Hybridization of CEVESA MIBEL market model based on market outcomes

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***Abstract*— Fundamental electricity market models tend to underestimate the real market prices because they do not properly represent the real variable production cost of the generation units, nor the strategic markup that generation companies add to their costs to price the offered energy. This markup can increase bid prices above the marginal cost of the generation units, which may leave bids out of the market, decreasing the total cleared production, but increasing the final market price. This paper proposes a simple procedure, based on the real market outcomes, to estimate these markups and improve CEVESA MIBEL market model by reducing the gap between the simulated and the real market prices.**

***Index Terms*—Iberian electricity market, electricity price markup, hybrid market models.**

I. INTRODUCTION

As it is a common issue with fundamental models, simulated market prices tend to be lower than the real market ones. This occurs because these models do not properly represent the real variable production cost of the generation units, nor the strategic markup that generation companies add to their marginal costs to price the energy they offer. In fact, this markup allows them to increase some bid prices, which may reduce their total cleared production but increase the final market price, increasing their portfolio revenue.

In the literature, hybrid models refer mostly to short-term numerical models that combine several techniques such as statistics, time series, deep learning, etc. This is the case, for example, of [1], [2], [3] or [4]. However, hybrid long-term fundamental models, based on the structural description of the generation resources and on optimization or Nash equilibrium problems to compute the generation dispatch from the costs and demand forecast, are much less common. Long-term estimations are better based on fundamental models, since the evolution of the generation resources, either taken as inputs from other works or national strategic energy plans, or estimated by the model itself, have a direct impact on the future dispatches and resulting prices, which models fitted to historic data lack. Some works combining fundamental models with numerical estimations or improvements are, for example, [2] that uses an econometric model to analyze the difference between the price output by the model and the real market price, where a positive gap between them is observed. The numerical model is used to correct the price that results from the dispatching model, but not the dispatch itself. In [5] the focus is rather on improving the dispatch of fundamental models by estimating the generation unit costs from market data. In this case, a heuristic criterion is applied considering only the prices of the cleared bids, since these bids reflect better the marginal unit costs. A performance indicator based on how frequently the plant is either producing when the price is below its cost, or not producing when the price is above its cost, is used to assess the quality of the variable costs' estimation. A similar approach is followed in [6] to correct the variable costs of the thermal plants of CEVESA, a hydro-thermal equilibrium model for the joint energy and secondary reserve capacity dispatch applied to the MIBEL electricity market. However, since the mentioned correction improved the price patterns but with an average value well below the real prices, the final monthly prices were further adjusted with a regression model. More complex models, such as models using neural networks, were also tested but did not significantly outperform the results from regression models.

This paper proposes an alternative numerical procedure to estimate the markup of the thermal generation units based on the real market outcomes, reducing the gap between the simulated and the real market prices, and therefore improving the prices and the production of the generation units computed by CEVESA. The methodology extends [5] and [6] but focuses on the generation units (plants) instead of technologies. It considers a monthly detailed estimation of the individual markup that should be added to the marginal cost (basically fuel and CO_2 costs) of each generation unit. This allows to account for specific strategic behaviors at the unit level that can be caused by intertemporal constraints or by the interactions with other markets such as the secondary reserve or the grid

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constraints markets. More specifically, the methodology consists of two steps. First, the bidding prices from the market data provided by the market operator (MO) and the variable costs of the offering units computed by CEVESA are compared. Then, the markups are computed by generation unit and used to correct CEVESA costs to better represent the bidding strategy of these units.

Following this initial section, Section II explains the methodology used to hybridize CEVESA, the data used to estimate the markups, and the metrics to evaluate the results. Section III analyses the numerical results of CEVESA for the Iberian electricity market for the baseline year 2019 with and without the hybrid approach, and Section IV presents the main conclusions of this work.

II. Methodology

CEVESA [7] is a hydro-thermal equilibrium model for the joint energy and secondary reserve capacity dispatch applied to the MIBEL electricity market. CEVESA can also compute investments on new centralized or distributed (behind-the-meter) generation capacity. It also includes the impact of electric vehicles (EV) on the power system [8], [9], and includes a simplified modeling of the economy of the electricity-based hydrogen [10]. CEVESA can deal with multiple single-price zones and represent market splitting among them. It runs in two steps. The first one optimally allocates the hydro resources, and the second one sets the marginal cost according to the thermal technologies (coal and combined cycle plants, since nuclear ones rarely set the market price) keeping the hydro resources fixed. CEVESA uses monthly fuel and CO_2 costs as it is a common practice of generation companies. Therefore, the basic objective is to improve CEVESA market prices by correcting the monthly costs of the thermal units based on their real bidding prices and on their impact on the market clearing. Indeed, since some units may strategically bid part or all their energy at very high prices to remain partially or totally out of the market (except under extreme scarcity conditions), bidding prices are compared to the market price to better estimate the right correcting markup. With these objectives, the main steps of the developed methodology are:

1. Market data downloading and preparation.
2. Time-dependent markup analysis of the cleared and not cleared units hourly bidding blocks (by comparing the energy prices of the bids with the market prices), with the focus on a monthly analysis.
3. Monthly markup estimations to correct the variable costs of CEVESA thermal units.
4. CEVESA simulations to assess the preferred markup estimation procedure and validations.

For transparency purposes, the MIBEL Market Operator (MO) makes available most market data on its web platform [11]. Similarly, the Iberian system operators (REN for Portugal, REE for Spain) also make available additional data in their respective platforms [12] and [13]. From all these platforms, the following data of the day-ahead market from 2016 to 2020 were downloaded:

- PDBC – Hourly schedule of the offering units that results from the clearing of the day-ahead market (before the TSOs solve the grid constraints).
- Day-ahead market bids: CAB/header files, that contain data to identify the offering units and the bid complex conditions (for example to guarantee the start-up costs recovery); and DET/detail files, that contains the detail of the 25 hourly block energy-price of the bids.
- Hourly electricity market prices for the Iberian System, downloaded from [14]. Since market splitting between Portugal and Spain is very infrequent (about 5% of the yearly hours in recent years), this situation was ignored.

Given that CEVESA sets the market price according to the marginal system price which is based on the variable cost of the marginal thermal units, only these units (excluding nuclear, which can be considered non-dispatchable in the Iberian System) were analyzed. For the selected units, it was possible to estimate which bids were accepted or not by comparing their bidding price with the actual market price. Those bids with a price equal to or less than the market price for a given hour were considered as cleared, and the others as rejected. Note, however, that this is an approximation because the complex condition of the bids allow defining intertemporal constraints which may prevent clearing all hourly bids, even if the prices are, apparently, low enough in some hours.

For combined cycle (CC) and coal (C) generation units Figure 1 shows the average hourly maximum price of the accepted bids and the minimum price of the rejected bids, for the years 2016 to 2020. It is possible to observe a common pattern in the first 3 years related to the net electricity demand [15]. For those hours with low net demand, only those thermal units with lower prices are cleared, and they need to bid at very low prices to remain switched on. Since for these years, CC plants have marginal costs larger than C plants, to be cleared at low net demand hours, CC plants need to bid with prices below C plants. For the years 2019 and 2020, the decrease of the gas price and the increase of the CO2 price reverse the merit order, forcing C plants to bid below CC plants to be cleared.

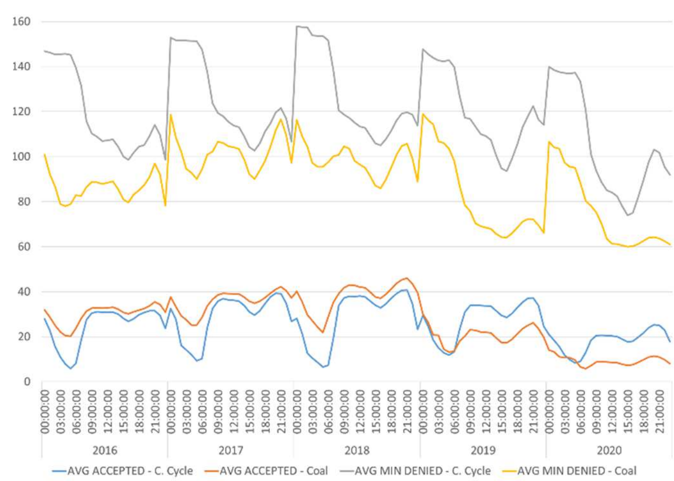

Figure 1 – Average hourly maximum accepted and minimum rejected bid prices of CC and C generation units (€/MWh).

Figure 2 shows a similar analysis for a monthly aggregation. There is a clear pattern on the highest accepted offer prices, for the first and last months of each year, explained by the highest energy demand in these months. Again, from 2019 and after, CC units become more cost-effective and marginal, setting the market price, and forcing C plants to bid with lower prices to be cleared.

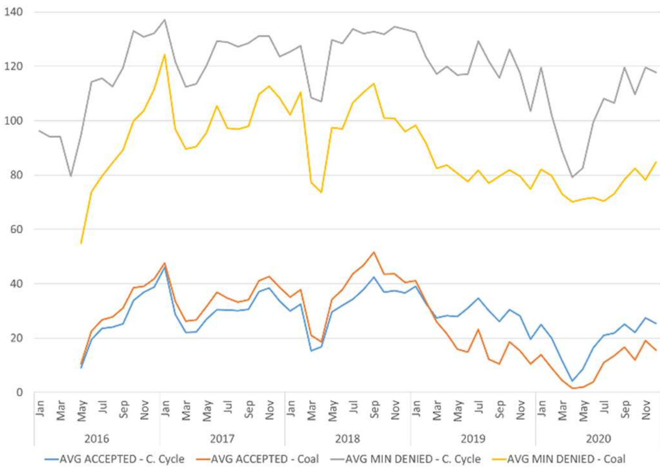

Figure 2 – Average monthly maximum accepted and minimum rejected bid prices of CC and C generation units (€/MWh).

The weekly aggregation is shown in Figure 3. Bid prices follow a similar behavior, with lower prices during the weekend days where the deamand is lower, and where cheaper units are enough to meet this demand. This behavior is not so evident from 2020 onwards.

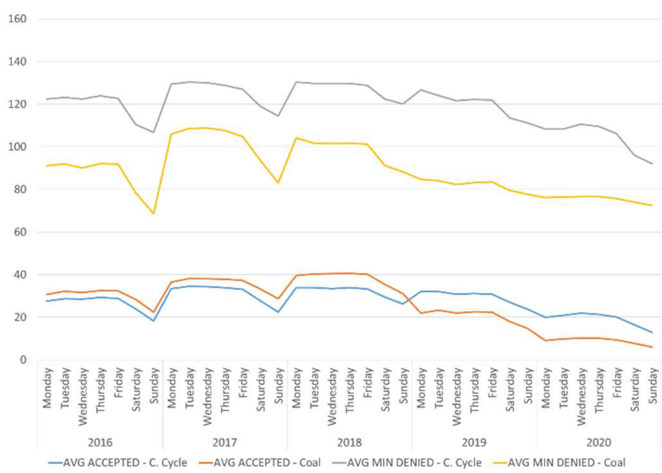

Figure 3 – Average weekly maximum accepted and minimum rejected bid prices of CC and C generation units (€/MWh).

Figure 4 shows the monthly average of the maximum price of the cleared units, and the minimum price of the rejected units, for CC (left) and C (right) plants. There is a price decrease for both technologies at the beginning of each year until March/April, which typically corresponds to the period in which there is larger hydro and wind generation. When approaching Summer, in months with low hydro and wind production, prices rise again. For the years 2019 and 2020 C bidding prices are, generally, lower than for the rest of the years.

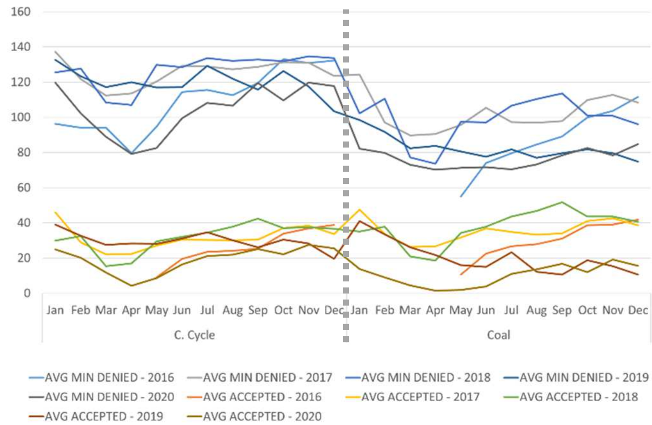

Figure 4 – Average monthly maximum accepted and minimum denied offer prices by technology, by year (€/MWh).

CEVESA uses monthly variable costs, so the objective was to estimate the right monthly markup $Mk_{u,m,y}$ to compute a corrected marginal cost for the CC and C units:

$$VC_{u,m,y}^{cor} = VC_{u,m,y} + Mk_{u,m,y} \tag{1}$$

where $VC_{u,m,y}$ is the variable cost (VC) computed by CEVESA for the thermal unit u, month m and year y, considering the fuel and CO_2 costs, $Mk_{u,m,y}$ is the markup used, and $VC_{u,m,y}^{cor}$ is the corrected cost. From the statistical analysis performed, several bidding strategies were identified:

- units that offer energy blocks with increasing but similar prices, and similar to their theoretical variable cost.
- units that are similar to the ones before except for some final blocks with significantly higher prices.
- units that offer all the energy at significantly high prices compared to their theoretical variable cost.

Since blocks with very high prices are only used in extreme scarcity conditions, the focus was on those units blocks cleared, since these scarcity conditions are very rare. As shown later, this was confirmed by the simulation results. Therefore, it was decided to compute $Mk_{u,m,y}$ with the following hypotheses:

- If unit u has one or more cleared bids during the month:

$$Mk_{u,m,y} = \max_{\substack{b \in h \\ h \in m}} \left(\lambda_{u,h,b,y}\right) - VC_{u,m,y} \tag{2}$$

where $\lambda_{u,h,b,y}$ is the energy price of the block b cleared (price below market price) for a given hour h for unit u.

- For those units without cleared bids during the whole month:

$$Mk_{u,m,y} = \max_{b \in h} \min_{h \in m} \left(\lambda_{u,h,b,y}\right) - VC_{u,m,y} \tag{3}$$

where $Mk_{u,m,y}$ only considers the lowest price $\lambda_{u,h,b,y}$ of the month m of the non-cleared bids.

Table I lists other alternatives that were tested to estimate the markups.

Table I. Computation Alternatives of the Markup.

If there are bids accepted	If no accepted bids	Code
$\max_{\substack{b \in h \\ h \in m}}(\lambda_{u,h,b,y})$	$\max_{b \in h} \min_{h \in m}(\lambda_{u,h,b,y})$	MAX-MAXMIN
$\operatorname{avg}_{b \in h} \max_{h \in m}(\lambda_{u,h,b,y})$	$\max_{b \in h} \min_{h \in m}(\lambda_{u,h,b,y})$	AVGMAX-MAXMIN
$\operatorname{avg}_{b \in h} \max_{h \in m}(\lambda_{u,h,b,y})$	$\min_{\substack{b \in h \\ h \in m}}(\lambda_{u,h,b,y})$	AVGMAX-MIN
$\operatorname{avg}_{b \in h} \max_{h \in m}(\lambda_{u,h,b,y})$	$\operatorname{avg}_{b \in h} \min_{h \in m}(\lambda_{u,h,b,y})$	AVGMAX-AVGMIN
$\max_{\substack{b \in h \\ h \in m}}(\lambda_{u,h,b,y})$	$\min_{\substack{b \in h \\ h \in m}}(\lambda_{u,h,b,y})$	MAX-MIN

Figure 5 represents the hourly average market prices for 2019, for the different alternatives in Table I. As can be seen, the estimations that make an average provide the worst results, given the fact that they include strategies of agents that tend to affect the market prices, as discussed later on. MAX-MAXMIN and MAX-MIN provide very similar results, leading to select the MAX-MAXMIN computation as the best operator.

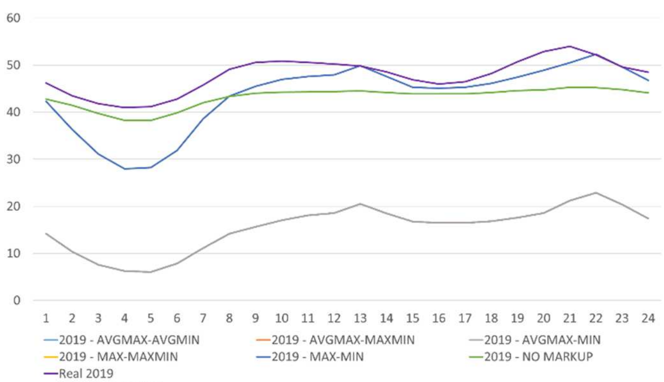

Figure 5 – Hourly Average Market prices for 2019, considering the scenarios in Table I (€/MWh).

III. Simulations

The variable costs of CEVESA thermal units are computed from the CO_2 and fuel costs of each technology, the efficiency, and the emission factors. A dataset of historical CO_2 emission costs was downloaded from [16], and API2 (for C units) and TTF (for CC units) spot market prices from [16] and [17], and averaged on a monthly basis. The variable cost is computed as:

$$VC_{u,m,y} = SC_u * FC_{u,m,y} + EMC_{u,m,y} \quad (4)$$

where SC_u is the units' specific consumption [Ton/MWh], $FC_{u,m,y}$ the fuel cost [€/Ton] and the $EMC_{u,m,y}$ is the emission costs [€/MWh]. The corrected VC is:

$$VC^{cor}_{u,m,y} = VC_{u,m,y} + Mk_{u,m,y} \quad (5)$$

After hybridization, equations (4) and (5) use $VC^{cor}_{u,m,y}$ instead of $VC_{u,m,y}$. Note that the correction of the VC also modifies the start-up and shutdown costs which are approximated based on the VC, ramps, and time needed to reach the technical minimum.

Figure 6 represents the markup $Mk_{u,m,y}$ (z axis), for different units (in the x axis) by year and month (y axis).

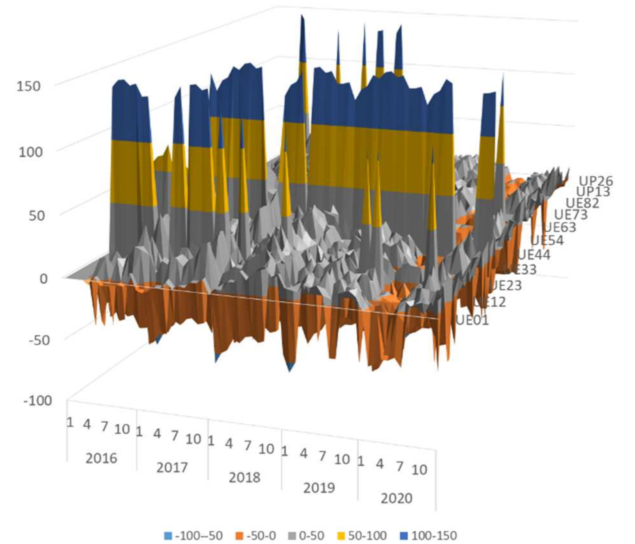

Figure 6 – Markup by year, month, and unit (€/MWh).

By analyzing $Mk_{u,m,y}$, it was noticed that the maximum monthly price of some units was below the marginal cost computed before the correction. This may be due to a strategic bidding to maintain the units switched on but does not reflect their real marginal costs. Indeed, intertemporal constraints of an optimized dispatch can already keep expensive units turned on if this compensates for the shutdown and start-up costs. The impact of accepting or not negative markups is shown in Figure 7.

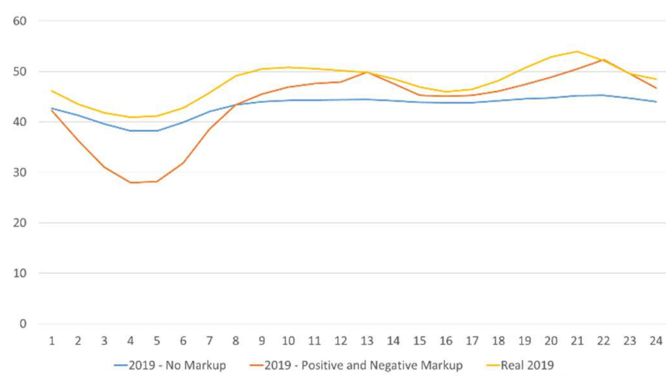

Figure 7 – Hourly Average Market prices for 2019, considering positive and negative markups (€/MWh).

Negative markups lead to additional errors in the model regarding the marginal costs and the merit order of the units. Although the resulting price seems closer to the real one for larger net demand hours, there is an anomalous drop in the first hours of the day. Therefore, only positive markups $Mk_{u,m,y}$ were finally accepted to correct variable costs.

Figure 6 also shows yellow and blue spikes, with markups of more than 50 €/MWh, which may move some blocks of these units out of the market unless extreme scarcity conditions arise. Unless the unit has no bids accepted in a month, the proposed approach ignores these large markups.

Figure 8 shows the hourly average market prices computed with CEVESA for 2019 (used for the whole calibration process). By comparing the real market price (yellow curve) with CEVESA results before the markup correction (orange curve) and after the correction (blue curve), it is possible to see that:

- the non-corrected result approximates the real price and shows a too flat profile from hours 8 to 24.
- the corrected results follow with a better performance compared to the real prices and leading to a less flat curve.

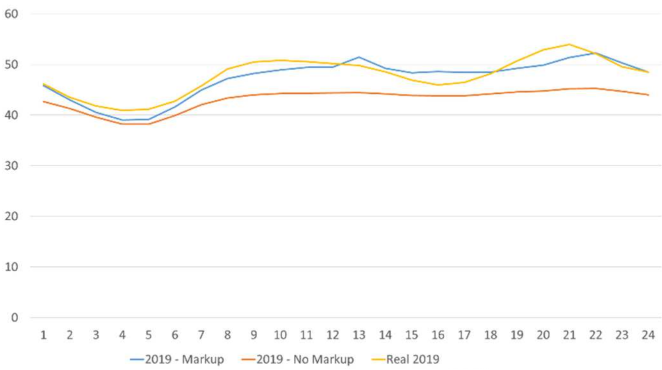

Figure 8 – Hourly Average Market prices for 2019, considering only positive markups (€/MWh).

Table II provides the weekly root square mean errors (RSME) of the results.

Table II. RMSE values for the markup and no-markup scenarios (€/MWh).

WEEK	RMSE MARKUP	RMSE NO MARKUP	WEEK	RMSE MARKUP	RMSE NO MARKUP
1	9.27	8.17	27	6.35	17.01
2	8.88	7.63	28	9.67	18.94
3	13.21	11.93	29	12.35	19.47
4	14.69	14.41	30	12.67	18.24
5	10.67	10.59	**31**	4.07	11.98
6	12.76	12.87	32	4.57	7.90
7	11.22	8.08	33	9.82	7.76
8	9.51	6.29	34	13.63	10.53
9	9.64	9.49	35	7.64	8.99
10	21.35	21.56	36	8.13	6.24
11	8.32	7.81	37	10.20	6.63
12	8.86	5.85	38	15.24	15.76
13	6.85	6.91	39	12.58	12.77
14	9.13	14.32	40	6.48	6.47
15	9.90	16.12	41	7.30	7.85
16	15.70	14.70	42	9.80	7.67
17	14.97	15.24	43	13.62	13.72
18	9.16	12.51	44	17.44	17.52
19	7.79	8.74	45	14.27	14.27
20	9.45	10.61	46	11.91	12.01
21	10.84	11.97	47	12.93	12.74
22	7.35	12.63	48	12.48	7.98
23	5.46	10.43	49	8.77	6.97
24	5.39	11.28	50	13.67	13.67
25	16.75	14.86	51	29.98	29.64
26	5.56	13.19	52	21.55	21.50
ANUAL	12.07	13.06			

The annual RMSE (€/MWh) with the correction is 12.07 vs 13.06 without the correction. The best RMSE value for the correction is reached on week 31, with a value of 4.07, and the best RMSE value for the scenario without markup is reached on week 12, with a value of 5.85 €/MWh.

IV. Conclusion

The underestimation of market prices is a common issue in fundamental market models, and hybrid techniques based on real data may help to correct this drawback. The costs of generation units are non-public sensible data and depend on the fuel and emissions costs that can more easily be estimated, but also on other logistic costs, on the efficiency and emissions factors of the plants, not publicly known, and on the strategic behaviors of the market agents. As simulations proved, the proposed markups estimation improves CEVESA market model outputs. Results also showed that markups must be estimated cautiously to avoid estimating specific punctual strategic behaviors that do not reflect real marginal costs or repetitive strategic behaviors. This is for example the case of negative markups that, as shown, are better ignored to improve results.

However, looking at specific weeks, there may still exist significant discrepancies between the computed and the real market results. This suggests that adding hourly or weekly or a unit monthly markup correction based on a simple model that accounts for hourly and weekday seasonality, could improve further CEVESA results, even when its variable costs are computed monthly.

Finally, additional tests should be done with additional years to confirm that the markup estimations are stable enough with time. This implies doing extensive market and cost data downloading and simulation. The authors are currently working on the daily and hourly markup refinements and on further testing considering additional years.

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