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Transition to Centralized Unit Commitment: An Econometric Analysis of Colombia's Experience[1]

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Abstract

This paper evaluates the impact of Resolution CREG 051 on the performance of the electricity markets in Colombia. We found out that productive efficiency has improved since the introduction of the Resolution, that is, the total costs of producing electricity have been reduced. This shows a positive impact of the Resolution. On the other hand, we also found that mark-ups and forward energy prices (from bilateral contracts) have increased since 2009, suggesting that there was an increase in the exercise of market power by producers. From the two previous points, we conclude that, although the productive efficiency has increased, the larger share of the efficiency gains were appropriated by the energy producers, rather than passed on to consumers.

Keywords: Energy markets, auctions, centralized unit commitment.
JEL classification: D22, D44, L94, Q41

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1. Introduction

Since 1993 the Colombian electricity sector went through major restructuring of its overall design. Two central regulatory interventions have affected the centralized planning dispatch and the rules of the Colombian's spot market, which operates by receiving day-ahead bids and using those bids for dispatch decision and calculation of the spot price.[2] Until 2001 the spot market, organized as an energy exchange, required generating units (plants) to self-commit generating capacity and submit a single hourly energy price offer along with a declaration of their maximum generating capacity for each of the 24 hours. Using these bids, the system operator would determine the least cost generation dispatch to satisfy demand on an hour by hour basis and determined the equilibrium price, or marginal price, as the price bid by the marginal plant (that is the highest cost plant needed to meet demand). This hourly equilibrium price was used to compensate all dispatched generating units. This mechanism amounts to running an hourly uniform price auction for energy. After 2001, the *Comisión de Regulación de Energía y Gas* (CREG)[3] determined that offer prices should be fixed for the entire 24 hours in which the plants were committed – see CREG-026 (2001).

In 2009 the CREG,[4] realized the possibility of productive inefficiencies of the existing market design due to the heterogeneity of generating technologies comprising hydro and thermal generating units, with very different cost structures. In particular such inefficiencies could arise from the non-convex cost structure of thermal generating units, since their startup and shut down costs were not explicitly accounted for in the dispatch optimization. The economic and engineering literature has extensively discussed the fact that in the presence of non-convexities, self-committed uniform price auction with energy only offer prices can lead to productive inefficiencies.[5] From the suppliers' perspective, thermal units face an unnecessary risk when restricted to submit energy only offer prices since if a unit is dispatched, the equilibrium price would need to be sufficiently high to compensate for startup costs. On the other hand,

[2] Thus, the Colombian electricity market is not, in a strict sense, a spot market. The energy price defined in this market is calculated *ex-post* by an optimization program, and used to settle the energy consumption and production among market participants. To be consistent with standard local terminology, we will follow the usual practice in Colombia and refer to the market and its price as "spot market" and "spot price", respectively.
[3] Colombia's energy regulatory agency.
[4] Documento CREG – 011 (2009), Resolución 051 (2009) and subsequent modifications.
[5] Sioshansi, O'Neill and Oren (2008), (2008b), (2010), O'Neill, Sotkiewicz, Hobbs, B.F., Rothkopf, and Stewart, (2005).

turning off thermal plants already running and turning on a lower marginal cost unit could result in an inefficient production by ignoring startup costs.[6]

Following recommended international best practices and academic literature the CREG undertook a redesign of the spot market and centralized energy dispatched. In broad terms the market became a pool, with multipart bids and centralized unit commitment. More precisely, generating units are now required to separate their offers into variable and quasi-fixed costs (startup and shut down). In this way generators now submit hourly bids for the next 24 hours consisting of three parts (complex bids): (1) Variable cost bid (the same for the next 24 hours), (2) Startup and shut down cost (the same for a three month period) and (3) maximum available capacity (a different value for each hour). Using this information the system operator determines the least cost generation needed to satisfy demand on an hour by hour basis, setting the equilibrium market clearing price as the price bid by the marginal plant. Ex post the system operator determines, which of the dispatched plants cannot recover their fixed costs given the energy market clearing price over the 24 hour period. Such plants are paid an uplift in addition to their energy sales revenues, which enables them to recover their fixed costs. Clearly, this centralized unit commitment approach solves the inefficiency issues but raises (or reinforces) new incentive problems. See, for instance, Oren and Sioshansi ; Sioshansi, Oren and O'Neill (2010), Sioshansi and Nicholson (2011).

While in a well-designed centralized unit commitment dispatch the system operator can determine the most efficient dispatch, the auction mechanism used to solicit generators data upon which the equilibrium prices and settlements are based, may compel generators to overstate costs.[7] This incentive to overstate costs is also true of self-commitment in an energy exchange, but complex bids allow for further strategic behavior. There are no theoretical studies with clear-cut results that rank the performance of one design vs. the other so the question remains an empirical one.[8] This study proposes a reduced form econometric analysis to evaluate empirically the ultimate benefits (if any) of the 2009 regulation in Colombia.

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[6] Sioshani, Oren and O'Neill (2010) provide a stylized example which shows that self-commitment in an energy exchange market can result in inefficient production of energy even if generators are price takers. This is a phenomenon due only to non-convexities in the cost structure of some generating units. See page 169, Table IV.

[7] A well designed centralized unit commitment dispatch requires a rich set of technological parameters to calculate the efficient dispatch but due to the way plants report their bids, some of this cannot be possible even under truthful biding. For example a single price bid for all 24 hours, can be interpreted as the average marginal cost, but this would results in an inefficient dispatch. Allowing for multipart price bids can improve efficiency provided that generators use the multipart format to reflect their true cost structure.

[8] See Sionashi and Nicholson (2011).

We focus on the economic effects of the 2009 regulation related to the economic consequences on the ideal dispatch based on the implementation of regulation 051 of 2009. More specifically, the impact on welfare for consumers, firm's surplus and economic efficiency.[9] Under uniform pricing and short-run inelastic demand, economic efficiency is equivalent to minimizing production costs.

To address these questions we use a reduced form econometric model in the spirit of Mansur (2008), modified to incorporate hydro generation which is a dominant resource in Colombian electricity market (67% of capacity).

Our main findings were: (1) Electricity is produced more efficiently since 2009, that is, the Resolution 051 contributed to higher productive efficiency. (2) We found evidence that bid marginal costs mark-ups and prices after 2009 were also higher than they would under the regime before the resolution, possibly as a result of an increase in market power. These findings suggest that consumers have not benefitted from the efficiency gains and although productive efficiency has increased because of a more efficient dispatch as intended, the additional strategic flexibility of generators may have reduced overall welfare by reducing consumers' surplus. We show that this is true even if we ignore the spot prices and focus only on the average price of bilateral contracts.

This paper is organized as follows. In section 2, we describe Colombia's electricity market rules, before and after 2009. We also describe the unit commitment problem that the system operator XM solves and how each plant is remunerated. Section 3 contains a description of the data used. The econometric analysis is presented and discussed in section 4 where we argue that productive efficiency has increased since 2009. Section 5 provides hard evidence of increase in market power after 2009 and that efficiency gains have not been passed on to consumers through lower prices. Section 6 contains the conclusions.

2. The problem

In this section we briefly explain Colombia's spot market design before and after the regulation of 2009 and the most important features of resolution 051 of that year.[10] We focus on the domestic market (national market) and ignore the international exchanges with Venezuela and Ecuador. The dispatch and spot market in these international exchanges is subordinated to the domestic market which is by far the

[9] Economic efficiency is by law, the regulatory agency objective function. See Law 143 (1994), Art. 6.

[10] Unless otherwise stated, in this paper before regulation 2009 means the period in between the regulation of 2001 and the regulation of 2009.

most important. Hence, from the perspective of this study, focusing on the national market is appropriate.

The spot market and energy dispatch prior to Regulation 051 (i.e. before 2009) can be summarized as follows. There are three relevant points in time: the day ahead (economic dispatch), the real time dispatch (real dispatch) and the day after (ideal dispatch). The main features of the economic dispatch are:

a) Plants sent two part bids: a minimum price at which they are willing to generate during the next 24 hours along with their maximum generating capacity for every hour of the next 24 hours.
b) Plants inform the Independent System Operator (ISO) on what fuel and plants configuration should be used for solving the unit commitment problem.
c) System operator estimates the following 24 hours total demand for each hour.
d) Basic technical characteristics of plants are given (ramp model for thermal plants, minimum energy operating restrictions $Q_{i,t}^{-}$ for hydro plants, minimum up-time, minimum down-time[11], etc. for thermal plants).
e) Automatic generation control restrictions (AGC) are given[12].
f) Transmission restrictions are given.
g) The economic dispatch optimizes every day the following function:

$$\sum_{t=0,\dots,23} \sum_{i} Pof_i \times p_{i,t}$$

where Pof_i is the price bid of plant i for the next 24 hours and $p_{i,t}$ is the production of plant i in hour t subject to hourly AGC, transmission, demand and technical constrains (ramps), environmental restrictions, etc.

This optimization defines the economic dispatch for every hour. It provides a scheduling plan for generating energy the next 24 hours.

Following the economic dispatch, real time generation proves sometimes to deviate from the planned economic dispatch for many different reasons: demand turns out to be slightly different than estimated demand in the day ahead, energy losses,

[11] Due to technical characteristics, once a thermal plant is started it must be on for a minimum time (minimum up time). The same is true when a thermal plant is shut down (minimum downtime).
[12] Power grids require closely balanced real time generation and load. AGC is a system for adjusting the power output of multiple generators.

overloaded lines, etc. Therefore, the system operator is required to fine tune the actual dispatch in real time. Once the real generation in the 24 hours has occurred the system operator calculates the ideal dispatch. The ideal dispatch is an ex-post calculation used for settlement purposes. The optimization problem that is solved is the following:

$$\min_{p_{i,t,}} \sum_i Pof_i \times p_{i,t}$$

s.t.

$$D_t \leq \sum_i p_{i,t} \quad (1)$$

where Pof_i is the price bid by plant i for the next 24 hours, $p_{i,t}$ is the production of plant i in hour t and D_t is actual demand at time t. Notice that the ideal dispatch is determined through an hour by hour optimization problem.

The ideal dispatch forms the basis for calculating the spot price.[13] Once the optimization problem of the ideal dispatch is solved for every hour, the market clearing price is calculated as the price bid by the marginal plant that is not saturated[14] (i.e., the marginal plant needed to meet demand which is not saturated).[15] We denote this equilibrium price as MPO_t. The hourly spot price, P_t is defined as this equilibrium price, $P_t = MPO_t$ (after 2009, the spot price has been modified by an uplift as explained below).

Since the real dispatch turns out to be different than the ideal dispatch, side payments are implemented to pay for any differences.[16]

After the regulation of 2009, the ideal dispatch solves a centralized unit commitment problem. Rather than minimizing the hourly costs of generation the objective function was set equal to the objective function of the economic dispatch (twenty four hour optimization problem), generators submit complex bids and side payments were introduced. The bids specify an energy offer price for the next twenty four hours, startup costs and maximum generating capacity for each hour in the next twenty four hours.

[13] More precisely this is a settlement price since technically speaking there is no spot market. Following the normal usage of the term in Colombian electricity sector we will continue calling this a spot price.

[14] A plant is saturated when it is operating under inflexible conditions. Intuitively, when it cannot change its output without violating technical restrictions. For example, a thermal plant in the middle of ramp is a saturated plant.

[15] Formally called *Máximo Precio de Oferta: MPO*

[16] These are called *reconcialiaciones,* positive and negative.

Once the optimization problem of the ideal dispatch is solved for the 24 hours the equilibrium price, MPO_t is calculated as the price bid of the marginal plant that is not saturated. The hourly spot price, P_t is defined as this equilibrium price plus an uplift, ΔI whereas the uplift is defined in the following way.

Let

$$I_i = \sum_{t=1}^{24} p_{i,t} \times MPO_t$$

be the plant's i income according to the ideal dispatch and:

$$C_i = \sum_{t=1}^{24} p_{i,t} \times Pof_i + \sum_{t=1}^{24} Par_i\, s_{i,t}$$

be the plant i generating cost (assuming truthful bidding).

Now let $GI_{i,t}$ be plant i energy production at the time when it is saturated (zero otherwise) and RP_i the positive reconciliation price, then the uplift is defined as[17]:

$$\Delta I \quad = \frac{\sum_i \ \max\{0, C_i - I_i\} + DI_i}{\sum_{t=1}^{24} D_t}$$

where:

$$DI_i = \sum_{t=1}^{24} GI_{i,t} \times (\max\{MPO_t, RP_i\} - \ MPO_t)$$

The hourly spot price is defined as:

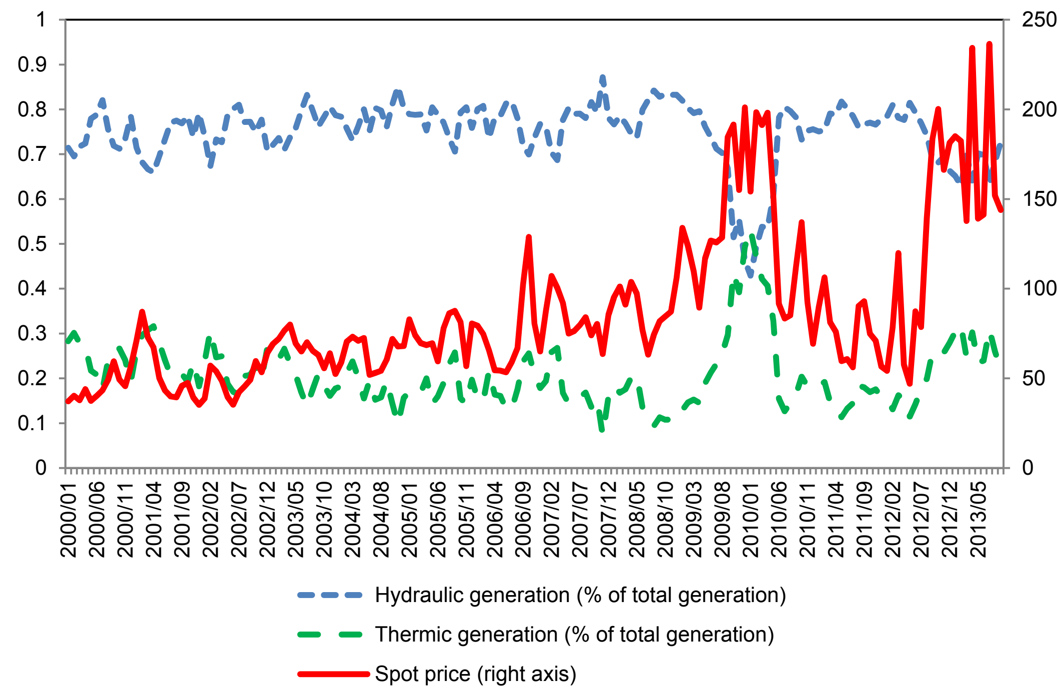
$$P_t = MPO_t + \Delta I$$

Therefore, the spot price guarantees that demand will pay for startups of dispatched plants, and energy production of saturated plants. Having defined the spot prices we now explain the settlements for the various agents. Agents are paid the spot price for any unit of produced energy (no matter if the plant is saturated or not) and (1) Hydro plants reimburse ΔI for each unit of energy produced. (2) Thermal plants for which $C_{N,i} \leq I_{N,i}$, reimburse ΔI . (3) Thermal plants for which $C_{N,i} > I_{N,i}$ make no reimbursement.

[17] For the objectives of this study it not relevant to define this price explicitly.

3. Data

Colombian electricity sector is a hydro dominated but diversified system. Next graph shows a time series since 2001 of the composition between hydro and thermal generation (as a proportion of total generation). The graph also shows the spot price (right axes measured in pesos per KWh).



One of the key variables that we will need to estimate for the econometric analysis in the next section is the marginal costs and opportunity costs of water. We take a pragmatic and standard approach common in the economic literature (Borenstein et.al (2002), Mansur (2008)). The methodology for estimating these marginal costs of plants that use coal and natural gas, as their principal fuel is based on: (1) The heat rate for each plant. (2) Fuels calorific value. (3) Fuels price (P). (4) Variable operating and maintenance costs (VOM) and (5) Taxes (CERE and FAZNI). Then the marginal cost of thermal plants is:

$$\text{Marginal Cost} = \frac{\text{Heat Rate}}{\text{Caloric Value}} * \text{P} + \text{VOM} + \text{CERE} + \text{FAZNI}$$

We use fuels price time series adjusted by caloric value and transport costs from UPME[18] and Heat rates are taken form XM's web page for all thermal plants. Also, we used different VOM costs, US$5/MWh for gas plants and US$6.9/MWh for carbon plants.

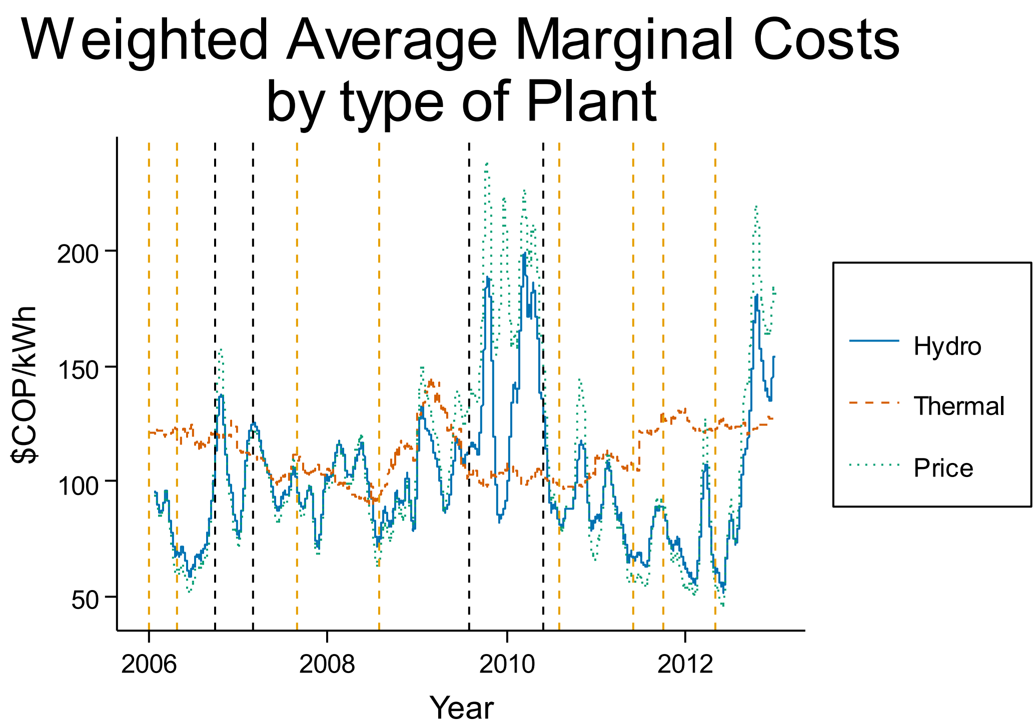
We use the daily official exchange rate (TRM) taken from, *Banco de la República*[19], to express marginal costs in pesos. CERE time series was obtained from XM's databases. FAZNI were calculated taking into account resolutions CREG 005 (2001) and CREG 102 (2006). These Resolutions set FAZNI at 1COP/kWh indexed to the IPP (Producer Price Index) month by month. According to the resolutions, the value is reset to 1COP/kWh in December 2006 and then continues indexed to the IPP. IPP is taken from DANE.[20]

The opportunity cost of water is one of the most difficult variables to pin down. For most of the exercises we used two versions of opportunity costs. Both versions yield similar results so we only discuss and report results for the second measure. For the first set we estimate the opportunity cost of water in one hour as the minimum between the plants bid price and the marginal cost of the most expensive thermal plant operating during that hour. The second definition of opportunity costs is: the minimum between the plant's bid and the marginal cost of the marginal dispatched plant.

The next figures show a weighted average by maximum capacity of plants marginal costs, hydro plants opportunity costs (second definition) and the spot price.[21] The figure suggests that marginal costs or opportunity costs have not changed dramatically compared to the spot price.

[18] Colombia's energy and mining planning department (Unidad de Planeación Minero Energética): http://www.sipg.gov.co/sipg/documentos/precios_combustibles

[19] Central Bank of Colombia.
[20] *Departamento Administrativo Nacional de Estadística*. The official national statistics agency.
[21] Except when explicitly mentioned, all prices are in constant prices (producer's price index - PPI) of December 2012.



Our econometric analysis uses a panel of 50 plants since January 1, 2006 to December 31, 2012 that are responsible for more than 95% of total generation

4. Econometric analysis

This section describes an econometric evaluation of the welfare consequences of Resolution 051, 2009, using data made available by *Comisión de Regulación de Energia y Gas* (CREG, the Colombian regulator for electricity markets) and XM (the system operator). The methodology used in this study closely follows the methodology used by (Mansur, 2008) to evaluate the effects of the market restructuring in PJM in 1999. This method is more sophisticated than the standard method used by Borenstein, Bushnell and Wolak (2002), which compares market outcomes with an ideal competitive benchmark that ignores start-up costs. That is, the standard method assumes that whenever a plant has a lower marginal cost than the spot price, it should have been used in the competitive benchmark. However, it might be optimal not to use a plant with a low marginal cost, but high start-up costs, if it is not required to run for long. Therefore, the standard method overestimates the welfare losses in the actual market. Mansur proposes a dynamic model that produces a more accurate evaluation of welfare losses. This methodology is particularly relevant for this study, since start-up cost is one of the central aspects of Resolution 051/2009.

More specifically, we estimate two models. The first model (output decisions model) estimates the quantity of energy produced as a function of price-costs markups in the present, past and future, since the actual decision to produce or not will depend on these markups. We calibrated this model with data before 2009, when the Resolution changed the rules, and we used the obtained model to simulate what the production would have been if no rule change had been implemented (i.e., dispatch continued to be based on energy only bids and generators bids continued to be based on marked up marginal cost.)

The second model considers an adjustment in prices, taking into account the fact that the Resolution changed the way that the power plants recover their costs and, therefore, changed the price formation mechanism. For this, we adapt the methodology described in Mansur's appendix A, and estimate prices as functions of demand, controlling also for El Niño and La Niña effects. More details about these procedures and our overall strategy of evaluation are given in the next section. The econometric model is a reduced form model that ignores agents' strategic behavior. Nevertheless, we perform several sensitivity analyses and alternative model specifications and conclude that results do not change substantially in these analyses. This suggests that our results are robust with respect to an econometric specification that explicitly incorporates agents' strategic behavior.

Our results indicate that Regulation 51 has improved welfare by reducing production costs. However, the observed prices are higher than the simulated prices, representing the spot price that would have prevailed in the absence of regulation (counterfactual). Moreover, these results do not change when we consider startup costs. The simulated counterfactual prices and estimated marginal and opportunity costs imply that after the Regulation 51 was implemented, markups have increase suggesting that, although the dispatch has been more efficient, there has been considerable exercise of market power to the detriment of consumers. In section 5 we show that this is still the case even if we use contracted prices rather than the spot price.

Our overall strategy is to use the period before 2009 to characterize firms' output decisions and aggregate supply. Using these characterizations we construct a counterfactual for the period after 2009, simulating what would have been firms' output decisions and prices consistent with observed aggregate demand. Since demand is mostly inelastic we assume that electricity demand has been unchanged by Regulation 51.

Our analysis is composed of the following parts: (1) We model and estimate firms output decisions based on markups while controlling for exogenous variables that are relevant at the firms' level, such as indicators of climate conditions (Niño and Niña events). This is particularly relevant as the hydro generation is very important in Colombia (68% of total generation). (2) We estimate this model using data before August 1, 2009 and two measures for the markup. For thermal plants we use the marginal costs estimated using fuel costs, heat rates, etc. and for the hydro plants we use opportunity costs as explained in section 3. For prices we use the observed spot prices. Using this information we define markups as the difference between prices and the corresponding marginal costs. (3) Using this model we estimate counterfactual output decisions after 2009.

We model pricing behavior using a very flexible aggregate supply curve similar to (Mansur, 2008) and estimate the model using data before 2009. This model is used to estimate counterfactual prices after 2009.

a) Output decisions

Firms' production decisions are estimated using data before 2009. Using this model production predictions are constructed both before (in sample estimation or model fit) and after the reform (out of sample estimation or forecast). In general in a dynamic model, assumptions on how firms create expectations of future prices are important, whereas here we focus on the correlation between future prices and production. Therefore, the model asserts that a firm's current output depends on historical, current, and future price-cost markups (pcm_{it}).

$$pcm_{it} = P_t - c_{it} \quad (1)$$

where i denotes a particular firm, t is the hour of the day, P_t is the spot or simulated price and c_{it} is the marginal or opportunity cost.

Then output q_{it} before 2009 is specified as:

$$q_{it} = \alpha_i + \beta_{1,i} pcm\_pos_{it} + \beta_{2,i} pcm_{it} + \beta_{3,i} pcm_{i,t-1} + \beta_{4,i} pcm_{i,t+1} + \beta_{5,i} \overline{pcm}_{it} + \beta_{6,i} \overline{pcm}_{i,t-24} + \beta_{7,i} \overline{pcm}_{i,t+24} + \gamma_0 niño + \gamma_1 niña + \vec{F} + \varepsilon_{it} \quad (2)$$

where α_i, are units' fixed effects, $\overline{pcm}_{it}$ is the average markup for the day, pcm_pos_{it} is a binary variable equal to *one* if there was a positive markup for firm i at time t and *zero* otherwise and $\vec{F}$ represents fixed time effects (for hours, weekdays and months). Notice that specific characteristics like minimum up times, minimum downtimes, load costs, start-up cost, ramping rates, etc., do not vary significantly in time and are undistinguishable from the unit fixed effects α_i, which captures all of this variation. To make the model more flexible, all variables except α_i and pcm_pos_{it}, are estimated using fifth-order polynomial functions. Compared to Mansur's model, more variables were added in order to adapt the methodology to Colombian electricity market. First of all, there are two indicator variables that are very important for all agents and generating units, representing El Niño and La Niña phenomena. These variables capture climate changes in the Pacific Ocean that affect precipitation in the country.

To consistently estimate equation (2) using Ordinary Least Squares, it is important that markups are not correlated with the error terms. Since output and markups (prices) are jointly determined in equilibrium this is most likely not the case. Also by ignoring the potential strategic interaction among firms, by ignoring output decision of other firms (other than i) in equation (2), we are potentially omitting variables which also call into question the independence of markups and the error term. As a result estimated coefficients may be biased. We have tried to mitigate some of these potential econometric problems by introducing instrumental variables and reporting sensitivity analysis for the main results. Below we provide a discussion of these issues. First, in order to get a sense of the model's fit and the role of introducing a more flexible specification, we report estimation results for the model with no polynomials nor calendar fixed effects.

Table 1, with no polynomials nor calendar fixed effects, shows the average coefficient for each variable across all plants, average standard error and the number of firms, out of 46 firms, for which the coefficient is significant at a 95% confidence level. The R^2 of this model is 0.06 and the variables are significant in most of the units evaluated; being the unit fixed effect and El Niño and La Niña phenomenon a key variable in almost all models. Also the coefficients signs of most variables are intuitive. The full model estimation with calendar effects and polynomial has an R^2 of 0.17. Tables 2 and 3 report the same results by resource type. There is notable difference in coefficients between El Niño and La Niña variables for thermal and hydro plants, which is consistent with our intuition.

Table 1. Summary of model for all Plants

Plants	Average of Coefficients	Average of Std. Errors	# of Coefs. Significant(5%)
(Intercept)	5,837,669	47,823	44
pcmpos	-199,534	69,777	35
pcm	13,993	2,824	26
pcmminus1	10,931	2,131	30
pcmplus1	8,209	2,135	17
meanpcm	13,243	3,608	33
meanpcmminus24	-4,452	2,285	36
meanpcmplus24	-20,373	2,283	34
nino	-78,944	69,154	41
nina	-34,246	44,558	38

Table 2. Summary of model for 17 Hydro Plants

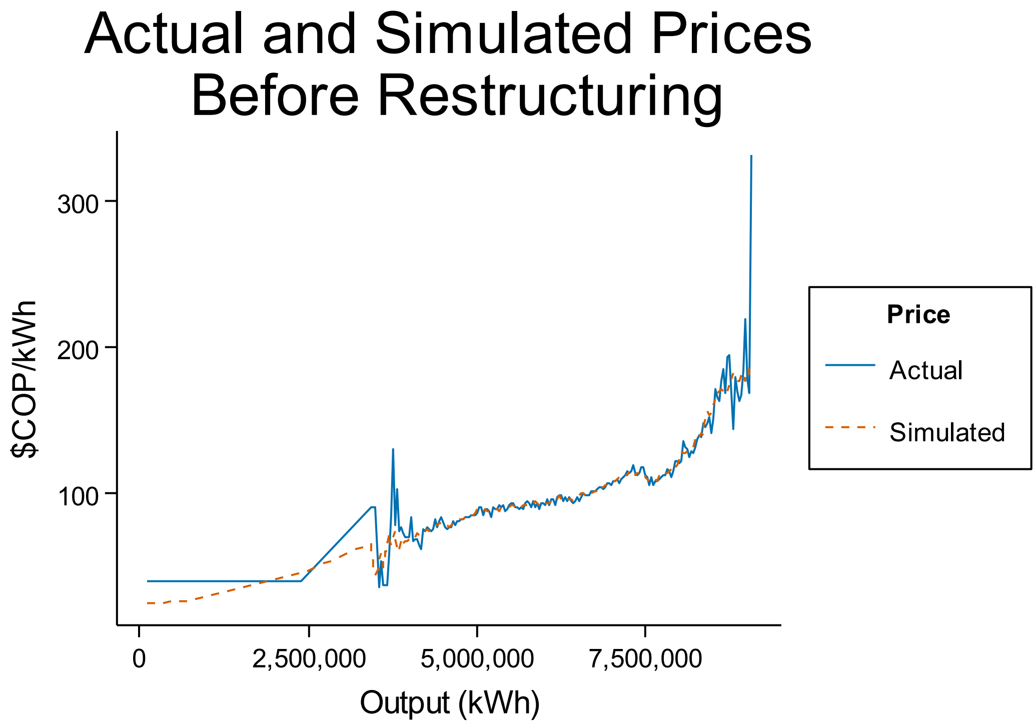
Plants	Average of Coefficients	Average of Std. Errors	# of Coefs. Significant(5%)
(Intercept)	4,901,643	34,957	17
pcmpos	-228,712	48,867	14
pcm	10,967	1,941	13
pcmminus1	7,664	1,504	13
pcmplus1	6,080	1,506	8
meanpcm	13,195	2,266	17
meanpcmminus24	-4,373	1,403	14
meanpcmplus24	-15,534	1,400	14
nino	-367,622	50,675	13
nina	-7,709	32,730	16

Table 3. Summary of model for 29 Thermo Plants

Plants	Average of Coefficients	Average of Std. Errors	# of Coefs. Significant(5%)
(Intercept)	936,026	12,866	27
pcmpos	29,178	20,910	21
pcm	3,026	883	13
pcmminus1	3,267	627	17
pcmplus1	2,129	629	9
meanpcm	48	1,342	16
meanpcmminus24	-79	883	22
meanpcmplus24	-4,839	883	20
nino	288,678	18,479	28
nina	-26,537	11,829	22

Taking into account the high concentration of Colombian electricity market, it is plausible that companies are not price takers. This is why endogeneity might be a problem in the models above. Even though the analysis has been performed at the unit level, it is possible that companies strategically influence the markup by price setting. That is why a final specification of the model is tested using instrumental variables. There are at least three possible candidates for instruments, the maximum commercial availability, bilateral contracts and “aportes hídricos”. The first one was discarded because of insufficient variability: it didn’t change at the hourly level and hardly between days. The bilateral contracts variable is theoretically very interesting. At the moment of setting prices it can be taken as exogenous and it captures some of the most relevant information for bidding in the day-ahead market. If the firm is long then it will be in its interest to bid high aiming to set the price as high as possible. Unfortunately, there are several issues that hindered the use of this instrument. First of all the data is not available by unit but by company, loosing part of the richness of the data. Moreover, there are 5 units which didn’t engage in any contract at all and many firms had very few contracts before 2009, reducing the estimation sample substantially. Despite these shortcomings, we performed some tests with the available data. The correlation between the instrument and the markup is 0.3, and the R^2 of the first stage averaged 0.12. Nevertheless in the second stage of the estimation we didn’t find a good fit. The third variable “aportes hídricos” is also very interesting as an instrument. Below we report results for this case (the complete model estimated using instrumental variables is described in Appendix B).

Next figure compares de estimated (in sample) aggregate supply curve (before 2009) with the observed aggregate supply curve (in sample).



The graph suggests that at least on average, the aggregate fitted (simulated) supply curve is similar to the actual supply curve.

b) Prices

As noticed in the previous section, the key independent variable is the markup which is determined by the price. In order to construct a better counterfactual, one has to acknowledge that the reform may have changed the market and consequently the prices. Therefore, following Mansur's appendix A, a counterfactual price $\hat{p}_t$, is simulated for the period after the reform, using the dynamics before the reform. [22]

Here the relationship between prices in the pre-2009 period and aggregate output is examined. The coefficient of aggregate output is allowed to vary by hour-of-day i (as well as include hour-of-day fixed effects) and a ten-part piecewise linear spline function (split by decile for each hour) is used. We also control for El Niño and La Niña indicators:

[22] We use the in-sample fit of the model to perform a sensitivity analysis of our results.

$$p_t = \alpha_i + \sum_{j(i)=1}^{10} \beta_{i,j(i)} D_t + \gamma_0 nino + \gamma_1 nina + e_t$$

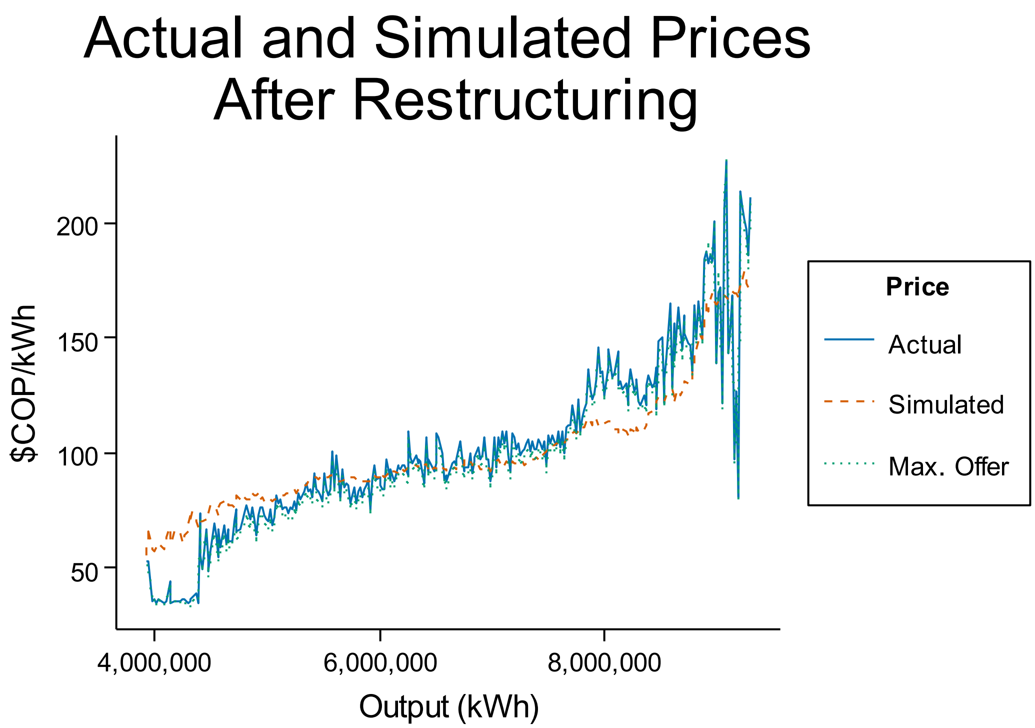
The function is extremely flexible and fits the pre-restructuring data with an R^2 of 0.92. With these estimated coefficients, a second series of prices is simulated after 2009. As in Mansur´s paper, this method requires a common support. The range of demand before 2009 was from 2,393,873[23] to 9,107,534 kWh. The demand increased and the range was 3,828,775 to 9,298,119 kWh after 2009. Finally, predicted prices are adjusted to reflect the actual variance observed in the post-restructuring period.

Before 2009, the standard deviation of the unadjusted predicted prices (p_t) (models fit or competitive benchmark) is much lower than that of actual prices (15.37132 and 30.73391, respectively). In order to increase the variance, the residuals from the regression of equation (3) based on the pre-2009 data are used. First, an AR(1) process is fitted to the residuals:

$$\hat{e}_t = \rho \hat{e}_{t-1} + u_t \ (4)$$

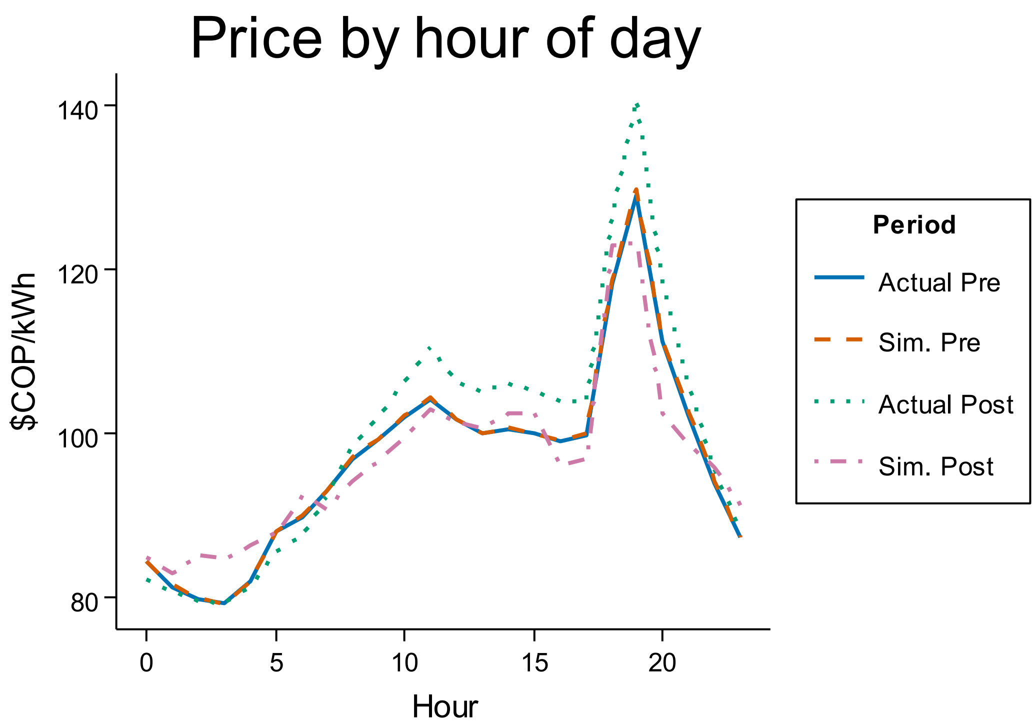
The estimated coefficient is $\hat{\rho} = 0.8$. Then, using a Monte Carlo simulation, a new series $\hat{e}_t$ is simulated by drawing from the sample distribution of u_t. Finally the error is added to p_t, to get the adjusted predicted prices. This process is repeated one hundred times and the results are averaged. The following two figures show the real prices and the simulated prices before and after the reform. Notice that the model predicts lower prices even if we compare them to marginal price (Max. Offer) after 2009 (recall the spot price after 2009 is the marginal price or maximum price offered by the marginal, non-saturated plant dispatched in the ideal dispatch, plus an uplift). These results raise concerns regarding market power after 2009 suggesting that, the spot price increase after 2009 is not due to marginal costs but, most likely, due to market power.

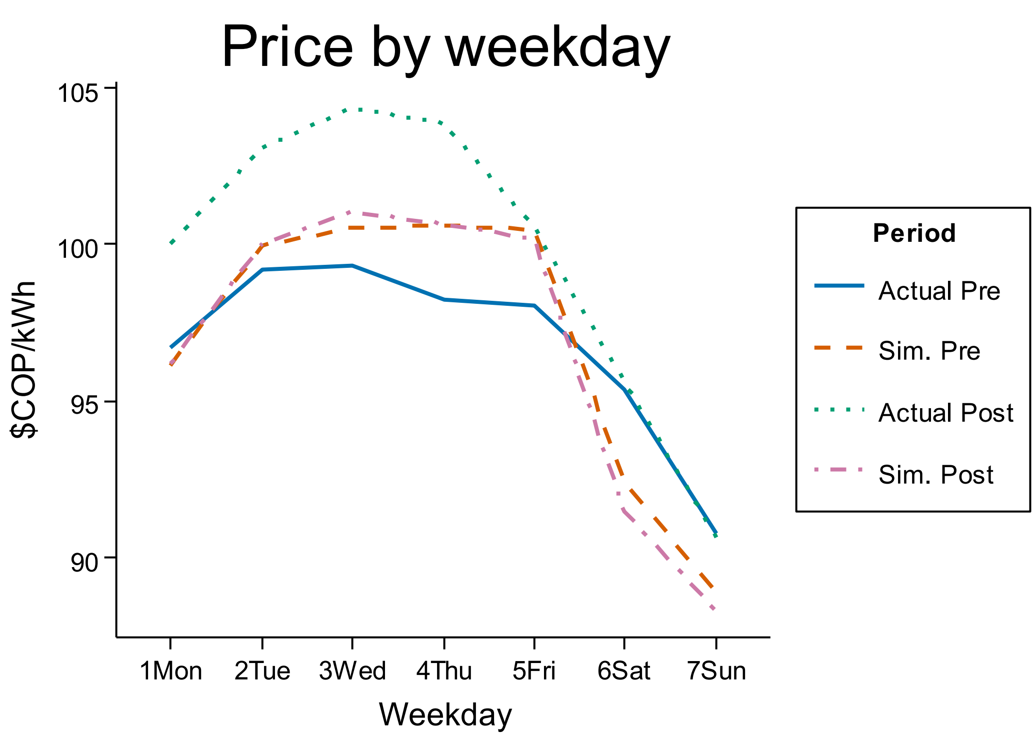
[23] There were only two values (121,228 and 798,678) below.



For the period before 2009, the model simulated prices are close to the real prices, whereas after the restructuring the volatility is similar but the simulated prices are consistently lower than those observed. This is very interesting since, as we will see below in the welfare comparisons', the empirical evidence strongly indicates that the new market design based on centralized unit commitment has improved welfare, relative to the counterfactual. Yet, the prices we are estimating for the counterfactual are lower than those observed, suggesting that exercise of market power has increased.

The next figure makes it clear that simulated prices are consistently lower than the actual prices (the sample fit before 2009 is almost perfect when averaged by hour by day, hence the blue line cannot be seen in the figure).


Price by hour of day
$COP/kWh
140
120
100
80
0
5
10
15
20
Hour
Period
Actual Pre
Sim. Pre
Actual Post
Sim. Post


Price by weekday
$COP/kWh
105
100
95
90
1Mon
2Tue
3Wed
4Thu
5Fri
6Sat
7Sun
Weekday
Period
Actual Pre
Sim. Pre
Actual Post
Sim. Post

c) Counterfactuals

Using the previous two models we are perform the following exercises that lead to different counterfactuals and welfare estimations.

Before 2009 we estimate the output decisions mode using observed markups.

1. For the output decisions model estimated with observed markups, we simulate output decisions using post 2009 observed markups. This simulation is of little importance in itself because it uses a model estimated under self-commitment and simulates it using as inputs markups under centralized unit commitment. Nevertheless, it is useful for the following reason. If the 2009 Regulation had no effect in the market, one would expect the simulated output to be similar to the observed one after 2009. As reported below, this is not the case and we have an indirect argument for concluding that after 2009 something actually changed in the market.

2. We use the output decisions model estimated from observed markups to simulate output (self-unit commitment) after 2009 but using simulated markups. In this case we interpret output as the one we would have observed in case no regulation had been introduced (under self-commitment).

d) Welfare Effects

Welfare effects measurements are based on direct production costs, i.e. variable costs, excluding the start-up costs. Below we analyze the role of startup costs in this simulation. Assuming that variable costs are represented by a linear function, the welfare effect of the Regulation (deadweight loss) is estimated in the following way:

$$\Delta W = \sum_{t=1}^{T}\sum_{i=1}^{N} c_{it}(q_{it} - \hat{q}_{it}) \quad (5)$$

where q_{it} is observed output of plant i during period t, $\hat{q}_{it}$ is simulated output under any of the three scenarios mentioned above and c_{it} is the marginal or opportunity cost.

Variable costs

Table 4 reports the results of this evaluation after normalizing aggregate simulated output per hour. To be more precise, since simulated (countefactual) prices after 2009 are lower than actual prices the output decisions models simulate higher output than actual demand. This explains the fact that the variable cost of producing energy in the counterfactual could be higher than the actual costs. Therefore, we normalize simulated output so that simulated aggregate output supply is equal hour by hour to aggregate demand. Actual outcomes correspond to observed values for aggregate output and aggregate variable costs. Real prices report also aggregate output and variable costs (deadweight loss and dead weight loss share are not relevant).[24] Results show that post 2009 results are different enough to claim that, conditional on the model; the Regulation indeed had a notable effect on aggregate output and variable costs.

The IVth model counterfactual, represents our best estimation of what would have been the unit commitment after 2009, had no resolution been implemented. It shows that centralized unit commitment has improved productive efficiency since its introduction.

Table 4. Welfare Implications of Production Inefficiencies

Model	2006-0	2007-0	2008-0	2009-0	2009-1	2010-1	2011-1	2012-1
Actual Outcomes								
Output	48.3	50.0	50.3	29.9	9.2	26.2	52.1	50.6
Total Variable Costs	4337	4934	4902	3214	1081	2394	4418	4986
IV Mixed								
Output	48.3	50.0	50.3	29.9	9.2	26.2	52.1	50.6
Total Variable Costs	4392	4964	4950	3308	1140	2571	4876	5536
Deadweight loss	-54	-31	-48	-94	-59	-178	-457	-550
DWL share	-1.26%	-0.62%	-0.97%	-2.92%	-5.43%	-7.42%	-10.35%	-11.03%

Notes: Output is measured in millions of MWh. Total Variable Costs and Deadweight loss are measured in $COP Billions[25].

Startup costs

[24] Deadweight loss share (DWL share) is calculated as welfare change as in equation 5 divided by actual (observed) aggregate variable cost.

[25] A Billion is 10^9.

As we mentioned at the start of this section, for welfare comparisons we have ignored additional costs due to startups. We find two difficulties in estimating these costs. First, although before 2009 we can count the number of startups using generation data (real dispatch) we don't have data for startup costs (before 2009, plants did not report startup costs) and second the econometric model, being a linear model, is not tailored for estimating startups in the counterfactual. To overcome these difficulties and get a sense of the actual startup costs and hence a better measure of welfare changes, we estimated startup costs before 2009 using the methodology reported in the Appendix. Then using real generation we estimated aggregate (observed) startup costs before and after 2009. The next table shows the results. Table 5 shows that after 2009 startup costs oscillated between 0.57% and 1.05% of variable costs and before 2009, between 0.58% and 0.80%. Since we find it difficult to estimate startups in the counterfactual using our model we assume that the startup costs after 2009 in the counterfactual were also between 0.58% and 0.80%. Hence we obtain an upper bound on welfare changes due to startup costs by assuming actual costs of 0.57% after 2009 (for every year) and counterfactual costs of 0.80% for every year. Therefore, a lower bound on the welfare gains of the regulation, in terms of startups costs after 2009, is -0.23% of variable costs (per year). It follows that welfare gains calculated in the previous table, based on variable costs overestimate the welfare gains of the regulation by less than 0.23% of variable costs.

Table 5. Start-Up and Variable Costs by Year in Million COP

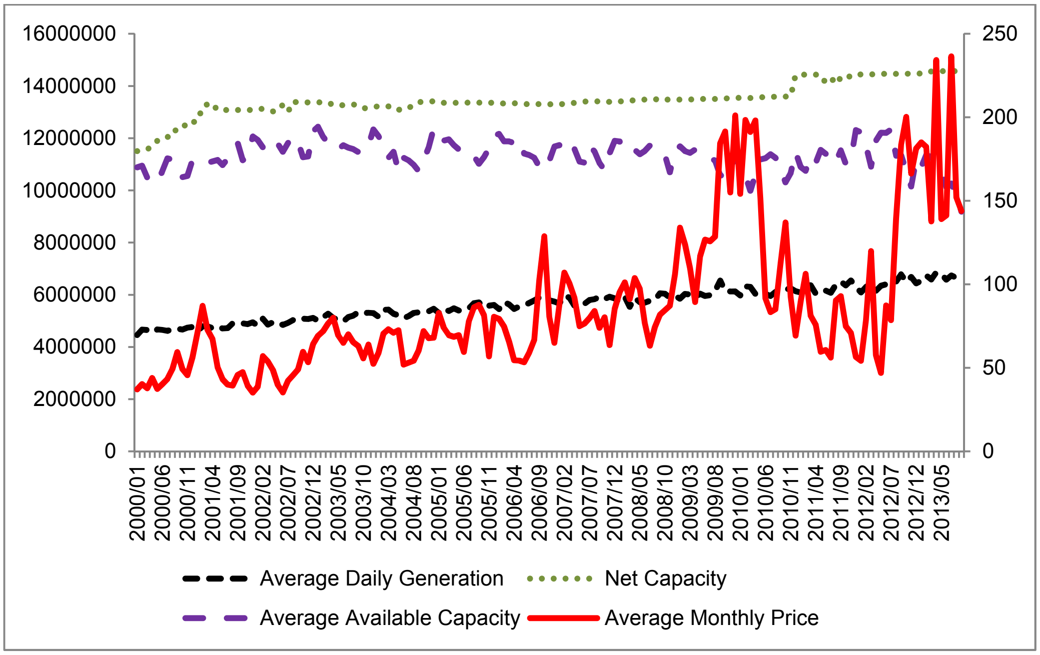
Period	StartUp.Cost	Var.Cost	Proportion
2006.0	34,745	4,337,337	0.80%
2007.0	29,251	4,933,579	0.59%
2008.0	28,490	4,902,022	0.58%
2009.0	19,363	3,213,772	0.60%
2009.1	6,130	1,081,287	0.57%
2010.1	19,138	2,393,550	0.80%
2011.1	46,458	4,417,575	1.05%
2012.1	45,600	4,985,843	0.91%

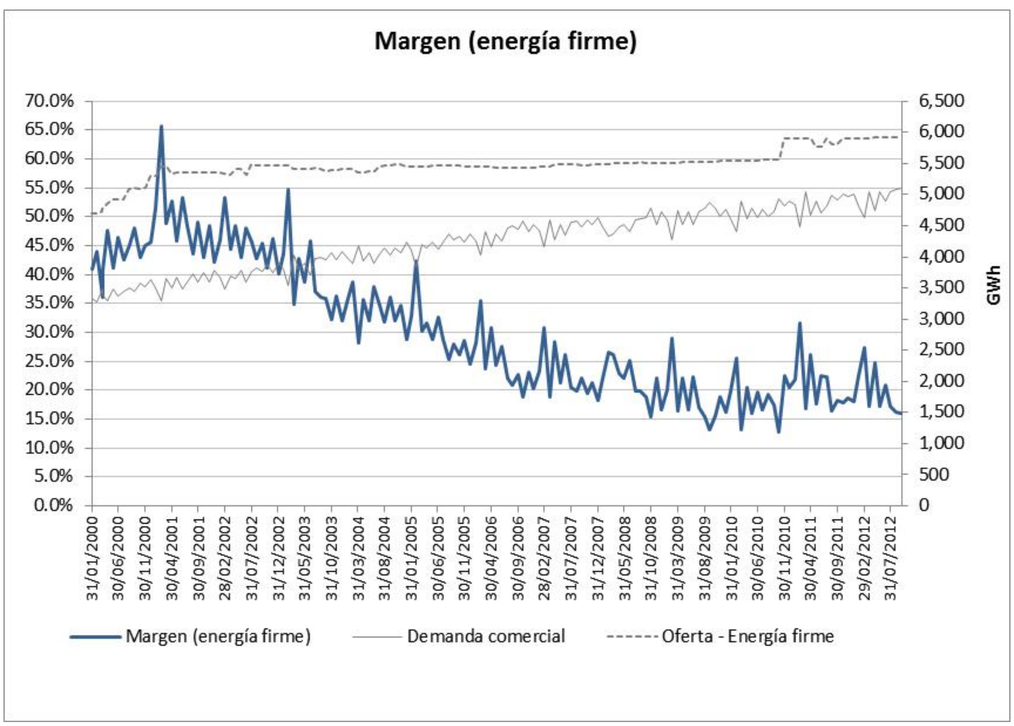
5. Market Power and Consumer Welfare[26]

The previous section shows that productive efficiency has risen since the introduction of centralized unit commitment dispatch. A natural question is then to assess the impact on aggregate welfare. As we described in the previous section, counterfactual (simulated) prices are lower than actual prices, suggesting that even though productive efficiency has increased the benefits might have not been passed on to consumers who have apparently experienced price increases. Moreover, if we assume that aggregate demand is elastic (at least in the long run), it is possible that overall welfare has decreased due to a decrease in allocative efficiency. In this section we do not measure the change in consumer's welfare but focus on the exercise of market power to determine if, generators have indeed increased their ability to exercise market power after the Resolution of 2009.

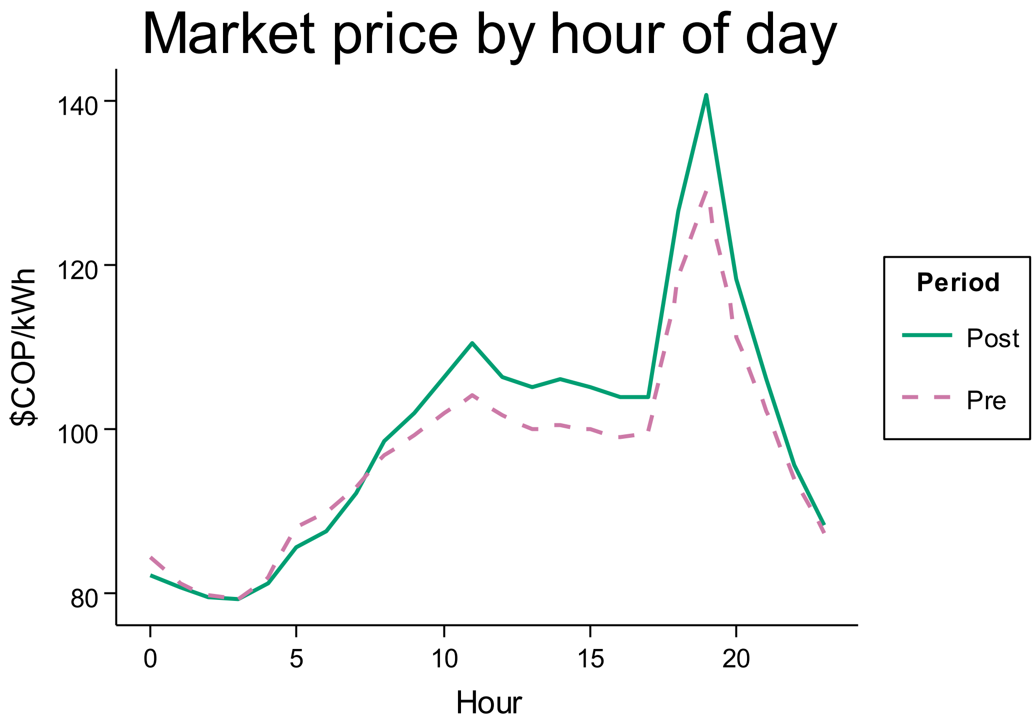
The next figure shows net capacity (measured in KW left axis), average available capacity (measured in KW left axis), average daily generation (measured in KWh left axis) and monthly average spot price (measure in KWh right axis). The graph suggests that there isn't a capacity or firm energy shortage in the Colombian electricity sector although, the difference between firm energy and aggregate demand has narrowed (see figure below). However, while this gap may have an effect on the opportunity costs of water, it should not have a direct effect on thermal plants' behavior unless they exercise market power so as to exploit strategically potential future water shortages and risk averse behavior by hydro plants. Given the difficulty of determining opportunity costs for hydro plants which would require a stochastic dynamic programing model, we do not study bid markups for these plants and only use a short run lower bound on that cost that ignores the present value of future scarcity to examine possible over use of hydro in the dispatch. Thus, we do not study whether markups for hydro plants are consistent with the diminishing gap between firm energy and aggregate demand. The point is that these phenomena, in a competitive setting, may affect the relative amount of thermal energy being used and hence the market clearing prices but should not be a determinant of thermal plants bidding behavior.

[26] Market power is an economic concept, and does not imply any value judgment. Mas Colell, Whinston and Green (1995) define market power as *the ability to alter profitably prices away from competitive levels*. Market power is always associated with inefficiencies, again an economic definition devoid of any value judgment. Depending on the context this may be inevitable or not. However, in all cases, the presence of market power only highlights the possibility of improvement (towards more efficient outcomes) though not its feasibility. Value judgments in economics are reflected in social objectives not in the positive description of economic systems.





Source: Presentación de Propuestas para el Sector Electrico. ECSIM, August, 2013.



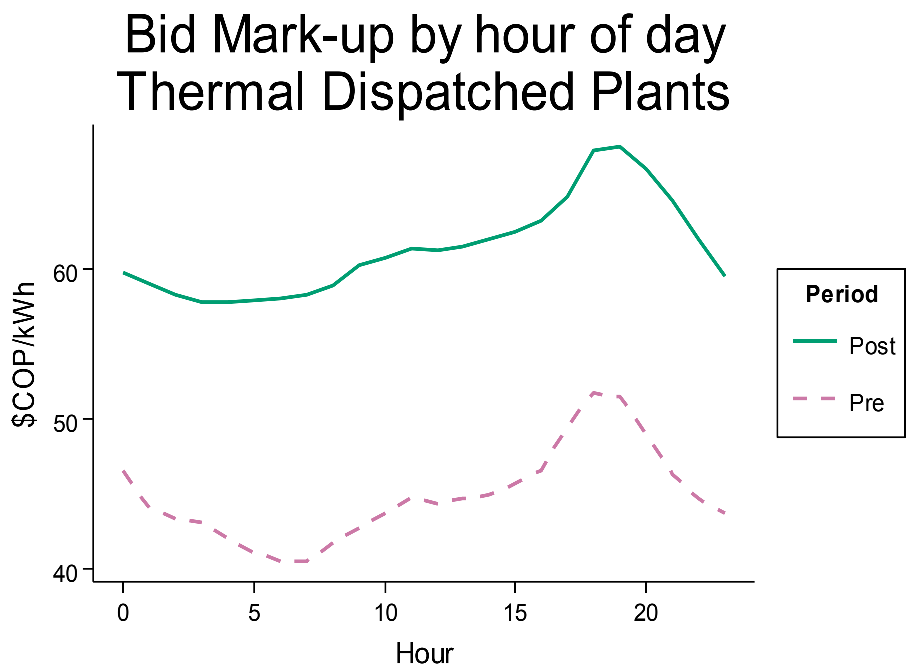
The previous section has made the case for the efficiency gains attributable to Resolution 051. We have also noted that the observed spot price is higher relative to what would have happened if Resolution 051 had not been implemented. This suggests that consumer surplus has decreased and, if efficiency has increased, then it must have been the case that that efficiency gains have not been passed on to the consumers. We first address our claim regarding market power. Obviously, our statement is based on our determination of marginal costs. Nevertheless, the following set of calculations suggests that the results are quite robust.

We first show our results on bid price markups for dispatched plants.[27] Next we qualify our results based on calculations that take into account some market phenomena that we might be missing in our approach. Specifically, periods in which the assumption of a unique operating fuel might result in underestimating the true marginal costs of thermal plants. Furthermore, a period of Government intervention might cast doubts on the determination of competitive market outcomes. We address these issues in the last section where we examine the role of contracts in determining consumer welfare.

[27] Similar results hold when we only consider inframarginal bid price markups.

a) Bid markups

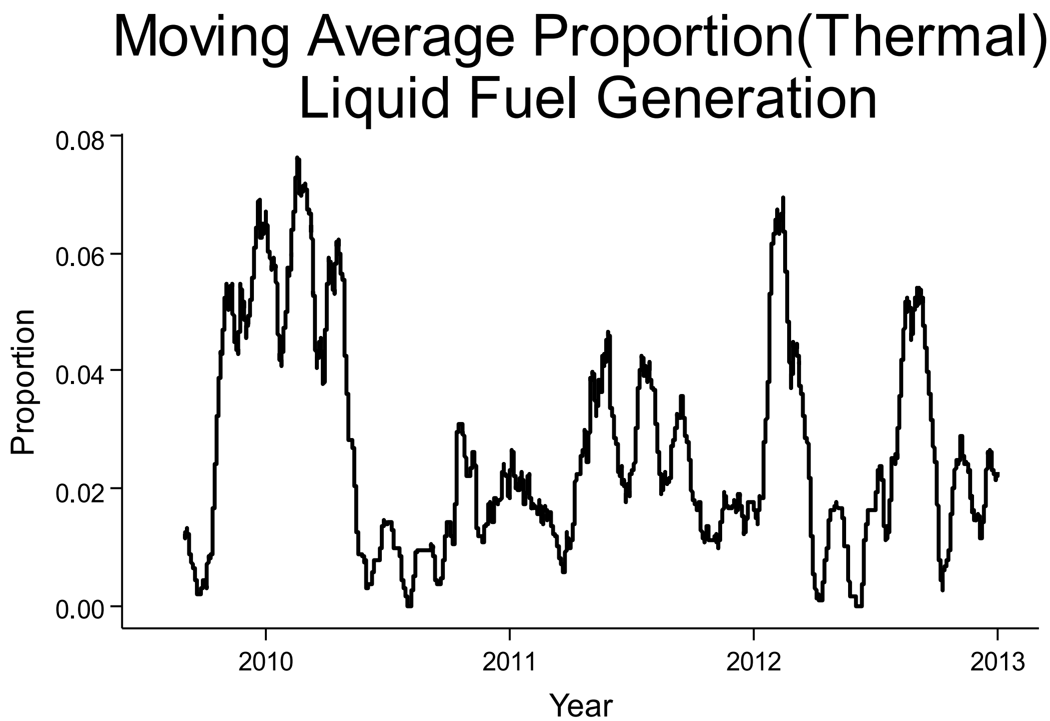
The next figure shows the weighted average by capacity of bid markup for dispatched plants before and after 2009.

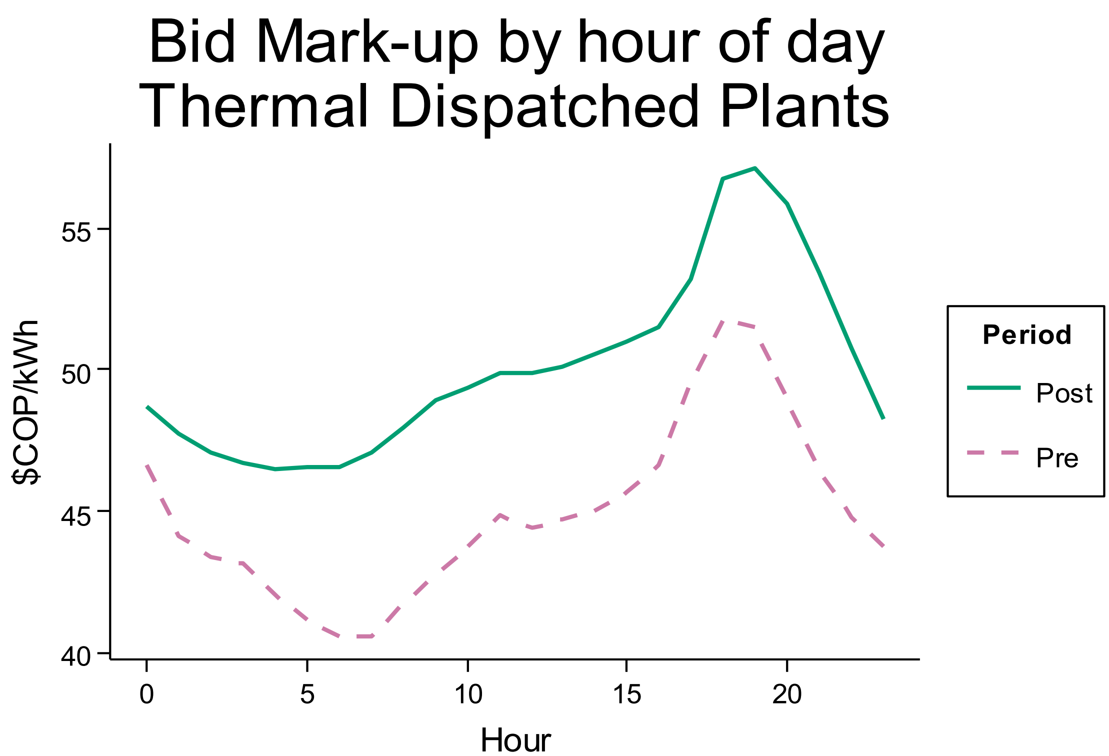


b) Controlling for plants using liquid fuel

So far, an important simplification in our analysis is the use of only one type of fuel for each thermal plant (the one used in the most common configuration of the plant). In reality this is not always true since plants change fuels according to their configuration, costs and supply constraints. Of particular importance is the case when plants have used liquid fuels, which is generally more expensive than carbon or gas. Therefore, we calculated which plants and in what periods (after 2009) plants used liquid fuels for operation and we omit such periods and these plants from the calculation of bid prices. This procedure will clearly underestimate market power and provides a conservative measure of noncompetitive behavior.

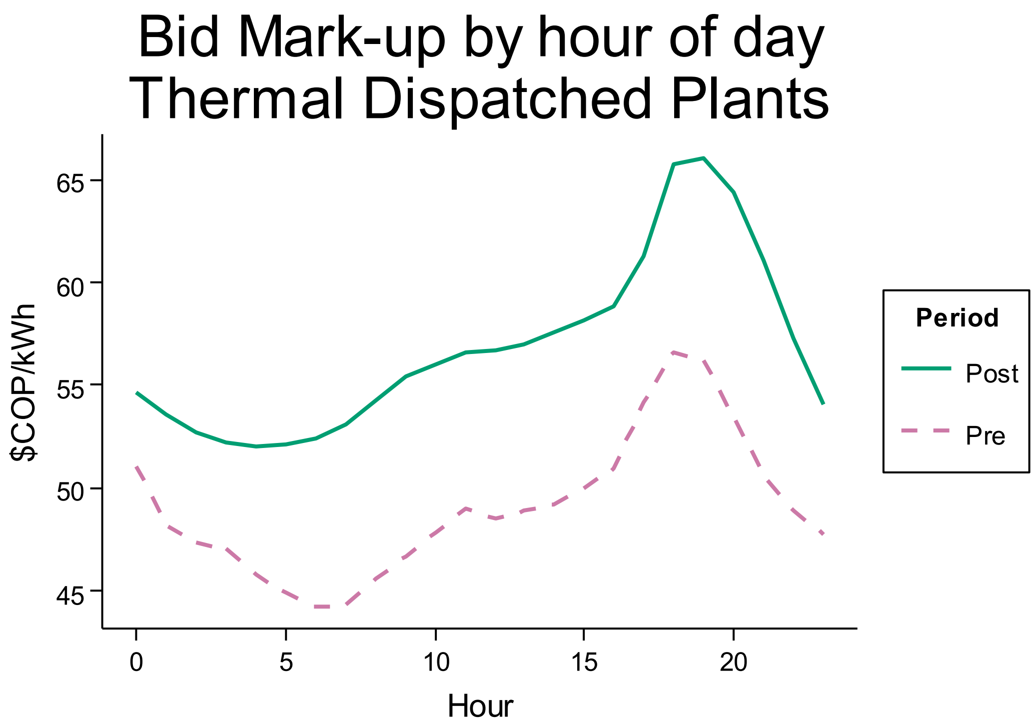
The next figure shows how much energy is produced with plants using liquids. The next two pictures show the recalculated bid markup. The result is robust to PPI inflation (see next subsection).


Moving Average Proportion(Thermal)
Liquid Fuel Generation
0.08
0.06
0.04
0.02
0.00
Proportion
2010
2011
2012
2013
Year


Bid Mark-up by hour of day
Thermal Dispatched Plants
55
50
45
40
$COP/kWh
0
5
10
15
20
Hour
Period
Post
Pre

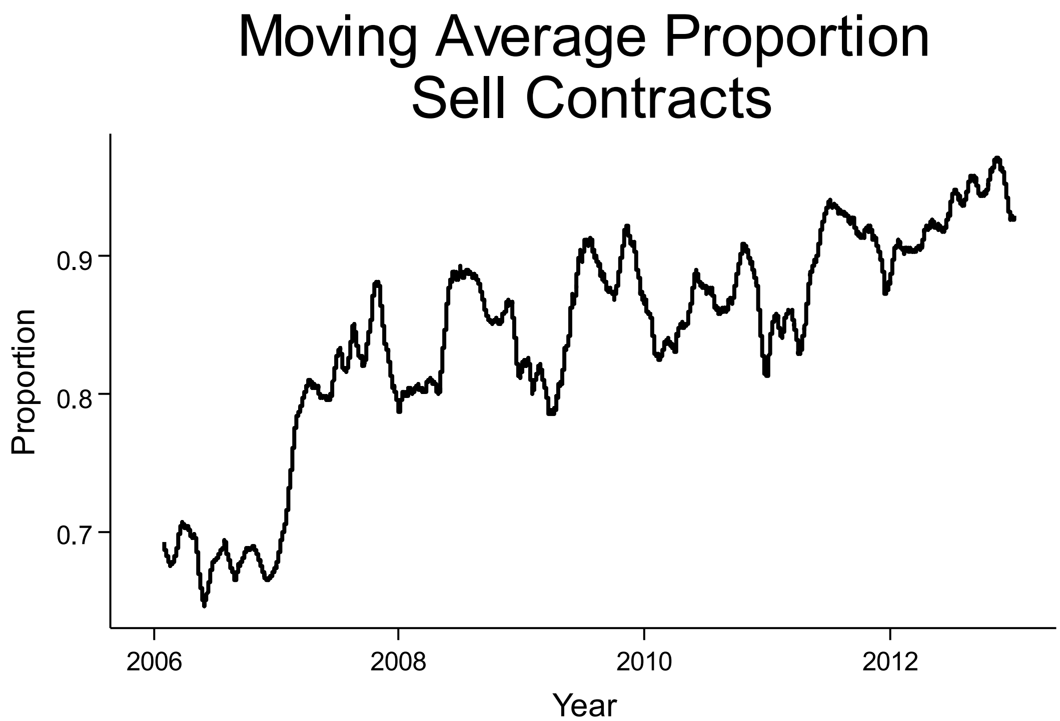
c) Periods of government intervention and PPI inflation

Finally, market participants have raised concerns regarding a period between 2009 and 2010 in which the Government intervened in the market. We take this period as starting October 2, 2009 (Resolution MME 18, 1686) and ending June 2, 2010 (Resolution CREG 070, 2010). The following figures omit in the calculation of bid price markups for that entire period and controls for producer's price index inflation.

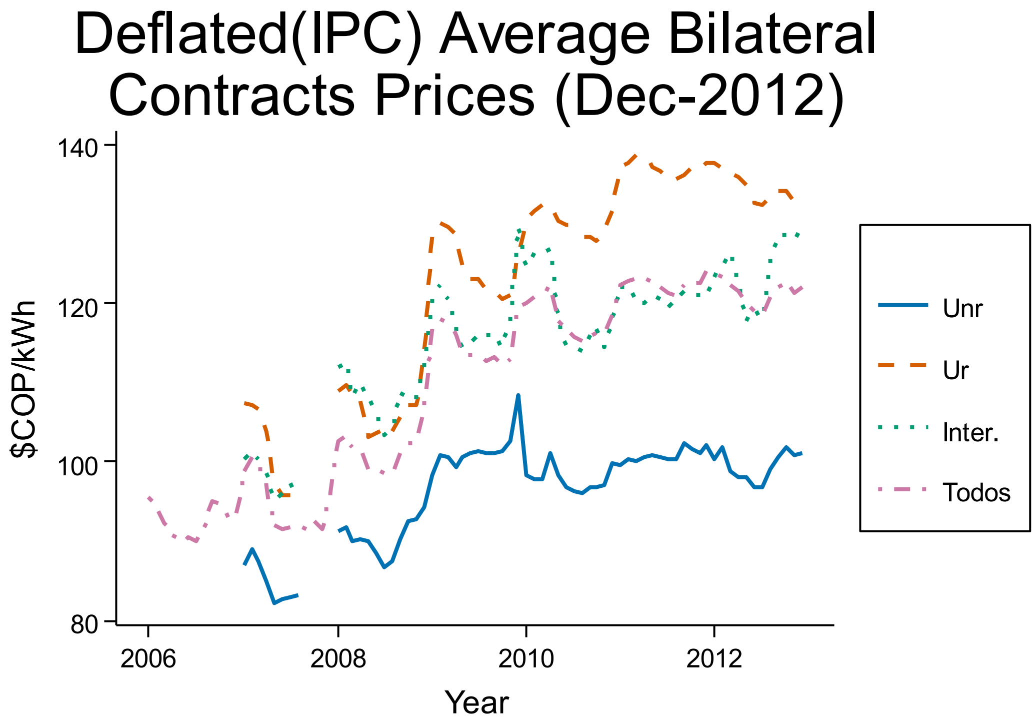


d) Contracts

Our final calculations take into consideration that there is a significant portion of electricity transactions take place through bilateral long term contracts so that consumers are not fully exposed to the spot marker. Nevertheless, even if the spot price is not the most relevant price and we focus on the price of bilateral contracts our claims are still indicative of the fact that productive efficiency gains have not been passed on to the consumers. First, as the next figure shows, even though energy contracted constitutes a high proportion of energy demand for the period under study it is below 100%. Second, one should expect forward prices to be correlated with the settlement price.



However, rather than dueling on the theory of forward prices and their relation to the price of the underlying asset we examine below available data regarding the Colombian bilateral contract market. Specifically, the next figure shows the average contract price per month for four different kinds of users. Regulated (Ur), unregulated (Unr), intermediaries (Inter) and for all users (Todos). Time series are expressed in December 2012 constant prices. The figure shows that there has been a substantial increase in average price of contracts since 2009.



6. Conclusion

This paper evaluates the impact of Resolution CREG 051 on the performance of the electricity markets in Colombia.

We found out that productive efficiency has improved since the introduction of the Resolution, that is, the total costs of producing electricity have been reduced. This shows a positive impact of the Resolution.

On the other hand, we also found that mark-ups have increased since 2009, suggesting that there was an increase in the exercise of market power by producers. This observation is consistent with findings for UK and Ireland, which in some phases have implemented centrally committed dispatch as Resolution 051 did.

From the two previous points, we conclude that, although the productive efficiency has increased, the larger share of the efficiency gains were appropriated by the energy producers, rather than passed on to consumers.

Results show that under different model specifications there is evidence supporting the claim that Resolution 051 of 2009 of CREG resulted in a positive welfare effect at least in terms of productive efficiency. This is even though simulated prices, reflecting what would have happened in case the Resolution had not been implemented, predict lower prices than the observed ones.

In spite of all the caveats and arguments regarding the calculation of marginal prices in our analysis, our results are robust.[28] Our revised analysis shows that even when accounting for government intervention and (when expensive liquid fuels where the rule) there is still a significant increase in mark ups after 2009, which is reflected in the bids and in the resulting spot prices. Furthermore, although most of the energy supplied to retail customers is contracted forward and as such insulated from spot price volatility, both theoretical and empirical evidence suggest that the persistent higher spot prices due to increased mark ups are correlated with forward contract prices which indirectly results in increased retail prices. Thus, the increase in spot prices after 2009 and the observed increase in average forward contract prices present strong evidence that the productive efficiency gains have not benefitted consumers. If demand is elastic, reduced retail prices would have also produced allocative efficiency gains. However, since retail prices have increased it is possible that allocative efficiency decreased by more than the productive efficiency gains so that social welfare has actually declined after Regulation 51 was implemented. Such possible decline in social welfare does not reflect a failure of the regulation to improve efficiency but rather a further indication that improvement in social welfare requires both, improvement in productive efficiency as well as sharing of these gains with consumers.

[28] See An Evaluation of CREG 051 – 2009 Regulatory Intervention in Colombian Electricity Market. December 19, 2013. Available at http://www.alvaroriascos.com/research/electricitymarkets/

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Appendix A: Construction of startup costs

Before 2009, startup costs were not reported by generators. To overcome this difficulty we used reported startup costs after 2009 and fuel prices to estimate startup costs before 2009. To do so we first calculated the most common operating fuel type by plant (next table).

Generator	StartUpFuel
TERMOCARTAGENA 1	Gas
TERMOCARTAGENA 2	Gas
TERMOCARTAGENA 3	Gas
MERILECTRICA 1	Gas
PAIPA 1	Coal
PAIPA 2	Coal
PAIPA 3	Coal
PAIPA 4	Coal
PROELECTRICA 1	Gas
PROELECTRICA 2	Gas
TERMOBARRANQUILLA 3	Gas
TERMOBARRANQUILLA 4	Gas
TEBSA TOTAL	Gas
TERMOCANDELARIA 1	Gas
TERMOCANDELARIA 2	Gas
TERMODORADA 1	Gas
TERMOEMCALI 1	Gas
TERMOFLORES 1	Gas
TERMO FLORES 4	Gas
GUAJIRA 1G	Gas and Coal
GUAJIRA 2G	Gas and Coal
TERMOCENTRO 1 CICLO COMBINADO	Gas
TASAJERO 1	Coal
TERMOSIERRAB	Gas
TERMOVALLE 1	Gas
TERMOYOPAL 2	Gas
ZIPAEMG 2	Coal
ZIPAEMG 3	Coal
ZIPAEMG 4	Coal
ZIPAEMG 5	Coal

For each thermal plant we have a six-month frequency series of fuel cost (in US dollars). Each plant, except for GUAJIRA 1 and GUAJIRA 2, uses either coal or gas as its main fuel. Because GUAJIRA 1 and 2 is the only plant that can use both types of fuel.

Fuel prices are reported as US dollars per Thermal Units (USD/MBTU). Coal and gas prices may differ across plants because of transportation costs and other economic factors. Start-up costs are reported for every thermal generator for the 2008-2012 period. Since fuel costs have a six month frequency we used a local regression model to construct a daily fuel cost data. For an appropriate fit of the LOESS model we use a smoothness parameter of $\propto = 0.3$. With the LOESS fit we construct a new database with the price of fuel for each plant in a daily frequency. Before running the LOESS model we transformed prices and costs to local currency (COP) and used the Producer Price Index (IPP) to deflate both start-up costs and fuel costs. Since the IPP has a monthly frequency, we used a LOESS fit with $\propto = 0.1$ to convert it to a daily series.

Because the prediction horizon is large (daily startup costs for the period 2006 - 2009) we want to use a simple model that avoids high variance and over fits the data. The econometric specification we used was a linear model of the form:

$$StartUpCost_{gt} = \beta_{g0} + \beta_g^T FuelCost_{gt} + \varepsilon_{gt}$$

Depending on the generator, $FuelCost_{gt}$ represents gas or coal fuel cost. In the case of GUAJIRA 1 and 2, $FuelCost_{gt}$ is a vector with gas and coal fuel costs as its components.

This model is fitted using minimization of the squared error subject to the positivity of the vector β_g^T. This problem can be formulated as a convex optimization problem and can be solved numerically. Whenever β_g^T is strictly positive, we will obtain the OLS solution.

The next table show the results.[29]For 12 generators the restriction on the coefficients β_g^T was binding. The next table reports the results of all other plants.

[29] The complete database can be found at: http://www.alvaroriascos.com/research/data/

Generator	R2	Generator	R2
TERMOBARRANQUILLA.3	0.57	TASAJERO.1	0.08
TERMOBARRANQUILLA.4	0.54	TERMOCENTRO.1	0.05
TERMOCARTAGENA.1	0.51	TERMOSIERRAB	0.08
TERMOCARTAGENA.2	0.61	TERMOVALLE.1	0.41
TERMOCARTAGENA.3	0.56	ZIPAEMG.2	0.03
TERMODORADA.1	0.36	ZIPAEMG.3	0.10
TERMOFLORES.1	0.14	ZIPAEMG.4	0.07
GUAJIRA.1	0.44	ZIPAEMG.5	0.13
GUAJIRA.2	0.35	TERMO.FLORES.4	0.05

Appendix B: General specification

The following are the estimation results for the general output decisions model, using as instrumental variables *Aportes Hídricos* and ignoring the period of Government intervention.

Table A1. Summary of model for all Plants

Plants	Average of Coefficients	Average of Std. Errors	# of Significant Coeff. (5%)
(Intercept)	4,007,679	3,983,698	28
Pcmpos	223,576	75,903	30
Pcm	221,546	155,733	7
pcm_2	-276	3,668	3
pcm_3	-30	102	3
pcm_4	0	1	1
pcm_5	0	0	3
pcmminus1	13,062	110,846	2
pcmminus1_2	3,418	1,846	7
pcmminus1_3	61	79	6
pcmminus1_4	-2	1	9
pcmminus1_5	0	0	9
pcmplus1	366,594	136,291	7
pcmplus1_2	1,139	3,664	3
pcmplus1_3	-140	98	5
pcmplus1_4	2	1	5
pcmplus1_5	0	0	5
meanpcm	-3,920,131	973,028	23
meanpcm_2	184,369	53,346	19
meanpcm_3	20,619	5,423	19
meanpcm_4	-762	152	23
meanpcm_5	6	1	17
meanpcmminus24	-2,640,696	775,370	18
meanpcmminus24_2	-466,474	94,388	17
meanpcmminus24_3	-2,171	3,767	23
meanpcmminus24_4	752	185	19
meanpcmminus24_5	-8	2	23
meanpcmplus24	4,169,466	1,208,527	25
meanpcmplus24_2	293,945	69,111	24
meanpcmplus24_3	-9,264	2,455	19
meanpcmplus24_4	-503	123	18
meanpcmplus24_5	8	1	21
Niño	-10,534,695	3,410,290	18
Nina	-4,373,193	2,434,354	27

Plants	Average of Coefficients	Average of Std. Errors	# of Significant Coeff. (5%)
factor(month)2	673,779	1,899,903	22
factor(month)3	1,455,971	1,728,539	23
factor(month)4	2,025,759	2,881,525	22
factor(month)5	3,142,409	4,207,668	19
factor(month)6	3,698,756	4,796,780	26
factor(month)7	1,571,778	4,156,210	21
factor(month)8	-8,870,423	5,752,356	26
factor(month)9	-3,561,142	4,117,038	28
factor(month)10	-8,995,412	3,716,836	22
factor(month)11	-462,391	4,001,576	25
factor(month)12	3,999,440	3,362,153	23
factor(wday)Sunday	3,687,658	2,455,495	21
factor(wday)Monday	-4,249,396	4,210,083	23
factor(wday)Tuesday	-612,219	4,130,158	23
factor(wday)Wednesday	4,465,163	2,739,774	25
factor(wday)Saturday	9,892,300	4,103,528	16
factor(wday)Friday	3,261,587	2,447,297	19