Market power in cost-based wholesale electricity markets: Evidence from Mexico*

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Abstract

Market power is an important concern for designers of restructured wholesale electricity markets. In a cost-based market, the price and quantity offers of generation plants are set based on a regulatory formula. This market design is used for most electricity markets in Latin America, in part because it appears to eliminate the potential for dominant firms to exercise market power. In this paper I study the performance of the cost-based model in the newly restructured Mexican electricity market. I show that large generation firms still have the ability to exercise market power. This behavior would be difficult for the market operator to detect, given the informational asymmetry between firms and regulators. Using data for 2018, I show that both the generation offer prices and the market price are higher in hours when firms have greater ability to exercise market power.

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1 Introduction

In the textbook model of a deregulated wholesale electricity market, generation firms submit step-function price and quantity bids for each of their plants into a wholesale market auction. The system operator takes the aggregate offer curve and intersects it with the market demand, determining the market price and dispatch quantities for each generator. In this model, oligopoly generators may have the ability and incentive to raise prices. Evidence from many electricity markets shows that firms respond to this incentive (Wolfram 1998; Borenstein et al. 2002).

Not all restructured electricity markets use this bid-based design. An alternative model is a cost-based market. This design shares the same outward appearance as a bid-based market, but with one major difference: the quantity and (especially) the price components of the bids are regulated. For thermal generation, the price component is set at the marginal cost of the plant, based on fuel input prices and the technical characteristics of the plant. For hydro generation, the system operator solves its own dynamic programming model to determine the value of water.

The cost-based design is especially prevalent in Latin America, with Colombia the only country in the region with a bid-based market. When Mexico introduced electricity market reforms in 2014, it adopted the bid-based design. In theory, this choice by Mexico was supposed to be a temporary measure until a more competitive market developed. In practice, despite the nominal increase in competition from the split of the government-owned incumbent CFE into five generation firms, there is no prospect of a change to the market design in the foreseeable future.

An important reason why countries adopted the cost-based model was to avoid the experiences of market power in bid-based markets, most notoriously in California in the early 2000s. The tradeoff is that the cost-based model incorporates many of the inefficiencies associated with regulation. For example, in hydro-based markets, there may be political pressure on the market operator to "keep prices low and pray for rain" in the months before a drought event.

More fundamentally, it is not certain that a cost-based market avoids the potential for firms to exercise market power. If firms can manipulate plant availability, or manipulate their input fuel costs, then they may have the ability and incentive to increase prices and profits. If this occurs, then the cost-based markets would incorporate the worst aspects of each market design: the inefficiencies of regulation and the market power problems with competition.

In this paper, I use a simplified model of the Mexican electricity market to illustrate the ability and incentive for firms to exercise market power in a cost-based market. I then use wholesale market bidding data from 2018 to calculate the ability to exercise market power for each of the largest generation firms. In most hours, the firms have limited ability to unilaterally increase the market price. However, in a small proportion of hours, the largest generators can create a substantial increase in the market price from a small reduction in their generation output. I then examine the empirical relationship between the market-power measure and the market price and generation offer prices. More market power is associated with higher market prices and (for some generators) higher offer prices.

Given the prevalence of cost-based markets in some regions of the world, and the continued adoption of this model by countries undergoing restructuring of their electricity industries, understanding the costs and risks associated with this market design are of first-order importance for economists. This paper is one of the first empirical studies of firm behavior in a cost-based market.

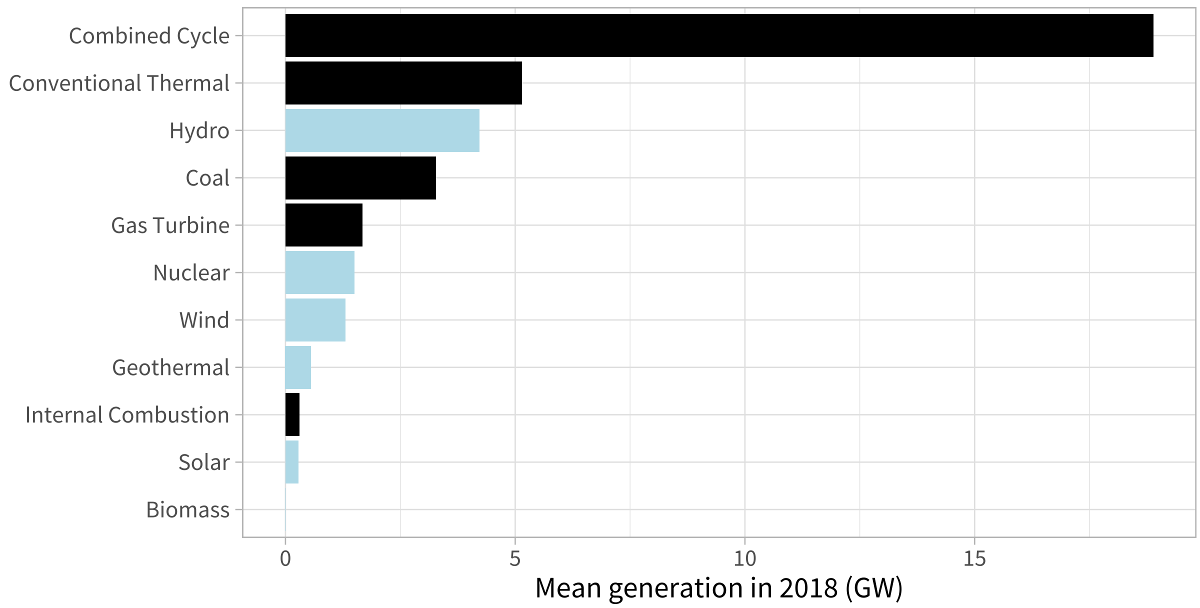
A closely related paper is Munoz et al. (2018). The authors use a theoretical model of investment by generation firms in a cost-based market to show that—even if the market design eliminates the exercise of market power in the short-run market—firms may strategically choose their capacities and technologies when making generation investments. This can lead to a long-run equilibrium different from what would arise in a competitive market. The authors also discuss the challenges for the regulator to correctly set the generation prices.

The rest of the paper is organized as follows. Section 2 provides background information on the electricity market in Mexico. Section 3 describes the data sources used in the analysis. Section 4 uses data for an example hour during 2018 to illustrate the potential for exercising market power in a cost-based market. Section 5 describes the empirical methodology and Section 6 provides the empirical results. Section 7 concludes.

2 Background information

The electricity market in Mexico is comprised of three unconnected systems: the *Sistema Interconectado Nacional* (SIN) that covers all of Mexico except the Baja California peninsula, and two smaller systems in the north and south of Baja California. During 2018, more than half of total generation was produced by combined cycle plants using natural gas (Figure

Figure 1: Mean output by generation type during 2018



Notes: Data on total generation by type is from CENACE (2019c).

1). There have been large changes in the composition of generation over the past 20 years, with natural gas displacing fuel oil as the dominant fuel. Diesel, fuel oil, and coal are still used but in smaller quantities. In recent years there has been considerable investment in wind and solar generation, taking advantage of Mexico's favorable geographical and climate conditions for renewable energy. Despite the growth in wind and solar generation, hydroelectricity is still the largest source of non-fossil-fuel generation.

Mexico was relatively late in implementing restructuring of its electricity market. For most of the past century, the dominant firm in the industry has been the government-owned Federal Electricity Commission (*Comisión Federal de Electricidad* or CFE). Starting in 2014, the Mexican energy reform split CFE into separate companies. Generation dispatch and operation of the transmission grid were assigned to a new independent system operator: the National Energy Control Center (*Centro Nacional de Control de Energía* or CENACE). CFE was split vertically into separate generation, transmission, distribution, and retailing companies. Privatization was not part of the energy reform in Mexico. All of the separated CFE businesses remain 100-percent owned by the Mexican government.

Within the generation business, CFE's plants were assigned to five generation firms. Because of concerns about the market dominance in transmission-constrained regions, the procedure to allocate the CFE's plants to the new subsidiaries minimized a regional

Table 1: Electricity generation capacity in GW, by owner and type

Owner	Fossil Fuel				Non-Fossil-Fuel				Total
	Coal	C.C.	Conv.	Other	Hydro	Nucl.	Wind	Other	
CFE Generation I		1.2	2.9	0.8	2.8				7.8
CFE Generation II	1.4	2.7	1.3	0.1	3.0				8.5
CFE Generation III		2.6	3.1	0.4	2.2	1.6		0.0	10.0
CFE Generation IV	2.8	0.5	1.1	0.7	3.3				8.4
CFE Generation VI	1.2	1.7	2.9	1.0	0.7		0.1	0.9	8.6
Pemex		0.2	0.8	0.7					1.7
Actis		2.2							2.2
Iberdrola		6.0		0.1					6.1
Naturgy		2.3					0.2		2.5
Other	0.6	7.1	0.2	2.0	0.5		3.7	0.7	14.8
Total	6.0	26.6	12.2	5.9	12.6	1.6	4.0	1.6	70.6

Notes: The table shows the total generation capacity in Mexico in gigawatts (GW), split by the generation owner and generation type. The "Other" category for fossil fuel generation includes internal combustion, gas turbines, and cogeneration. The "Other" category for non-fossil-fuel generation includes biomass, geothermal, and solar. "C.C" = combined cycle. "Conv." = conventional thermal. "Nucl." = nuclear.

Herfindahl-Hirschman Index. Each of the new CFE generators has generation capacity between 8 and 10 GW, or 11 to 14 percent of the total capacity in Mexico (Table 1). Because the CFE generators include many old and inefficient thermal generation plants, their share in generation output is lower than their share in generation capacity. Most of the combined cycle generation capacity in Mexico is owned by private firms.

Private generation firms began investing in Mexico several decades before the 2014 energy reform. Industrial and commercial electricity consumers could build generation plants to supply their own consumption. Independent generators (including most of the combined cycle plants) were required to sign power purchase agreements with CFE. Responsibility for these legacy agreements was passed to a sixth CFE generation company: CFE Generation V. Since the energy reform, new generation participants have entered the market, especially in wind and solar.

Given the dominant role of the CFE generation firms in the wholesale market, the energy reform envisaged a transition period with cost-based regulation of the generation offers. Firms are required to report the technical characteristics of the generation plants to CENACE. CENACE combines this technical information with a fuel-price formula to calculate the marginal cost of generation from each plant. Each day, firms submit their price and quantity offers into the day-ahead market. Before running the dispatch algorithm, CENACE compares the price component of the offers against the calculated marginal cost and rejects offers that lie outside a 10-percent tolerance band.

3 Data

The main data source for the analysis is the public information provided by the system operator CENACE. I focus on the day-ahead market during 2018. Before 2018, the market design was not fully developed, and some types of generation were not included in the offer curve. After 2018, the new Mexican government started to weaken the boundaries between the CFE generation companies. For the analysis, I focus on the SIN market. This excludes the two smaller markets in Baja California.

Similar to wholesale electricity markets in the United States, the Mexican electricity market is based on a nodal pricing design. There are slightly fewer than 2500 nodes in the system. Each of these nodes is assigned a price every hour, where the price is defined as the marginal cost of meeting a one MWh increment in demand at that location. I use the hourly nodal prices from the day-ahead market for 2018 (CENACE 2019e). Because I do not account for transmission constraints that could lead to the exercise of local market power, I collapse the hourly nodal prices into a single "market" or "system" price. Each node is assigned to a load region based on the information in the node catalog (CENACE 2019b). Within each load region I take the simple unweighted average of the nodal prices. I then take the weighted average of the prices across the different load regions, where the weights are the hourly load quantities in each region (CENACE 2019a).

The generation offer data for the day-ahead market is reported in CENACE (2019d). The data includes four categories of generation offer: thermal, dispatchable intermittent, nondispatchable, and hydroelectric. The thermal generation offers include information on the minimum and maximum dispatch quantities, the startup costs that must be recovered for the plant to begin operation, and up to eleven price and quantity blocks. The thermal offers also include the cost and quantity of providing ancillary services (spinning and non-spinning reserves and secondary regulation). The dispatchable intermittent offers include a generation forecast quantity and up to three quantity blocks with forecast probabilities and incremental costs. In practice all of the costs for intermittent generation are zero. The offers for the nondispatchable generation only include the generation quantity each hour.

The hydroelectric offers include the minimum and maximum generation quantity as well as the cost and quantity of ancillary services provision. The offer data provided by CENACE (2019d) does not include an offer price for the hydroelectric generation. Instead, I use data from the weekly wholesale market reports (CENACE 2019f). These reports include two figures with the daily opportunity cost of water and the daily maximum generation quantity for the 16 major hydroelectric reservoirs in the Mexican market. I extract the approximate daily plant-level opportunity costs from these figures using a combination of pixel-level measurements with optical character recognition.

I combine the four types of generation offers into a stylized offer curve. For the thermal generation, I create an initial quantity block equal to the minimum generation, with the price set as the startup cost divided by the minimum generation quantity. The price and quantity thermal offers give the incremental cost of additional thermal generation. The intermittent and nondispatchable generation is included in the offer curve with a price of zero. The hydroelectric generation is included with a price equal to the opportunity cost of water.

The offer curve ignores several important features of the real-world dispatch algorithm: the transmission constraints, the provision of ancillary services, the thermal ramping constraints, and discrete problem of whether to start up the thermal plants. For each hour in the data, I calculate an adjustment factor so that the total demand in that hour crosses the offer curve at the average market price. This ensures that the dispatch prices and quantities from the stylized model match the real-world prices and quantities.

The identity of the generation firms, plants, and units in the offer data is hidden with a masked identifier. These identifiers remain the same for all hours of 2018. I construct a database of the characteristics and ownership of all generation plants in Mexico by combining two databases: the generation plant data in the long-term system planning model (Secretaría de Energía 2019) and the generation plant permit data (Comisión Reguladora de Energiá 2019). I then match the maximum generation capacity of the plants in the generation database (for which I know the plant name, location, owner, and type) to the maximum generation of the plants in the offer data. This matching procedure provides the identity of the largest firms in the offer data.

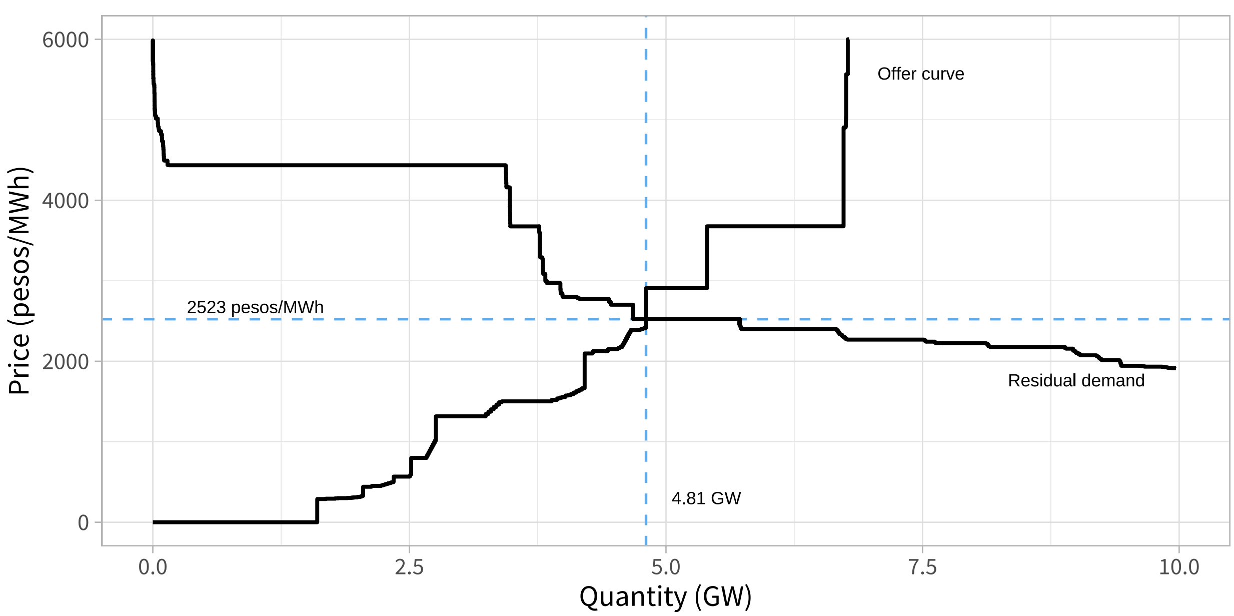
The hourly generation quantity dispatched for each firm in the day-ahead market is reported in CENACE (2019a). Using the aggregate demand and the stylized offer curve, I construct the residual demand faced by each major generator in every hour. The residual demand is a step function equal to the total demand less the supply of the competitors at each price. In the next section I show how the residual demand can be used to analyze the ability of firms to influence the market price through their generation offer behavior.

4 Illustrative model

In a bid-based wholesale electricity market, firms have considerable flexibility to choose the offer price and offer quantity for each of their generation plants. In a cost-based market, the offer prices and quantities are regulated. In this section, I show how the generation firms in a cost-based market might still be able to exercise market power. There are at least two ways they can do so: (i) strategic manipulation of input prices, and (ii) strategic use of plant outages or availability.

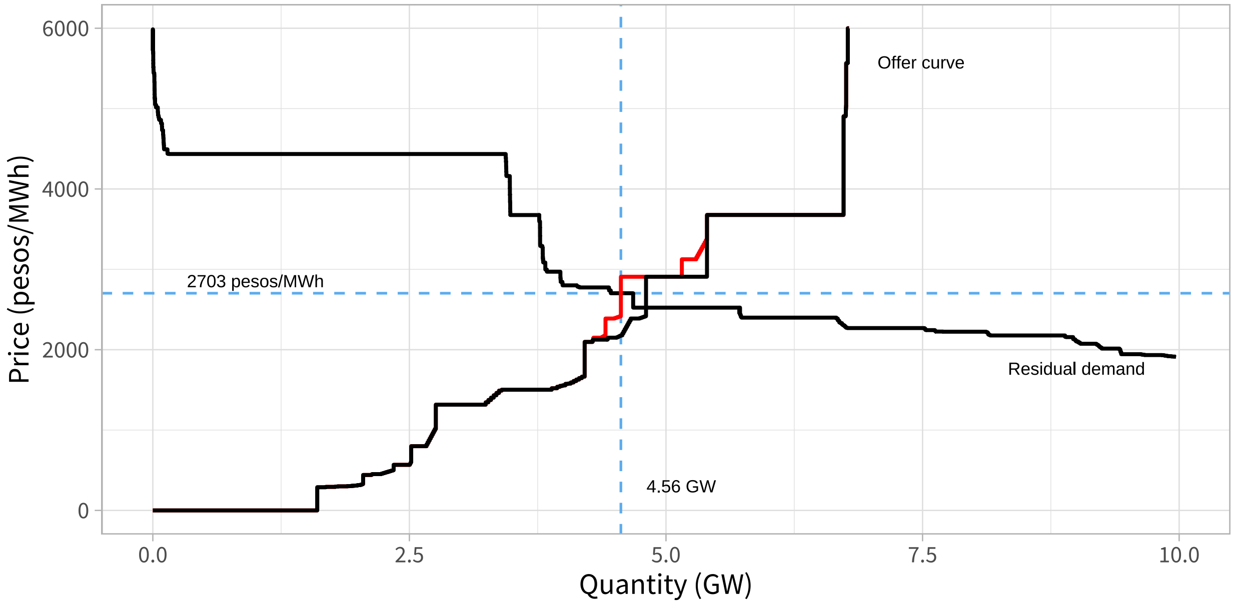
For illustrative purposes, I focus on one generation firm (CFE Generation III) during one hour of 2018 (Figure 2). The offer curve is constructed using the procedure described in Section 3. At each price, the residual demand faced by CFE III is calculated as the different between the total market demand in the hour and the generation offers of all other firms in the market. By construction, the offer curve crosses the residual demand curve at the market price in that hour (2523 pesos/MWh) and the dispatched generation quantity of CFE III in that hour (4.81 GW).

Figure 2: Offer curve and residual demand for CFE III during one hour



Notes: The figure shows the offer curve and residual demand for CFE Generation III in the SIN market, at 7:00PM on September 26, 2018. The price is the load-weighted average price for the system.

Figure 3: Effect of changing the offer price for one thermal generation unit



Notes: The figure shows the effect on the market price of increasing the offer price for one generation plant by 1000 pesos/MWh.

In a bid-based wholesale market, the analysis of market power would proceed based on the assumption that the firm could choose any offer curve, subject to the technical constraints of its generation units. Changing the offer curve would change the intersection point with the residual demand. The residual demand curve traces out the possible combinations of price and quantity available to the firm. Given its cost structure, the firm could choose the point along its residual demand that would maximize its profits (Hortacsu and Puller 2008).

Despite not having complete flexibility in its bidding behavior, a firm in a cost-based wholesale electricity market may still be able to adjust its offer curve in order to increase its profits. One approach is to increase the regulated cost for one or more of its plants. For example, suppose CFE III could increase the marginal cost for one of its thermal plants by 1000 pesos/MWh (Figure 2). This change in the cost for one plant would lead to a reordering of the offer curve. As a result, the offer curve would cross the residual demand at a higher price: 2703 pesos/MWh instead of 2523 pesos/MWh. CFE III would receive the higher market price for all of its generation output. Although the generation quantity for CFE III would be lower, its total generation revenue would increase by 1.5 percent.

In spite of the regulation, there are several ways in which a generation firm could increase the regulated cost of a plant. For example, it may not be profit-maximizing to exert effort to minimize the cost of fuel purchases. Note that a fuel supplier will always want to sell its product for a higher price. If it is also profit-maximizing for the fuel purchaser to pay a higher price, then it is extremely difficult for the regulator to prevent an arrangement in which the two parties agree on a higher price. The organizational structure of the fuel supplier and the fuel purchaser is of little relevance. Prices will be higher even between two independent firms. No agreement between the firms is even necessary: all that is required is for the fuel purchaser to exert less effort during price negotiations.

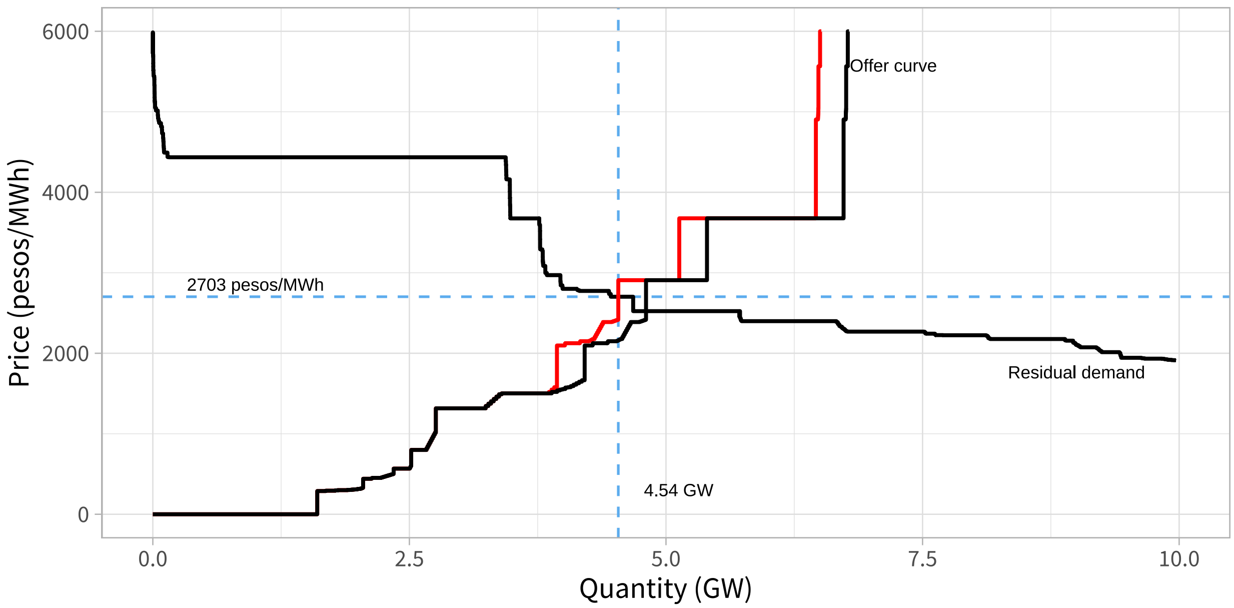
For example, Cicala (2015) shows that regulated generation firms in the United States exhibited more variation in the prices they paid for coal than in the prices they paid for natural gas . This is because the coal market is more opaque and is based on bilateral negotiations between coal suppliers and generators. By comparison, there is a liquid and transparent market for natural gas. Regulators could compare reported natural gas costs to the Henry Hub benchmark. After deregulation, input prices for coal generators fell by much more than input prices for natural gas generators.

In the case of the Mexican wholesale electricity market, the prices used to calculate the regulated marginal cost are based on international fuel price benchmarks. However, these benchmark prices may not reflect the local supply and demand conditions for the fuel at the plant location. For example, if there are constraints in the natural gas pipeline network, the relevant opportunity cost for using natural gas may be different from the accounting price. For this reason, generation firms in Mexico can ask for a revision of the fuel price index (Secretaría de Energía 2018). In theory, this procedure could be used strategically to increase the offer price for selected plants.

Another way to adjust the offer price is to take advantage of the fuel-switching capability of some types of thermal generation plants. There may be large differences in the cost of generation between natural gas and diesel and fuel oil. Changes in the fuel source could also change the regulated offer price: the natural gas price benchmarks are different for pipeline natural gas compared to liquified natural gas. In a bid-based wholesale electricity market, it will be profit-maximizing for a firm to choose the lowest-cost fuel from the cheapest supplier, because the offer price is not connected to the input cost. This may not be true in a cost-based market. Strategic switching to a more expensive fuel could lead to higher, not lower, profits.

The second method by which a generation firm in a cost-based wholesale market can increase profits is by strategically varying the availability of its generation plants. During

Figure 4: Effect of changing the offer quantity for one thermal generation unit



Notes: The figure shows the effect on the market price of withholding the generation for one generation plant.

certain hours of the year, a small change in plant availability can lead to a large increase in the system price. For the example hour, suppose CFE III takes one of its combined cycle plants offline (Figure 4). This has the effect of shifting in the offer quantity for all higher prices. In this example, the market price would increase to 2703 pesos/MWh as the result of the reduced availability. CFE III would receive this higher price for its entire output.

A generation firm can make a plant unavailable by, for example, reporting a fuel shortage or taking it down for emergency maintenance. Timed correctly, this can lead to higher prices for the other plants owned by the firm. For Mexico, capacity withholding is explicitly prohibited in the market rules and the system operator is required to notify the market monitor of any suspected cases. However, there are many valid reasons for taking a plant offline. It is challenging for the system operator or the market monitor to distinguish between genuine and strategic plant outages.

In the next section I describe a procedure to calculate the ability of the largest generation firms in the Mexican wholesale electricity market to exercise market power, based on the residual demand that they face in each hour. I then show an empirical test of whether the market price or the generation offer price are higher in hours when the firms have greater ability to exercise market power.

5 Empirical methodology

The residual demand curve faced by a generation firm is the foundation for the empirical analysis of market power in wholesale electricity markets. As shown in Equation (1), the residual demand for firm i in period t at a price P is the difference between the market demand at the price P ($Q_t(P)$) and the total quantity offered by the competitors of i at the price P.

$$DR_{it}(P) = Q_t(P) - \sum_{j \neq i} S_{jt}(P) \tag{1}$$

The inverse residual demand, $DR_{it}^{-1}(q_{it})$, is the market-clearing price for which total quantity supplied will equal total quantity demanded, assuming firm i produces a quantity q_{it}. The slope of the inverse residual demand provide a measure of the ability of firm i to increase the market price. For steeper inverse residual demand, a small decrease in q_{it} will lead a larger increase in P_t.

The inverse semielasticity of residual demand formalizes the concept of market power (McRae and Wolak 2014). The inverse semielasticity for firm i in period t is defined as the change in the market price (measured in pesos/MWh) from a 1 percent reduction in the quantity supplied by firm i in period t. Because the residual demand is a step function, the slope of the residual demand is not well-defined: it is either zero or infinite. For this reason, the calculation of the inverse semielasticity requires an approximation based on a bandwidth parameter α. Equation (2) shows the inverse semielasticity for firm i in period t (η_{it}) as a function of the inverse residual demand and the bandwidth parameter.

$$\eta_{it} = \frac{1}{100\alpha} \left[DR_{it}^{-1}((1-\alpha)q_{it}) - DR_{it}^{-1}(q_{it}) \right] \tag{2}$$

The inverse semielasticity is bounded below by zero. A value of zero is the case in which the firm has no market power, because a small reduction in output does not affect the market price. Larger values of the inverse semielasticity correspond to greater market power—the same small reduction in output has a larger effect on the market price.

The inverse semielasticity η_{it} is a measure of the **ability** of firm i to exercise market power in period t. To test the extent to which firms take advantage of their ability to increase the market power, I study the relationship between the market price P_t^{mkt} and a summary measure of the η_{it} for the major generation firms in period t. Equation (3) shows the formulation of the linear regression.

$$P_t^{mkt} = \beta\bar{\eta}_t + f(Q_t) + \gamma c_t + \xi_t + \varepsilon_t \tag{3}$$

In this equation, the dependent variable P_t^{mkt} is the weighted-average nodal price for the market during period t, where the weights are based on the quantity demanded at each location. The variable $\bar{\eta}_t$ is a summary measure of the inverse semielasticities for the major firms. For the base analysis I use the unweighted mean of the η_{it}. I show the results using the maximum of the firm-level η_{it} as a robustness check.

An important determinant of the system price in period t is the aggegrate quantity demanded in period t, Q_t. In electricity markets, few customers face the real-time market price for their consumption, so aggregate demand does not depend on the price. I use three alternative functional forms for the relationship between aggregate demand and price: (i) a linear relationship, (ii) a higher-order orthogonal polynomial in aggregate demand, and (iii) a set of dummy variables representing 10 MW bins of aggregate load. The polynomial and binned dummy variables allow for a flexible nonlinear relationship between quantity and price.

Another determinant of the electricity market price is the price of input fuels. The term c_t in Equation (3) represents daily international fuel price benchmarks for natural gas and fuel oil. These benchmarks are included in the formulas used for the regulated marginal cost in

The term ξ_t represents a set of time fixed effects. These comprise hour-of-day, day-of-week, and month-of-sample fixed effects. These fixed effects absorb additional variation over time in the determinants of price that are not captured by the system demand and fuel price variables. Finally, ε_t is a mean-zero and constant-variance regression error term.

I also study the relationship between the offer price for firm i in period t and the inverse semielasticity η_{it} faced by the firm in that period. The offer price P_{it} is defined as the price along the offer curve of firm i at the actual generation quantity q_{it} of firm i in period t:

$$P_{it} \equiv S_{it}^{-1}(q_{it}) \tag{4}$$

As shown in Equation (5), the offer price of a firm is regressed on the inverse semielasticity, plus the same controls that were included in Equation (3).

$$P_{it} = \beta_i \eta_{it} + f(Q_t) + \gamma c_t + \xi_t + \varepsilon_t \tag{5}$$

I report results for two versions of Equation (5): one which pools the offer prices for all of the major generation firms and includes firm fixed effects, and another which runs a separate regression for each individual firm.

6 Results

All five of the CFE generation companies have substantial ability to unilaterally increase the market price during some hours of the year (Table 2). The maximum observed inverse semielasticity is 148 pesos/MWh. This means that a 1 percent reduction in generation output of the firm would increase the system price by 148 pesos/MWh, or 9.4 percent of the mean price. In most hours the ability to exercise market power is much lower. For the largest generator (CFE III), the mean inverse semielasticity during 2018 was 6.4 pesos/MWh, or 0.4 percent of the mean price. For all of the generation firms, there are hours in which the inverse semielasticity is zero: a small reduction in output has no effect on the market price.

The CFE generators had the greatest ability to exercise market power during September 2018 (top panel of Figure 5). This did not correspond to the period with the highest demand (middle panel) or market price (bottom panel). Demand in the Mexican electricity market is highest during the summer months from May until August. This is also the period with the highest prices. Apart from September, there was another smaller peak in the inverse semielasticity in late May 2018, matching the annual peak in demand and price.

At low values, the inverse semielasticity is uncorrelated with market prices. Only at high values of the inverse semielasticity is there a positive correlation between the price and inverse semielasticity (Figure 6). The graph is constructed by splitting the hours during 2018 into deciles of the mean inverse semielasticity. The distribution of prices is similar for deciles 1 to 8. The mean price, as well as the 25th and 75th percentile of prices, are higher during the hours corresponding to the highest decile of the inverse semielasticity. There are a few hours with extremely high market prices—these all occurred during hours with the highest inverse semielasticity.

Table 2: Summary statistics for residual demand analysis for 2018

Variable	Min	Mean	SD	Median	Max
Inverse semielasticity					
CFE Generation I	0.00	4.42	6.70	2.49	147.84
CFE Generation II	0.00	4.84	6.40	2.92	147.84
CFE Generation III	0.00	6.44	8.77	3.73	147.84
CFE Generation IV	0.00	4.35	5.45	2.69	62.11
CFE Generation VI	0.00	3.73	5.95	1.67	76.90
Mean	0.00	4.75	5.50	3.12	69.11
Fuel oil price (USD/barrel)	49.88	63.95	6.28	65.38	77.13
Natural gas price (USD/MMBTU)	2.41	3.12	0.62	2.93	7.68
System load (GW)	18.83	32.99	4.29	33.11	43.07
System price (pesos/MWh)	447.11	1578.85	733.72	1465.74	7959.67

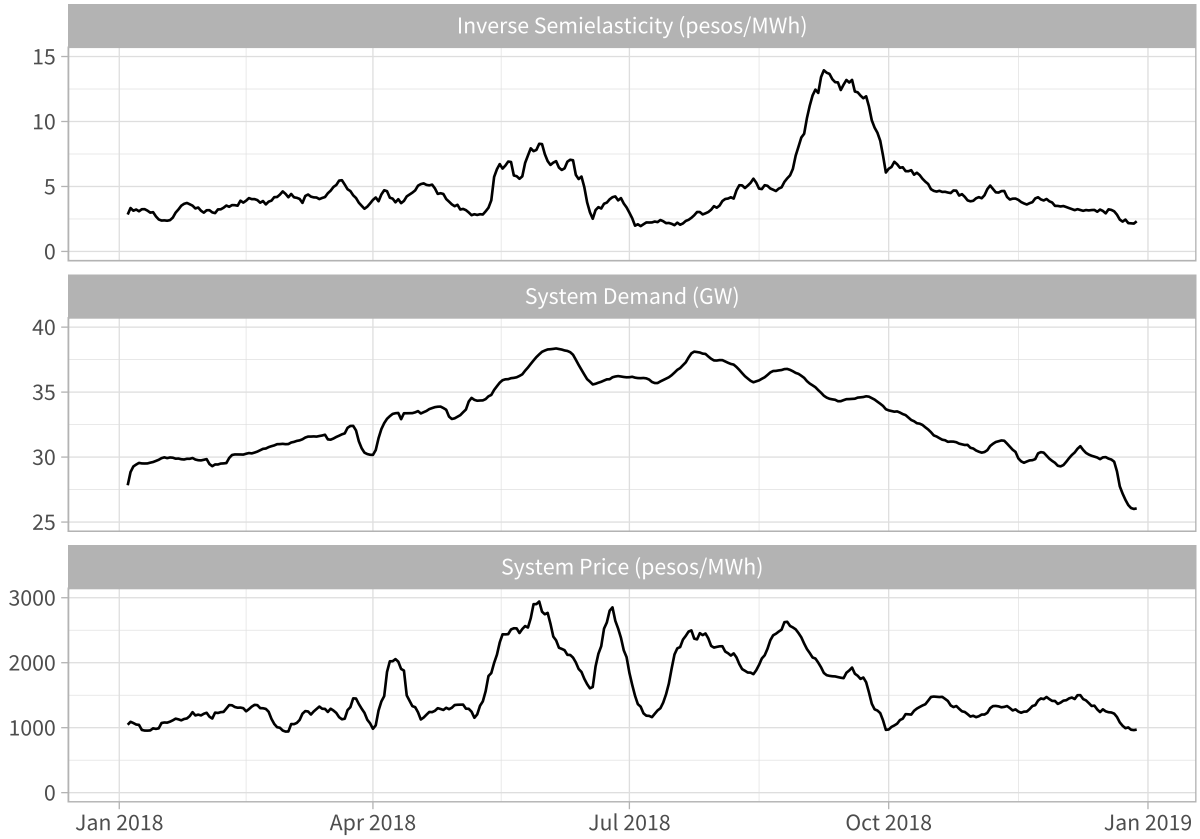
Notes: The inverse semielasticities represent the increase in system price corresponding to a 1 percent reduction in generation. The fuel oil price is the US Gulf Coast No. 6 Fuel Oil 1.0% Sulfur FOB price. The natural gas price is the Houston ship channel price. System load and price are for the SIN only (that is, they exclude the two Baja California systems).

These descriptive results confirm that unilateral market power is not an ever-present feature of the Mexican electricity market. For most hours, the major generation firms have limited ability to exercise market power, and there is no relationship between the market price and the measure of market power. However, for a small fraction of hours in the year, the firms do have the ability to unilaterally increase the market price. The market price is higher during those hours when the generation firms are most able to influence the price.

Estimation results for Equation (3) confirm the positive relationship between the mean inverse semielasticity and the market price (Table 3). For all specifications, the relationship between the inverse semielasticity and the market price is positive. The coefficient is significant at the 5 percent level in Columns 1 and 2 and significant at the 10 percent level in Column 3. However, the economic magnitude of the effect is small. An increase in the inverse semielasticity by one standard deviation is associated with a 20 pesos/MWh (0.028 standard deviations) increase in the market price. This small average result is consistent with the exercise of market power during a few problematic hours of the year.

Other results in the table are of economic interest. Prices are higher during hours with higher load (Column 2 of Table 3). A one standard deviation increase in the load is associated with an increase of 669 pesos/MWh (0.91 standard deviations) in the market price. Higher natural gas prices are associated with higher electricity prices (significant

Figure 5: Inverse semielasticity, system price, and system demand during 2018

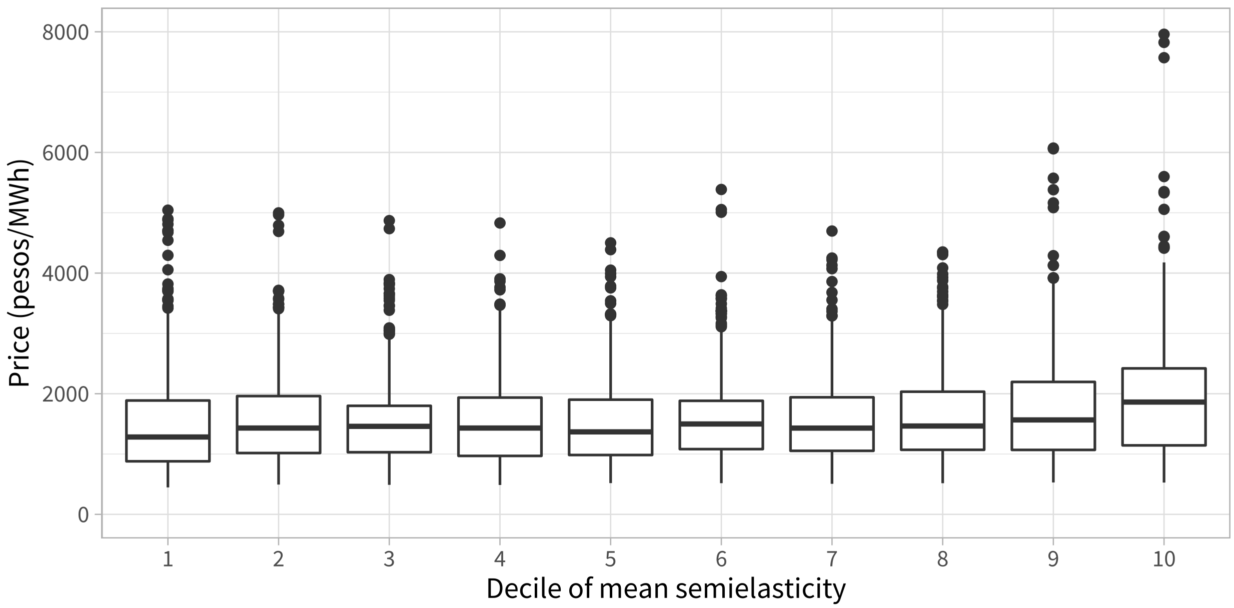


Notes: Each graph shows the one week (168 hours) moving average of the corresponding variables: the mean inverse semielasticity of residual demand for the major generation firms, the SIN demand in GW, and the weighted mean SIN price.

at the 1 percent level in Column 3). Fuel oil prices have a negative but not statistically significant relationship with electricity prices.

Robustness checks in Columns 4 and 5 of Table 3 support the above findings. Allowing for flexibility in the relationship between load and price has a meaningful effect on the market power estimates: the coefficient of the inverse semielasticity is more than 30 percent lower in the specification with a flexible polynomial in load (Column 3) instead of a linear function of load (Column 2). However, there are only minor changes in the coefficients from switching from a polynomial to discrete bins of load (Column 4). Column 5 uses the maximum inverse semielasticity of the five CFE generators, instead of the mean. The magnitude of the coefficient is smaller (3.07 pesos/MWh) and it is significant at the 5 percent level.

Figure 6: Relationship between system price and deciles of the inverse semielasticity of residual demand



Notes: The vertical axis shows summary statistics for the system price. The horizontal axis shows deciles of the mean inverse semielasticity of residual demand during 2018. Lower deciles mean lower values of the inverse semielasticity and less market power. Each box shows the mean (horizontal line), the 25th percentile, and the 75th percentile. The length of the vertical lines is capped at 1.5 times the interquartile range. Outlying values falling outside of this range are shown as individual points.

The marginal offer price for the generation bids in the day-ahead market is higher when the inverse semielasticity is larger (Column 1 of Table 4; significant at the 5 percent level). A one standard deviation increase in the inverse semielasticity is associated with an increase in the offer price of nearly 10 pesos/MWh. This average effect pooled across the five CFE generation companies masks variation between the firms. The relationship between the inverse semielasticity and the offer price is positive and statistically significant for CFE I and II (Columns 2 and 3 of Table 4). The effect is negative and statistically significant for CFE IV (Column 5). The coefficients for CFE III and CFE VI are not statistically significant. For CFE III, the coefficient is negative but close to zero.

7 Discussion

The characteristics of electricity generation mean that wholesale electricity markets are uniquely susceptible to the exercise of market power. Some of the first attempts at electricity

Table 3: Estimation results for relationship between system price and measure of generator market power, for 2018

	(1)	(2)	(3)	(4)	(5)
Inverse semielasticity	12.098	5.449	3.726	3.830	3.070
	(2.582)	(2.217)	(2.128)	(2.145)	(1.360)
Natural gas price		59.443	70.510	71.809	71.485
		(26.369)	(25.880)	(29.751)	(25.868)
Fuel oil price		-14.036	-10.956	-12.453	-11.064
		(7.862)	(7.751)	(7.861)	(7.723)
System load (GW)		156.130			
		(11.804)			
Inverse semielasticity	Mean	Mean	Mean	Mean	Max
Load controls	None	Linear	Poly	Flex	Poly
Weekday and hour FE	Y	Y	Y	Y	Y
Month-of-sample FE	Y	Y	Y	Y	Y
Observations	8,735	8,735	8,735	8,735	8,735

Notes: Each observation is one hour during 2018. The dependent variable in all models is the weighted mean nodal price in the hour, where the weights are the load in each region. The model is shown in Equation (3). The inverse semielasticity variable is the mean inverse semielasticity for the major generators, calculated using the formula in Equation (2), with a bandwidth parameter $\alpha = 0.1$. Polynomials in load (Column 3 and 5) are seventh-order orthogonal polynomials. Standard errors in parentheses are clustered by date.

Table 4: Estimation results for relationship between generator offer price and measure of generator market power, for 2018

	(1) Pooled	(2) CFE I	(3) CFE II	(4) CFE III	(5) CFE IV	(6) CFE VI
Inverse semielasticity	1.742	2.036	3.586	-0.054	-2.705	1.555
	(0.719)	(0.843)	(1.139)	(0.794)	(1.168)	(0.980)
Natural gas price	21.195	-16.334	59.542	2.849	33.222	23.761
	(24.004)	(21.992)	(30.146)	(29.316)	(27.511)	(30.741)
Fuel oil price	2.240	4.824	6.090	2.154	3.906	-5.624
	(4.197)	(4.510)	(4.783)	(4.951)	(4.478)	(5.003)
Firm FE	Y	N	N	N	N	N
Load controls	Poly	Poly	Poly	Poly	Poly	Poly
Weekday and hour FE	Y	Y	Y	Y	Y	Y
Month-of-sample FE	Y	Y	Y	Y	Y	Y
Observations	42,718	8,544	8,544	8,544	8,543	8,543

Notes: The dependent variable in each model is the offer price of a generation firm in an hour, calculated as the price on the offer curve at the dispatched generation of the firm in that hour (Equation (4)). Each observation in Column 1 is a firm-hour. Columns 2 to 6 show the results separated by firm. Each observation in these columns is an hour. All models include a seventh-order orthogonal polynomial in load, as well as month-of-sample, day-of-week, and hour-of-day fixed effects. Standard errors in parentheses are clustered by date.

industry restructuring were marred by notorious episodes of market power (Borenstein et al. 2002). Market designers have learned from these early experiences. The standard model for a bid-based market includes elements to reduce the ability and incentive of firms to exercise market power. These include price caps, forward contracts between generators and retailers, and automated bid monitoring.

In this paper, I showed the implementing a cost-based market does not eliminate the problem of market power. During certain hours, large generation firms still have the ability to unilaterally increase the market price. Despite the regulation of their offers, firms can still strategically manipulate their generation costs or their plant availability. In the Mexican wholesale electricity market, I showed that the hours in which firms had the greatest ability to exercise market power are associated with higher offer prices and higher market prices.

In a bid-based market, firms have the ability to freely choose a combination of price and quantity that lies along their offer curve. This means that any market outcome in the cost-based market could also be achieved in the bid-based market. As a result, it might appear that cost-based markets weakly dominate bid-based markets in reducing the problem of market power.

However, this conclusion misses two major problems that are unique to cost-based markets. The exercise of market power in a cost-based market may introduce large economic costs. Firms may shut down cheap plants in favor of running more expensive plants, or buy fuel from more expensive sources. Firms might find it profitable to run their generation plants in an inefficient fashion—but this behavior increases the overall cost for society of electricity production. Market power in a bid-based market is mostly a distributional issue between generators and retailers. Market power in a cost-based market can lead to large losses in economic efficiency.

Second, the exercise of market power in a cost-based market is much harder to detect. The type of actions described above—switching to different fuels or taking a generation plant offline—are part of everyday operations for every electricity generator. It is difficult for a market monitor to identify when these operations take place because the firm is exercising market power.

There are other challenges for cost-based markets (Munoz et al. 2018). Regulators do not know the correct fuel price to include in the offer curve of the thermal generation plants. International or regional benchmarks are blind to local prices that could differ due to transportation constraints. Conversely, plant-level prices have greater potential for strategic manipulation through inefficient procurement. Another problem occurs in markets with large-scale hydroelectric generation. Calculating the correct opportunity cost of water is a complex problem requiring the solution of a dynamic stochastic program. Solving this problem involves many forecasts and parameter assumptions by the system operator—and in some markets these could be subject to political manipulation.

A fundamental problem for regulators in every industry is **information**. Firms always know more about their local market conditions that regulators—and firms may not have an incentive to truthfully report all relevant information to regulators. The advantage of a market mechanism is the aggregation of information from all market participants through market prices. By regulating the offer prices in a cost-based wholesale market, this information aggregation is lost, likely leading to a more inefficient market outcome.

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