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Measuring a paradox: Zero-negative electricity prices

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Abstract

With the increasing participation of renewable sources, prices of energy commodity in the day-ahead markets have been decreasing and in increasing number of hours to zero or even negative prices. However, in hours with prices and charges equal or below zero, end-users may still pay significant prices for the 'free' electricity, which presents a paradox. This paper analyses the zero-negative price paradox in a highly decarbonized electricity market. We use Seasonal ARIMA methods with hourly data from the Spanish power system (2021-2024). We find that non-energy system costs increase when day-ahead prices decrease. Thus, customers do not receive efficient price signals to adjust their consumption when more renewables are available. In other words, some benefits of lower prices seem to be traded-off with this "price paradox". Similar results can be anticipated in other countries with increasing share of renewables. Future studies of welfare impact of electricity prices should consider how to minimize these increasing non-energy costs.

Keywords : Energy-only market, day-ahead electricity markets, negative prices, renewables, decarbonization, ancillary services.

JEL Classification D47, L10, L22, L50, L94

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Measuring a paradox:

Zero-negative electricity prices

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1. Introduction

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 (Heptonstall et al., 2021; Borenstein et al., 2023). In electricity markets, bids from RES shift the supply curve to the right and lower the day-ahead prices. During the hours with of high levels of RES production, the day-ahead prices can be close to zero or even negative (Jamasb et al., 2024). However, consumers observe that hourly 'zero' prices for electricity 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 (Brandstätt et al., 2011; Newbery, 2023b). In 2023, record hours of negative prices across the European bidding zones (6,470 hours) were reached, the previous record being in 2020 during the covid lockdown (1,923). [1] In 2023, 27 out of 50 bidding zones experienced their highest number of negative prices since 2017 (ACER, 2024b). In the Netherlands, negative prices reached -500 €/MWh (CREG, 2023).

We explain and measures 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 (Joos et al., 2018; O'Shaughnessy et al., 2021; Newbery, 2023a). We discuss the future implications of this trend and possible solutions. Next, we investigate how day-ahead electricity prices and other hourly system costs evolve. 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 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: in 2023, 50.3 % of the electricity generated was produced by wind and photovoltaics (REE, 2024). Moreover, the Spanish power system has a relevant characteristic: its cross-border capacity with European continent (France) is 7.5% of the average demand (3TW), far from the 15% electricity interconnection target (European Commission, 2023).[2] The results from this study are relevant for other countries on the decarbonization path.

[1] A bidding zone is the largest geographical area in which bids and offers from day-ahead market participants can be matched without the need to attribute cross-zonal capacity. Currently, there are 50 bidding zones in Europe, mostly defined by national borders (ACER, 2024c).

[2] Between 2020 and 2024, peaked hourly demand was between 38 and 40 TWh.

The paper is organized as follows. Section 2 describes the zero-negative price paradox. Section 3 describes the Spanish case. Section 4 outlines the methodology, and data used. Section 5 presents the results. Section 6 is conclusions and policy recommendations.

2. The Zero-negative Price Paradox

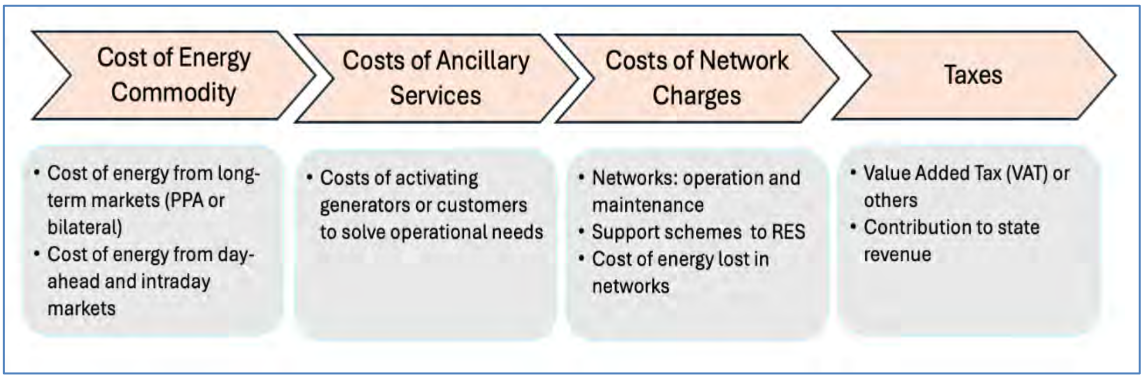
2.1. Cost of Energy as Commodity

The final electricity cost to customer includes four main components comprising cost of energy commodity, ancillary services (AS), network charges and taxes. Cost of energy commodity includes the energy consumed and is set in the long-term and day-ahead electricity markets. Long term markets are private power purchase agreements (PPA) or other forms of bilateral contracts, through which RES producers and consumers can aim to hedge their future revenues and costs against price volatility in the day-ahead markets (Figure 1).

The generation and consumption not cleared in long-term contracts is traded in the day-ahead markets. A feature of the day-ahead markets is that the clearing price for all bids is set by the most expensive cleared technology, namely marginal cost pricing mechanism or "pay-as-cleared". Marginal pricing incentivizes generators to bid at their marginal variable cost and non-dispatchable technologies (e.g., nuclear) have incentives to submit bids at zero prices to always be cleared (Keppler et al., 2022).[3]

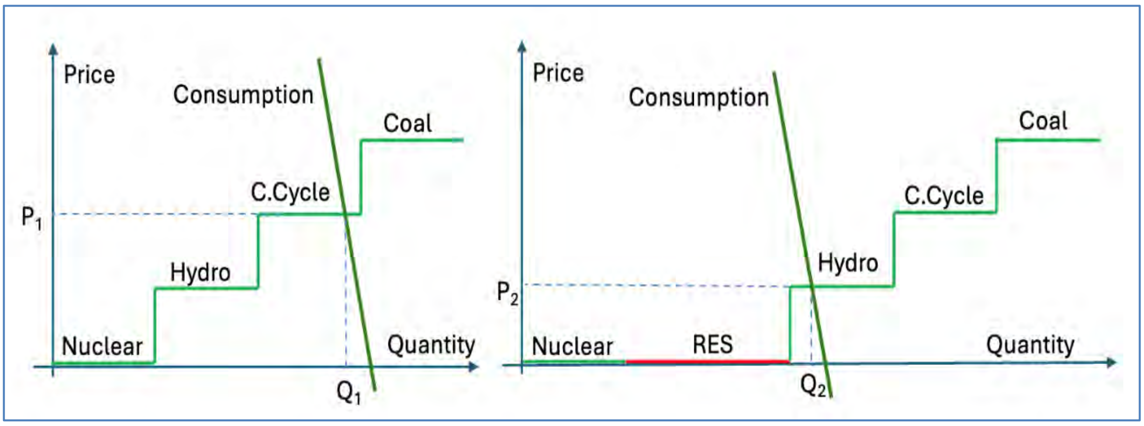
Due to their low operation costs, RES producers have incentive to submit bids close to zero prices, if cannot store production (Jamasb et al., 2024). Large-scale connection of RES has a marked effect on the market supply curve and especially during the hours when RES production is at its peak. Figure 2 depicts the supply and demand curves in a day-ahead market before RES, while Figure 3 shows how inclusion of RES results in lower market clearing price (P_2<P_1).

Figure 1. Components of the final electricity price paid by customers in their bills.
Source: own elaboration



[3] See https://www.epexspot.com/en/downloads for description of key aspects of day-ahead markets.

Figures 2(left) and 3 (right). Electricity market supply and demand curves.
Figure 2 represents equilibrium before RES (P_1, Q_1). Figure 3 includes RES (P_2, Q_2).
Source: Own elaboration



When demand is not elastic, some RES bids might not clear in hours with peak RES production, a potential "missing money" problem (Newbery, 2016). In these cases, some generators have incentive to submit bids with negative prices for several reasons. First, some thermal plants have high costs to start, ramp up or down, or ramp down at short notice, e.g. nuclear (Schill et al., 2017). Second, some generators can compensate negative revenues with revenues from production subsidies, capacity remuneration or selling RES guarantee of origin certificates to suppliers (Prokhorov et al., 2022).[4] Third, some generators have contractual obligations under a PPA and operate to avoid financial penalty (CREG, 2023).[5] In some countries, regulation may not allow RES to stop producing (Brandstätt et al., 2011). This picture might slightly change as demand becomes more elastic, or with connection of storage devices (Kittner et al., 2017; O'Shaughnessy et al., 2022) (see Figure 4).

The schedule of generation and consumption for each next 24 hours is initially set in the day-ahead markets (Step 1). Agents can adjust their day-ahead market's schedule in the intraday-markets up to one hour before dispatch (OMIE, 2024) (Step 3).[6] System operators must validate that schedules from the day-ahead and intraday markets do not cause overload, voltage issue or grid stability problems. If needed, they activate units not cleared in the markets and/or curtail other units through AS (Steps 2 and 4).[7] Final schedule is implemented (Step 5).[8] Figure 5 shows the sequence of these steps.

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[4] Guarantee of Origin certificate is a proof to final customers that a given quantity of energy provided by suppliers was produced from clean generation.
[5] In many countries, nuclear production is sold in long-term markets to hedge generators and consumers against price volatility in day-ahead market. Thus, few volumes are traded in the day-ahead markets.
[6] Intraday markets are used to address weather conditions and uncertainty in the forecasts of RES production for the future hours.
[7] In the European Regulation, AS used to activate or curtail units within a bidding zone is termed as 'redispatching'.
[8] If the system operator identifies an unforeseen situation in real-time, they use AS to activate specific units not scheduled and/or curtail other units scheduled in real-time.

Figures 4. Market equilibrium (P_3, Q_3) where P_3 is negative. In this case, RES and nuclear provide negative bids to be dispatched, but not all available RES in the day-ahead is cleared.
Source: Own elaboration

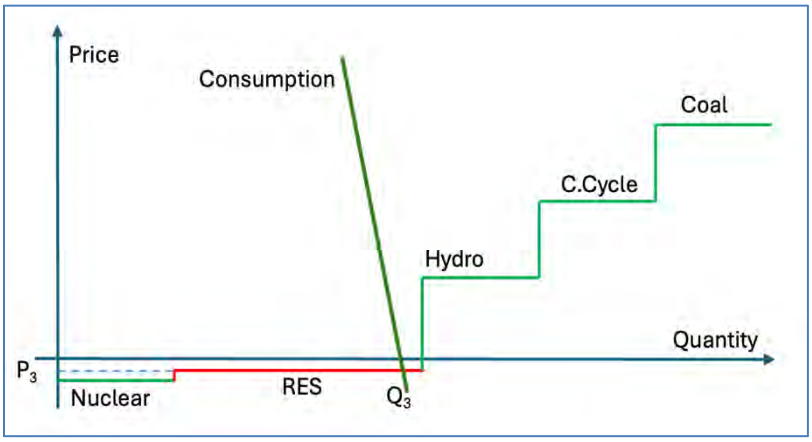
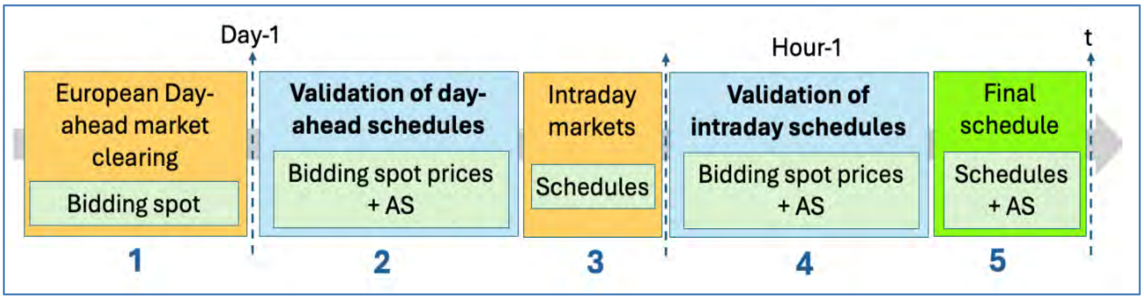


Figure 5. Steps to transform the day-ahead market schedule (left side) on the final schedule (right side). Note: In some countries, procurement of some AS might be done before step 1.
Source: Own elaboration



2.2. Ancillary services

RES can challenge network operation since wind and photovoltaics plants are inverted-based resources (IBR) whose operational behavior slightly differ from the conventional rotating synchronous generation units. (Denholm et al., 2021; Ahmed et al., 2023). Moreover, RES production is variable and dependent on the availability of sun or wind, and sunny/windy locations are often far from large consumption areas with limited network capacity.[9] The large-scale connection of RES made of IBR is behind increasing volumes in AS to solve operational needs and ensure system reliability (Qays et al., 2023; Davi-Arderius et al., 2024b).[10]

[9] This effect might be stronger when supporting schemes for RES distort locational decisions (Newbery et al., 2023b).
[10] Operational needs include alleviating grid bottlenecks (congestions), controlling voltage with reactive energy flows, solving system stability problems, inertia problems or imbalances between total generation and demand (Schermeyer et al., 2018; Davi-Arderius et al., 2024a).

In 2023, AS volumes accounted for 58 TWh (3% of total demand) and 3.8 b€ in Europe.[11] AS Costs include compensations to the activated and curtailed units and they are paid by the load in Europe, i.e. all the customers within bidding zone. While volumes of AS implied an average curtailment of less than 1% of total European RES production (12 TWh), they were more pronounced in Germany (4.01%), Hungary (1.19%) and Spain (1.18%) (Cole et al., 2021; ACER, 2024a).[12] Some studies forecast annual volumes of more than 800 TWh in Europe by 2040 with an annual cost of over 100 b€ (Thomassen et al., 2024). AS can also have environmental impact when scheduled RES is replaced by conventional pollutant technologies (Davi-Arderius and Schittekatte, 2023).

2.3. Network charges and taxes

Network charges are an economic mechanism to remunerate system operators, networks and other system costs such as capacity markets.[13] Before the introduction of smart meters, network tariffs were the same regardless of the hour of consumption.[14] Smart meters facilitate application of different tariffs depending on the time of consumption, namely Time-of-Use (ToU) tariffs. Accordingly, ToU tariffs can also be used to provide economic incentives for consuming in certain hours over others (Enrich et al., 2024).Traditionally, the highest tariffs are used during peak demand hours, i.e. at around noon or early evening on workdays to incentivize reducing consumption at peak time, thus reducing grid congestion and avoiding costly conventional technologies.[15] Taxes include value-added taxes or other specific taxes levied at national or regional level. Network charges and taxes are out the scope of this analysis.

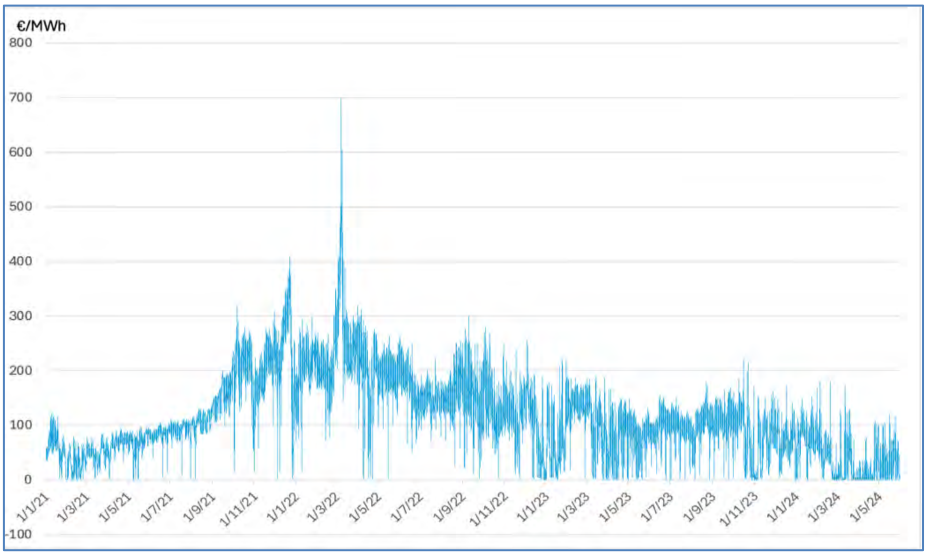
3. The Spanish Case

Between 2021 and 2023 in Spain, photovoltaic capacity increased from 11.8 to 26.0 GW (+121%) and wind capacity from 27.7 to 30.9 GW (+12%). In this period, annual electricity demand slightly decreased: 256 (2021) to 244.7 TWh (2023). This is partially due to the strong growth of small generation installed behind-the-meter in households,

[11] These volumes do not include Balancing AS (ACER, 2024a).
[12] AS Costs may include compensation to units to be available when needed and the activations themselves. In some cases, the load pays the AS costs directly, in others indirectly when generators assume AS costs. In 2022, AS costs (redispatching costs) in Europe peaked at 4.2 b€, which likely caused by the higher gas costs related to starting some thermal units. In 2023, wind and solar production in Europe was 469 and 200 TWh, respectively (ACER, 2024a, 2024b).
[13] In capacity markets, generators are paid to make their capacity available (Aagaard and Kleit, 2022).
[14] Some traditional meters could differentiate accumulated consumption between two periods (peak and off-peak hours). However, they do not distinguish between hours and days as smart meters do.
[15] Higher consumption at peak time would imply starting some coal or gas plants, with corresponding impact the day-ahead price as more costly marginal plants set the clearing price.

known as self-consumption, which reached 7TW at the end of 2023.[16] In this period, annual volumes of energy activated in AS increased by 59%, from 10.4 (2021) to 16.5 TWh (2023), while annual costs increased by 148%, from 864 (2021) to 2,145 M€ (2023). In the same period, day-ahead prices peaked during the gas crisis, but quickly decreased due to the normalization of the gas markets and the new RES (Figure 5). Between 1st January and 31st May 2024, over 32.4% of the hourly prices were below 5 €/MWh, while 541 out of 3,647 (14.8%) hours are equal to zero or negative (REE, 2024).

Figure 5. Hourly prices in the day-ahead markets (Spanish bidding zone) 1.1.2021 - 31.5.2024. Source: REE (2024).



Zero-negative prices occur in more than 20% of the hours between 12h and 17h, which coincide with peak demand during peak solar production. This highlights that demand is not sufficiently flexible to adapt to the day-ahead prices (Figure 6).

In days with peak RES production and zero day-ahead prices, customers pay for the electricity in the form of AS costs, which presents a zero-negative price paradox. In Figure 7, AS costs in Spain are classified between Generic AS (grey and light blue) used to alleviate grid bottlenecks and Balancing AS (orange) used to solve the imbalances between generation and demand. The rest of operational needs are solved with Generic AS. This Figure shows a typical day with several hours with day-ahead prices (blue bars) below to zero (from 12h to 18h). However, AS costs (grey, light blue and orange) sum more than 0.3M€, which represent around 18€/MWh paid by customers.[17] At nighttime

[16] https://www.unef.es/es/comunicacion/comunicacion-post/en-2023-se-instalaron-en-espana-1706-mw-de-autoconsumo-fotovoltaico

[17] In Spain, AS are divided into three groups: Generic AS made after day-ahead, Generic AS made after intraday, and balancing AS. Generic AS are used to resolve operational needs, except for imbalances between generation and consumption (Table 1) (Davi-Arderius et al, 2024a).

(22h to 24h), AS costs fall significantly, coinciding with when combined cycle reaches maximum production (Figure 8).

This pattern is similar to other power systems with large amounts of RES. In energy-only markets (EOM) this phenomena or 'paradox' is due to the need to deliver system reliability with short-term markets (Newbery, 2016).[18]

Figure 6. Percentage of hourly day-ahead prices lower or equal than 1 €/MWh (orange bars) and average electricity demand (green line) between 1.1.2021 and 30.5.2024.
Source: Own elaboration based on REE (2024).

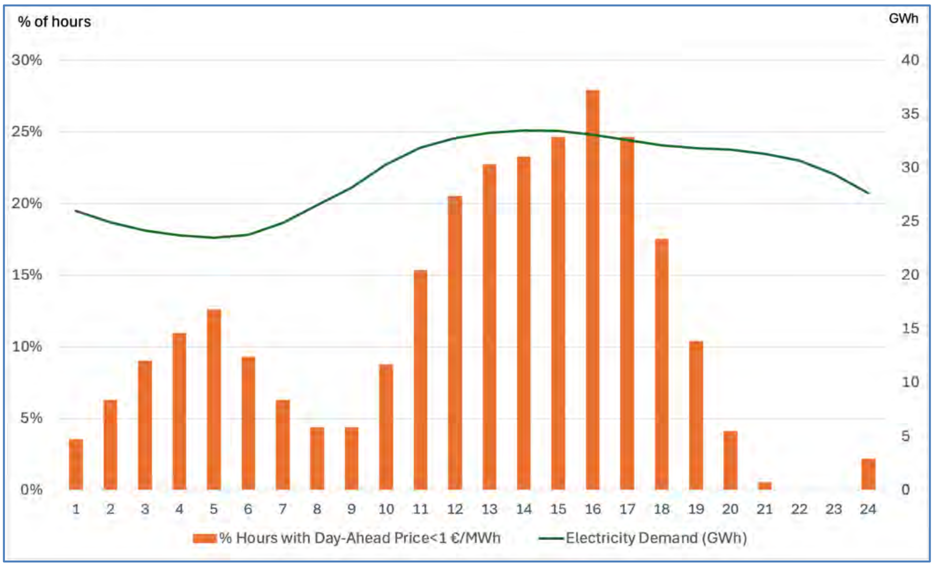
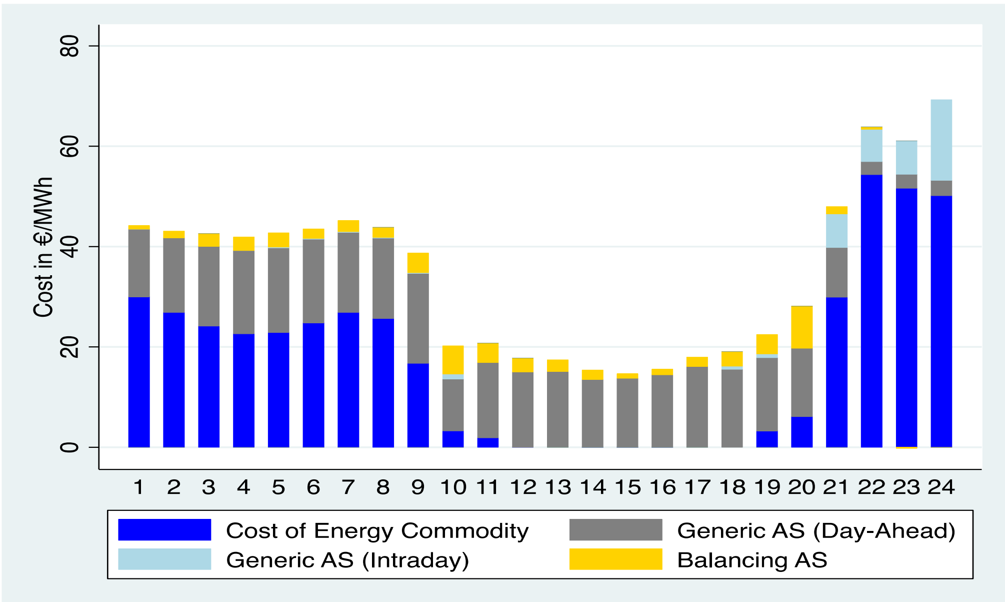
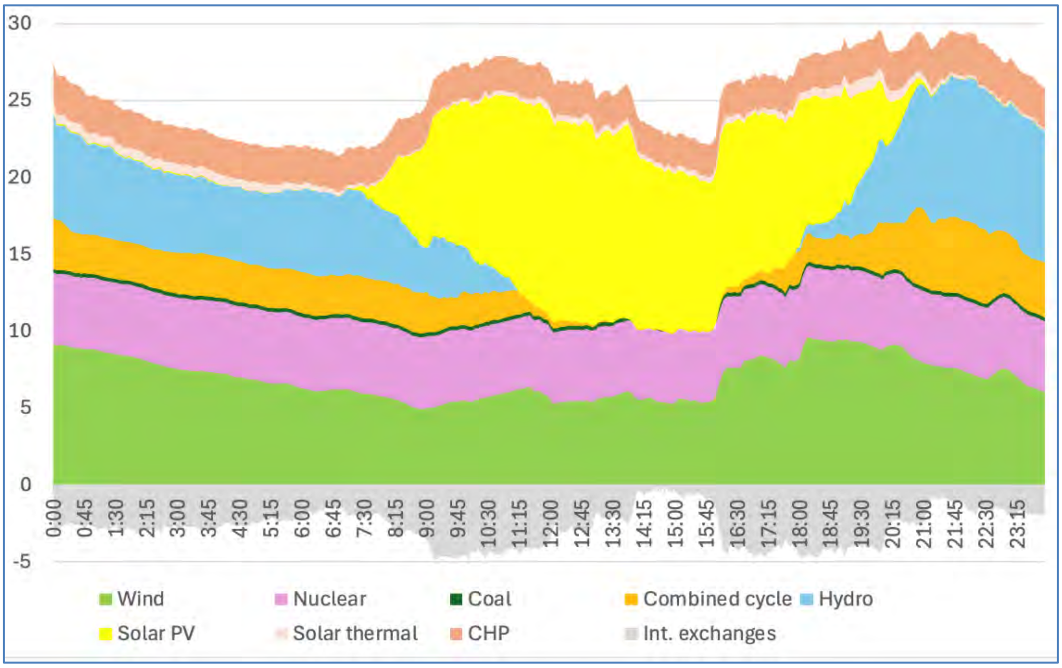


Figure 7. Hourly day-ahead prices and AS costs for a day with prices≤0 during some hours (5.5.2024).
Source: Own elaboration based on REE (2024).



[18] An energy-only market is made of short-term energy markets -day ahead, intraday or ancillary services.

Figure 8. Hourly production by technology (5.5.2024).
Source: own elaboration based on REE (2024).



4. Methodology and Data

4.1. Methodology

In this section we describe the empirical approach followed to analyze how AS have evolved between 2021 and 2024. We estimate three models of total costs, day-ahead costs, and balancing costs of ancillary services. In the Total Cost Model, we estimate how the hourly day-ahead electricity price (WP_t) and the electricity demand ($Demand_t$) affect the total costs of AS (AS_t).[19] Equation 1:

$$\Delta AS_t = \hat{\beta}_0 + \hat{\beta}_1 \cdot \Delta AS_{t-1} + \hat{\beta}_2 \cdot \Delta WP_t + \hat{\beta}_3 \cdot \Delta WP_t^2 + \hat{\beta}_4 \cdot \Delta Demand_t +$$

$$\hat{\beta}_5 \cdot \Delta Demand_t^2 + \sum_{m=1}^{11} \hat{\alpha}_m \cdot M_t^m + \hat{\beta}_6 \cdot holiday_t + \hat{\emptyset} \cdot \Delta AS_{t-24} + \varepsilon_t \qquad (1)$$

$$AS_t = daGAS_t + idGAS_t + BAS_t \qquad (2)$$

We include the square of them to better capture their patterns. Estimated $\hat{\beta}_2$, $\hat{\beta}_3$, $\hat{\beta}_4$and $\hat{\beta}_5$ coefficients represent the short-run effect of day-ahead price and demand, i.e. the

[19] Variables are differentiated to ensure stationarity (Kwiatkowski et al., 1992). It is noteworthy that a bidirectional causality might exist between the two explicative variables: i.e., the day-ahead price (WP_t) might be explained by electricity demand ($Demand_t$), and vice versa. A robustness check in Appendix A includes the individual estimates with each independent variable and shows that the results remain consistent.

effect on the next hour.[20] $\hat{\beta}_1$ and $\widehat{\emptyset}$ corresponds to the lagged effect autoregressive model, which captures the time memory of the model. Seasonality is controlled with a dummy variable for each month m of the year (M_t^m) and another ($holiday_t$) equals to 1 for weekends or national holidays from Monday to Friday. In Equation 2, $daGAS_t$ denotes the costs of Generic AS after the day-ahead, $idGAS_t$ denotes the costs of Generic AS after the intraday markets, and BAS_t corresponds to costs of the Balancing AS.

In the AS Model, we estimate how the day-ahead price (WP_t) and the electricity demand ($Demand_t$) affect the costs of Generic AS made after the day-ahead ($daGAS_t$) and after the intraday markets ($idGAS_t$). Equations 3 and 4, respectively:

$$\Delta daGAS_t = \hat{\beta}_0 + \hat{\beta}_1 \cdot \Delta daGAS_{t-1} + \hat{\beta}_2 \cdot \Delta WP_t + \hat{\beta}_3 \cdot \Delta WP_t^2 + \hat{\beta}_4 \cdot \Delta Demand_t + \hat{\beta}_5 \cdot \Delta Demand_t^2 + \sum_{m=1}^{11} \hat{\alpha}_m \cdot M_t^m + \hat{\beta}_6 \cdot holiday_t + \widehat{\emptyset} \cdot \Delta daGAS_{t-24} + \varepsilon_t \quad (3)$$

$$\Delta idGAS_t = \hat{\beta}_0 + \hat{\beta}_1 \cdot \Delta idGAS_{t-1} + \hat{\beta}_2 \cdot \Delta WP_t + \hat{\beta}_3 \cdot \Delta WP_t^2 + \hat{\beta}_4 \cdot \Delta Demand_t + \hat{\beta}_5 \cdot \Delta Demand_t^2 + \sum_{m=1}^{11} \hat{\alpha}_m \cdot M_t^m + \hat{\beta}_6 \cdot holiday_t + \widehat{\emptyset} \cdot \Delta idGAS_{t-24} + \varepsilon_t \quad (4)$$

In the Balancing Model, we estimate how hourly day-ahead price (WP_t) and the demand ($Demand_t$) affect the costs of Balancing AS (BAL_t). Equation 5:

$$\Delta BAL_t = \hat{\beta}_0 + \hat{\beta}_1 \cdot \Delta BAL_{t-1} + \hat{\beta}_2 \cdot \Delta WP_t + \hat{\beta}_3 \cdot \Delta WP_t^2 + \hat{\beta}_4 \cdot \Delta Demand_t + \hat{\beta}_5 \cdot \Delta Demand_t^2 + \sum_{m=1}^{11} \hat{\alpha}_m \cdot M_t^m + \hat{\beta}_6 \cdot holiday_t + \widehat{\emptyset} \cdot \Delta BAL_{t-24} + \varepsilon_t \quad (5)$$

To compare the costs of each component, we calculate the long-run effect, i.e. the average impact of each coefficient in each year. Equation 6:

$$Long\ run\ effect = \frac{\hat{\beta}_i}{(1-\hat{\beta}_1-\widehat{\emptyset})} \quad (6)$$

In all estimations, we use maximum likelihood since we include the lagged endogenous variable. Ordinary least square could lead to bias problems related to potential autocorrelation of residuals (Davi-Arderius et al, 2024a).

[20] The selection of variables is based on Davi-Arderius et al. (2024a), where determinants of AS are estimated. These models include the AR1 and AR24 estimates. Thus, a change in one hour "has some memory" and affects the next hours and days. This effect is solved when we calculate the long-term effect that considers both AR1 and AR24 coefficients (Equation 9).

4.2. Data

The data used in this study includes hourly data from the Spanish bidding zone between 2021 and 2024 (May 31st). This data is a combination of operating data published by the Spanish TSO and market data published by the Spanish NEMO (REE, 2024; OMIE, 2024) and contains just under 30,000 observations. Table 1 presents summary statistics of the data used.

Table 1. Summary statistics of our dataset (N=29,204)

Variable	**Description**	**Units**	**Mean**	**St. Dev.**	**Min**	**Max**
WP_t	Price in day-ahead markets	€/MWh	111.660	74.044	-1.500	700.000
AS_t	Total AS costs	€/MWh	8.105	6.393	-5.050	95.680
$daGAS_t$	Costs of Generic AS after day-ahead market	€/MWh	3.359	3.819	-1.780	41.150
$idGAS_t$	Cost of Generic AS after intraday market	€/MWh	2.476	4.382	-2.430	93.770
BAL_t	Costs of balancing AS	€/MWh	2.270	2.443	-6.900	80.620
$Demand_t$	Total electricity demand	GWh	29.206	4.875	15.479	44.103

Table 2 shows the cost of energy commodity and AS that customers pay through their bills according to their consumption. The last column shows the overrun attributed to AS costs, which peaks in 2024 to +36.19% of total AS overruns. The average cost of energy peaks in 2022 during the gas crisis and decreases every year until 2024 when gas markets normalize. However, AS overrun follows the opposite pattern and increases. In other words, some consumer surplus related to lower cost of energy commodity are partially neutralized due to the increasing AS costs, which describes a paradox. Total AS Costs increase every year reaching 3.1b€ in 2024.

As shown in Figure 9, the relationship between AS costs and electricity demand does not follow a clear pattern. However, AS costs and day-ahead prices follow a U-shaped correlation as shown in Figure 10, i.e. AS costs increase when day-ahead prices decrease or increase.

Table 2. Costs of energy commodity, AS costs and overrun (calculated as the AS Costs over costs of energy as commodity). Note: data represents the average hourly values for each year. Note: Values for 2024 correspond to period between 1.1.24 and 31.5.24, while Total AS Costs for 2024 are projected

Year	**Cost of energy commodity** [€/MWh]	**Generic AS after day-ahead** [€/MWh]	**Generic AS after intraday** [€/MWh]	**Balancing AS** [€/MWh]	**Total AS Costs** [€/MWh]	**AS Overrun**	**Total AS Costs** [M€]
2021	+111.94	+2.02	+1.08	+1.31	**+4.40**	**+3.9%**	**1,097**
2022	+167.53	+2.29	+2.54	+2.73	**+7.56**	**+4.5%**	**1,850**
2023	+87.11	+4.26	+3.40	+2.68	**+10.34**	**+11.8%**	**2,707**
2024	+35.77	+6.99	+3.45	+2.51	**+12.95**	**+36.2%**	**3,144**

Figure 9. AS costs (AS_t) vs electricity demand ($Demand_t$).

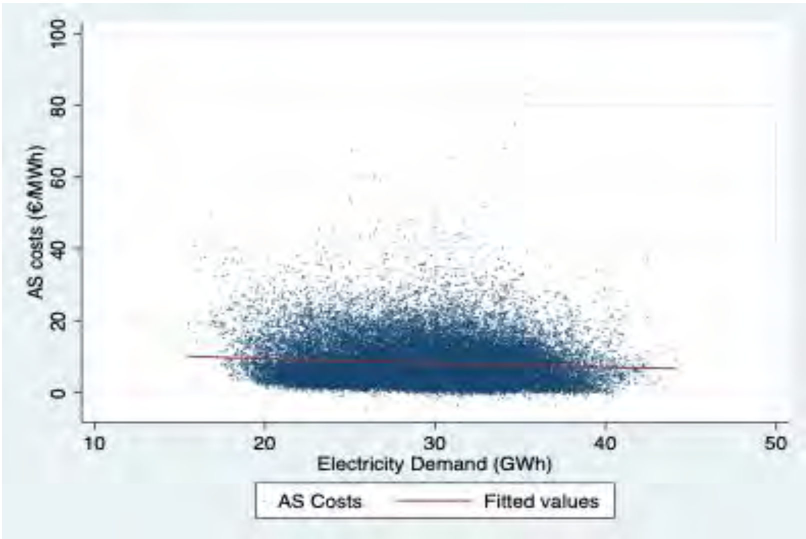
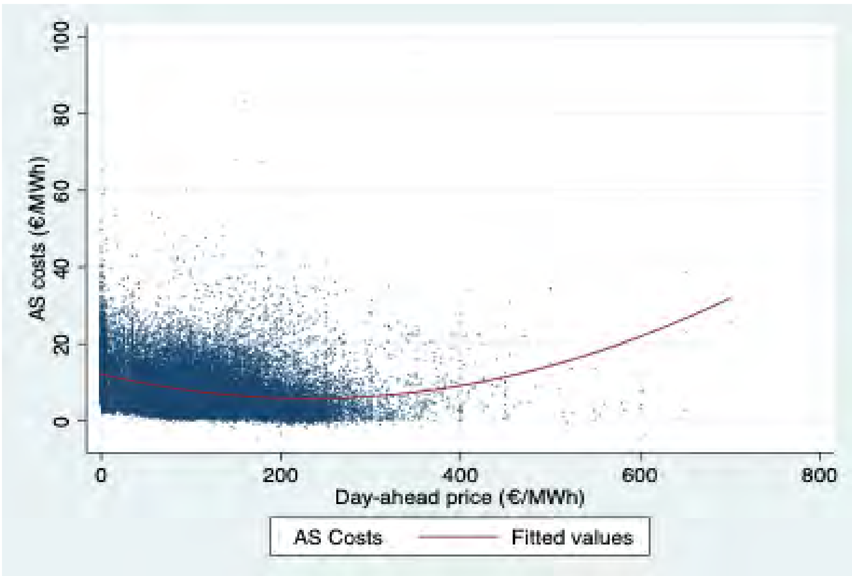


Figure 10. AS costs (AS_t) vs cost of energy commodity (WP_t), i.e. cost of commodity vs. cost of services.



5. Results

This section describes the main results of the analysis of the paradox in hours with prices and charges equal to or below zero. We investigate how day-ahead prices and hourly AS costs paid by end-customers evolve. Table 3 shows the estimates from the Total Costs Model (column 1), the AS Model (columns 2 and 3) and the Balancing Model (column 4). In all cases, the estimates correspond to short-term effects, i.e. the effect on the costs from each explicative variable. As we use variables in differences in our estimates, the results should be understood as the change on the independent variable explained by a change in the explanatory variables, i.e. how AS costs change when day-ahead prices or demand change.

To compare the coefficients from each column, we calculate the long-term effects using Equation 6. As shown in Table 4, the AS costs (non-squared coefficients) are significantly and negatively correlated with the price of the electricity commodity, while being slightly significantly and positively correlated with total demand. In other words, AS costs increase by +0.018 €/MWh for each €/MWh reduction in price of energy commodity, while there is a small significant positive coefficient related to square of cost ($+4.4 \cdot 10^{-05}$ €/MWh).

On the other hand, AS costs increase by +0.23 €/MWh for each additional MWh scheduled in the day-ahead, while there is a small significant negative coefficient related to the square of the cost (-0.003 €/MWh). Bearing in mind the patterns shown in Figure 6, the AS costs are amplified as zero-negative prices happen more often in hours with high electricity demand.

Table 3. ML estimations for AS costs paid by customers.

	(1) ΔAS_t	(2) $\Delta daGAS_t$	(3) $\Delta idGAS_t$	(4) ΔBAL_t
$WP\ (\Delta WP_t)$	-0.0183^{****}	-0.0522^{****}	0.0427^{****}	-0.00530^{****}
	(0.00197)	(0.000413)	(0.00185)	(0.000883)
$WP^2\ (\Delta WP_t^2)$	0.0000453^{****}	0.0000637^{****}	-0.0000211^{****}	-0.00000423
	(0.00000469)	(0.000000898)	(0.00000429)	(0.00000274)
$Demand\ (\Delta Dem_t)$	0.235^{**}	-0.904^{****}	1.066^{****}	0.522^{****}
	(0.112)	(0.0277)	(0.0985)	(0.0525)
$Demand^2\ (\Delta Dem_t^2)$	-0.00308^{*}	0.0137^{****}	-0.0137^{****}	-0.00944^{****}
	(0.00187)	(0.000506)	(0.00164)	(0.000901)
AR1	-0.298^{****}	0.0877^{****}	-0.339^{****}	-0.300^{****}
	(0.00151)	(0.00303)	(0.00118)	(0.000843)
AR24	0.277^{****}	0.471^{****}	0.319^{****}	0.171^{****}
	(0.00193)	(0.00179)	(0.00154)	(0.00206)
Constant $(\widehat{\beta_0})$	3.978^{****}	0.893^{****}	3.353^{****}	1.889^{****}
	(0.00406)	(0.00111)	(0.00293)	(0.00107)
N	29923	29923	29923	29923

Standard errors in parentheses: $^{*}\ p < 0.10$, $^{**}\ p < 0.05$, $^{***}\ p < 0.01$, $^{****}\ p < 0.001$

Table 4. Long-term determinants of AS Costs (€/MWh).

	Total AS Costs	Generic AS Costs after day-ahead	Generic AS Costs after intraday	Balancing AS Costs
	ΔAS_t	$\Delta daGAS_t$	$\Delta idGAS_t$	ΔBAL_t
WP (ΔWP_t)	-0.018	-0.125	+0.042	-0.005
WP^2 (ΔWP_t^2)	$+4.4 \cdot 10^{-05}$	$+14.4 \cdot 10^{-05}$	$-2.1 \cdot 10^{-05}$	n/s
$Demand$ (ΔDem_t)	+0.230	-2.048	+1.045	+0.462
$Demand^2$ (ΔDem_t^2)	-0.003	0.031	-0.013	-0.008

When disaggregating by AS, costs of Generic AS made after day-ahead (non-square coefficients) are negatively correlated with the cost of energy commodity and the total electricity demand. These costs show the largest coefficients between all AS: they increase on +0.125 €/MWh for each €/MWh less in the cost of energy commodity, while increase on +2.048 €/MWh for each MWh less in the demand. Conversely, Costs of Generic AS made after intraday (non-square coefficients) are positively correlated with the cost of energy commodity and total electricity demand. They decrease by -0.042 €/MWh for each €/MWh reduction in the cost of energy commodity and decrease by -1.045 €/MWh for each MWh reduction in the demand. The different sign of AS costs is explained by the different operational needs solved after the day-ahead and intraday markets (Davi-Arderius et al., 2024a). Finally, costs of balancing AS are negatively correlated with the cost of energy commodity, but positively correlated with the total electricity demand. In all cases, the square coefficients are small.

All these results show that scheduling large volumes of RES (lowering the cost of the energy commodity) increases AS costs. Total AS costs might even increase further if total electricity demand increases. It is noteworthy that costs from disaggregated AS follow different patterns (in terms of signs and coefficients), which shows that operational needs behind them are different as found in Davi-Arderius et al. (2024a). In sum, higher decarbonized power system implies higher AS costs to customers, which clearly describes the zero-negative price paradox in the electricity markets that partially neutralizes the price signals provided by the day-ahead markets.

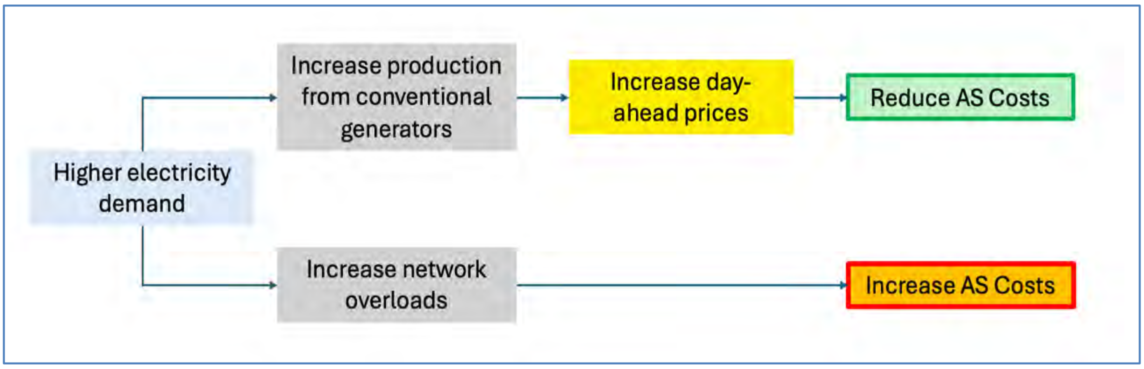
6. Conclusions

This study measures an interesting paradox which can be anticipated in highly decarbonized power systems. AS costs increase when the cost of energy commodity decrease (increasing participation of RES) or electricity 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 electricity markets. Accordingly, these 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). The absence of effective price signals can impact economic viability and efficiency of demand response services or installing storage.[21]

We show that highly decarbonized energy-only systems can become a hybrid system of energy commodity trading and services trading (AS). Moreover, the provision of AS becomes an interesting economic alternative opportunity for generators (or customers) to earn revenues when day-ahead prices are zero or negative. However, providing AS needs capacity and units that can quickly ramp up and down on request. However, not all technologies have the same response speed, or may need costly storage devices to start under bad weather conditions (sun or wind). In some cases, the location of a AS provider in the network might matter, for instance to solve specific grid bottlenecks. Here, storage can play a role due to quick ramp up and down ability and does not depend on the availability of wind or sun.

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. For instance, higher electricity demand has two different effects on the day-ahead prices and AS costs in Figure 9. On the one hand, higher demand would imply starting some coal or gas plants, with corresponding impact on the day-ahead price as the more costly marginal plant sets the clearing price (yellow box), but AS costs would reduce due to the schedule of these technologies (green box). On the other hand, higher demand would increase loads, which in turn could strain the grid, which would result in additional AS costs (orange box). Thus, the resulting AS cost would depend on the trade-off (and interaction) effects.

Figure 9. Impacts on (hourly) AS Costs from electricity demand becoming more elastic in response to more frequent zero-negative prices.
Source: Own elaboration.



[21] A supplier might have incentive to adopt specific Demand Response Services with customers to adapt their consumption to the available RES production at each time, minimizing the need to procure costly energy from other generators during peak demand hours.

A second 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 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.

Third, national energy planning assessments such as National Energy and Climate Plans in Europe must assess future operational needs to identify potential AS and their costs. This enables setting proper regulatory instruments in advance such as specific technical requirements for RES, or incentivizing some locations over others. The European Reform of Electricity Market Design includes some provisions related to the "need to perform national reports on the estimated needs for flexibility for a period of at least 5 to 10 years" (European Commission, 2023c).

Fourth, 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). For instance, current Generic AS cannot be used for all operational needs. On the one hand, structural and repetitive congestion issues can be procured through long-term AS with predictable costs, instead of procuring activations just after the day-ahead gate closure, which opens the possibility for market failure or market power. On the other hand, non-congestion issues -voltage or inertia problems- need to be solved with specific AS. If these problems are repetitive and predictable, a new AS with long-term market-based procurement might provide efficient incentives for third parties to invest in voltage control or inertia equipment. In the long-term, this would provide more economically efficient solutions for the system than procuring repetitive AS some hour ahead. In these cases, regulators should compare increasing AS costs from RES (IBR), i.e. inertia, with the activation of spinning to maintain stability.

Fifth and related to the previous recommendation, 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. This would minimize the number of times the unit is connected and disconnected in a year, which would reduce their maintenance and operating costs. In the case of units repetitively curtailed, i.e. RES, regulators could assess whether the costs of retrofitting IBR or implementing storage devices would provide savings on AS Costs.

Tables 5 and 6 describe additional recommendations with pros on cons related to their implementation. Future research could focus on two different directions: on the technical analysis to reduce AS volumes and on the procurement rules to reduce their costs.

Table 5. Regulatory and policy recommendations aimed at reducing AS costs.

Regulatory recommendations	Pros	Cons
Reassessment of the operational criteria used to activate and procure AS	• Reducing AS volumes would directly reduce AS Costs	• Potential asymmetric information problem between regulators and system operators
Regular monitoring report of AS costs and activations	• Higher transparency on the AS procured and AS costs	• Risk if agents can use the published information to anticipate future actions from system operators (market power)
AS Costs defined a year ahead and included in the network charges (instead of assigning hourly AS Costs to the hourly consumption)	• Costs for customers are more predictable in the long-term • Retailers and large customers (PPA) might include AS Costs (in hourly procurement it is very difficult to hedge AS Costs)	• Many uncertainties when forecasting AS volumes long-term in advance • Need to link with the long-term procurement of AS to make their costs more predictable • Units pay AS Costs, although they do not increase the need for AS, i.e. unfair allocation of AS Costs
AS Costs are also paid by generators and storage (not only customers)	• Technological neutral approach is respected • Generators have incentives to consider its potential impact on system costs when defining bids, especially relevant for storage	• Difficult to monitor if generators bids are efficiently internalizing AS costs
Customers (or independent aggregators) pay different AS costs considering their capability to increase demand under zero-negative prices	• Customers and independent aggregators have more efficient hourly price signals to increase demand when there is a surplus of RES	• Principle of non-discrimination might not be respected
Moving from zonal prices to nodal prices	• Efficient solution to provide locational information and align grid bottlenecks (congestions) with market prices	• Limited efficiency for some specific operational needs beyond grid bottlenecks such as deficit or surplus of reactive energy or deficit of adequacy reserves to ramp up/down.
Assessing future operational needs to identify potential AS and their costs (grid bottlenecks, operational constraints, needs for balancing and other services) in national energy planning assessments such as National Energy and Climate Plans in Europe	• Efficient solution to compare results from different scenarios	• Results are limited to the definition of scenarios and hypothesis made in advance • Definition of scenarios requires assuming future hypotheses with a lot of uncertainty

Table 6. Regulatory and policy recommendations aimed at reducing AS costs.

Regulatory recommendations	Pros	Cons
Long-term procurement for AS	• Efficient market signal to incentivize some resources to retrofit and participate in AS, which increases liquidity • Efficient solution for structural and repetitive operational needs	• Definition of volumes well in advance is related to uncertainty • System Operators might have incentives to over procure to minimize risks • Less efficient for unforeseen operational needs.
Short-term procurement for AS	• Does not incentivize resources to retrofit and participate in AS, which increases liquidity	• Procured volumes match with the AS needed • Need to set price caps to limit potential market power
Market-based procurement of AS (compensation for provision of AS defined by market bids)	• Efficient solution to procure in the long-term if liquidity is high • Efficient pricing mechanism: a different price might fit for each case	• Risk of market power is participants can anticipate their repetitive procurement in the short-term (day-ahead), i.e. in-dec gaming • Need to set price caps to limit potential market power
Rule-based procurement of AS (compensation for provision AS defined by the regulator in advance)	• Predictable AS costs for customers and AS providers	• Asymmetric information problem between regulators and AS providers • Risk of setting AS prices far from the optimal price, i.e. too high or too low
Creating of specific AS to deal with specific operational need	• Higher transparency in the operational needs for potential participants that should retrofit its installations	• Minimum volume of operational needs is required • Risk of fragmenting the market if technical requirements to participate become very different than the rest of AS. Value stacking might be affected
Move from predetermined ToU to dynamic tariffs	• Less distortion of ToU on zero or negative day-ahead prices	• Difficult to calculate and implement transparent and efficient dynamic tariffs • Less predictable costs for suppliers and customers.
Definition of time periods in ToU tariffs also consider the potential RES production	• Less distortion of ToU on zero or negative day-ahead prices	• Difficult to find a balance between minimizing grid congestions and increasing consumption of peak RES production • Difficult to predict zero-negative prices long-term in advance

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Appendix A – Robustness checks

Table A.1. ML estimations for AS costs.

	(1) ΔAS_t	(2) ΔAS_t	(3) $\Delta daGAS_t$	(4) $\Delta daGAS_t$
WP (ΔWP_t)	-0.0180****		-0.0518****	
	(0.00196)		(0.000422)	
WP^2 (ΔWP_t^2)	0.0000465****		0.0000611****	
	(0.00000466)		(0.000000926)	
$Demand$ (ΔDem_t)		0.189*		-0.974****
		(0.111)		(0.0308)
$Demand^2$ (ΔDem_t^2)		-0.00227		0.0150****
		(0.00186)		(0.000563)
AR1	-0.298****	-0.298****	0.119****	0.150****
	(0.00151)	(0.00150)	(0.00297)	(0.00299)
AR24	0.276****	0.272****	0.506****	0.490****
	(0.00193)	(0.00193)	(0.00173)	(0.00187)
Constant $(\widehat{\beta_0})$	3.979****	3.981****	0.904****	0.973****
	(0.00403)	(0.00405)	(0.00108)	(0.00122)
N	29,923	29,923	29,923	29,923

Standard errors in parentheses: * $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$, **** $p < 0.001$

Table A.2. ML estimations for AS costs.

	(1) $\Delta idGAS_t$	(2) $\Delta idGAS_t$	(3) ΔBAS_t	(4) ΔBAS_t
WP (ΔWP_t)	0.0430****		-0.00398****	
	(0.00186)		(0.000852)	
WP^2 (ΔWP_t^2)	-0.0000146****		-0.00000555**	
	(0.00000430)		(0.00000270)	
$Demand$ (ΔDem_t)		1.318****		0.454****
		(0.101)		(0.0521)
$Demand^2$ (ΔDem_t^2)		-0.0177****		-0.00834****
		(0.00168)		(0.000898)
AR1	-0.334****	-0.327****	-0.298****	-0.299****
	(0.00118)	(0.00117)	(0.000848)	(0.000841)
AR24	0.324****	0.360****	0.174****	0.173****
	(0.00154)	(0.00151)	(0.00203)	(0.00205)
Constant $(\widehat{\beta_0})$	3.374****	3.384****	1.892****	1.891****
	(0.00293)	(0.00299)	(0.00104)	(0.00108)
N	29,923	29,923	29,923	29,923

Standard errors in parentheses: * $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$, **** $p < 0.001$