential electricity generation by technology and scenario aggregated over all bidding zones

3.2.2 Economic parameters

Figure 23 presents a histogram of the scenarios' price distribution from 0 to 130 €/MWh and the unweighted mean electricity prices. On the right-hand-side, it also presents the number and unweighted average of observations above 130€/MWh. In the following, we analyze how the different scenario dimensions affect the distribution of electricity prices and the role of different technologies as price-setters.

- *Supply-side variability:* The figure depicts that with 30%-40% of prices at the level of electrolyzers' opportunity costs at the level of 31.27 €/MWh, this technology is the main price-setter in all scenarios with a high share of variable renewables, namely the **Base**, **Flex** and **H2Price↑** scenarios. Conversely, the **vRE↓** scenario more closely resembles our current power system, as thermal power plants – in this case particularly H_2 turbines with their marginal costs of 79.37 €/MWh – are the main price-setting technology. As a result, this scenario exhibits the highest time-weighted European average price supporting the conclusion from Section 3.1.2 that a higher share of thermal power tends to increase electricity prices.
- *Demand-side flexibility*: While increasing demand-side flexibility from EVs and HPs does not significantly affect price distribution below 130 €/MWh, it increases the frequency of prices above this value. This result is mainly driven by fuel boilers available to substitute electric heat provision at high levels of electricity prices. However, the unweighted average of prices above 130 €/MWh in the **Flex** scenario decreases as demand-side flexibility decreases the number of unvoluntary load shedding events at the maximum price of 4000 €/MWh.

- *Sector-coupling*: Although the increase in H_2 price significantly increases electrolyser capacities, their role as price-setting technology decreases. Particularly, electrolysers set the price at their increased opportunity costs of 81.91 €/MWh in 30% of hours in the **H2Price↑** scenario compared to 37% in the **Base** scenario. Conversely, the share of prices below 10 €/MWh increases from below 30% to nearly 50%.

The results raise the question, when the price is determined by an electricity supply technology and when it is set by the demand-side. Figure 25 addresses this question at the example of the **Flex** scenario in Italy (IT). It compares Italy's price duration curve to utilization rates of demand- and supply-side technologies. Low prices are observed, when electrolyzers charge electricity at 100% of their capacity, whereas variable renewables are curtailed, as indicated by a utilization rate below 100%. On the other hand, electrolyzers determine the market price at the level of 31.27 €/MWh, if their electricity charge is lower than its maximum potential, yet variable renewables generate electricity at 100% of their available capacity. In this scenario, waste power is the least expensive thermal power plant in Italy, setting the price at 100 €/MWh, while fuel boilers determine the price at levels above 300 €/MWh, when they are not used at their maximum. As described above, price levels in between those that can be assigned to marginal costs of electricity generation or consumption technologies result from shadow prices of load shifters, such as storages, electric vehicles and heat pumps. Resulting volume-weighted average prices in the additional scenarios demonstrate similar dynamics as described in section 3.1.2. and are depicted in Figure 24.

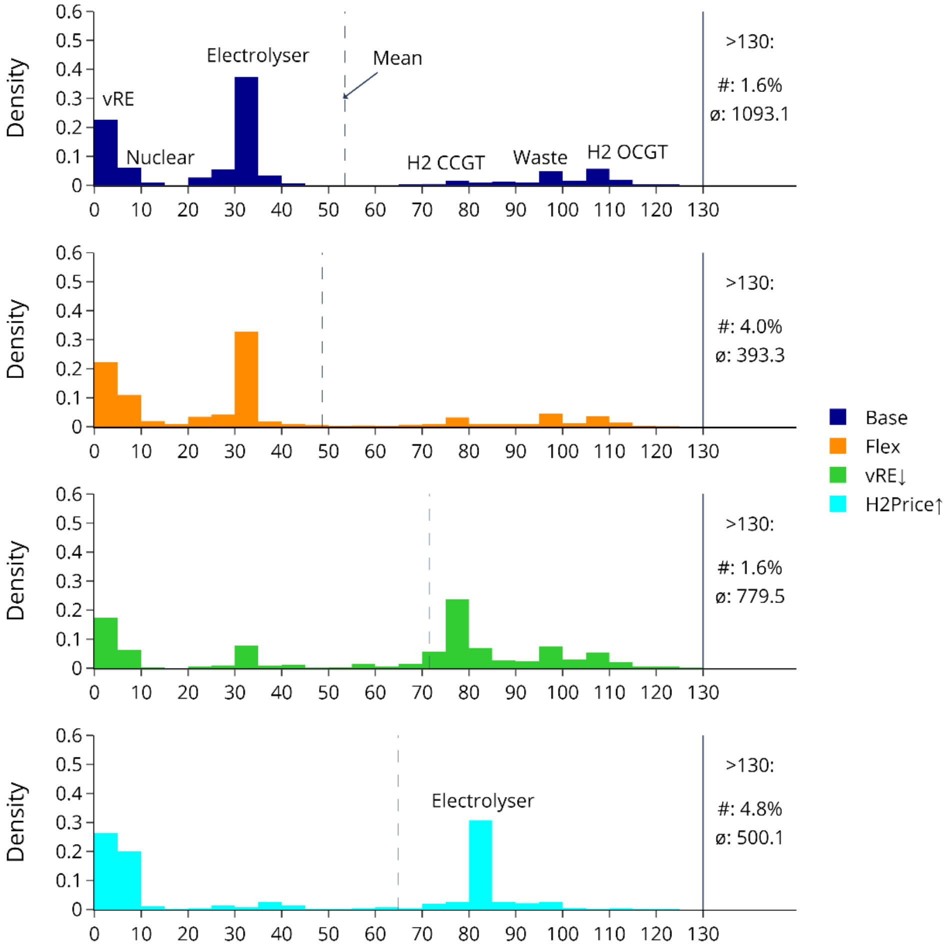

Figure 23. Histogram of electricity prices by scenario, truncated at 130 €/MWh. Overall mean is depicted by the dashed vertical line, while the average (Ø) and number (#) of prices above 130 €/MWh are presented on the right side of the plot.

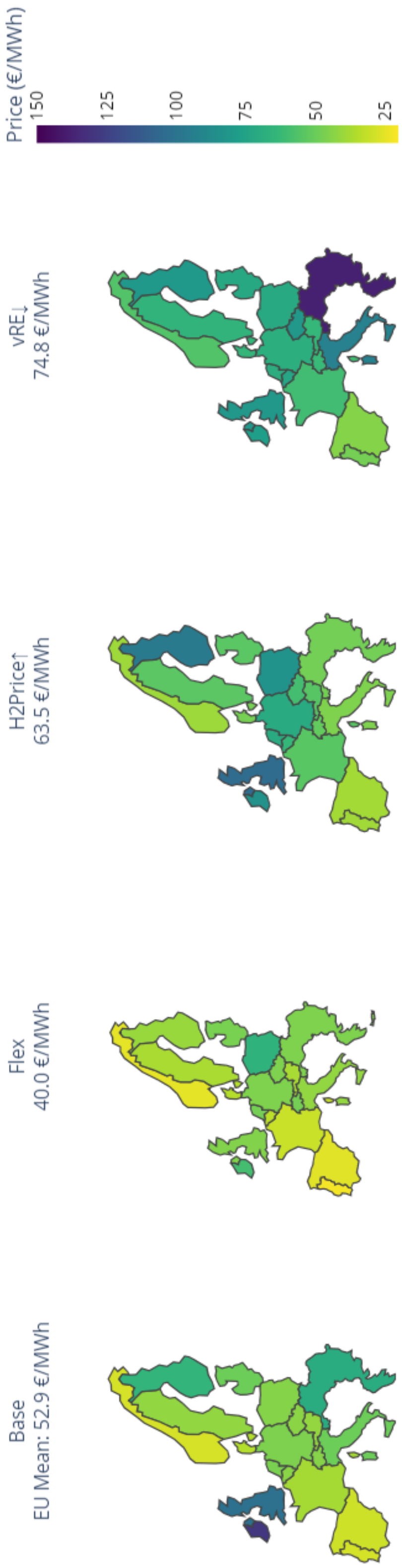

Figure 24. Annual volume-weighted average of hourly day-ahead market price by scenario by bidding zone with the European average depicted above each map

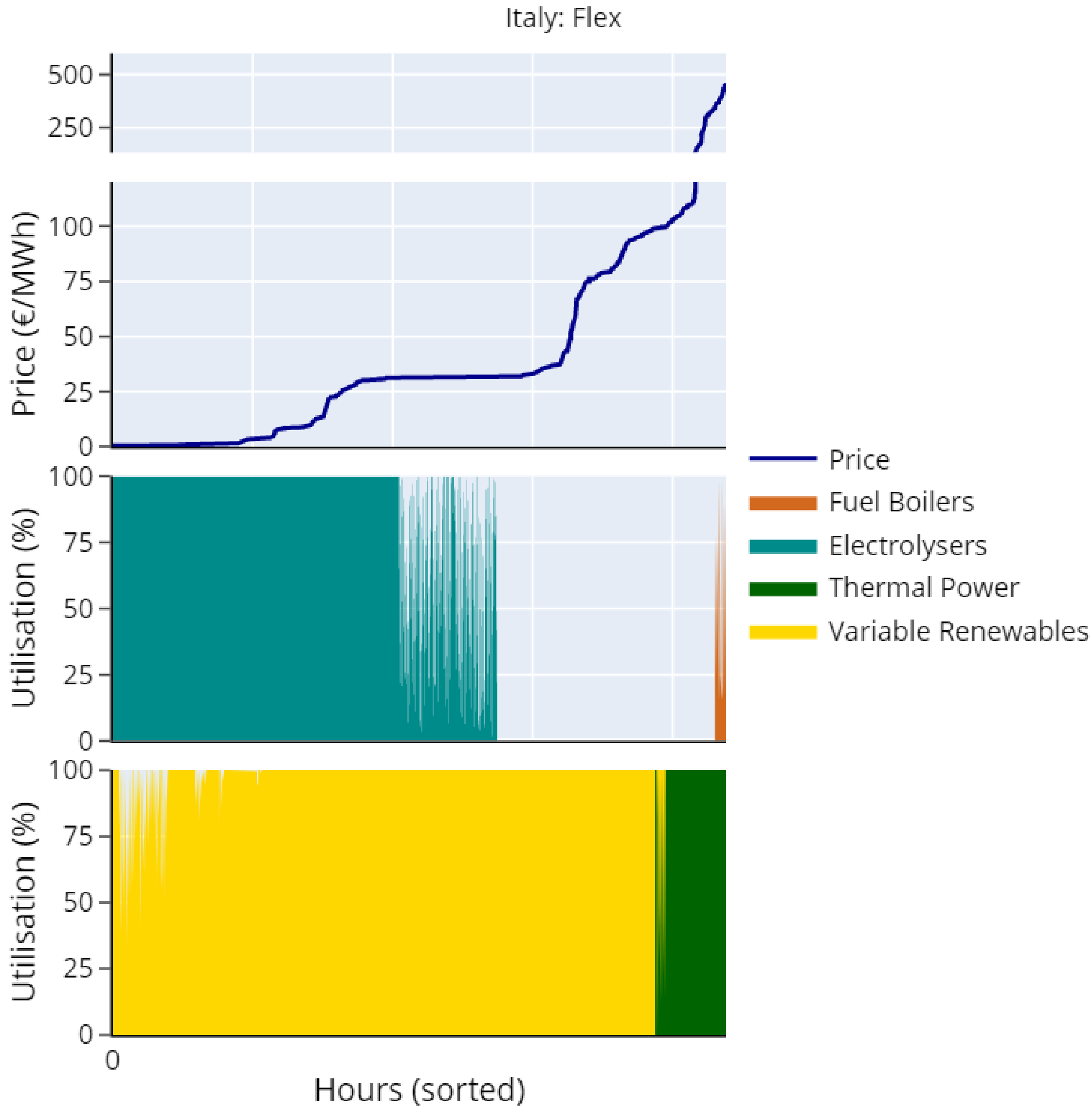

Figure 25. Price duration curve and corresponding utilization rates of demand- and supply-side technologies in the Flex scenario in Italy

Figure 26 shows the rate to which annual investment and operating costs of solar PV, wind onshore and electrolyzers can be recovered from market revenues in the four scenarios. In contrast to Section 3.1.2, all scenarios, but the **vRE↓**-scenario, exhibit a larger share of unprofitable solar PV and wind onshore investments. Particularly, almost all solar PV and approximately a quarter of wind power plants are unprofitable in the **Base** scenario. While this result hardly changes with the introduction of demand-side flexibility in the **Flex** scenario, a majority of vRE becomes profitable in the **H2Price↑** scenario. Hence, investors in variable renewables seem to benefit from a high share of thermal power and a high H_2 import price. Due to their significant role as price-setting technology, the rate of cost-recovery of electrolyzers is more robust across scenarios. Particularly, they appear to be able to sell a sufficient amount of H_2 for a price higher than the average electricity load costs. Figure 27 and Figure 28 depict load cost factors (i.e. average load costs divided by the average electricity price) and costs of final energy consumption of the different sectors considered, respectively. Indeed, H_2 electrolyzers are able to buy electricity below the average price throughout all scenarios and countries. Yet, the disparity of electrolysers' load cost factors increases among countries in the **H2Price↑** scenario, when a country's availability of low-cost electricity gains more significance. Similarly, H_2, consumption costs are constant at the level of 45 €/MWh in the low-H_2-price-scenarios, while they diverge in the **H2Price↑** scenario. Furthermore, the figures show that inflexible loads are similarly exposed to price risks as generators of electricity, while flexible loads in the **Flex** scenario are able to achieve lower load costs and therefore, lower costs of final energy consumption.

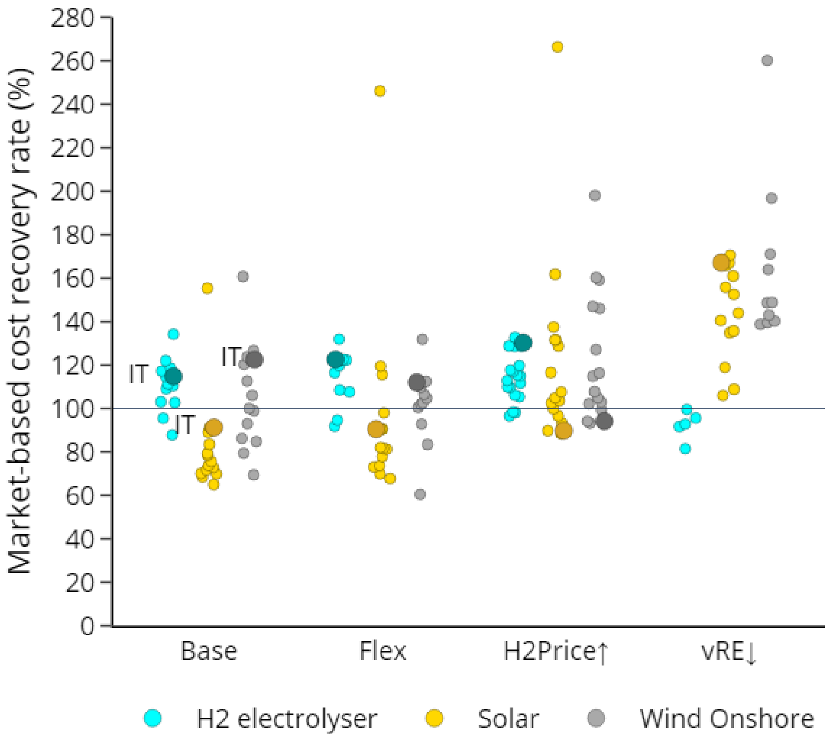

Figure 26. MPI #32: Market-based cost recovery rate by technology and scenario truncated at 260% excluding 4 observations in total. Each dot represents a bidding zone with Italy highlighted as an example.

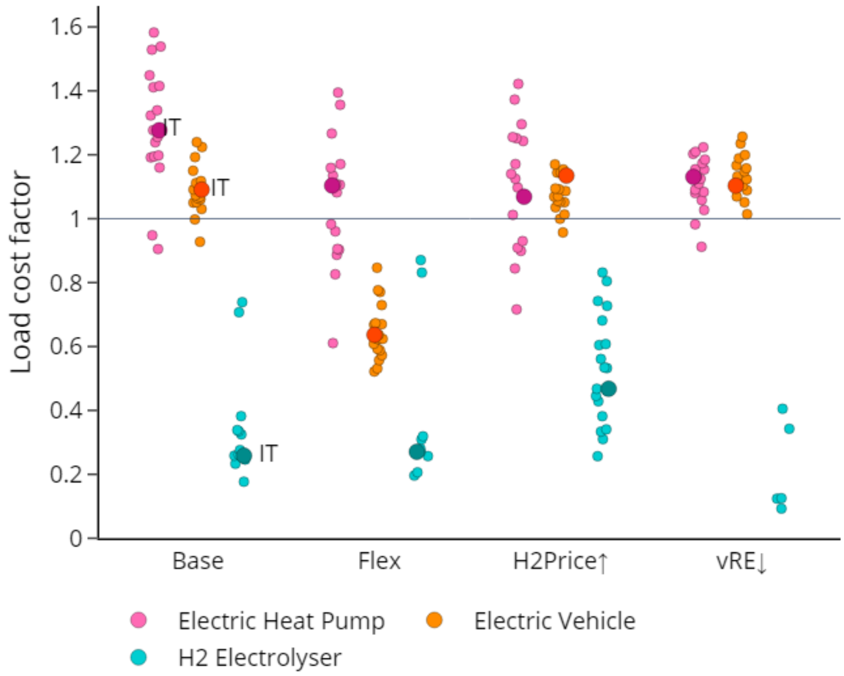

Figure 27. Load cost factors of electricity demand technologies as average electricity load costs divided by zonal average electricity price. Each dot represents a bidding zone with Italy highlighted as an example.

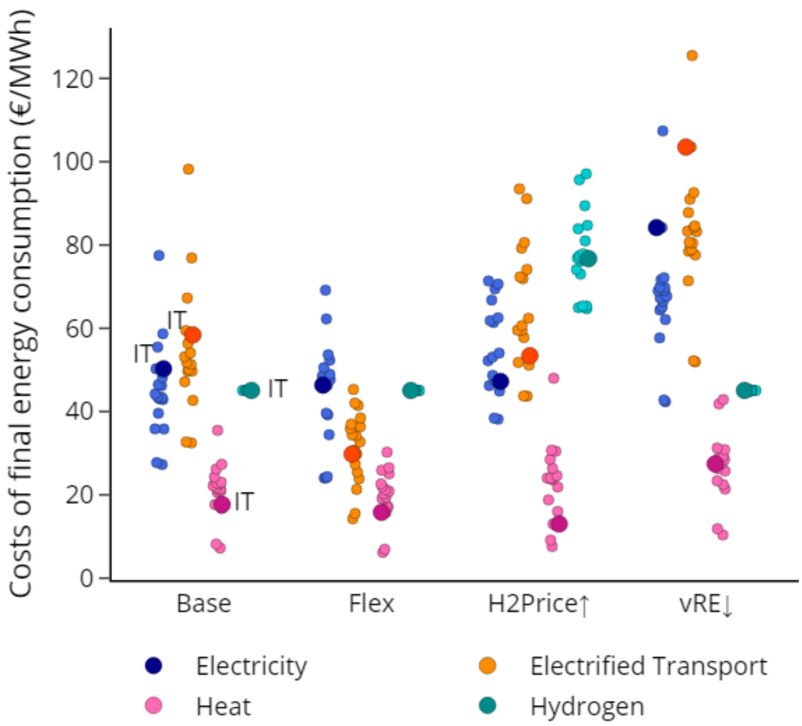

Figure 28. Costs of final energy consumption by sector. Each dot represents a bidding zone. “Electricity” includes remaining electric load not covered by the other depicted sectors with Italy highlighted as an example.

3.3 Contracts for Difference

This section presents results of the **target** scenario and the scenarios simulating four types of CfDs as described in Section 2.2.3.3.

3.3.1 System characterization

Figure 29 (left) depicts all aggregated electricity generation and hydrogen capacities in the **target** scenario, which – similar to the **variable** scenario S3 – is characterized by a large share of solar PV capacities, followed by wind onshore. The right side of the figure compares investments in wind onshore and electrolyzer capacities in the **target** scenario to the CfD scenarios. By construction, in the **1way**, **2way** and **financial** CfD scenarios, there are more investments in the *High MV* wind type, while there are more installed capacities of the *High FLH* wind type in the **basic** CfD scenario. Interestingly, electrolyzer capacities are higher in all CfD scenarios. An explanation can be found in Figure 30, which shows that both absolute and relative curtailment decrease in all CfD scenarios compared to the **target** scenario. Since wind curtailment particularly decreases, electrolyzers, whose deployment was shown to be correlated to wind generation [23], benefit from this effect.

The result shows that the incentives induced by CfD designs (cf. Section 2.2.3.3) affect dispatch in the future power market. On the one hand, virtual variable costs under the **1way** and **2way** CfD as well as the "produce and forget" incentive under the **basic** CfD cause wind to be dispatched at lower market prices. On the other hand, full load hours also increase under the financial CfD, where short-term dispatch is not distorted, indicating that the higher dominance of the *High MV* wind type also causes curtailment to decrease. Additionally, dispatch is also affected by prices, which, in turn are also influenced by CfD design.

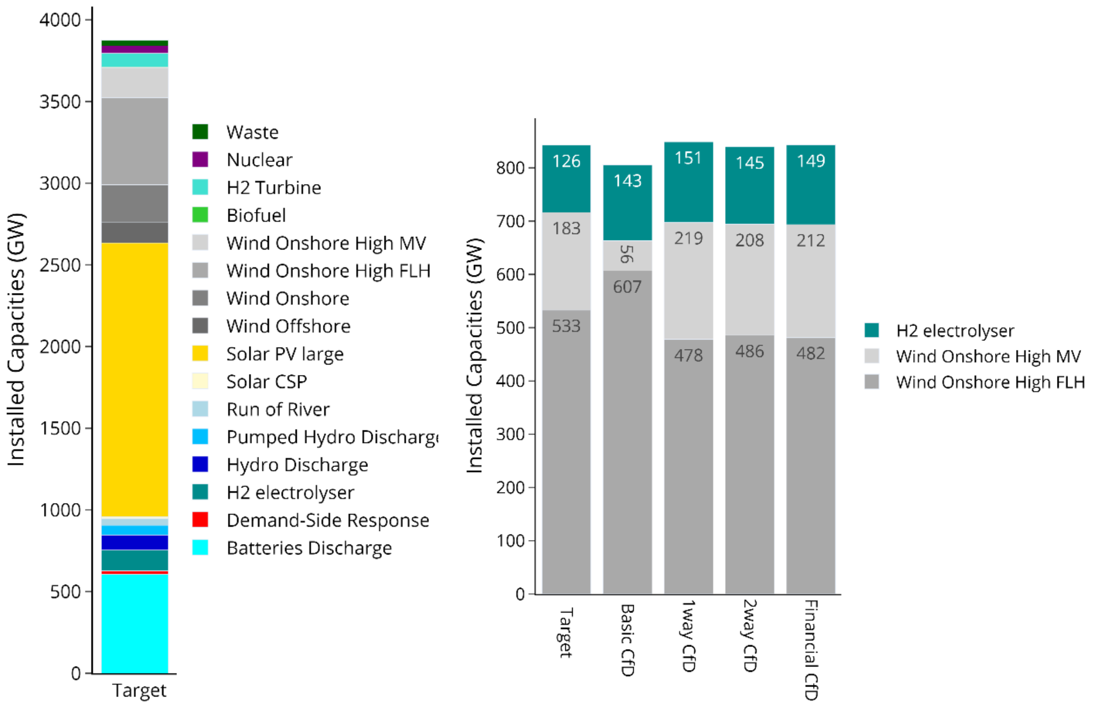

Figure 29. Installed electricity and hydrogen generation capacities in the target and CfD scenarios aggregated over all bidding zones

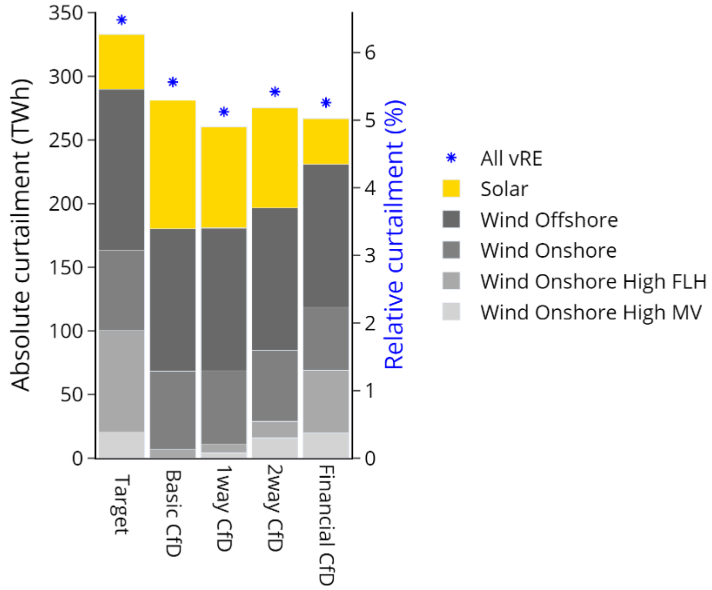

Figure 30. MPI #17: Total absolute and relative curtailment of potential electricity generation by technology and scenario aggregated over all bidding zones

3.3.2 Economic parameters

Figure 31 depicts price duration curves by scenario at the example of Denmark. As described in Section 3.1.2, electrolyzers are setting the price in our scenarios at a level of around 31€/MWh. Since electrolyzer capacities and deployment increase in all CfD scenarios, the number of hours, where they are setting the price, also increases. Furthermore, the altered variable costs are reflected in the lowest prices occurring in the **1way** and **2way** and the **basic** CfD scenario at negative levels and 0, respectively.

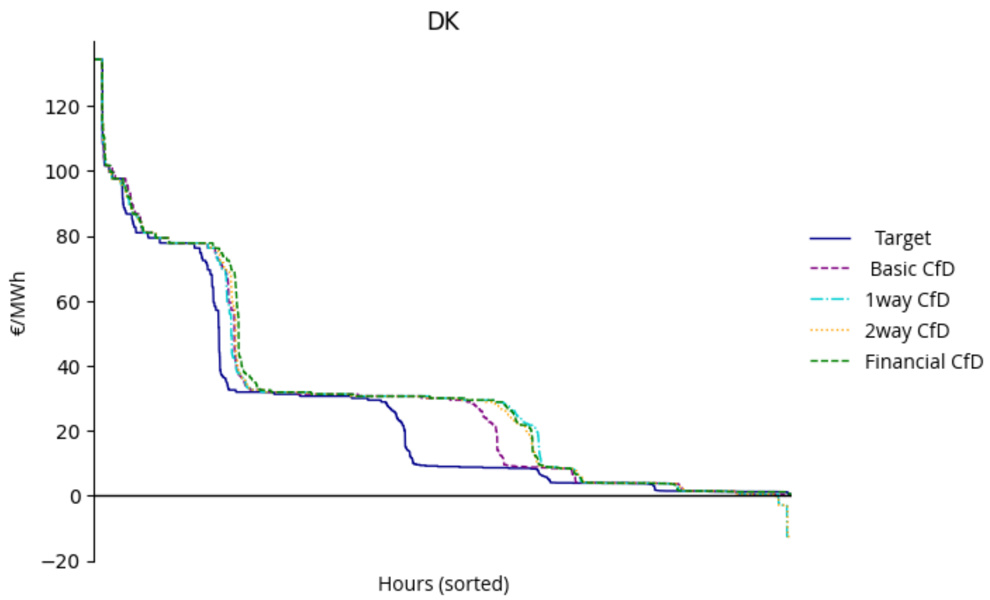

Figure 31. Price duration curve in Denmark (DK) by scenario

This difference in market outcomes among the **target** and CfD scenarios, particularly in terms of prices and wind dispatch, has consequences for the profitability of wind onshore in the CfD scenarios. Particularly, the market-based cost recovery, i.e. the cost recovery rate without CfD payments, generally increases in the CfD scenarios compared to the **target** scenario. A major reason for this result is the increase in electrolyzer activity that lifts prices. Consequently, CfD payments lead to an excess recovery of costs in numerous bidding zones in our CfD scenarios. Since CfD payments are defined by ex post reference prices, but ex ante determined strike prices (cf. Figure 37 in the Annex), ex post realized payments can deviate from ex ante expectations, which – by construction – ensure a cost recovery rate of 100% plus a risk premium of 7% (cf. Figure 38 in the Annex). Figure 32 and Figure 33 show that across Europe, the ex post rate of cost recovery is higher than 100% for the vast majority of wind types, bidding zones and CfD types. Yet, one can also observe some exceptions, particularly for the *High MV* type under the **financial** CfD (in Denmark, Spain, Poland and the Netherlands). Furthermore, the *High FLH* type becomes unprofitable in the Balkans under both the financial and the **2way** CfD. This result highlights the different risks associated with each type of CfD considered. Future research should investigate these risks in further scenarios of future electricity markets to derive a robust conclusion on the risk profile of each CfD type.

Figure 34 compares total system costs including CfD expenditures across all scenarios and shows that they are lowest in the **target** scenario. However, when accounting for the fact that most wind power plants are not profitable in this scenario (cf. Figure 39), such that these investments will not occur without any subsidy, which is represented by the “profitability gap” in the Figure, the **2way** and **financial** CfD incur lower system costs than the **target** scenario. Overall, the findings highlight a trade-off between investor risks and system costs of the different types of CfDs considered. While the robustness of this result should be further investigated, it is in line with Veenstra & Mulder [24].

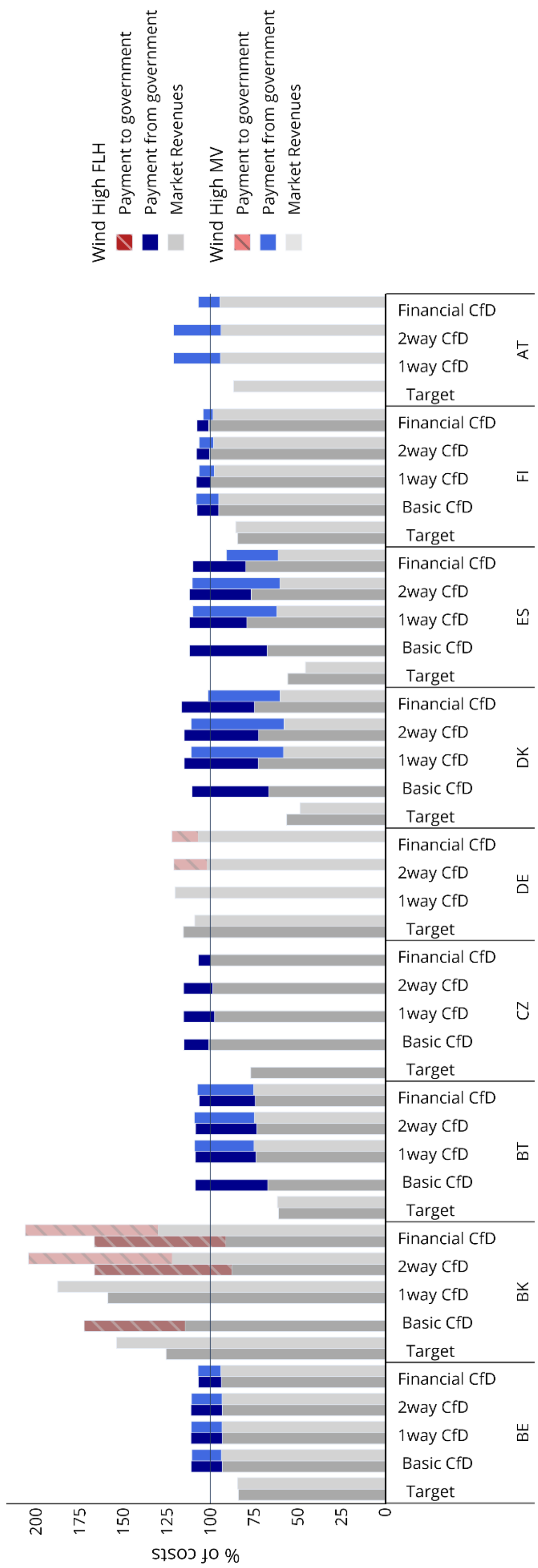

Figure 32. MPI #32: Rate of ex post cost-recovery from market revenues and CfD payments of wind onshore by wind technology and CfD type in the last 9 bidding zones in alphabetical order

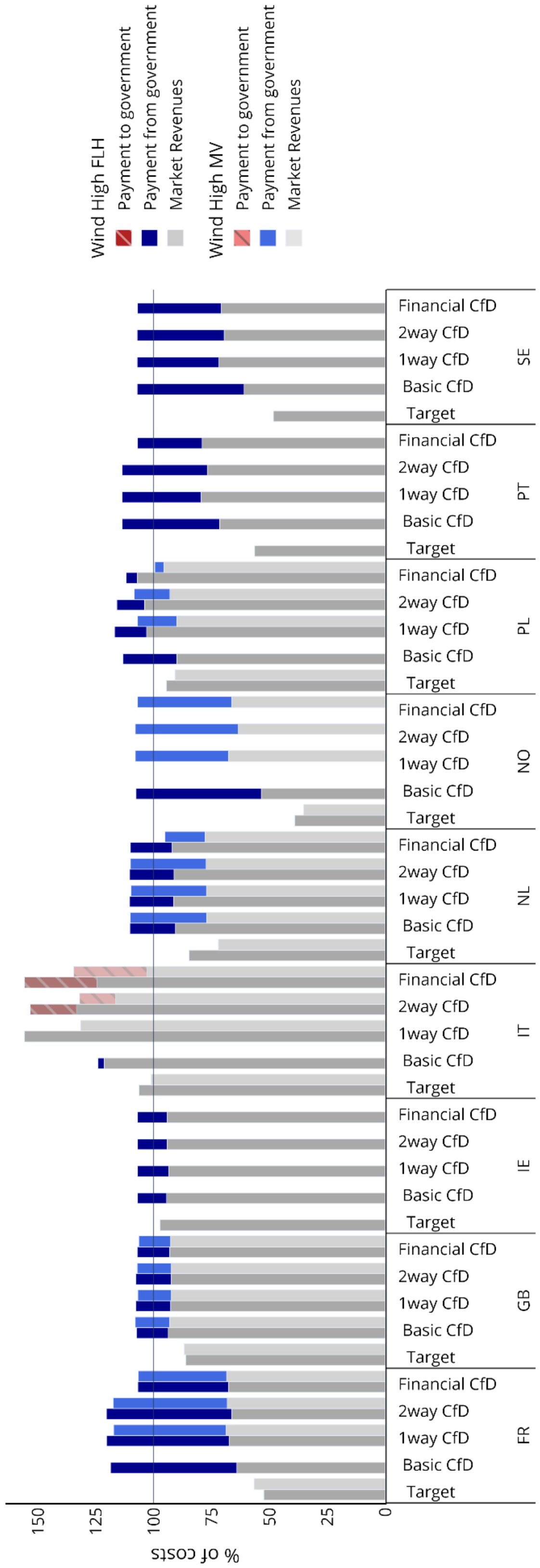

Figure 33. MPI #32: Rate of ex post cost-recovery from market revenues and CfD payments of wind onshore by wind technology and CfD type in the last 9 bidding zones in alphabetical order

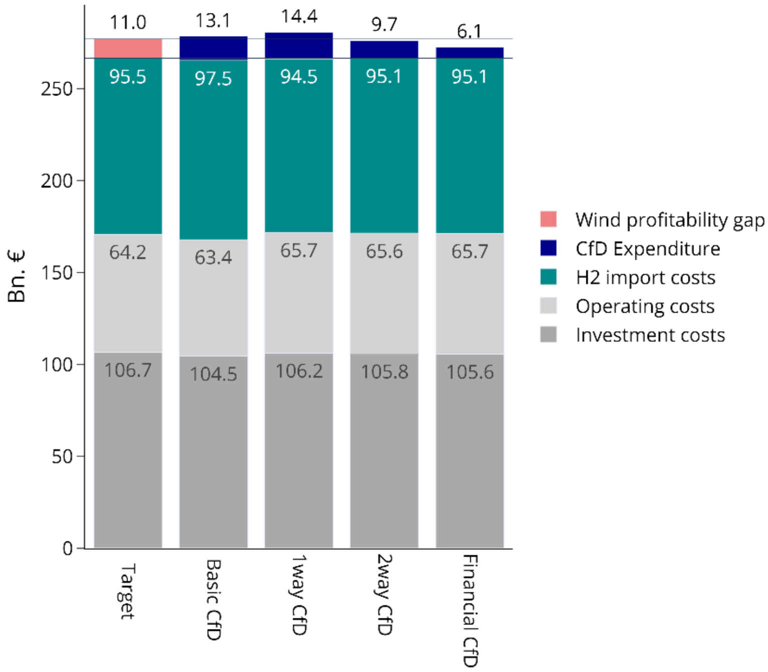

Figure 34. MPI #26: Total system costs distinguished by investment costs, operating costs (MPI #27), H_2 import costs and CfD expenditure (wind profitability gap) by scenario aggregated over all bidding zones

3.4 Discussion

In this section, we discuss the limitations of the presented work to then outline our results' main implications for market design.

3.4.1 Limitations

Allowing our model to represent a large geographical and technological scope, while keeping it computationally tractable, required us to make several simplifying assumptions that should be considered when drawing conclusions from our results.

There are several reasons why our analysis is not suitable to estimate total future system costs or to derive recommendations on optimal system design. Some capacities in our model are endogenous, while others are exogeneous. In terms of electricity generation capacities, vRE, batteries, and H_2 are largely a result of cost-minimising investments under imperfect foresight, while hydro and other thermal capacities are exogenous. Furthermore, capacities in our model do not result from specific security of supply targets. In contrast, they result from imperfect foresight as the investment optimization in our model only considers a sample of typical and extreme weeks. Additionally, our analysis is based on a single year snapshot, such that we do not capture investments or decommissioning paths. In terms of demand-side capacities, heat pumps, fuel boilers and electric vehicle charging capacities are exogenous, while electrolyzers are entirely endogenous. Power and H_2 transmission lines in our model are exogeneous and we do not consider zonal-internal grid congestion. Finally, while total energy demand in our scenarios considers all sectors, it does not include each of their components. For instance, the transport sector neglects heavy-duty traffic or aviation. Furthermore, the industrial hydrogen demand is constant and not substitutable by electricity.

In turn, our analysis was designed to provide insights on dynamics in the future electricity market, particularly to identify drivers of prices and profitability of certain investments. The model simplifications allowed us to include technologies that are likely to affect markets in the future, namely, technologies capable of shifting load between sectors and time steps, such as heat pumps, electric vehicles, electrolyzers and long-term storages. Yet, in terms of electricity generation we neglect two aspects that could affect our market price results. Particularly, our mains scenarios only consider a single vRE profile per bidding zone and neglect thermal power plants' ramp and start-up constraints. Furthermore, cost assumptions are uniform across bidding zones. Hence, our results should not be interpreted as a projection on the future level of market prices, but rather used to identify drivers of future market dynamics. Similarly, our results on profitability of investments by technology and bidding zone are unlikely to adequately project adequate levels of cost-recovery rates, but provide insights on drivers of profits of different technologies in an imperfect short-term market. Due to the above-mentioned limitations on aspects related to investments in thermal power plants, our profitability analyses focus on investments in wind onshore and solar capacities as well as electrolyzers.

Furthermore, results rely on the assumption of perfect competition in the electricity and H_2 market. Hence, electricity generators and consumers are assumed to act rational and not to exert market power and all actors are implicitly assumed to be fully exposed to real-time wholesale market prices.

3.4.2 Implications for market design

Overall, the findings allow the conclusion that the current European electricity market design is generally suitable for the future power system as – under certain assumptions – it results in efficient price signals. In contrast to the common notion that a fully decarbonized electricity market incurs very extreme prices – with variable renewables setting the price at levels near zero in the majority of hours and peak power plants or load shedding setting the price in times of scarcity events – our results show that a flexible, cross-sectoral demand-side is able to stabilize and smooth market prices. Particularly, our results indicate that a new demand-side driven merit-order can emerge in the future market power market under the following conditions:

- A high degree of coupling of the power sector with the heat, traffic and industrial sector.
- Actors in these sectors that are capable of and incentivized to shift load between time steps or substitute electricity with other energy carriers.
- A competitive market for power and other renewable fuels, such as hydrogen.

A well-developed hydrogen and electricity grid as well as demand-side exposure to real-time market prices, amongst others, can ensure these conditions to hold.

However, future prices are shown to be volatile and dependent on uncertain parameters. According to our results, they particularly depend on prices of renewable fuels, such as hydrogen and the allowed role of thermal power in the market.

Contracts for Difference constitute an instrument to address these price risks. Our results show that they should be carefully designed as they potentially affect investment and dispatch of wind power as well as electrolyzers in the future power market. In turn, prices and profits of wind power are affected. Since CfDs define payments based on ex ante defined strike prices, yet ex post realized reference prices, these changes in market outcomes are shown to affect ex post profitability of wind onshore. In the majority of our studied scenarios, we find an excess of cost recovery for the majority of power plants, while some do not recover their costs, particularly under the financial CfD. Hence, future research should investigate the robustness of this result to derive implications for risk premia of investors under different types of CfDs and their implications for system costs. Further market design implications of the results of this project are discussed in Deliverable 5.5.

4 Conclusion

This study sheds light on the complex dynamics of the future Pan-European electricity market, focusing on the drivers of electricity prices and the profitability of variable renewable energy sources (vREs) under different market designs. A key finding is that, contrary to expectations, electricity prices in future decarbonized systems will not always reflect the low variable costs of renewable sources. Conversely, prices may frequently exceed these costs due to the opportunity costs of cross-sectoral demand, particularly from electrolyzers and other flexible technologies. Electrolyzers play a significant role as a price-setting technology, especially in scenarios with high levels of variable renewables and sector coupling.

The study also highlights that demand-side flexibility – including flexible electric vehicles and heat pumps – can reduce load shedding and curtailment and the required level of electricity generation capacities. However, while flexible demand can smooth prices, price risks remain substantial, especially for investors in vREs and inflexible electricity consumers, who face exposure to volatile and uncertain price levels. Particularly, annual averages of zonal electricity prices are shown to vary by at least 25 €/MWh among the scenarios and are particularly dependent on the share of thermal electricity generation and the H_2 import price. Furthermore, a higher level of electricity transmission capacity is shown to decrease prices in scenarios with a high share of variable renewable electricity generation.

Contracts for Difference (CfDs) are an instrument to mitigate these price risks. Governmental CfDs that stipulate payments from the government to renewable electricity producers based on the difference between a strike price and market prices, can provide revenue stability. However, the design of these contracts is critical as they affect market outcomes, particularly curtailment, electrolyzer deployment and electricity prices. Since CfDs' underlying strike prices are determined ex ante based on market expectations, but payments are defined according to ex post outcomes, most studied scenarios result in an over-recovery of costs of wind power plants. In contrast, certain wind onshore plants fall short of recovering their costs, particularly under the financial CfD scenario. This finding indicates that different types of CfDs require different risk premia. Yet, future research is required to study the robustness of this result.

In summary, our results suggest that that the current market design is generally suitable for the fully decarbonized future electricity market as it can result in efficient price signals. However, this only holds true under certain conditions, i.e. perfectly competitive markets for all energy carriers with a perfectly integrated flexible demand-side. While resulting price levels exceed variable renewables' low cost in a substantial number of hours, exact levels are uncertain and depend on the realization of these conditions. Consequently, market actors are exposed to significant price risks and are likely to require instruments to mitigate these risks. Contracts for Difference constitute such an instrument. Their design should be chosen carefully as it has important implications for market outcomes and investor risks.

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Annex

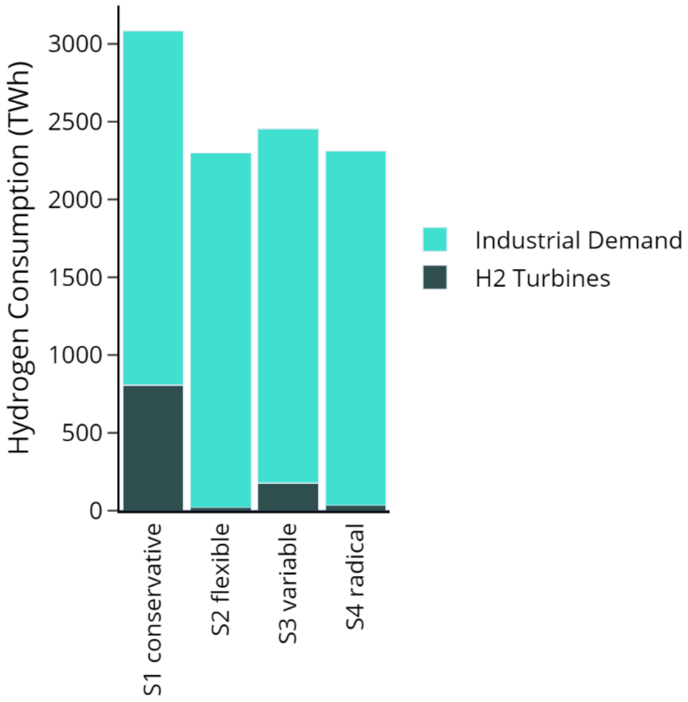

Figure 35. Hydrogen consumption aggregated over all bidding zones by scenario and source

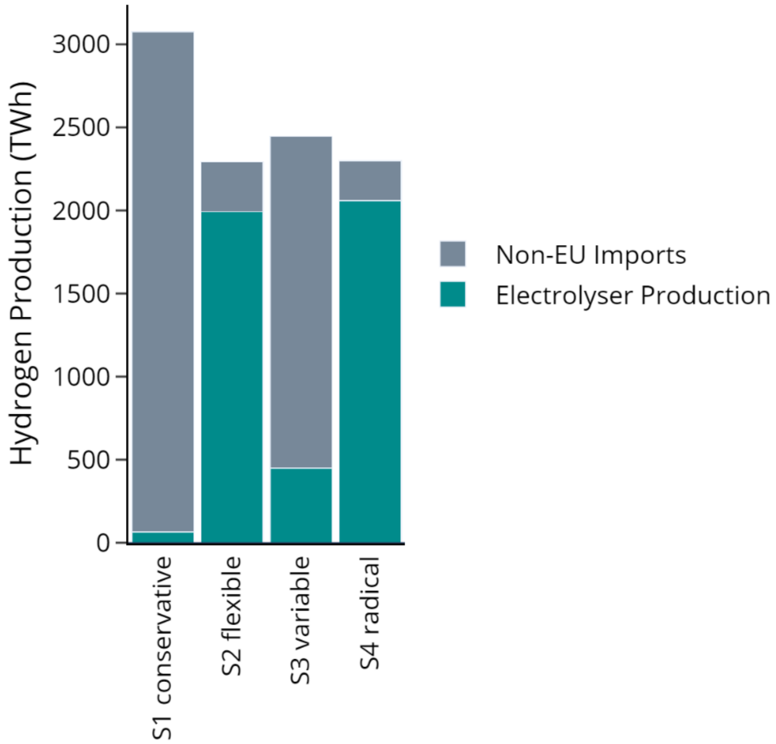

Figure 36. Hydrogen production aggregated over all bidding zones by scenario and source

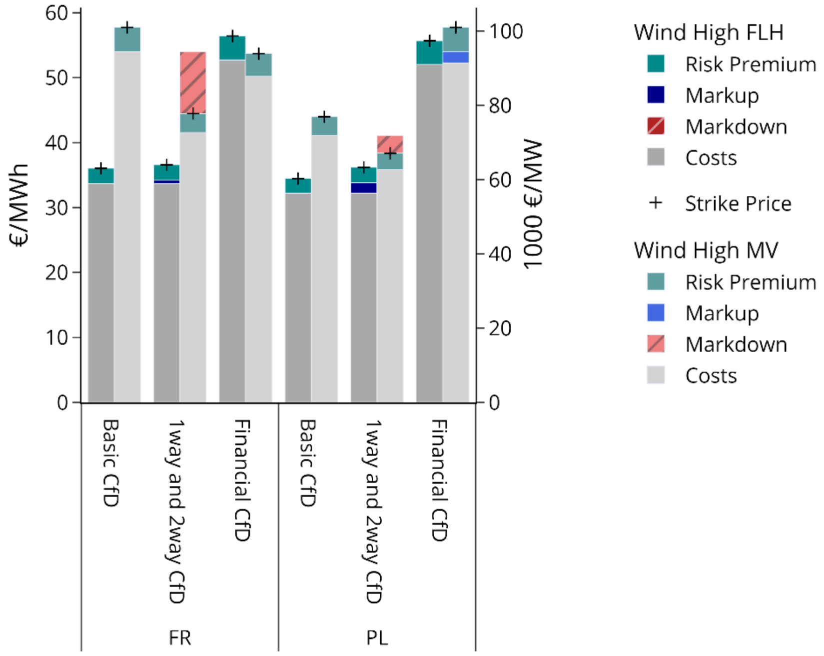

Figure 37. Optimal ex ante strike prices by wind type in France (FR) and Poland (PL)

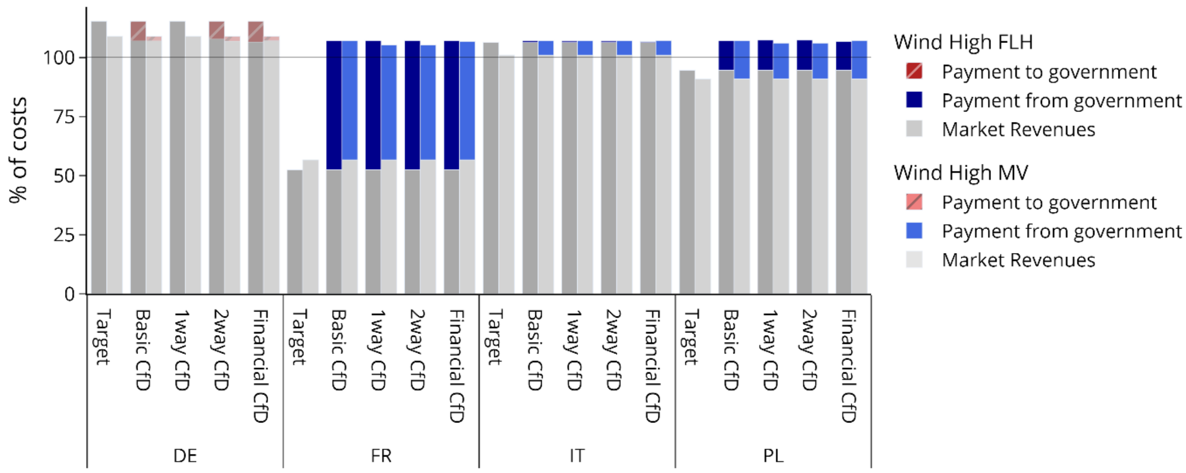

Figure 38. Ex ante expected rate of cost recovery by wind type in Germany (DE), France (FR), Italy (IT) and (PL)

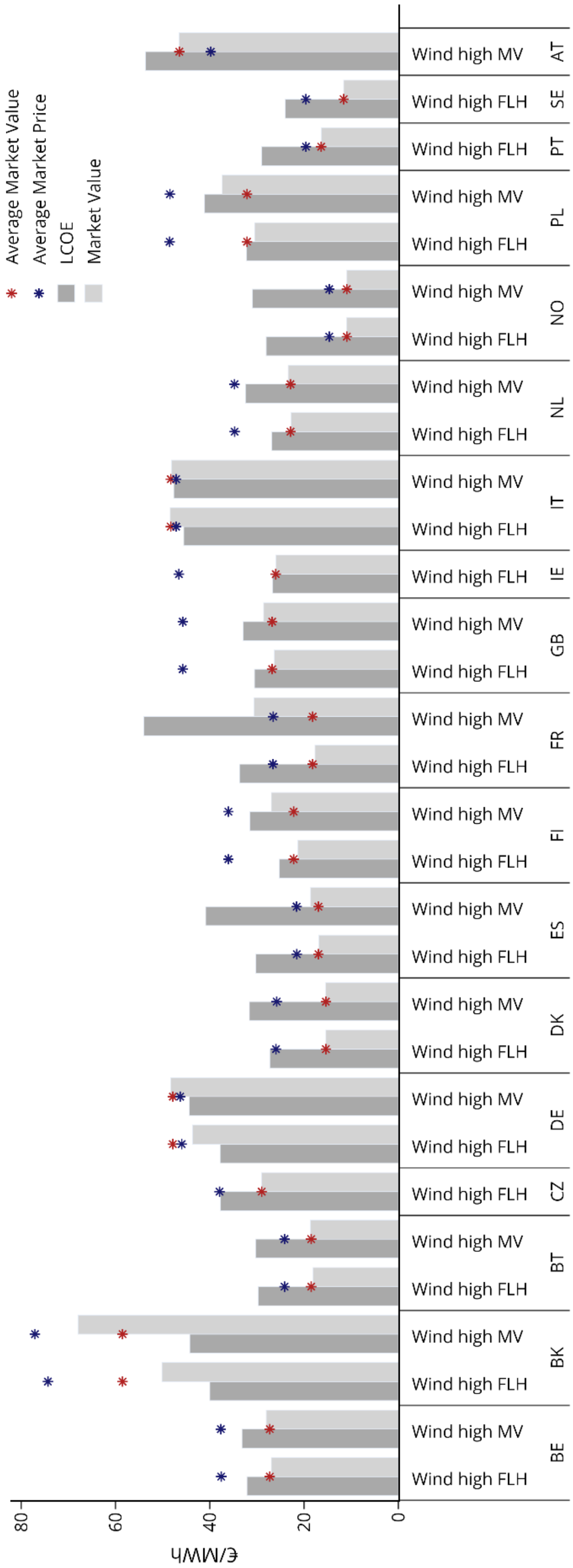

Figure 39. Profitability of new wind onshore power plants by type and bidding zone in the target scenario