# *MODELLING PRICE DYNAMICS IN ELECTRICITY SYSTEM MODELS*

Carla Mendes, Centre for Environmental Policy, Imperial College London, c.tavares-mendes@imperial.ac.uk
Iain Staffell, Centre for Environmental Policy, Imperial College London, i.staffell@imperial.ac.uk
Richard Green, Imperial College Business School, Imperial College London, r.green@imperial.ac.uk

## Overview

Electricity market models have been a fundamental tool used by policymakers and participants to guide their decisions in terms of shaping future power markets or investing in emerging technologies. However, all too often models lack transparency and validation (Pfenninger et al., 2017; Ringkjøb et al., 2018).

Current electricity system models generally optimise expected supply and demand in order to minimise the total power system cost. One of their strengths is the accurate representation of dispatch decisions by incumbent generators, but they struggle to reproduce realistic daily variation and spreads of prices (Ward et al., 2019). Literature on the validation of time-dependent variations of price outputs produced by these models is still scarce.

The relevance of replicating realistic power prices in terms of their volatility and spread goes beyond their importance to create good investment signals for new investors. In the coming years, electricity markets will undergo extensive reforms to decarbonize demand and supply, in ways that will increase price volatility. Demand profiles will become more volatile as the use of electric vehicles and electricity for both space heating and cooling increase. The generation mix is also changing rapidly, with variable renewable technologies increasing their participation in the electricity market, making it harder to predict the impacts of price variation on generation.

Many of the solutions to help accommodate these changes rely on arbitrage for their business case (e.g., over space for transmission, or over time for storage). Therefore, an inadequate representation of electricity price volatility in current models can lead to an underestimation of the revenue available to storage technologies and transmission grids (with energy-only remuneration), and thus the optimal amount of investment in them. The homogenous price signals that result from these modelling tools will also misrepresent the size of price cannibalization on renewables, the value of flexible peak capacity, and so on.

## Methods

For our analysis, we employ the electricity market model EuroMod. EuroMod is an aggregated nodal price market model that connects 27 European countries using net transfer capacities (Figure 1). It considers the technical restrictions of power plants with a representation of storage technologies, such as hydropower and batteries. It runs on an hourly basis and generates country-specific hourly generation mix, nodal electricity prices and trade flows. The model has been tailored to analyse the future European energy transition up to 2050. The future energy system is assumed to develop according to the reference scenarios given by the TYNDP 20 scenarios, and the hydrological inflow data we employ is derived from the ENTSO-E hydrological model PECD (de Felice, 2020; ENTSOG & ENTSOE, 2021).

To better represent electricity prices, we changed the total system cost function from the standard type based on a marginal cost step function to a quadratic form. This reflects generators' flexibility to bid below or above their marginal costs. Additionally, we incorporate start-up costs into the model by post-processing the electricity price. Following Staffell & Green (2016), we account for start-up costs when computing electricity prices and the optimal capacity mix, but not when computing the hourly dispatch decisions, thus avoiding the need for more demanding integer programming. By using a non-linear form for system costs and by including starting costs, we were able to develop more realistic supply and price curves that significantly improve the model's skill at representing daily price variation. Furthermore, external effects on prices derived by interconnectors were also considered, by extending the model to the European level. Finally, a statistical calibration process is introduced to account for other factors that might affect power plants' marginal costs such as the impact of supply margins (i.e., the difference between available capacity and demand) on agents' strategic behaviour that occur during scarcity situations, as suggested by (Mahler et al., 2022).

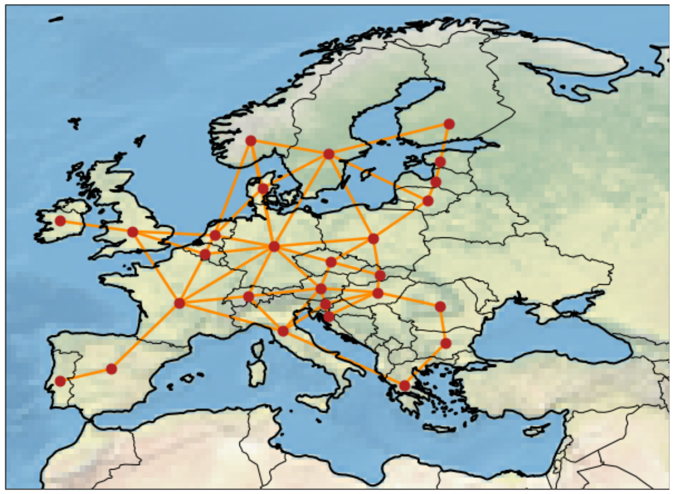

Figure 1: Spatial dimension used in EuroMod with grid connections

## Results

This is work-in-progress and we do not yet have results to present. We are currently in an advanced modelling stage (final calibration of EuroMod) and the results are expected to be finalised mid to end of March and will be therefore included in the paper draft submitted to the IAEE Tokyo conference. As indicated in the methods section, we expect the results to highlight the impacts of these model changes on the accuracy of electricity price simulations. Particularly, we expect to be able to simulate electricity prices that can represent not only the yearly average prices but also the amplitude of price spikes. In addition, by performing a cross-comparison between the historic period of 2017-2021 and 2050, we will be able to compare the impact of different market conditions brought by the European energy transition on electricity prices. This is of particular relevance as it plays a central role in guiding the decisions of both market participants and policy makers. It also provides better market signals regarding future revenues to support investment decision on key technologies to support the current energy transition.

## Conclusions

The decarbonisation of electricity markets is disturbing demand and supply in ways that increase price volatility. Structural models of day-ahead markets account for price formation mechanisms and techno-economic constraints, allowing us to find the optimal price to minimize total system costs. They usually predict quite well yearly average prices but, typically, misrepresent the volatility and amplitude of price spikes. Solutions that help to accommodate the current energy transition rely on arbitrage opportunities. Therefore, an inadequate representation of electricity prices volatility can lead to an underestimation of the revenues available for storage and transmission grids. Having a bottom-up model with a representation of supply technical characteristics, the value of interconnectors and storage units, as well as a non-linear cost function, allows us to develop more realistic supply and price curves that improve the daily and yearly price volatility. These new model features make it a suitable tool for exploring the impacts of price volatility and price spreads within the market as well as to investigate the importance of price variation on arbitrage earnings and price cannibalisation of different technologies.

## References


de Felice, M. (2020). *ENTSO-E Hydropower modelling data (PECD)*. https://zenodo.org/record/3985078#.Yg4g7i-l1pQ

ENTSOG, & ENTSOE. (2021). *TYNDP 2020 Scenarios Report*.

Mahler, V., Girard, R., & Kariniotakis, G. (2022). Data-driven structural modeling of electricity price dynamics. *Energy Economics*, *107*, 105811. https://doi.org/10.1016/j.eneco.2022.105811

Pfenninger, S., DeCarolis, J., Hirth, L., Quoilin, S., & Staffell, I. (2017). The importance of open data and software: Is energy research lagging behind? *Energy Policy*, *101*, 211–215. https://doi.org/10.1016/j.enpol.2016.11.046

Ringkjøb, H. K., Haugan, P. M., & Solbrekke, I. M. (2018). A review of modelling tools for energy and electricity systems with large shares of variable renewables. In *Renewable and Sustainable Energy Reviews* (Vol. 96, pp. 440–459). Elsevier Ltd. https://doi.org/10.1016/j.rser.2018.08.002

Ward, K. R., Green, R., & Staffell, I. (2019). Getting prices right in structural electricity market models. *Energy Policy*, *129*, 1190–1206. https://doi.org/10.1016/j.enpol.2019.01.077