The Geography of Wind Power Price Effects in Europe

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1 Introduction

The European electricity system is entering a period of profound transformation. At the centre of this transition are two closely related challenges. The first comes from the demand side. Electricity is expected to play an increasingly important role in transport, heating, industry and digital infrastructure, as electric vehicles, heat pumps, AI and data centres expand. The International Energy Agency (IEA) estimates that electricity demand in the European Union will increase by around 300 TWh by 2030, which is roughly as much as Italy uses in a year. Meeting this additional demand will require a substantial expansion of electricity supply.

The second challenge concerns the cost and security of that supply. Despite the progress of the energy transition, fossil fuels still accounted for around 28% of EU electricity generation in 2024. This continues to expose European electricity prices to fluctuations in international fuel markets and geopolitical shocks. The energy crisis of 2021–2022 provided a particularly clear example. Following the sharp increase in natural gas prices, wholesale electricity prices reached unprecedented levels across Europe: the European Power Benchmark averaged EUR 230/MWh in 2022, 121% above its 2021 level. Although prices have since declined, they remain sensitive to developments in fossil-fuel markets, while high energy costs continue to represent an important concern for European households and industrial competitiveness.

Europe therefore faces the challenge of producing substantially more electricity while keeping it affordable and reducing its exposure to fossil-fuel shocks. Renewable energy has become a central part of the response. Its expansion has already transformed the European generation mix, rising from around 15% in 2000 to almost 50% in 2025, as shown in Figure 1.1. Wind has played a particularly important role in this transformation: it is now the largest renewable source of electricity generation in the EU, and the second-largest source overall, after nuclear power, and is expected to become the largest by 2030.

This expansion has important consequences for electricity prices. Wind generation has a very low marginal cost and, when available, can replace more expensive conventional generation. Additional wind generation can therefore reduce wholesale electricity prices through the conventional merit-order effect. In this sense, wind can contribute not only to decarbonisation but also to reducing the exposure of electricity markets to expensive fossil-fuel generation.

However, a lower electricity price does not always reflect the same market conditions. When electricity prices are high, additional wind can reduce the need for costly conven-

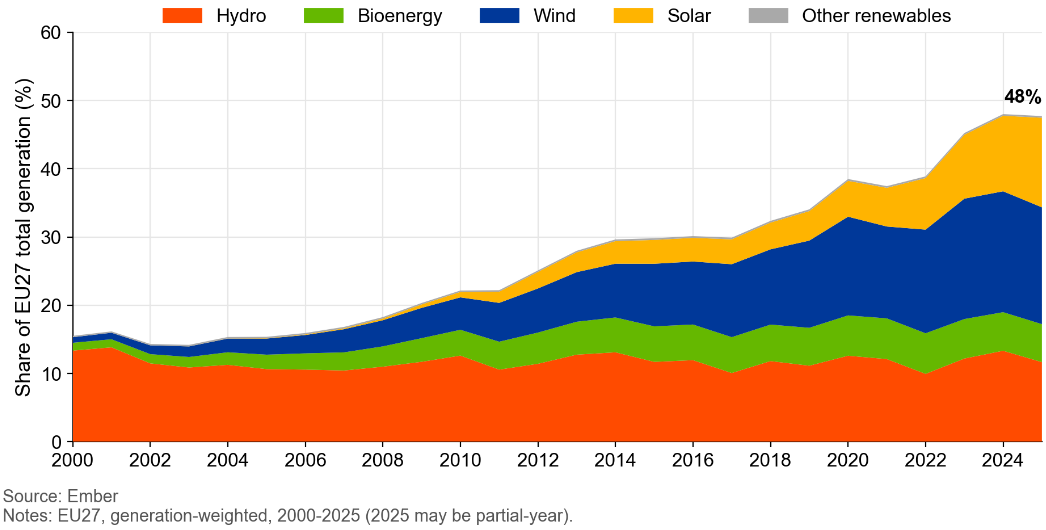


Figure 1.1: Growth of renewable and wind generation in the European Union

tional generation. When prices are already low, further price reductions may instead occur when electricity supply is abundant relative to demand.

In these situations, reducing production is not always immediate or costless. Some conventional power plants face technical constraints and costs when rapidly reducing output or shutting down, while renewable generation that cannot be consumed, stored or exported may have to be curtailed—that is, deliberately reduced despite being available. As a result, electricity prices may need to fall substantially, and can even become negative, before supply and demand are brought back into balance. As renewable penetration increases, the ability of electricity systems to manage periods of abundant supply therefore becomes increasingly important.

This suggests that the relationship between wind generation and electricity prices cannot necessarily be characterised by a single average effect. The same increase in expected wind generation may be associated with different price responses across different parts of the electricity-price distribution. Moreover, the extent of this variation need not be the same across Europe.

European electricity systems differ substantially in their generation mix, renewable penetration, hydropower resources and degree of cross-border interconnection. These characteristics provide different margins through which variations in renewable generation can be accommodated. Reservoir hydropower, for example, can shift generation across time, while cross-border interconnection allows electricity to be exchanged with neighbouring markets. Electricity systems with different combinations of these characteristics may therefore exhibit different wind–price relationships.

This motivates the central question of this thesis:

How does the relationship between expected wind generation and electricity *prices vary across the conditional price distribution and across European electricity systems?*

To answer this question, the thesis studies hourly day-ahead electricity prices and expected wind generation across 17 European bidding zones over the period 2019–2025. Quantile regression is used to estimate the relationship between expected wind generation and the conditional electricity-price distribution separately for each bidding zone. The analysis focuses on the 5th, 50th and 95th conditional quantiles, allowing the wind–price relationship to be compared between the lower tail, the centre and the upper tail of the conditional price distribution.

The estimates reveal substantial heterogeneity along both dimensions. Expected wind generation is associated with lower conditional electricity prices across most bidding zones and quantiles, but the magnitude of this relationship differs considerably across markets. In several bidding zones, including France, Germany–Luxembourg and Spain, the estimated wind coefficient is substantially more negative at the 5th conditional quantile than at the median or the 95th quantile. In other markets, the coefficients are smaller in absolute magnitude and considerably more similar across quantiles. The distributional relationship between wind generation and electricity prices therefore has a clear geographical dimension.

The thesis then investigates whether this geographical heterogeneity is systematically related to differences in electricity-system characteristics. Bidding zones are classified along three dimensions: renewable penetration, hydro flexibility and interconnection capacity. Combining these dimensions makes it possible to compare electricity systems with different configurations of renewable generation and potential adjustment margins.

The comparison shows that renewable penetration alone does not provide a complete description of the observed heterogeneity. Markets with similar renewable penetration can exhibit substantially different wind–price relationships depending on their broader system configuration. In the sample, bidding zones combining substantial hydro flexibility or interconnection capacity generally display more moderate wind coefficients and smaller differences across conditional quantiles, whereas some markets with more limited adjustment margins exhibit considerably stronger lower-tail relationships. These comparisons are descriptive rather than causal, but they are consistent with the idea that the price consequences associated with variable renewable generation depend on the broader electricity system into which that generation is integrated.

The contribution of this thesis is therefore to connect two dimensions of the wind–price relationship that are often examined separately: its variation across the conditional electricity-price distribution and its geographical heterogeneity across European electricity systems. Using a common empirical framework across 17 bidding zones makes it possible to compare not only whether expected wind generation is associated with electricity prices, but also how the shape of this relationship differs across markets with different structural characteristics. As renewable penetration continues to increase, understanding this heterogeneity becomes increasingly relevant for assessing how European electricity systems accommodate larger amounts of variable renewable generation.

2 Institutional Background

European electricity markets are organised around a sequence of trading stages. Electricity can be traded before the day of delivery in forward markets, on the day before delivery in the day-ahead market, and closer to real time in the intraday market. Finally, balancing mechanisms are used to correct remaining differences between scheduled generation and consumption in real time (ACER, b).

Forward markets allow producers and consumers to trade electricity in advance and hedge against future price fluctuations. The day-ahead market determines prices and scheduled production for each delivery period of the following day. After the day-ahead market has cleared, participants can adjust their positions in the intraday market as new information becomes available. Finally, in real time, Transmission System Operators (TSOs), the entities responsible for the secure operation of the electricity grid, use balancing markets to ensure that electricity generation and consumption remain equal.

This thesis focuses on the day-ahead market. This market plays a central role in European electricity trading and provides the main price reference for short-term wholesale electricity. The empirical analysis therefore studies how changes in expected wind generation affect day-ahead electricity prices.

2.1 Day-Ahead Price Formation

In the day-ahead market, electricity producers submit offers indicating how much electricity they are willing to supply and at what price, while buyers submit corresponding demand orders. These orders are combined to determine which generators are required to satisfy expected electricity demand and the price at which the market clears.

To understand how the day-ahead electricity price is determined, it is useful to start from the costs faced by electricity producers. Different generation technologies have different costs of producing an additional unit of electricity, called *marginal cost*. For wind and solar power, the marginal cost is very low because producing an additional unit of electricity requires no fuel. Fossil-fuel generators, in contrast, face fuel and carbon costs and therefore generally have higher marginal costs.

In the day-ahead market, generators submit offers to supply electricity. Broadly speaking, generators with lower marginal costs can offer electricity at lower prices than more expensive technologies. When these offers are ordered from the lowest to the highest price, they form the market supply curve. This ordering of generation from cheaper to more expensive sources is commonly referred to as the *merit order*.

Electricity demand must then be matched with sufficient generation. Starting from the cheapest offers, progressively more expensive generation is accepted until enough electricity is available to meet demand. **The last offer required to satisfy demand is the *marginal unit*, and its offer determines the market-clearing price**. Under the marginal pricing system used in the European day-ahead market, accepted generators receive this common market price, regardless of the price at which they individually offered their electricity (European Commission).

Figure 2.1 illustrates this mechanism. It also shows why an increase in expected wind generation can reduce electricity prices. Because wind has a very low marginal cost, additional wind supply increases the amount of low-cost electricity available to the market. Less electricity must then be produced by more expensive generators, potentially replacing the marginal unit with a cheaper one and lowering the market-clearing price. This mechanism is known as the *merit-order effect*.

Figure 2.1 illustrates this mechanism.

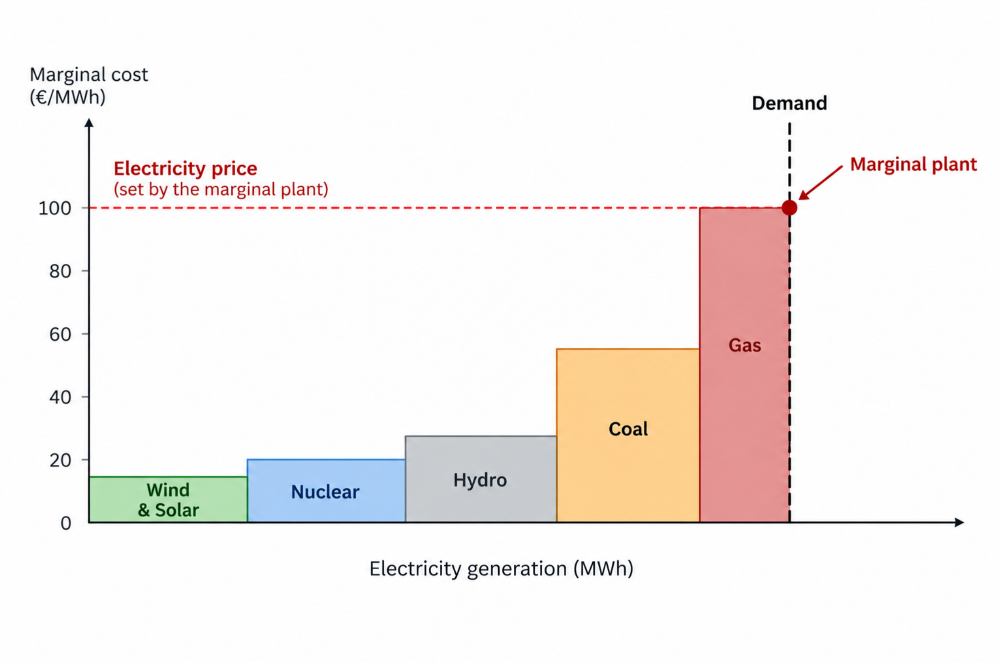


Figure 2.1: Day-ahead electricity price formation and the merit-order effect

This mechanism explains why additional wind generation can reduce wholesale electricity prices. When expected wind generation increases, more low-marginal-cost electricity becomes available. This reduces the amount of more expensive generation required to satisfy demand and can therefore lower the market-clearing price. This is commonly referred to as the *merit-order effect*.

The magnitude of this effect can depend on market conditions. An additional unit of wind generation may displace different technologies depending on the level of demand, the availability of other generation, and the ability of the electricity system to accommodate additional supply. This provides the economic motivation for examining whether the wind-price effect differs across the electricity-price distribution.

2.2 Bidding Zones and Market Coupling

The European electricity market is not characterised by a single electricity price. Instead, it is divided into *bidding zones*. **Within each bidding zone, market participants trade electricity at a common day-ahead price** and electricity exchanges are generally not subject to explicit cross-zonal capacity constraints, while exchanges between bidding zones depend on the transmission capacity available between them (ACER, a).

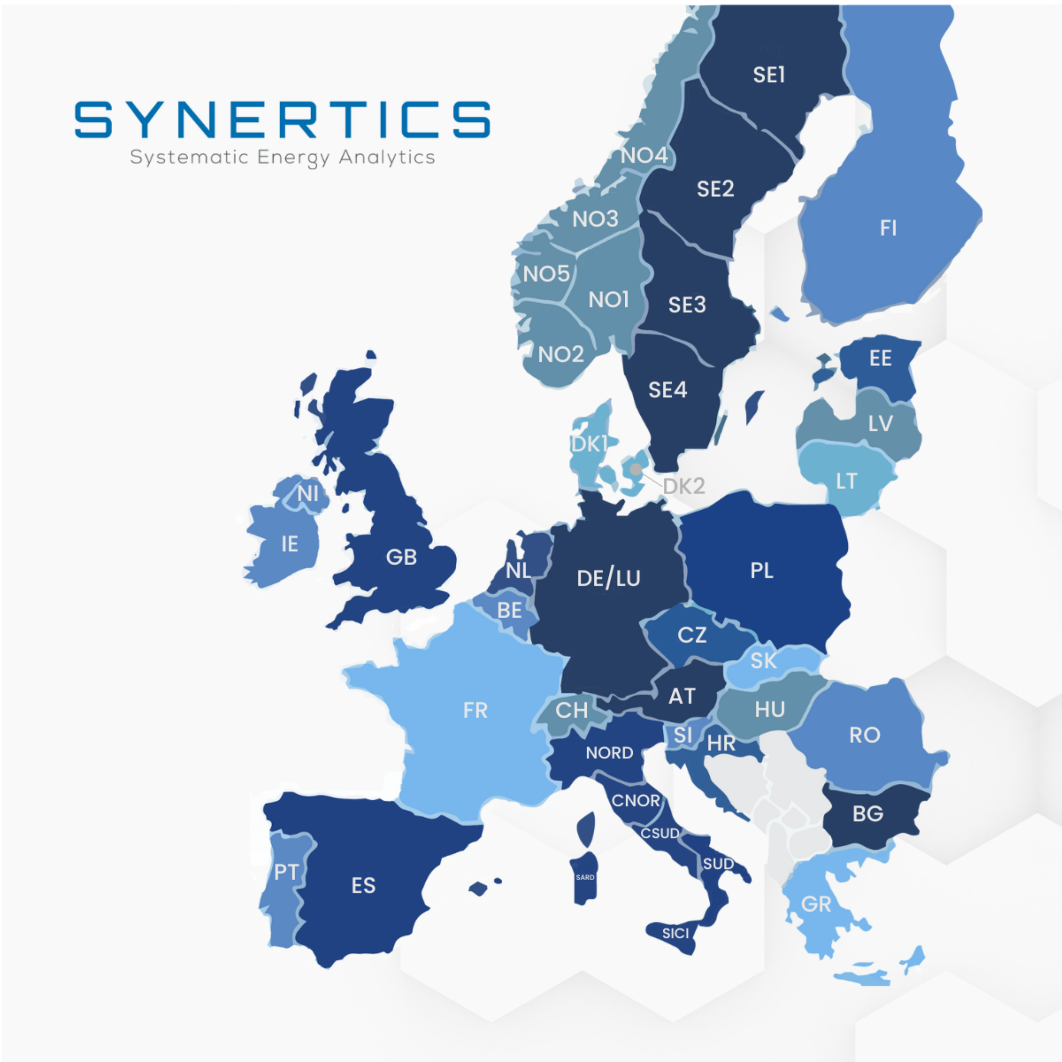


Figure 2.2: European electricity bidding zones

Source: ENTSO-E.

European day-ahead markets are connected through *market coupling*. The market-clearing process considers both electricity bids and the transmission capacity available between bidding zones. When sufficient transmission capacity is available, electricity can flow from a lower-price zone towards a higher-price zone, contributing to price convergence. When cross-border transmission capacity is constrained, prices can differ across neighbouring bidding zones (ACER, a).

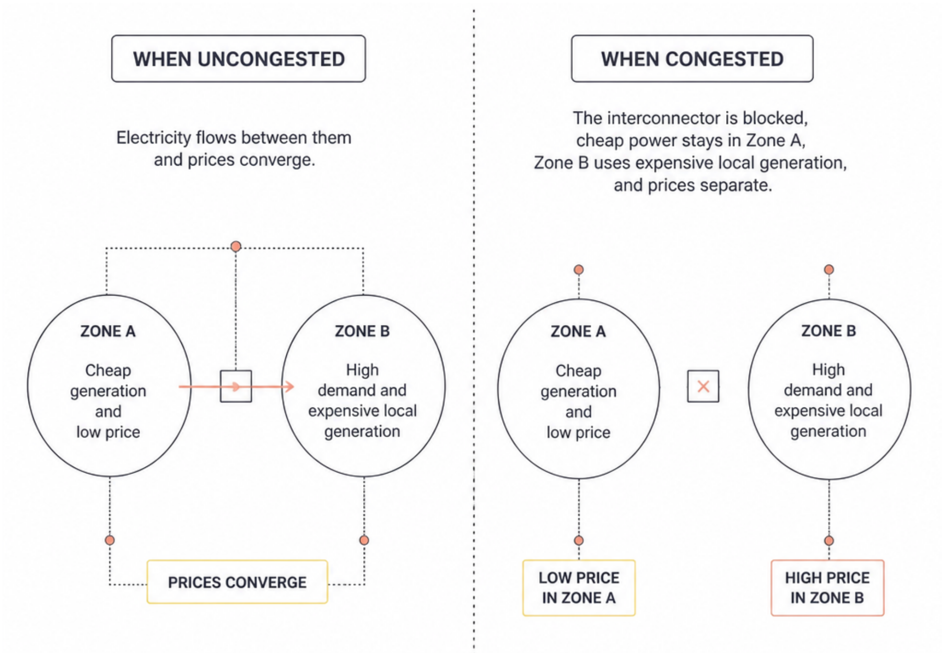


Figure 2.3: Constrained cross-border interconnection

Interconnection is therefore particularly relevant for the integration of wind generation. When wind production is abundant in one bidding zone, surplus electricity can be exported to neighbouring markets if sufficient transmission capacity is available. Conversely, when cross-border capacity is limited, a larger share of the adjustment must occur within the domestic electricity system.

This institutional structure motivates the geographical dimension of the empirical analysis. The effect of additional wind generation may depend not only on domestic market conditions but also on the ability of each bidding zone to accommodate or export additional renewable electricity.

3 Literature Review

A large literature shows that increasing renewable generation tends to reduce wholesale electricity prices through the *merit-order effect*. Because wind and solar have very low marginal costs, additional renewable supply shifts residual demand away from more expensive conventional generators and lowers the price set by the marginal unit. Early empirical evidence documents substantial merit-order effects in European electricity markets (Sensfuß et al., 2008; Hirth, 2013). More recent cross-European evidence confirms that increasing renewable penetration is generally associated with lower wholesale electricity prices, although the magnitude of this relationship varies across countries and market conditions (Cevik and Ninomiya, 2022).

An average price effect, however, provides only a partial description of the relationship between renewable generation and electricity prices. Electricity-price formation is highly nonlinear, and the relationship between additional wind generation and prices may differ across market conditions. Quantile-regression studies provide direct evidence of such distributional heterogeneity. Using German electricity-market data, Hagfors et al. (2016) and Maciejowska (2020) show that the effect of wind generation varies substantially across the conditional price distribution and can become particularly strong at low price quantiles. Huisman and Stet (2022), modelling the 24 hourly prices jointly within a quantile framework, similarly find that renewable supply affects the tails of the electricity-price distribution more strongly than its centre. Evidence from Italy points in the same direction: Sapio (2019) finds stronger renewable price effects under relatively low-price conditions and shows that greater market integration can alter these price dynamics.

Importantly, however, the direction and magnitude of this distributional heterogeneity are not universal across electricity markets. Evidence from the Californian electricity market shows that the effects of renewable generation can vary differently across the conditional price distribution (Westgaard et al., 2021). Similarly, Ajanaku and Collins (2024) document substantial differences in the merit-order effect of wind across U.S. wholesale electricity markets, including an unusual positive relationship between wind penetration and prices at lower quantiles in the ERCOT real-time market.

Recent European evidence provides an especially relevant example of cross-market heterogeneity. Studying the NO2 bidding zone in Norway and Germany around the introduction of the NordLink interconnector, Bjørndal et al. (2026) find markedly different wind–price patterns across the conditional price distribution. In Germany, the negative effect of wind is stronger toward the lower part of the distribution, whereas in NO2 the estimated wind effect becomes progressively more negative toward higher quantiles. This contrast shows that even closely integrated European electricity markets need not exhibit the same distributional wind–price relationship. Together, these studies suggest that the relationship may depend on characteristics of the electricity system rather than following a universal pattern across markets.

One potential explanation for this heterogeneity is the ability of electricity systems to accommodate variable renewable generation. As renewable penetration increases, electricity prices tend to be systematically lower during periods of high renewable production, reducing the market value of additional renewable generation—the so-called *cannibalisation effect* (Hirth, 2013). Whether abundant renewable generation translates into particularly low prices depends, however, on the adjustment margins available to the electricity system. Flexible generation, storage, demand response and cross-border trade can help accommodate additional renewable supply.

This connection between renewable price effects and flexibility is examined explicitly by Huisman et al. (2022). Using German electricity-market data, they show that wind and solar supply affect the tails of the electricity-price distribution asymmetrically, with higher renewable supply associated with a fatter left tail and a thinner right tail. They interpret these distributional effects in the context of the ability of electricity systems to counterbalance weather-driven renewable supply. Their results therefore provide a link between the distributional effects of variable renewables and the flexibility of the electricity system.

Hydropower can provide a particularly important source of flexibility in systems with large reservoir capacity. Unlike variable renewable generation, reservoir hydropower can shift production across time by storing water and adjusting generation in response to electricity-market conditions. Hirth (2016) shows that this flexibility can substantially facilitate the integration of wind power: comparing hydro-rich and thermal electricity systems, the study finds that dispatchable hydropower mitigates the decline in the market value of wind as wind penetration increases. This suggests that differences in flexible hydro resources may contribute to differences in the price response to wind across European electricity systems.

Cross-border integration provides another important adjustment margin in the European context. Interconnection can allow surplus renewable electricity to be exported, while at the same time transmitting renewable supply conditions between neighbouring markets. Recent evidence from European bidding zones illustrates this dual role. Stiewe et al. (2025) show that the market value of wind and solar depends not only on domestic renewable penetration but also on renewable generation in neighbouring markets. Stronger interconnection mitigates domestic cannibalisation while increasing exposure to cross-border renewable supply; for wind, the overall effect of interconnection is to stabilise domestic market value. The importance of interconnection is also visible at the level of individual market links. Studying NordLink between Norway and Germany, Bjørndal et al. (2026) show that increased transmission capacity affects price formation and the transmission of market conditions between the two interconnected price areas. These findings reinforce the idea that the price consequences associated with wind generation may depend on the broader electricity system in which that generation is integrated.

Despite these advances, two dimensions of the literature remain only partially connected. High-frequency studies of distributional renewable price effects have predominantly focused on individual markets or a small number of interconnected price areas. Cross-European studies, by contrast, generally examine average effects, lower-frequency data, or renewable market values rather than systematically comparing the wind–price relationship across the conditional price distribution in a common high-frequency framework. For example, Cevik and Ninomiya (2022) provide evidence of heterogeneous renewable price effects across European countries using monthly data, while Stiewe et al. (2025) examine cross-border cannibalisation across European bidding zones but focus on renewable market value.

A further gap concerns the connection between this distributional heterogeneity and differences in the structure of electricity systems. The existing literature provides strong reasons to expect hydropower, interconnection and other forms of flexibility to influence the integration of variable renewables. However, these mechanisms have typically been examined either within individual markets or through renewable market values, rather than alongside a systematic comparison of conditional wind–price relationships across a broad set of European bidding zones.

This thesis connects these strands by studying the geographical and distributional heterogeneity of the wind–price relationship across European electricity markets. Using hourly day-ahead data and a common empirical framework, quantile regressions are estimated separately for 17 European bidding zones at the 5th, 50th and 95th conditional price quantiles. This makes it possible to compare both the magnitude and the shape of the conditional wind–price relationship across markets.

The analysis then relates this cross-market heterogeneity to three characteristics of the electricity system: renewable penetration, hydro flexibility and interconnection capacity. Bidding zones are classified according to different combinations of these characteristics, allowing markets with similar renewable penetration but different potential adjustment margins to be compared. The contribution is therefore to connect three dimensions that have largely been studied separately: the merit-order relationship associated with wind generation, its variation across the conditional electricity-price distribution, and its geographical heterogeneity across European electricity systems with different structural characteristics.

4 Data

4.1 Sample and Data Sources

The analysis uses hourly data from European electricity markets over the period 2019–2025. The unit of observation is a bidding zone–hour. The hourly frequency reflects the organisation of the day-ahead electricity market, in which prices are determined separately for each delivery hour, and allows the data to capture substantial intraday variation in demand, renewable generation and electricity prices.

The final sample covers 17 European bidding zones: Austria (AT), Belgium (BE), Germany–Luxembourg (DE_LU), Western and Eastern Denmark (DK_1 and DK_2), Spain (ES), France (FR), Croatia (HR), Central-Southern Italy (IT_CSUD), Sardinia (IT_SARD), Sicily (IT_SICI), Southern Italy (IT_SUD), the Netherlands (NL), Southern and Northern Norway (NO_2 and NO_4), Poland (PL), and Portugal (PT). The use of bidding zones rather than countries reflects the geographical organisation of European wholesale electricity markets. In countries divided into multiple bidding zones, electricity prices and market conditions may differ across zones and are therefore treated separately.

The sample focuses on bidding zones with economically meaningful wind generation and sufficiently complete wind data over the sample period. Several zones available in the underlying dataset are consequently excluded. Switzerland (CH), Slovakia (SK), NO_3, NO_5, IT_NORD and IT_CNOR have very limited wind generation in the available data. Finland (FI) and Sweden (SE) are excluded because of data-quality issues in the wind series, while Hungary (HU) and NO_1 have limited wind generation and provide little variation in the wind series over the sample period.

The main electricity-market data are obtained from the ENTSO-E Transparency Platform. The dataset contains day-ahead electricity prices, day-ahead forecasts of electricity demand, wind and solar generation, actual electricity generation by technology, and information on nuclear availability. Series from the different sources are harmonised to a common hourly frequency and matched at the bidding-zone level.

4.2 Electricity Prices and Wind Forecasts

Day-ahead wholesale electricity prices are measured in euros per megawatt-hour (EUR/MWh) for each bidding zone and delivery hour. These prices are determined in the day-ahead market before physical delivery, as described in Chapter 2. The data retain negative and zero prices where they occur.

Expected wind generation is measured using the day-ahead wind-generation forecast reported by ENTSO-E. Where both series are available, onshore and offshore wind forecasts are combined to obtain total expected wind generation for each bidding zone and delivery hour. Wind generation, originally reported in MW, is converted to gigawatts (GW).

The forecast series provides a measure of expected wind availability for the relevant delivery period, based primarily on anticipated weather conditions and installed generation capacity. It differs conceptually from realised wind generation, which reflects both available wind resources and the subsequent operation of the electricity system.

The forecast observations available from ENTSO-E do not necessarily correspond exactly to the forecast vintage observed by market participants at the time of day-ahead market clearing. Forecasts may be updated after day-ahead prices have been determined. The series is therefore interpreted as a measure of expected wind availability for the relevant delivery period rather than as an exact reconstruction of the information set available at the moment of market clearing.

4.3 Other Electricity-Market Variables

The dataset also contains day-ahead forecasts of electricity demand and solar generation. Solar forecasts are expressed in GW, combining the available solar-generation forecast series within each bidding zone. Day-ahead load forecasts provide the corresponding measure of expected electricity demand for each delivery hour.

Information on other electricity-generation technologies is obtained from ENTSO-E actual-generation data. Run-of-river hydro generation is measured at hourly frequency and converted from MW to GW. Information on nuclear availability is constructed from the available ENTSO-E nuclear data and matched to the corresponding bidding zone and delivery hour.

The electricity-market dataset is complemented with daily European energy-market variables, including TTF natural-gas prices, coal prices, and EU ETS allowance prices. Daily observations are matched to the corresponding hourly electricity-market observations.

The dataset also contains national public-holiday indicators, constructed according to the calendar applicable to each bidding zone.

4.4 Common Renewable-Generation Factors

To describe broader renewable-generation conditions across European electricity markets, the dataset includes common wind and solar factors. These factors are constructed from groups of bidding zones with related renewable-generation patterns.

Within each group, the underlying hourly renewable-generation series are standardised and their first principal component is extracted. Separate factors are constructed for wind and solar generation.

For each bidding zone, the corresponding factor is constructed using a leave-one-out procedure: the renewable-generation series of the focal zone is excluded before the principal component is calculated. The resulting variables therefore summarise common renewable-generation variation in related European markets without mechanically including the focal zone's own series.

4.5 Institutional Variables

The sample period includes several changes in European electricity-market design and regulation. The dataset therefore contains zone-specific indicator variables identifying the bidding zones and delivery periods affected by these arrangements.

The institutional variables cover the Iberian Exception and its gas-cost adjustment in Spain and Portugal; the Interim Coupling arrangement and the subsequent introduction of Core Flow-Based Day-Ahead Market Coupling in Central Europe; Nordic Flow-Based Market Coupling; the French ARENH+ arrangement; the Slovak nuclear fixed-price arrangement; and the United Kingdom's exit from EU day-ahead market coupling.

Each indicator takes the value one for the bidding zones and delivery periods associated with the corresponding arrangement and zero otherwise. A detailed description of the individual arrangements, their geographical coverage and implementation periods is reported in Appendix A.1.

4.6 System Characteristics

Three additional variables are constructed to characterise differences across the electricity systems in the sample: renewable penetration, hydro flexibility, and interconnection capacity.

Renewable penetration is measured as average expected wind and solar generation relative to average electricity load in each bidding zone. Hydro flexibility is constructed from reservoir and pumped-storage hydro capacity and expressed relative to average load.

Interconnection capacity measures cross-border transfer capacity relative to average load.

Expressing these characteristics relative to average load makes the measures comparable across bidding zones of substantially different sizes. Their use to classify bidding zones into High and Low groups is described in Chapter 5.

4.7 Sample Construction and Harmonisation

The raw data are harmonised at the hourly bidding-zone level. Variables reported in MW are converted to GW where appropriate, and observations from different sources are matched by bidding zone and delivery hour. Observations for which the variables required for the empirical analysis are unavailable are excluded. The resulting panel is therefore unbalanced, and the number of usable observations may differ across bidding zones.

Particular attention is required for changes in bidding-zone definitions over the sample period. In Italy, Calabria (IT_CALA) and Southern Italy (IT_SUD) are combined to construct a continuous IT_SUD series following changes in the geographical configuration of the Italian electricity market. For overlapping observations, electricity prices are aggregated using electricity demand as weights, while physical quantities such as generation and demand are summed across the two areas. This preserves a geographically consistent Southern Italian series over the sample period.

The final dataset preserves the hourly structure of European day-ahead electricity markets while providing a harmonised dataset across the bidding zones included in the analysis. The empirical strategy is described in Chapter 5.

5 Empirical Strategy

The empirical analysis studies the relationship between expected wind generation and day-ahead electricity prices across European bidding zones. The empirical strategy consists of two complementary specifications. First, a linear model is used to estimate the average wind–price relationship in each bidding zone. Second, quantile regressions are used to examine whether this relationship differs across the conditional electricity-price distribution.

All models are estimated separately for each bidding zone using hourly observations. The 24 delivery hours are pooled within each market, while systematic intraday differences are absorbed through hour-of-day fixed effects. The specifications additionally include calendar fixed effects, short-run electricity-market fundamentals, and lagged electricity prices as described below.

5.1 Baseline Linear Model

The analysis begins with a linear specification estimating the conditional mean relationship between expected wind generation and day-ahead electricity prices. For each bidding zone i, the model is

$$P_{it} = \alpha_i + \beta_i Wind_{it}^{DA} + \gamma_i' X_{it} + \delta_{ym} + \lambda_{dow} + \mu_h + \varepsilon_{it}, \tag{5.1}$$

where i indexes bidding zones and t indexes hourly observations. P_{it} is the day-ahead electricity price, measured in EUR/MWh, and $Wind_{it}^{DA}$ is the day-ahead forecast of wind generation, expressed in GW. The term μ_h denotes hour-of-day fixed effects, while δ_{ym} and λ_{dow} denote year-by-month and day-of-week fixed effects, respectively.

The vector X_{it} contains the remaining short-run determinants of electricity prices included in the specification. These include day-ahead forecasts of electricity demand and solar generation, run-of-river hydro generation, nuclear availability, daily TTF natural gas prices, coal prices, EU ETS allowance prices, public holidays, and the institutional variables described in Chapter 4.

Electricity prices display substantial persistence and recurring temporal patterns. The specification therefore includes the electricity price observed 24 and 168 hours earlier. These lags capture short-run price persistence as well as recurring daily and weekly market conditions.

To account for renewable-generation conditions outside the focal bidding zone, the analysis also includes common wind and solar factors. These factors summarise broader weather-driven variation in renewable generation across related European electricity markets and help separate the local wind–price relationship from common renewable conditions affecting multiple markets simultaneously.

The specification also includes a set of calendar controls. Year-by-month fixed effects absorb seasonal variation and slower-moving changes in electricity-market conditions, while day-of-week fixed effects account for systematic differences in electricity demand and market activity across the week. Hour-of-day fixed effects absorb systematic intraday differences in electricity prices and market conditions. A public-holiday indicator captures additional changes associated with national holidays. Calendar variables are constructed according to the local time and holiday calendar of each bidding zone.

The analysis uses the day-ahead forecast of wind generation rather than realised wind output, as explained in Chapter 4. Conditional on the included market fundamentals and temporal controls, β_i is interpreted as the conditional relationship between expected wind generation and day-ahead electricity prices in bidding zone i.

The coefficient β_i is initially expressed in EUR/MWh per additional GW of expected wind generation. Since European bidding zones differ substantially in size, these coefficients cannot be compared directly across markets. An additional GW represents a relatively small supply shock in a large electricity system but a much larger shock in a small one.

To construct a comparable measure across bidding zones, each estimated coefficient is therefore rescaled to represent an increase in expected wind generation equivalent to 1% of the bidding zone's average electricity demand:

$$\widetilde{\beta}_i = \widehat{\beta}_i \left(0.01 \times \overline{L}_i\right), \tag{5.2}$$

where $\overline{L}_i$ denotes average electricity demand in bidding zone i, expressed in GW. The normalised coefficient $\widetilde{\beta}_i$ therefore measures the change in the conditional mean electricity price associated with an increase in expected wind generation equal to 1% of average load. The normalisation changes only the scale of the coefficient and does not alter the underlying regression estimate.

Because hourly electricity-market observations may exhibit both heteroskedasticity and serial dependence, inference for the linear model is based on heteroskedasticity- and autocorrelation-consistent standard errors using a Newey–West covariance estimator with 24 hourly lags.

5.2 Quantile Regression Model

The linear model characterises the wind–price relationship through a single conditional-mean coefficient. However, this average relationship may conceal substantial differences across the electricity-price distribution. Quantile regression allows the coefficient on expected wind generation to vary across different points of the conditional distribution (Koenker and Bassett, 1978).

This approach is particularly useful for wholesale electricity prices, which are characterised by substantial dispersion, strong asymmetries, and occasional extreme observations. Previous studies show that the effect of renewable generation can differ considerably across the conditional price distribution (Hagfors et al., 2016; Maciejowska, 2020; Sapio, 2019; Huisman and Stet, 2022).

For each bidding zone i and quantile τ, I estimate

$$Q_\tau\left(P_{it} \mid Wind_{it}^{DA}, X_{it}\right) = \alpha_{i\tau} + \beta_{i\tau} Wind_{it}^{DA} + \gamma_{i\tau}' X_{it} + \delta_{ym,\tau} + \lambda_{dow,\tau} + \mu_{h,\tau}, \qquad (5.3)$$

where $Q_\tau(P_{it} \mid Wind_{it}^{DA}, X_{it})$ denotes the τ-th conditional quantile of the day-ahead electricity price. The coefficient $\beta_{i\tau}$ measures the change in that conditional quantile associated with an additional GW of expected wind generation, holding the remaining covariates constant.

The explanatory variables, lagged prices, and fixed effects are the same as in Equation 5.1. This ensures that differences between the conditional-mean and quantile estimates reflect the part of the conditional price distribution being modelled rather than differences in the underlying specification.

To account for renewable-generation conditions outside the focal bidding zone, the specification includes common wind and solar factors. These are constructed from groups of European bidding zones with similar renewable-generation patterns. Within each group, hourly renewable-generation series are standardised and their first principal component is used to capture their dominant common variation.

When constructing the factor for bidding zone i, the focal zone is excluded from the underlying set of series. This leave-one-out construction prevents the common factor from mechanically incorporating the same wind or solar generation used as a local explanatory variable. The factors therefore capture broader renewable-generation conditions shared across related European electricity markets.

The main analysis focuses on three points of the conditional electricity-price distribution:

$$
\begin{aligned}
\tau &= 0.05 \quad \text{lower conditional quantile,} \\
\tau &= 0.50 \quad \text{median conditional quantile,} \\
\tau &= 0.95 \quad \text{upper conditional quantile.}
\end{aligned}
\tag{5.4}
$$

These quantiles are not interpreted as exogenously defined market regimes. In particular, the 5th conditional quantile does not simply correspond to the 5% of observations with the lowest realised electricity prices. Instead, the quantile regression estimates how the conditional distribution of electricity prices varies with expected wind generation after accounting for the other variables included in the specification.

For cross-market comparison, the quantile coefficients are normalised using the same relative wind shock introduced for the linear model:

$$
\widetilde{\beta}_{i\tau} = \widehat{\beta}_{i\tau} \left(0.01 \times \overline{L}_i\right). \tag{5.5}
$$

Thus, $\widetilde{\beta}_{i\tau}$ measures the change in the τ-th conditional electricity-price quantile associated with an increase in expected wind generation equivalent to 1% of average load in bidding zone i. Applying the same normalisation to each quantile allows both cross-market and within-market comparisons on a common scale.

5.3 Heterogeneity by System Characteristics

To investigate whether the wind–price relationship differs across electricity systems, bidding zones are classified according to three structural characteristics: renewable penetration, hydro flexibility, and interconnection capacity.

Renewable penetration is measured as average expected wind and solar generation relative to average electricity load. Hydro flexibility is measured as reservoir and pumped-storage hydro capacity relative to average load, while interconnection capacity is likewise expressed relative to average load. Expressing each characteristic relative to load allows comparison across electricity systems of substantially different sizes.

For each characteristic, a bidding zone is classified as *High* when the corresponding measure is equal to or greater than 30% of its average load, and as *Low* otherwise:

$$
Group_{i,k} = \begin{cases} \text{High}, & S_{i,k} \geq 0.30, \\ \text{Low}, & S_{i,k} < 0.30, \end{cases} \tag{5.6}
$$

where $S_{i,k}$ denotes characteristic k, expressed as a share of average load in bidding zone i.

The same 30% threshold is applied to all three characteristics. This provides a common and transparent classification rule that does not depend on the relative position of a bidding zone within the estimation sample, as would be the case with a median split. The threshold is used as an empirical classification device rather than as a technological boundary between high- and low-flexibility electricity systems.

The three binary classifications are then combined to characterise each bidding zone along all three dimensions simultaneously. A bidding zone can therefore belong to one of eight possible configurations:

$$
\begin{aligned}
&(\text{Renew H}, \text{Hydro H}, \text{IC H}), \quad (\text{Renew H}, \text{Hydro H}, \text{IC L}), \\
&(\text{Renew H}, \text{Hydro L}, \text{IC H}), \quad (\text{Renew H}, \text{Hydro L}, \text{IC L}), \\
&(\text{Renew L}, \text{Hydro H}, \text{IC H}), \quad (\text{Renew L}, \text{Hydro H}, \text{IC L}), \\
&(\text{Renew L}, \text{Hydro L}, \text{IC H}), \quad (\text{Renew L}, \text{Hydro L}, \text{IC L}).
\end{aligned} \tag{5.7}
$$

Here, *Renew*, *Hydro*, and *IC* refer respectively to renewable penetration, hydro flexibility, and interconnection capacity, while H and L denote the High and Low classifications defined above. Not all eight theoretical configurations necessarily appear in the sample.

This combined classification is used to organise the cross-country comparison of the estimated wind coefficients. Rather than treating renewable penetration, hydro flexibility, and interconnection as independent characteristics, it allows the analysis to consider the configuration of the electricity system as a whole. In particular, it makes it possible to compare markets with similar renewable penetration but different sources of system flexibility, such as hydro resources or interconnection capacity.

The estimated coefficients are ordered according to these system configurations in the results section. This comparison is descriptive: differences across groups are interpreted as systematic heterogeneity in the estimated wind–price relationship and not as causal effects of renewable penetration, hydro flexibility, or interconnection capacity.

The underlying values of the three system characteristics and the 30% classification threshold are presented graphically in Chapter 6.

5.4 Inference and Time-Series Dependence

The use of hourly observations raises two related time-series issues: serial dependence and heteroskedasticity. Electricity prices are highly persistent and exhibit recurring daily and weekly patterns. The specification addresses these features through lagged electricity prices, hour-of-day, day-of-week, and year-by-month fixed effects, while the remaining serial correlation and heteroskedasticity are accounted for in statistical inference.

For the linear regressions, inference is based on heteroskedasticity- and autocorrelation-consistent Newey–West standard errors with a maximum lag of 24 hours. The quantile regressions use the corresponding HAC covariance estimator for quantile-regression coefficients, with a Bartlett kernel and a maximum lag of 24 hours.

The HAC correction addresses serial dependence and heteroskedasticity in the regression residuals. It does not, by itself, constitute a correction for non-stationarity. The empirical specifications are therefore interpreted as conditional relationships between expected wind generation and day-ahead electricity-price levels, conditional on the rich set of temporal controls, lagged prices, and market fundamentals described above.

6 Results

This chapter presents the estimated relationship between expected wind generation and the conditional distribution of day-ahead electricity prices across European bidding zones. The analysis first documents how the wind coefficient varies across the 5th, 50th, and 95th conditional price quantiles. It then examines whether the substantial cross-market heterogeneity in these estimates is systematically related to differences in renewable penetration, hydro flexibility, and interconnection capacity.

6.1 Wind Effects Across the Conditional Price Distribution

Figure 6.1 reports the estimated wind coefficients at the 5th, 50th, and 95th conditional quantiles of the day-ahead electricity-price distribution. To facilitate comparison across electricity systems of different sizes, all coefficients are normalised to represent an increase in expected wind generation equivalent to 1% of average load in the respective bidding zone.

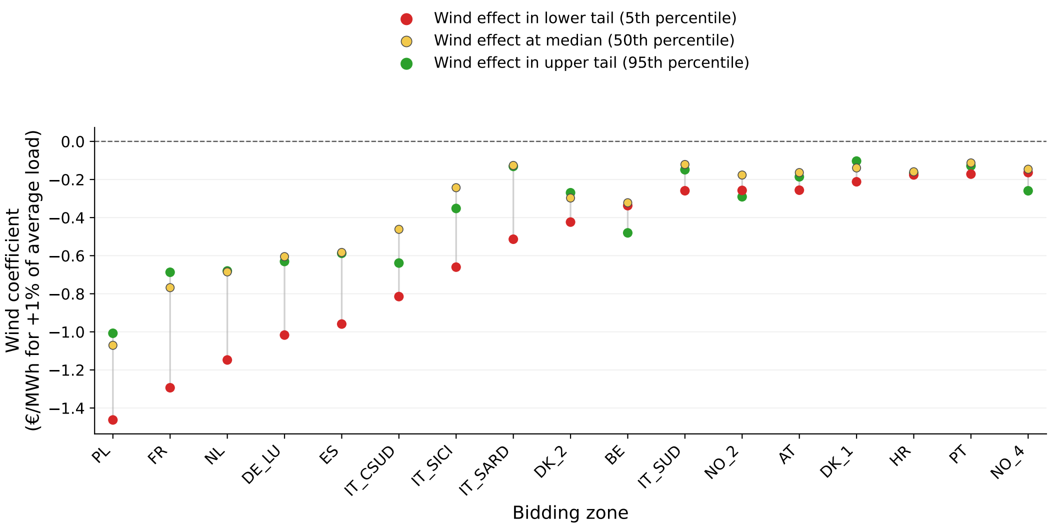


Figure 6.1: Estimated relationship between expected wind generation and the conditional electricity-price distribution. Coefficients are reported at the 5th, 50th, and 95th conditional quantiles and are normalised to represent an increase in expected wind generation equivalent to 1% of average load in each bidding zone. More negative coefficients indicate a stronger negative conditional relationship between expected wind generation and electricity prices.

Two main features emerge from the estimates. First, expected wind generation is associated with lower conditional electricity prices across most bidding zones and quantiles. The negative wind–price relationship is therefore not confined to a particular part of the conditional price distribution.

Second, and more importantly, the magnitude of this relationship varies substantially both across quantiles and across bidding zones. In several markets, the wind coefficient is considerably more negative at the 5th conditional quantile than at the median or the 95th conditional quantile. This pattern is particularly visible in France, Germany–Luxembourg, Spain, the Netherlands, and Poland. In other markets, including Portugal, Denmark, Austria, and the Norwegian bidding zones, the estimated coefficients are smaller in absolute magnitude and the differences across quantiles are generally more limited.

France provides a particularly clear example. An increase in expected wind generation equivalent to 1% of average load is associated with a reduction of approximately EUR 1.3/MWh at the 5th conditional quantile, compared with around EUR 0.75/MWh at the median and EUR 0.7/MWh at the 95th conditional quantile. Germany–Luxembourg and Spain display a similar ordering.

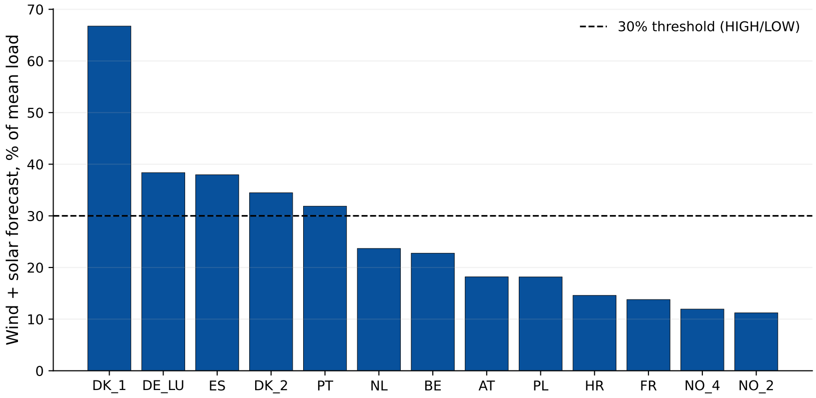
These estimates indicate that the wind–price relationship cannot be fully characterised by a single coefficient. In several European markets, expected wind generation is associated with a substantially stronger price reduction in the lower tail of the conditional price distribution. However, the magnitude of this lower-tail amplification differs considerably across electricity systems.

The remainder of the analysis investigates whether this geographical heterogeneity is systematically related to observable characteristics of the electricity systems.

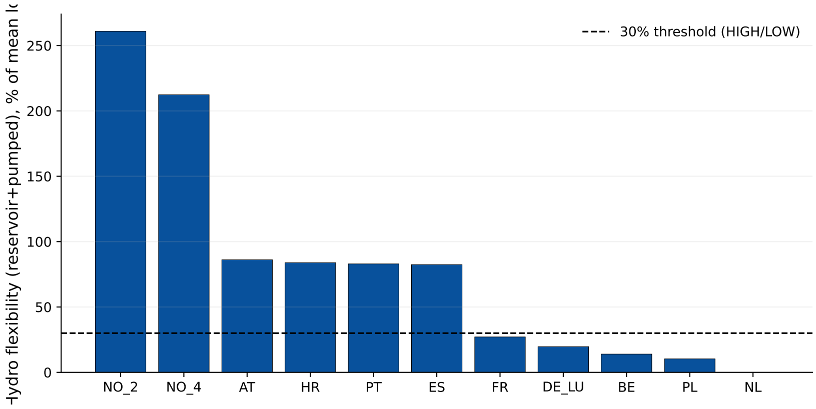
6.2 System Characteristics

As described in Section 5.3, bidding zones are classified along three dimensions that may be relevant for the integration of variable renewable generation: renewable penetration, hydro flexibility, and interconnection capacity. Each characteristic is expressed relative to average electricity load, and bidding zones are classified as *High* when the corresponding measure is at least 30% of average load and as *Low* otherwise.

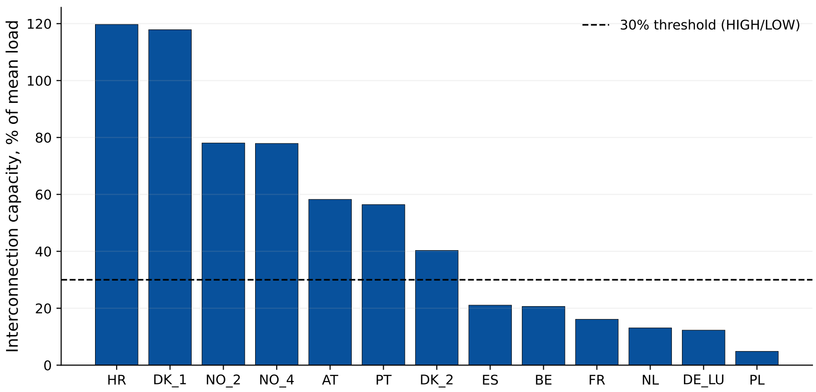
Figure 6.2 shows the underlying values used to construct these classifications.



(a) Renewable penetration



(b) Hydro flexibility



(c) Interconnection capacity

Figure 6.2: Electricity-system characteristics used in the High/Low classification. Renewable penetration, hydro flexibility, and interconnection capacity are expressed as percentages of average electricity load. The dashed line indicates the 30% threshold used to distinguish High and Low values.

The figure highlights substantial structural differences across the electricity systems in the sample. Renewable penetration is particularly high in Denmark, Germany–Luxembourg, Spain, and Portugal, whereas a number of other markets remain below the 30% threshold.

Hydro flexibility is considerably more concentrated geographically. The Norwegian bidding zones stand out because reservoir and pumped-storage hydropower are large relative to electricity demand. Austria and Croatia also exhibit substantial hydro flexibility, while Portugal and Spain remain above the classification threshold. By contrast, several Continental European markets have relatively limited reservoir and pumped-storage capacity relative to load.

A different geographical pattern emerges for interconnection capacity. Croatia, Denmark, Norway, Austria, and Portugal have relatively large cross-border transfer capacity compared with the size of their electricity systems, whereas larger Continental markets such as Germany–Luxembourg, France, the Netherlands, and Poland lie below the 30% threshold.

The three dimensions therefore capture distinct features of European electricity systems. In particular, high renewable penetration does not necessarily coincide with high hydro flexibility or high interconnection capacity. This variation allows bidding zones with similar renewable penetration but different potential adjustment margins to be compared.

6.3 Wind Effects by System Characteristics

Figure 6.3 combines the quantile-regression estimates with the system classification. Bidding zones are ordered according to their High/Low configuration in renewable penetration (*Renew*), hydro flexibility (*Hydro*), and interconnection capacity (*IC*). The figure therefore makes it possible to compare the conditional wind–price relationship across different configurations of European electricity systems.

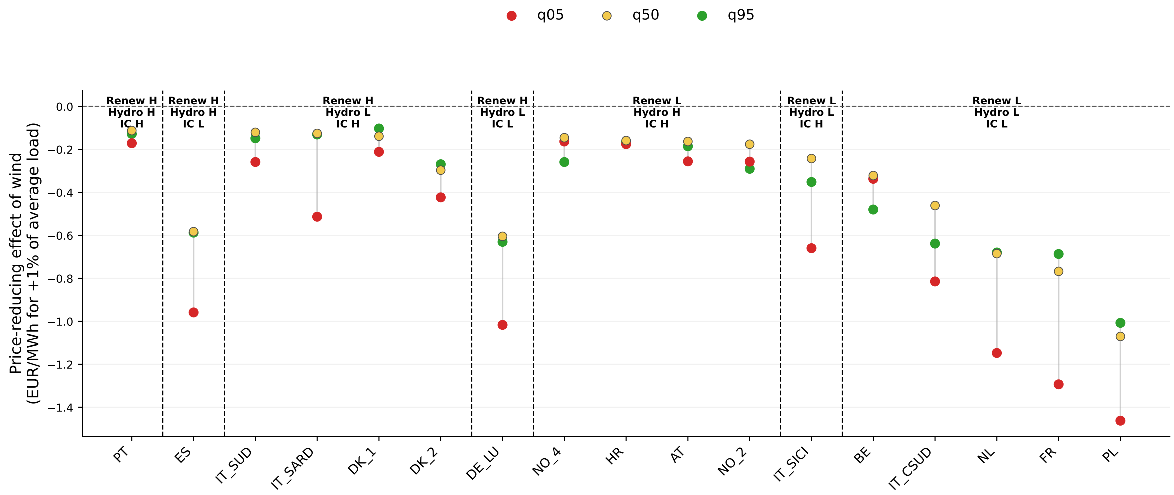


Figure 6.3: Estimated wind effects across conditional price quantiles, grouped by electricity-system characteristics. H and L indicate, respectively, values above and below the 30% threshold for renewable penetration (Renew), hydro flexibility (Hydro), and interconnection capacity (IC). Coefficients are normalised to represent an increase in expected wind generation equivalent to 1% of average load. More negative values indicate a stronger price-reducing relationship associated with expected wind generation.

A clear pattern emerges from the comparison. Bidding zones combining high renewable penetration with substantial hydro flexibility or interconnection capacity tend to display relatively moderate wind coefficients and smaller differences across conditional quantiles. Portugal, for example, is classified as High along all three dimensions and exhibits relatively small and closely grouped coefficients across the conditional price distribution.

The comparison between electricity systems with high renewable penetration is particularly informative. Denmark (DK1) combines high renewable penetration with high interconnection capacity but relatively low hydro flexibility. Its estimated wind coefficients remain relatively close across the three conditional quantiles. Spain, by contrast, combines high renewable penetration and high hydro flexibility with lower interconnection capacity. Its wind coefficient becomes considerably more negative at the 5th conditional quantile than at the median and upper quantile.

Germany–Luxembourg provides a further contrast. The market has high renewable penetration but is classified as Low in both hydro flexibility and interconnection capacity according to the thresholds used here. The estimated wind coefficient is substantially stronger in the lower conditional price quantile. This differs from the relatively flatter profile observed in DK1, where high renewable penetration is accompanied by considerably greater interconnection capacity.

The differences are also visible among markets with lower renewable penetration. The Norwegian bidding zones combine exceptionally high hydro flexibility with substantial interconnection capacity and display comparatively moderate differences across conditional quantiles. At the other end of the classification, markets such as France, the Netherlands, and Poland are below the 30% threshold for renewable penetration, hydro flexibility, and interconnection capacity. These markets display some of the largest estimated wind effects in absolute terms, particularly toward the lower part of the conditional price distribution.

Taken together, the results suggest that renewable penetration alone does not provide a complete description of the cross-market heterogeneity in the wind–price relationship. Markets with similar renewable penetration can display substantially different conditional wind coefficients depending on their broader system configuration. Conversely, different forms of flexibility may be associated with different ways of accommodating variations in expected renewable generation.

The results are consistent with the interpretation that hydro flexibility and cross-border interconnection provide adjustment margins that may moderate the price effects associated with variations in wind generation. Reservoir hydropower can shift generation across time, while interconnection allows electricity to be exchanged across markets when domestic renewable availability changes. These mechanisms are consistent with the comparatively moderate quantile differences observed in several highly flexible and interconnected systems.

The comparison should nevertheless be interpreted as descriptive rather than causal. The system characteristics are not randomly assigned, and bidding zones differ along many dimensions beyond the three characteristics considered here. The group comparison therefore does not identify the causal effect of hydro flexibility or interconnection on the wind–price relationship. Instead, it documents a systematic association between the configuration of European electricity systems and the heterogeneity of the estimated conditional wind effects.

The main empirical finding is therefore not simply that expected wind generation is associated with lower electricity prices. The magnitude of this relationship varies substantially across the conditional price distribution, and the extent of this variation differs across European electricity systems. The group comparison indicates that these differences are related to the broader configuration in which renewable generation is integrated, particularly the availability of hydro flexibility and cross-border interconnection.

7 Conclusion

This thesis has examined the relationship between expected wind generation and day-ahead electricity prices across European electricity markets. Rather than focusing on a single average effect, the analysis uses quantile regression to examine whether the wind–price relationship differs across the conditional electricity-price distribution and whether this heterogeneity is systematically related to the structural characteristics of different electricity systems.

7.1 Summary of Key Findings

The empirical analysis produces three main findings.

First, expected wind generation is associated with lower day-ahead electricity prices across most bidding zones and conditional quantiles. However, the magnitude of this relationship differs substantially across European electricity markets. The effect of a comparable increase in expected wind generation is therefore far from uniform across bidding zones.

Second, the wind–price relationship varies across the conditional electricity-price distribution. In several markets, including France, Germany–Luxembourg and Spain, the estimated wind coefficient is considerably more negative at the 5th conditional quantile than at the median or the 95th conditional quantile. In other markets, including several Nordic bidding zones, the coefficients are smaller in absolute magnitude and more similar across quantiles. The effect associated with expected wind generation therefore depends not only on the electricity market considered, but also on the part of the conditional price distribution being examined.

Third, this cross-market heterogeneity is systematically related to differences in electricity-system characteristics. Classifying bidding zones according to renewable penetration, hydro flexibility and interconnection capacity reveals substantial differences in the configuration of European electricity systems. Markets combining high renewable penetration with substantial hydro flexibility or interconnection capacity generally display more moderate wind coefficients and smaller differences across conditional quantiles.

The comparison among high-renewable markets is particularly informative. DK1 combines high renewable penetration with high interconnection capacity and displays relatively similar coefficients across the conditional price distribution. Spain combines high renewable penetration and high hydro flexibility but lower interconnection capacity, and exhibits a considerably stronger wind coefficient at the lower conditional quantile. Germany–Luxembourg combines high renewable penetration with lower hydro flexibility and interconnection capacity according to the classification used in this thesis, and also displays pronounced lower-tail amplification.

A similar pattern emerges among markets with lower renewable penetration. The Norwegian bidding zones combine substantial hydro flexibility and interconnection capacity and exhibit comparatively moderate differences across quantiles. By contrast, France, the Netherlands and Poland are classified below the threshold for renewable penetration, hydro flexibility and interconnection capacity and display some of the largest estimated wind coefficients, particularly toward the lower part of the conditional price distribution.

Taken together, these results suggest that renewable penetration alone does not provide a complete description of the relationship between wind generation and electricity prices. The broader configuration of the electricity system appears to matter for understanding why similar wind shocks are associated with different price responses across European markets. These comparisons are descriptive, however, and should not be interpreted as identifying causal effects of hydro flexibility or interconnection capacity.

7.2 Policy Implications

The results highlight an important consideration for the continuing integration of variable renewable generation in Europe. Additional wind generation enters electricity systems that differ substantially in their generation mix, hydro resources, cross-border integration and other adjustment margins. The price effects associated with renewable generation should therefore be considered in the context of the electricity system in which that generation is integrated.

In particular, the stronger lower-tail wind coefficients observed in some markets indicate that the price response associated with expected wind generation can become considerably larger in parts of the conditional price distribution. At the same time, the cross-country comparison shows that this pattern is not uniform. Markets with substantial hydro flexibility or interconnection capacity often exhibit more moderate differences across conditional quantiles.

These findings are consistent with the economic role of flexibility in electricity systems. Reservoir hydropower and storage can shift electricity supply across time, while cross-border interconnection allows electricity to be exchanged across markets when renewable availability differs geographically. Other sources of flexibility, including demand response and flexible generation, may provide additional adjustment margins.

The results do not establish that increasing any particular form of flexibility would causally reduce the price effects documented in this thesis. The High/Low classification provides a descriptive comparison across electricity systems rather than an identification strategy for the causal effect of individual system characteristics. Determining the optimal combination of storage, interconnection, dispatchable generation and demand-side flexibility would additionally require information on system constraints, investment costs and the marginal value of each technology.

Nevertheless, the results indicate that the consequences of increasing renewable generation cannot be understood from renewable penetration alone. Electricity systems with similar levels of renewable penetration can display substantially different wind–price relationships depending on their broader structural configuration. This heterogeneity becomes particularly visible when the analysis moves beyond the centre of the conditional price distribution and considers its lower tail.

The main contribution of this thesis is therefore to document that the relationship between expected wind generation and electricity prices is heterogeneous along two interconnected dimensions: across the conditional price distribution and across electricity systems with different structural characteristics. A natural extension for future research would be to move beyond the descriptive classification used here and identify more directly the causal contribution of individual flexibility mechanisms to the way European electricity markets absorb increasing amounts of variable renewable generation.

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A Data

A.1 Institutional and Market-Regime Controls

Table A.1 reports the institutional and market-regime changes accounted for in the empirical analysis. Each indicator takes the value one only for the bidding zones and delivery periods affected by the corresponding arrangement.

Table A.1: Institutional and market-regime controls

Arrangement	**Zones**	**Delivery period**	**Mechanism**
Iberian Exception / MIBEL gas-cost adjustment	ES, PT	15 Jun 2022–31 Dec 2023	Direct intervention in wholesale price formation through gas-cost adjustment.
Interim Coupling	AT, CZ, DE_LU, HU, PL, SK	18 Jun 2021–8 Jun 2022	NTC-based implicit day-ahead coupling on selected Central-Eastern European borders.
Core Flow-Based Day-Ahead Market Coupling	AT, BE, HR, CZ, FR, DE_LU, HU, NL, PL, SI, SK	From 9 Jun 2022	Flow-based capacity allocation in the Core CCR.
Nordic Flow-Based Market Coupling	DK	From 30 Oct 2024	Flow-based day-ahead capacity allocation in the Nordic CCR.
France ARENH+	FR	1 Apr–31 Dec 2022	Additional regulated nuclear allocation; not a direct market-clearing cap.
Slovak nuclear fixed-price arrangement	SK	2023–2025	Regulated/off-market nuclear supply arrangement for households.
GB exit from EU market coupling	FR, BE, NL	From 1 Jan 2021	EU-side interconnectors with GB no longer implicitly coupled through SDAC.

B Figures

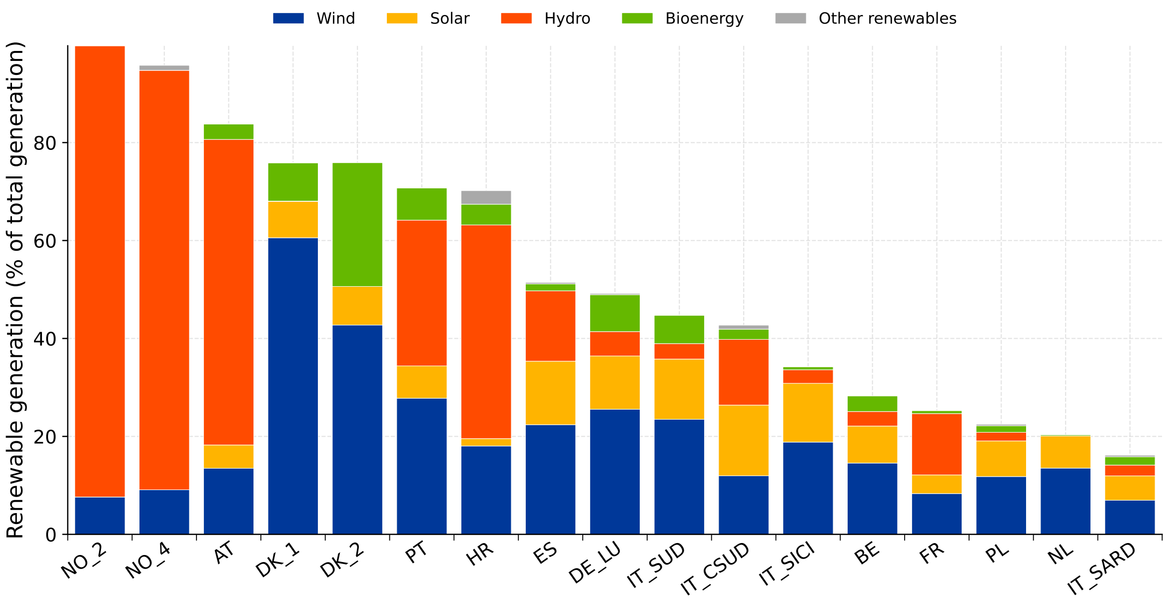

Figure B.1: Renewable electricity generation shares by zones.

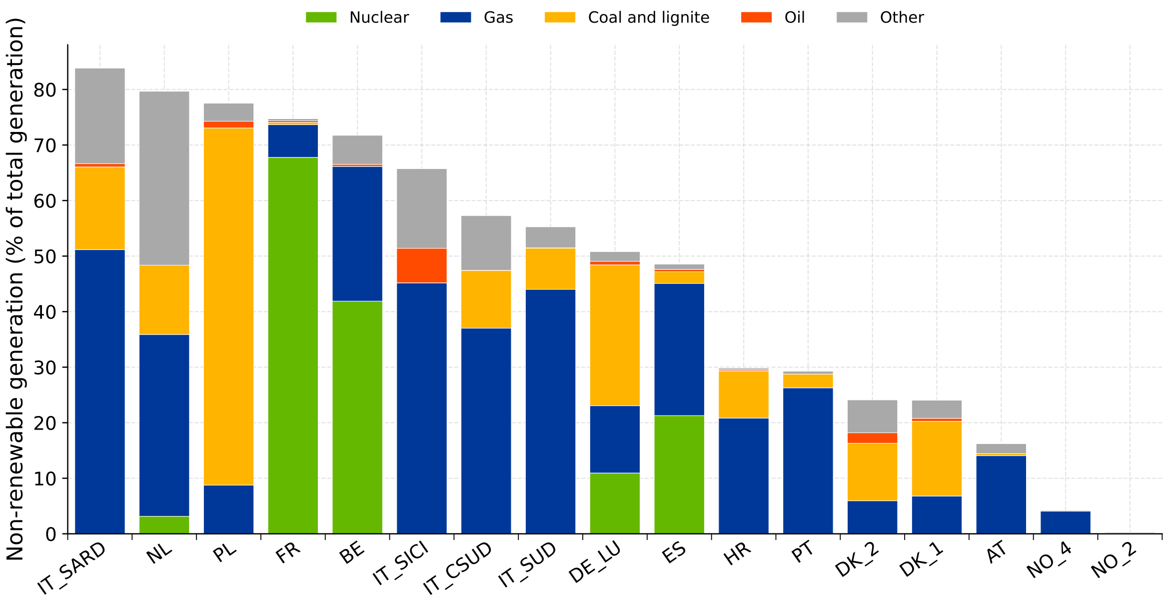

Figure B.2: Non-renewable electricity generation shares by zones.

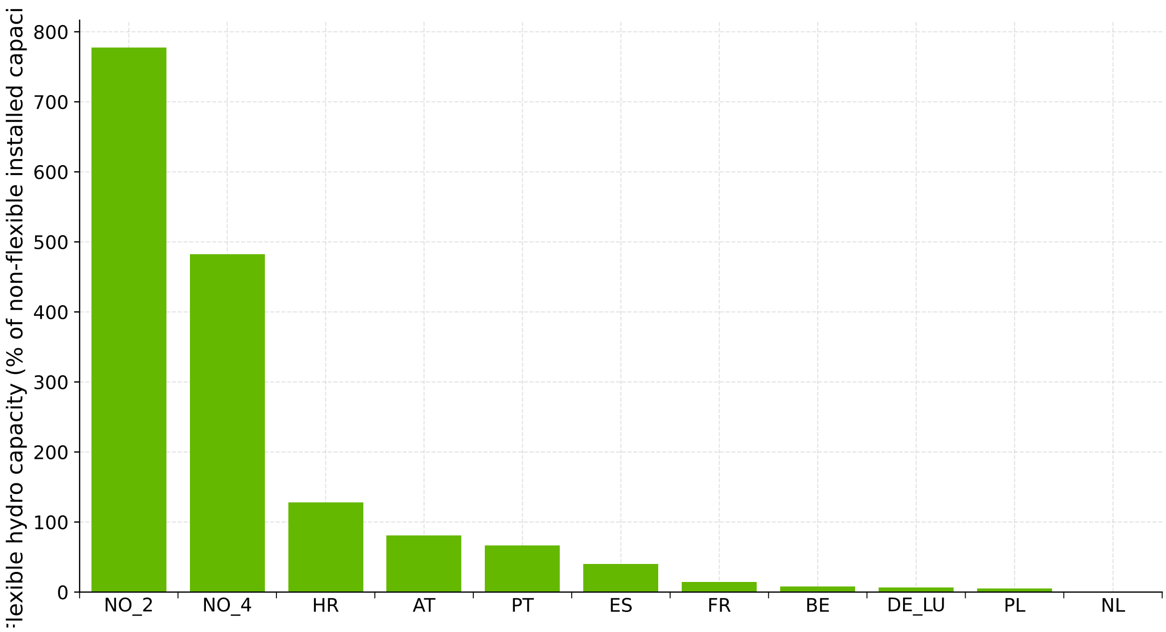

Figure B.3: Hydro flexibility across zones, computed as the sum of reservoir and pumped-storage hydro capacity relative to non-flexible installed generation capacity. Denmark and Italy (CSUD, SUD, SARD, SICI) also have hydro flexibility but are not included due to data unavailability.

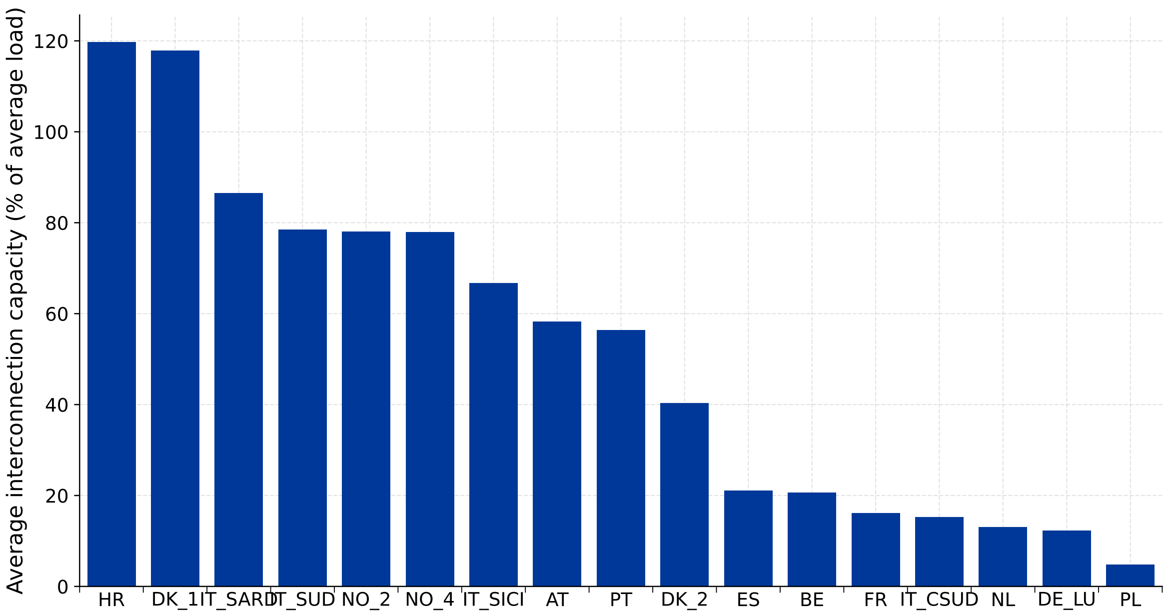

Figure B.4: Interconnection capacity relative to total electricity demand.

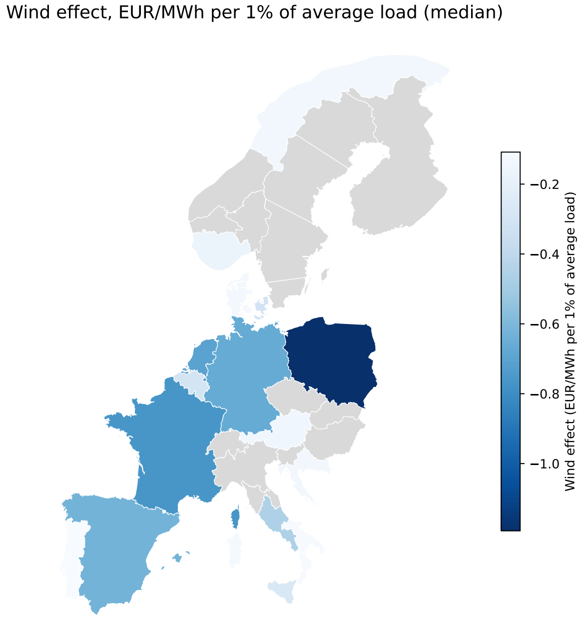

Figure B.5: Map of electricity price responses to an increase in wind forecast generation of 1% of average demand.