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Innovative Electricity Market Designs to Support a Transition to (Near) 100% Renewable Power System: First Results from H2020 TradeRES Project

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Developing innovative electricity market designs to facilitate a sustainable transition to (near) 100% renewable power systems while meeting societal needs is a crucial and actual topic of research. This article presents preliminary key findings from the H2020 European project TradeRES, addressing this critical topic. The project uses agent-based and optimization models to effectively capture the behaviour of different market players, and to analyse the current and future power system energy mixes of selected European case studies with different physical and spatial scales from: i) local energy communities and local energy markets (LEMs); ii) national/regional - the Netherlands, Germany, and Iberia (Portugal and Spain); and iii) pan-European energy markets. The first results on LEMs indicate a substantial economic benefit for participants and enhanced revenue streams for distributed energy resources, able to i) incentivise further decentralised investments; ii) promote the growth of variable renewable energy systems (vRES) and iii) increase flexibility at the local level. The outcomes are sensitive to the tariffs' structure, while the retail sector competitiveness was identified as a critical parameter affecting its efficiency. For the pan-European and national/regional case studies, the first set of simulations had consistent outcomes, namely, by pointing out current design of energy-only markets to be insufficient to incentivize the high levels of vRES foreseen in Europe. Different support schemes (e.g., fixed market premia, contract for differences) were tested and results suggest they may play a relevant role in effectively covering the cost of vRES in a market environment.

1 Introduction

Existing electricity markets, mainly designed in a period where conventional fully dispatchable power technologies dominated, rely on marginal-cost pricing to efficiently deploy available resources and provide technologic investment incentives. This market principle becomes dysfunctional in power systems with a significant share of variable renewable energy systems (vRES) like wind and solar photovoltaic (PV) both technologies that have marginal costs close to zero [1].

Despite the environmental benefits associated with the large-scale integration of vRES, their variability can lead to situations where excess energy floods the electricity markets, causing prices to drop to zero or even be negative. Using agent-based simulation or autoregressive models, several studies have analysed this phenomenon, designated as the "merit order effect", which has been already observed in various electricity markets [1]. While the decrease associated with the merit order effect can benefit consumers, for certain levels of vRES penetration, it leads to a reduction in the power producers' profits, often referred to as the "self-cannibalization effect" [2]. This effect can, for instance, decrease the incentives to invest in new capacity needed to achieve the ambitious European renewable targets for the next decades. On the other hand, when demand is high and vRES generation is low, energy prices increase. Unforeseen events, like the energy crisis in Europe, have exacerbated the volatility in energy prices and raised major concerns related to existing market designs, investment risk, and the protection of the consumers, as recently highlighted by the European electricity market reform consultation [3].

The European energy goals for 2030 [4] and beyond are clear and highlight the path for the energy transition to decarbonize the power systems having wind and solar PV playing important roles. Additionally, supported by the decentralization and digitalization of the power systems,

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new market players and designs are expected to arise aiming to reflect, among others, the value of existing and new flexibility sources (*e.g.*, distributed storage, flexible consumers/prosumers) and remunerate them adequately, integrate the end-user consumers/prosumer and local energy communities to stimulate flexibility offered by demand response in an economically efficient manner, and facilitate sector coupling (between the electricity system and other energy sectors/vectors, *e.g.*, heat/H_2) [5].

The project TradeRES [6], is developing innovative electricity market designs that address society's challenges during the transition to a nearly 100% renewable power system. The focus is on creating sustainable market designs with efficient investment incentives for systems relying on vRES. These designs also seek to integrate with other energy sectors and encourage flexible electricity demand, while ensuring security of supply and efficiently managing market risk to protect consumers from extreme swings in energy expenses. To achieve such goal the project is developing new tools for analysing electricity markets, and engaging key stakeholders in the development and use of the simulation tools.

This work presents the first set of results obtained with the new market designs developed within TradeRES, using new models capable to incorporate the behaviour of different market players. The project addresses existing and future power system energy mixes of European countries with physical differences as well as different spatial scales from: *i)* local energy communities and local energy markets (LEMs); *ii)* three national/regional - the Netherlands, Germany, and Iberia (Portugal and Spain); and iii) pan-European energy markets. The different designs are assessed based on quantitative market performance indicators such as captured costs by vRES players and investment cost recovery.

Future market scenarios with near 100% renewable energy systems (RES) were constructed within the TradeRES project, for power system energy mixes of European countries that use, as input, data from ENTSO-E and 2030 national energy and climate plans [4], [7]. Four possible optimal operation scenarios for electrical power systems, considering a near 100% renewable power system energy mix were created (*S1*- *S4*) [8]. These scenarios, used only in national/regional and pan-European markets simulations, vary based on demand flexibility and assumptions regarding power generation, such as thermal capacity, hydrogen power plants, and curtailment.

Different target shares of non-thermal renewable energy in the pan-European region were explored in the supply side, ranging from approximately 85% (*S1* and *S2*) to a minimum of 95% (*S3* and *S4*). On the demand side, sector coupling and demand-side flexibility by adjusting the number of electric vehicles and the annual exogenous hydrogen demand were explored. Specifically, lower levels of exogenous hydrogen demand were considered in *S1* and *S3*, while higher levels were considered in *S2* and *S4*. Cross-border transmission capacities and conventional demand were exogenously set according to year 2030 in ENTSO-E's Global Ambition scenario. Load and capacity factor time series are based on the weather year 2019. Scenario *S0* represents the transition from the European power system *status quo* in 2019. The initial generation mix for this scenario is based on ENTSO-E's European resource adequacy assessment capacities for 2030, with partial adjustments based on the 2030 national energy and climate plans. These scenarios were optimized using the Backbone model [9], which provides information such as energy mixes and the hourly optimal operation of the power system. Figure 1 illustrates the different scenarios conditions and timelines.

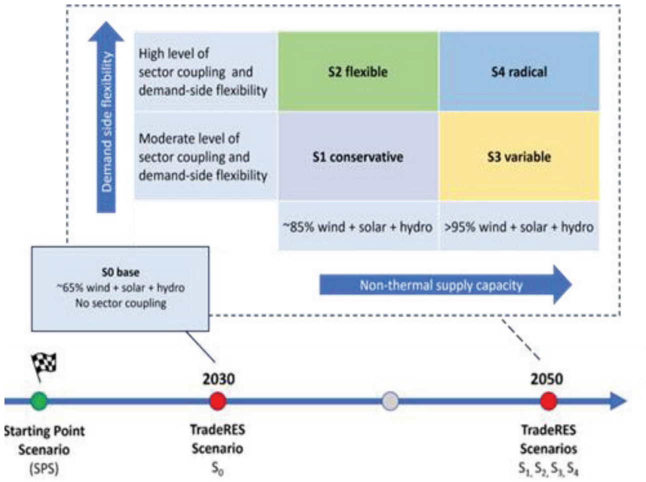

Figure 1. TradeRES scenarios and timeline.

The timeline in Figure 1 outlines the key milestone years for the scenarios and includes the Starting Point Scenario (SPS) that precedes the TradeRES project's beginning, corresponding to the year 2019. This year was mainly used to *calibrate* the different models used.

2 Local energy markets

Local energy markets (LEM) are an innovative concept facilitating direct energy trading at a local scale, enabling prosumers to interact and engage in mutually beneficial transactions without relying on intermediary entities like retailers, aggregators, or nominated energy market operators. This approach avoids substantial transactional fees, leading to advantageous energy prices for both local producers and consumers. Furthermore, it offers the added advantage of partially or entirely circumventing unfavorable retail tariffs that may involve significant price discrepancies between import and export tariffs. The analysis of LEM takes place at various levels of focus, aiming to examine the impacts of LEM on the involved stakeholders and the effects on the operational and market layers of the system. In Figure 2 two specific environments of focus within the LEM Simulation Framework of TradeRES are illustrated [10]. The first environment, labelled "broad", highlights interactions with the strategic retailer, while the second environment, labelled "narrow", concentrates on studying the LEM mechanisms, such as mid-market rate, double auction, and others.

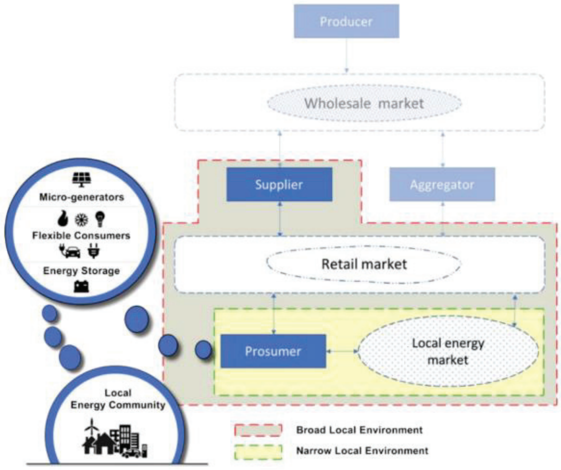

Figure 2. Environments of LEM Simulations Framework.

The project also considers retail market characteristics as relevant parameters, with a particular focus on the tariff structure. Time-of-Use (ToU) and dynamic tariffs are typical tariff structures investigated under various case studies. These investigations help in understanding how LEM can influence the behaviour of different actors in the energy community and how it can impact the overall functioning of the energy market.

Some indicative results of the initial simulation stage are based on the interaction of a centrally managed LEM and a retailer that can strategically set the offered tariffs [11]. Figure 3 (a,b), extracted from [10], shows the LEM price together with the tariffs that have been optimally chosen by the retailer, given the wholesale price, under the dynamic and ToU structure. Figure 3 (c,d) shows the utilisation of flexible resources (storage) under the different tariff schemes.

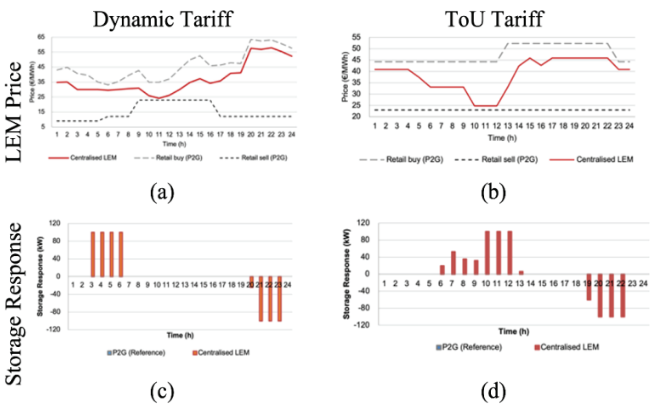

Figure 3. Interaction of the LEM with the strategic retailer.

It should be noted that the introduction of the LEM increases the social welfare by increasing competitiveness and shifts significantly surplus to prosumers leading to a more fair and democratised distribution of wealth, improved profitability of DERs [12] and enhanced price signals for decentralised investments. Among the significant findings, it is also the dependency of the efficiency of tariffs structures on the competitiveness of the retail sector, pinpointing that it is important to establish, monitor and maintain a highly competitive market environment [10].

At local community level, a regulatory framework of local energy communities (LEC) highlighting their role in power systems and their potential, benefits, and functions was presented [13]. A strategic bidding process for LECs was presented in [14]. This strategic bidding considers the active participation from LEC in wholesale markets without intermediaries.

2.1 Blockchain in Local Energy Markets:

Energy markets have traditionally relied on centralized systems to oversee and record transactions between actors. Such systems, typically broker-mediated, have long been the standard. However, the emergence of blockchain technology offers an alternative approach: decentralization. At its core, blockchain operates as a distributed ledger, documenting every transaction and contractual agreement, with options for both public and private configurations. The design and immutable nature of the blockchain not only provide exceptional data integrity but also introduce the concept of 'smart contracts'. These automated agreements allow consumers and prosumers to engage in energy trading based on specific conditions, such as buying power at favorable prices. Furthermore, the connection between blockchain and cryptocurrencies like Ethereum creates opportunities for direct peer-to-peer transactions, potentially using stablecoins tied to regional currencies. Given the transparent yet unchangeable nature of blockchain transactions, platforms are emerging that leverage artificial intelligence for more efficient energy trading.

3 National and regional energy markets

Three national/regional electricity markets are analysed: two related to the Central European market - EPEX SPOT: the Netherlands (case study B) and Germany (case study C), and one related to the Iberian electricity market – MIBEL (case study D). The studies are conducted using different models and computational systems as described in the following subsections.

3.1 The Dutch Market – case study B

The large-scale potential of offshore wind energy in the North Sea puts the Netherlands in a privileged position to accommodate large shares of vRES to meet both domestic and foreign electricity demand. Therefore, the main research question addressed during the first iteration of the NL case study is: “*To what extent can an energy-only market with/without vRES targets provide system adequacy for a 100% RES system by 2030 and 2050?*”

To answer this question, a coupled AMIRIS-EMLabpy model approach is used to test different market design options. AMIRIS and EMLabpy are both agent-based models. EMLabpy was developed by TU Delft in order to investigate the influence of policy on investments in power generation. Within the NL case study, EMLabpy was co-simulated with AMIRIS (developed by DLR, see Section 3.2 below) in order to complement EMLabpy with AMIRIS’ detailed representation of the electricity market. In particular, AMIRIS allows representing flexibility options of the power system and evaluating several RES support mechanisms but lacks the possibility to model investments in power generation (further details available at [15]).

3.1.1 Scenarios, input data and limits of the analysis

During the first iteration of the NL case study, the two specific design options tested were: *i)* an energy-only market without vRES targets, designated as *EOM*, and *ii)* the energy-only market with vRES targets, designated as *EOM_VRES*. The results are obtained for the period between 2019 and 2050 on a yearly basis.

The initial set of power plants are the ones installed before 2019 and the plants to be commissioned until the year 2024. This set of power plants is obtained from KEV 2022 [16]. The candidate technologies to be installed include *i)* large PV systems, *ii)* wind (both onshore and offshore), *iii)* biomass CHP, and *iv)* gas (both OCGT and CCGT). The investment costs, fixed costs, fuel costs, other variable costs, technical lifetime and efficiency of the technologies are obtained from the TradeRES database [17].

A major limitation of the first iteration of the NL case study is that fuel, CO_2 and technology costs are fixed to the level of the year 2030. For instance, the CO_2 cost is fixed to the projected price for 2030 of 93 €/tonne. These assumptions give unrealistic results because, in reality, the capital costs of RES are expected to decrease and, in contrast, fossil fuel and CO_2 prices are expected to increase. In the second iteration, increasing fossil fuel and CO_2 costs and decreasing RES capital costs will be considered. For this reason, the following results should be regarded as preliminary and the numbers are expected to change significantly in the next iteration.

3.1.2 Simulation results and analysis

Some (preliminary) findings of the first iteration of the NL case study regarding some key market performance indicators (MPIs) include:

- *The share of RES in total electricity demand* reaches a limit of around 60% in the case of the profit-based EOM without vRES targets (‘*EOM’*) against about 80% in the EOM case with vRES targets (‘*EOM_VRES*’; see Figure 4). This indicates that a profit-based EOM is not sufficient to achieve a very high share of RES in total electricity demand (*i.e.*, 80% or more).
- Over the years 2035-2050, both system adequacy indicators *Loss of Load Expectation (LOLE)* and *Expected Energy Not Served (EENS)* are slightly lower in the EOM case than in the EOM_VRES case, whereas the so-called ‘*supply ratio’* – defined as the minimum of hourly supply/hourly demand over the year – is slightly higher in the EOM case. This indicates that the security of supply is slightly better in the EOM case than in the EOM_VRES case. The main reason for this (small) difference is that the capacity of dispatchable technologies is slightly lower in EOM_VRES (due to the higher installed vRES capacities in this case).
- From 2035 to 2050, the *average annual electricity prices* are significantly lower (about 20 €/MWh) in the EOM_VRES case than in the EOM case (due to the higher installed vRES capacities in EOM_VRES). As a result, the indicator of the *market-based cost recovery* is substantially higher in the EOM case than in the EOM_VRES case. On the other hand, however, the indicator *costs to society – i.e.,* the electricity price + the vRES support costs per unit of electricity consumed – is only slightly higher (about 5 €/MWh) in the EOM_VRES case than in the EOM case.

It should be recalled, however, that the findings summarised briefly above are preliminary, first-iteration results and that they can change substantially in the follow-up, final iteration under less stringent, more realistic modelling assumptions.

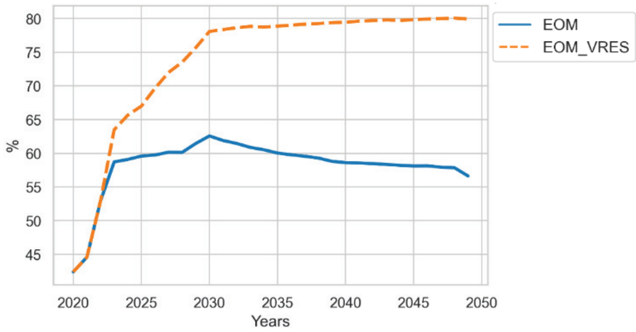

Figure 4. Evolution of RES share in total electricity demand in the Netherlands for two market design options.

3.2 German Market – case study C

In Germany, the pace of deployment of renewable energies has taken up some speed recently after slowing down in the years before, compared to the maximum installations of the past. Still, it remains very unsure if the targeted expansion will be met as it is drastically above recent expansion rates, especially for wind energy, both onshore and offshore. Midst of the ongoing energy transition, the German government decided to evaluate the development of market-driven deployment of renewables and to present a proposal by March 2024 for financing renewables after the coal phase-out. In the following analyses, the associated question shall be addressed: Are remuneration schemes for fluctuating renewable energies needed and, if so, how could they be designed? To this end, a range of remuneration schemes for renewable energy sources with regards to their power system effects and assess the overall market dynamics via market performance indicators were analysed.

3.2.1 Scenarios, input data and limits of the analysis

The analyses on the German case study are carried out using the Agent-based Market model for the Investigation of Renewable and Integrated energy Systems (AMIRIS) [18]. AMIRIS simulates electricity prices endogenously based on the simulation of strategic bidding behaviour of prototyped market actors. Their bidding behaviour does not only reflect marginal prices but can also consider effects of support instruments like market premia, uncertainties and limited information [19].

Multiple simulations with a range of five different remuneration schemes for renewable energy sources were run, namely, no remuneration ("NONE"), capacity premia ("CP"), fixed market premia ("MPFIX"), variable market premia on a monthly basis ("MPVAR") - effectively a one-way contract for differences (CfD) design, and two-way CfD with a monthly reference period ("CFD"). For calibration, the fixed market premia are adjusted in an iterative process, such that each renewable energy technology refinances on average and, at the same time, overpayments are avoided. Thus, each technology's revenues exactly match their total cost within a 0.1% tolerance. The other remuneration schemes are parameterized using the total costs and associated generation from the calibrated fixed market premium simulation and hence, distinct effects of a remuneration scheme may be isolated. Besides the different remuneration schemes, all scenario parameterisations are equal and are based on the above mentioned *S1* scenario. Technology-specific annualised cost and revenue were examined as well as economically induced curtailment situations.

3.2.2 Simulation results and analysis

Preliminary results reveal that total system costs for dispatch are quite similar with or without support instruments. However, the market performance indicator "market-based cost recovery" in Figure 5 clearly shows that renewables need remuneration schemes as their market revenues are significantly too low to cover their costs under the scenario assumptions: Between 75% (wind onshore) and 85% (PV) of the total cost cannot be covered at the day-ahead market. Renewables that are remunerated through a capacity premium achieve almost as much refinancing on the market as in the case of NONE. If, in contrast, renewables are remunerated through production-dependent support instruments (MPFIX, MPVAR and CFD), this results in slightly lower wholesale market prices and hence lower revenues, as the market premia received will be factored into the traders' bids. Although not shown, the market performance indicator "total cost recovery" presents values close to 100% if support mechanisms are employed. This confirms that the parameterisation of the simulations leads to support instruments that are both effective and efficient as RES recover their cost and overpayments are avoided. Reflecting very small differences in the market-based cost recovery, the average premium payments per technology reach similar values. They amount to around 30 €/MW for PV, to around 33 €/MWh for wind onshore, and to around 45 €/MWh for wind offshore (Figure 6).

3.3 Iberian Market – case study D

In 1998, the Portuguese and Spanish governments started working together to create the Iberian Electricity Market (MIBEL) to foster the integration of their respective electrical systems.

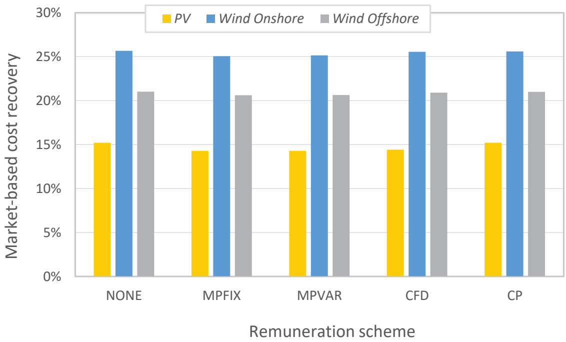

Figure 5. Market-based cost recovery at the DAM for different RES and support schemes.

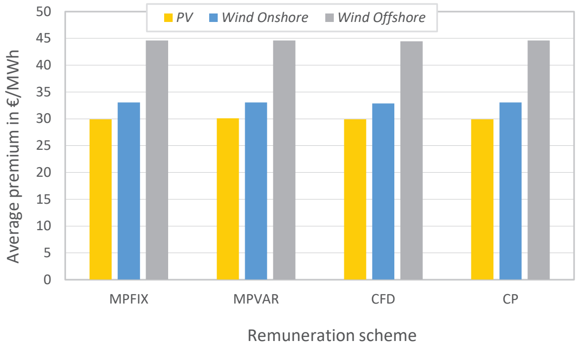

Figure 6. Average premium paid for different RES.

MIBEL was fully launched on July 1st, 2007, providing a framework for granting access to all interested parties following the norms of equality, transparency, and impartiality, aiming to benefit the consumers of both countries. MIBEL is composed of day-ahead and intraday auctions markets, an intraday continuous, and bilateral markets, being responsible for the ratification of all private bilateral agreements for electrical energy acquisition in Iberia.

Portugal and Spain are among the European countries with a higher penetration of vRES in their power systems. The main research questions addressed in the Iberian case study are as follows: *i)* "*How can short-term markets be made more efficient in order to better integrate short-term vRES fluctuations?*" and *ii)* "*Are vRES remuneration support schemes needed and if so, how should they be designed?*" To answer these questions, the agent-based models MASCEM [20] and RESTrade [15] are applied to a starting point scenario that was constructed considering the status quo of the Portuguese and Spanish power systems using historical data from the year 2019. Different market design bundles for vRES producers are analysed, namely, *i) EOM, ii) CP, iii) MPfix*, *iv) MPvar*, calculated to ensure full cost recovery of the vRES investments, *v) 1wayCfD*; *vi) 2wayCfD*, and *v)* capped premium (*MPcap*). In this paper, preliminary results to answer the research questions are presented using the data from 2019.

To run this case study, MASCEM's MIBEL day-ahead model is used for the simulation of Iberian's day-ahead session, and RESTrade models to execute ancillary services market after each day-ahead session. It should be noted that these models aim to simulate and replicate real spot market's operation as well as to test and study new market designs including vRES contribution to ancillary services. However, they do not consider nor study investment decisions.

3.3.1 Scenarios, input data and limits of the analysis

To tune and test the market models, real publicly available day-ahead bids from the Iberian market [21] for the whole year of 2019 have been used to feed MASCEM. Each bid includes the following details: hourly period, date, country, trading unit code, type of offer (*i.e.*, buy or sell), energy amount in MWh, unit price in EUR/MWh, and the indication if the bid was traded after market execution. Using real data to feed and tune the market models, enables to simulate and compare the simulation outcomes with the real-world results. This comparison is presented in detail in [8].

3.3.2 Simulation results and analysis

2019 was a stable year in MIBEL without cases of LOLE, EENS, and vRES curtailments. Portugal and Spain had similar shares of non-fossil fuel generation of 55% and 62%, respectively. In Portugal, the renewable generation share was 55%, and in Spain, it was 39%, which results in a levelized 0.22 and 0.18 t CO_2/MWh emissions per country, respectively. Spain also had a share of 23% of carbon-neutral nuclear production. The yearly levelized day-ahead prices in both countries were 50.24 and 50.14 €/MWh, respectively. They had a full price convergence of 0.13 €/MWh with less than 5% occurrences of market splitting.
Due to prices observed in day-ahead markets, it was difficult for technologies to recover their production costs from EOM. Figure 7 illustrates the EOM cost recovery of the most significant technologies in the Iberian countries considering a discount rate of 4%. Analyzing the figure is possible to conclude that only gas, nuclear, and large-scale solar PV can recover their production costs from EOMs. Thus, these preliminary results show that with the parametrisations and data used, all the other technologies can need support schemes and/or capacity mechanisms to be economically viable. These results can also be partially explained by the high average balancing penalties of 9.32 and 10.69 €/MWh in Portugal and Spain, respectively. These costs contribute to reducing the market remuneration of vRES. Changes to market designs of ancillary services are needed to reduce those costs.
Against this background, six different support schemes for onshore wind were simulated. It is considered that the support schemes will support new onshore wind investments for 12 years with a discount rate of 4% (check [8] for details about the investment parameters). Figure 8 presents the simulated Portuguese and Spanish costs with each support scheme to wind power plants during 2019.
On the other hand, in Portugal, the 2019 wind power productivity was above the average, which increases their remuneration in other support schemes analysed concerning the variable premium, except the two ways CfDs.

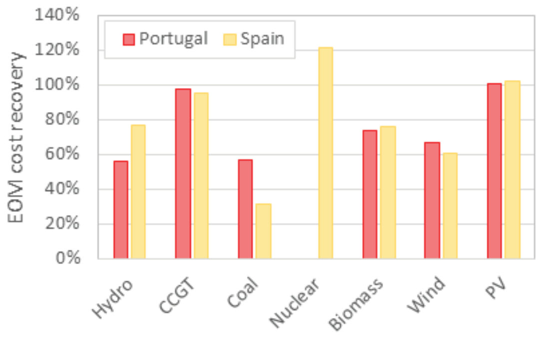

Figure 7. Market-based cost recovery of the technologies in Portugal and Spain.

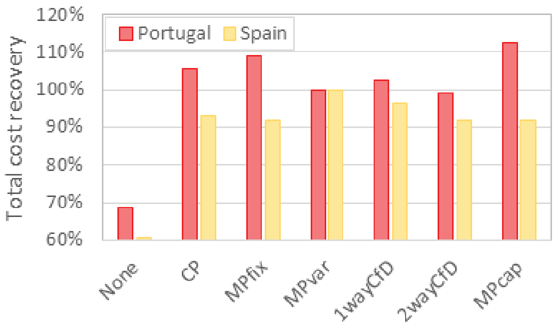

Figure 8. Costs with wind power plants in Portugal and Spain for different support schemes.

Preliminary results of this case study indicate that while in Portugal, wind power investors recovered their production costs, in Spain, it only happened when considering the variable premium scheme.

4 pan-European energy markets – case study E (EnBW)

In the pan-European case study, the profitability of wind power in different scenarios of fully decarbonized European wholesale markets and how they are impacted by different types of CfDs as support schemes were studied. For these simulations, were applied the open-source energy system modelling framework Backbone [9]. TradeRES Pan-European power system model covers all EU27-countries except of Malta, Cyprus and Iceland, but it includes Great Britain. One bidding zone per country or aggregates of countries as Luxembourg and Germany as well as the Baltic and Balkan states were simulated. A soft-linking methodology consisting of investment and operational optimisation phases, both implemented in Backbone in linear programming mode was employed. The investment optimisation phase represented a year using 5 typical - selected using random sampling [22] - and 2 extreme weeks, while the operational optimisation phase employed a rolling horizon that sequentially optimised the next 24 hours while modelling the remaining 364 days at a coarser resolution in the look-ahead window. It was interpreted that the marginal value of the energy balance constraint as wholesale electricity prices under the assumption of perfect competition similar to, *e.g.*, [22].

Two different wind power technologies per node were included and characterized by different capacity factor time series.

4.1 Simulation results and analysis

For the preliminary results, were chosen scenario *S3*, namely the scenario with an enforced share of non-thermal renewables of 95% and a moderate level of demand flexibility, as our "Reference". This scenario's simulation results indicate that profitability of wind power across technologies and countries is heterogeneous. Particularly, in some countries both wind power plant technologies are profitable, while one or both are unprofitable in others. Subsequently, four different types of CfDs as support schemes for wind power were introduced to this scenario. CfDs are financial contracts that specify payments from (to) the government to (by) a renewable power producer that are determined by a reference price p^R and a strike price s in €/MWh. Generally, for a renewable power producer with electricity production q_t in period $t \in (1, T)$ and a wholesale market price p_t, revenues of wind power technology $i \in (1, 2)$ in node $n \in (1, N)$ under a CfD are given by $\sum_{t=1}^{T}(p_{tn}q_{tin} - (p^R - s)q_{tin})$. From a regulator's perspective, the introduction of such contracts is two-fold. Firstly, the introduction of contracts for difference can incentivise investments in wind power by reducing wholesale market revenue risks. Secondly, contracts for difference can cap wind power plant's wholesale market revenues and make consumers participate in their low production costs.

As market design bundles, four different types of CfDs in our Pan-European model were implemented. (1) The first one implemented is a simple two-way CfD with $s = LCOE_{in}$, *i.e.*, levelized costs of energy for power plant i in node n and p^R=p_{tn}, *i.e.*, hourly market price in node n according to our reference scenario S3. (2) A complex two-way CfD with $s = LCOE_{in}$ and p^R=$\overline{p_n}$, where $\overline{p_n} = \frac{\sum_{t=1}^{T}\sum_{i=1}^{2}p_{tn}q_{tin}}{\sum_{t=1}^{T}\sum_{i=1}^{2}q_{tin}}$ represents the average market value of wind power in node is used, *i.e.*, the average market value of the two wind power technologies. (3) A complex one-way CfD with $s = LCOE_{in}$ and p^R=$\overline{p_n}$, if $\overline{p_n} < s$ and 0 otherwise is also modelled. Finally, a newly developed financial CfD, where payments are independent of MWh produced are also implemented [23]. Particularly, the revenues of a power plant under a financial CfD is given by $\sum_{t=1}^{T}p_{tn}q_{tin} + S_{in} - R_n$, with $S_{in} = \sum_{t=1}^{T}\sum_{i=1}^{2}LCOE_{in}q_{tin}$ and for equal capacities $R_n = \frac{\sum_{i=1}^{2}\sum_{t=1}^{T}p_{tn}q_{tin}}{2}$, *i.e.*, average wholesale market revenues. The market designs are then implemented under the assumption that the reference simulation result represents the expected market results of the power plant producers and therefore, ex ante expected payments to or from the government. Particularly, it is assumed that under a simple one-way CfD, power plant producers expect to receive a payment of $\sum_{t=1}^{T}(p_{tn} - LCOE_{in})q_{tin})$ on top of their wholesale market revenues, which is subtracted from their investment costs. Similarly, for the financial CfD subtract $S_{in} - R_n$ as defined above from investment costs. For the complex one-way and two-way CfD the variable costs were changed according to expected payments per MWh, namely $\overline{p_n} - LCOE_{in}$ for the two-way CfD case and $\min\{0, \overline{p_n} - LCOE_{in}\}$ for the one-way CfD case. For all market design simulations, we remove the constraint enforcing a certain share of non-thermal renewable energy to study, which market design can lead to this target share in the most effective way.

Figure 9 shows installed capacities for the reference as well as market design simulations. It can be seen that fewer new wind capacities are installed under the simple and financial CfD case in exchange for more battery storage and solar PV power, while most new wind capacities are installed under the *2way CfD* case. Figure 10 represents a snapshot of differences in investments for Finland and France. In both scenarios, the capacity mix of the financial CfD scenario comes closest to the Reference case. In conclusion, our preliminary results indicate that different types of CfDs can incentivize investments in wind power plants, yet, the type of CfD chosen affects the mix of power plant technologies and resulting wholesale electricity prices.

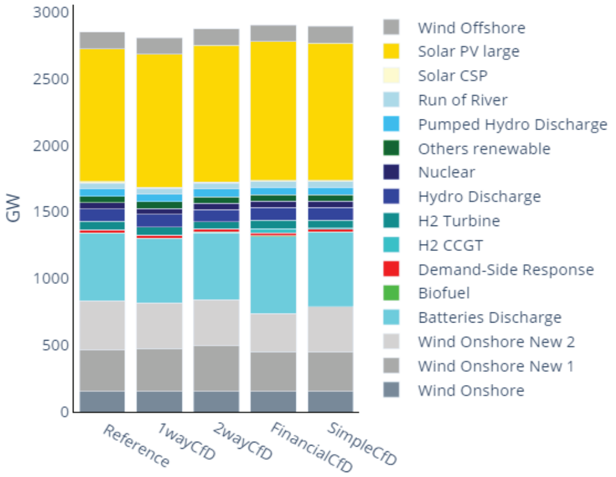

Figure 9. Installed capacities aggregated over all nodes.

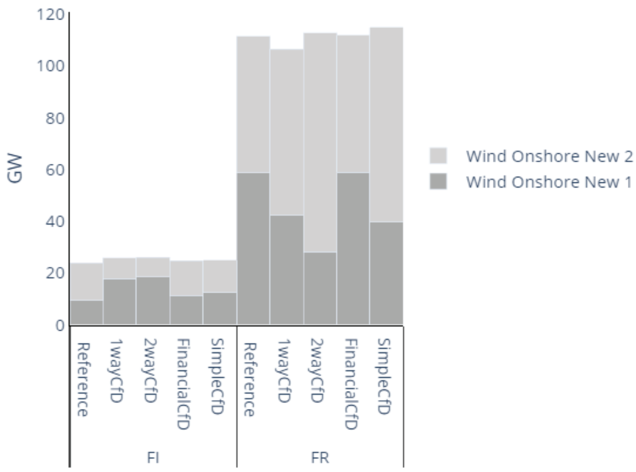

Figure 10. Investments in new wind power capacities for two selected nodes.

5 Final remarks

This work presents the first set of results obtained with the new market designs developed within TradeRES, using tools capable of incorporating the behaviour of different market players were presented in this work.

Results show that during the period studied from 2019 to 2050, all vRES need support schemes to be attractive to their investors due to the high penetration of the (near) zero marginal cost technologies. Therefore, changes to current market designs shall decrease the power system costs and increase the market value of vRES, reducing the need for externalities like support schemes and capacity mechanisms. Furthermore, more decentralized variable generation incentive the development of local energy communities and markets, helping system operators manage imbalances at lower costs to end-use consumers.

The project TradeRES will continue to develop tools and test different elements of market designs to provide recommendations for the best designs to achieve nearly 100% carbon-neutral power systems.

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