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# Measuring a paradox: Zero-negative electricity prices

**EPRG Working Paper EPRG2413**

**Cambridge Working Paper in Economics CWPE2451**

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The large-scale integration of renewable electricity sources (RES) is transforming the operation and economics of the power systems. However, ensuring operational reliability of such a system can result in technical challenges and costly solutions related to the procurement of ancillary services (AS). In electricity markets, bids from RES shift the supply curve to the right and lower the day-ahead prices. During the hours of high levels of RES production, the day-ahead prices can be close to zero or even negative. However, consumers observe that hourly 'zero' prices do not necessarily equate to 'free' electricity in those hours.

At first glance this might seem irrational. However, some generators submit negative bids when they can recover loss of sales (e.g., RES subsidies) with other revenues or ramping up or down their plants is technically difficult or costly (e.g., nuclear plants). The frequency of this phenomenon is rising leading to calls for revisiting market design and system-wide solutions. In 2023, record hours of negative prices in European bidding zones (6,470 hours) were reached, the previous record being in 2020 during the covid lockdown (1,923). In 2023, 27 out of 50 bidding zones experienced their highest number of negative prices since 2017.

We explain and measure a paradox in the zero-negative prices of day-ahead electricity markets, when integrating large volumes of RES in the power system result in increasing economic effects among generators and for consumers. In recent years, the analysis of electricity markets has attracted the attention of many scholars. However, to our knowledge, zero-negative prices and hourly operational costs from AS have not been analysed jointly.

We use hourly data published by the Spanish Transmission System Operator (2021-2024) and the methodology is based on a Seasonal ARIMA (SARIMA). This study focuses on Spain, a country with a high share of RES: 50.3% of the electricity was produced by wind and photovoltaics in 2023. Moreover, the Spanish power system has a limited cross-border capacity with European continent, 7.5% of the average demand (3TW), far from the 15% electricity interconnection target. The results from this study are relevant for other countries on the decarbonization path.

We find that AS costs increase when the cost of energy commodity decrease (increasing participation of RES) or demand increases. Under zero or negative prices, the total hourly costs (AS + day-ahead price) paid by customers turn into positive, which neutralizes some of the economic signals given by day-ahead markets. Accordingly, end-users do not receive the correct price signal to increase their consumption when there is surplus of RES, even when time-of-use tariffs might be near zero (at weekends in Spain). In sum, higher decarbonized power system implies higher AS costs to customers, which presents the zero-negative price paradox in the electricity markets that partially neutralizes the price signals provided by the day-ahead markets. The absence of effective price signals can impact economic viability and efficiency of demand response services or installing storage.

Our main conclusion is that maximizing consumer surplus in highly decarbonized power systems requires minimizing the sum of the costs of the energy commodity (day-ahead price) and total AS costs. Both cost variables must be assessed together and the trade-offs between them seem increasingly significant.

A recommendation in many studies is to use nodal prices to set locational incentives to generators. However, its efficiency is related to the specific operational constraint behind AS activations. If AS are used to solve grid bottlenecks (congestions), nodal pricing would provide schedules that internalize the locational grid constraints. However, if AS are used to solve other operational needs (e.g., voltage, inertia or deficit of adequacy reserves to ramp up/down), the efficiency of nodal pricing might be limited. In these cases, specific AS should be used in bidding or nodal pricing schemes.

Finally, regulators need to monitor AS costs and identify improvements to decrease its volumes and costs. AS costs can be reduced by acting on three dimensions at the same time: on creation of new AS for the upcoming new operational needs, on operational criteria used to activate AS (quantity), and on procurement rules that set their costs (prices). Moreover, regulators must monitor the times (and hours) each generator is activated or curtailed in AS, especially due to the need to solve grid operation constraints. In the case of units with certain number of hours of operation, i.e. Combined Cycles, regulators can assess procurement schemes to minimize AS costs. For instance, annual auctions to set predictable costs for both the generator and customers.

Finally, we present a set of additional recommendations with pros and cons related to their implementation. Future research could focus on two directions: on technical analysis to reduce AS volumes and on procurement rules to reduce their costs.

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Publication August 2024