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A structural model to evaluate the transition from self-commitment to centralized unit commitment

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ABSTRACT

We introduce a dispatch model of Colombia's independent system operator in order to study the relative merits of self-commitment vs. centralized unit commitment. We capitalize on the transition that took place in Colombia in 2009 from self-unit commitment to centralized unit commitment and use data for the period 2006–2012. In our analysis we simulate a competitive benchmark based on estimated marginal costs, startup costs and opportunity costs of thermal and hydro plants. We compare the differences between the self-commitment for the period 2006–2009 and the competitive benchmark to the differences between the bid-based centralized unit commitment and the competitive benchmark after the transition. Based on these comparisons we estimate changes in deadweight losses due to misrepresentation of cost by bidders and dispatch inefficiency. The results suggest that centralized unit commitment has improved economic efficiency, reducing the relative deadweight loss by at least 3.32%. This result could in part be explained by the observation that, before 2009, there was an underproduction of thermal energy relative to the competitive benchmark and it supports the claim that dispatch efficiency has improved after the transition.

1. Introduction

Unit commitment decisions in modern electricity markets are made either by the system operator or by individual generators. Both systems have existed in different countries, but so far it is not clear which system - centralized markets or with self-commitment – is more efficient. While centralization may allow pursuing the optimal dispatch, incentive problems may defeat this advantage. The main source of problems is the complexity, nonlinearity and non-convexities that are present in electricity markets. Indeed, the economic and engineering literature have extensively discussed the fact that in the presence of non-convexities, self-committed uniform price auctions with energy only offer prices can lead to productive inefficiencies.[1] From the suppliers' perspective, thermal units face an unnecessary risk when restricted to submitting energy only offer prices since if a unit is dispatched, the market clearing price would need to be sufficiently high to compensate for startup costs. On the other hand, turning off thermal plants that are already running and turning on a lower marginal cost unit could result in inefficient production due to ignoring startup costs.[2]

While in a well-designed centralized unit commitment the system operator can determine the most efficient dispatch, the auction

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[1] Sioshansi et al. (2008b, 2010), O'Neill et al. (2005).
[2] Sioshansi et al. (2010) provide a stylized example which shows that self-commitment in an energy exchange 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.

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mechanism used to solicit generator data, upon which the market clearing prices and settlements are based, may compel generators to overstate costs.[3] 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 relative the other, so the question remains an empirical one.[4] This paper attempts to provide evidence that is relevant to the problem in question, by taking advantage of a natural experiment promoted by the regulator in Colombia in 2009, when it passed from self-commitment to centralized markets. More specifically, this study proposes a structural model of the dispatch to evaluate empirically the ultimate benefits (if any) of the 2009 regulatory intervention in Colombia.

To understand the change in Colombian electricity markets, we need to review a few facts. Between 2001 and 2009, the Colombian electricity market regulated by *Comisión de Regulación de Energía y Gas* (CREG), the spot market[5] was organized as an energy exchange, requiring generating units (plants) to self-commit generating capacity and submit one price for the next 24 h in which the plants were committed – see CREG-026 (2001) -, along with a declaration of their maximum generating capacity for each of the next day 24 h. In 2009 CREG[6] decided to change from self-commitment to centralized commitment and undertook a redesign of the spot market and centralized energy dispatch (Comisión de Regulación de Energía y Gas, 2009a, 2009b). 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 “complex bids” consisting of three part bids for the next 24 h: (1) variable cost bid (the same for the next 24 h), (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 market clearing price as the price offered 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-h period. Such plants are paid a “make whole payment” in addition to their energy sales revenues, which enables them to recover their fixed costs and out of merit variable cost (due to transmission constraints). Clearly, this centralized unit commitment approach solves the inefficiency issues but raises (or reinforces) new incentive problems. See, for instance Sioshansi et al. (2010), Sioshansi and Nicholson (2011).

In our analysis we simulate a competitive benchmark based on estimated marginal costs, startup costs and opportunity costs of thermal and hydro plants. We compare the differences between the competitive benchmark and self-commitment for the period 2006–2009 to the differences between the bid-based centralized unit commitment and the competitive benchmark after the transition. Based on these comparisons we estimate changes in deadweight losses due to misrepresentation of cost by bidders and dispatch inefficiency. The results suggest that centralized unit commitment has improved economic efficiency, reducing the relative deadweight loss by at least 3.32%. This result could in part be explained by the observation that, before 2009, there was an underproduction of thermal energy relative to the competitive benchmark and it supports the claim that dispatch efficiency has improved after the transition.

This paper is a follow up paper to Riascos et al. (2016) that uses econometric techniques to address the problem of economic efficiency and provide evidence of increased exercise of market power by generators after the transition to centralized unit commitment. In contrast to that paper, here we use an explicit model of the dispatch that better represents the actual production and pricing decisions based on economic conditions (demand, costs, etc.) and plants' technological restrictions. This approach allows us to quantify more precisely the relative merits of centralized unit commitment in terms of economic efficiency[7]. Under uniform pricing and short-run inelastic demand, economic efficiency corresponding to social welfare maximization is equivalent to minimizing production costs. Although the focus of this paper is not on investment planning issues, we recognize that there are some interactions between strategic investment decisions and dispatch decisions even under perfect competition, as shown in Sauma and Oren (2006), Sauma and Oren (2007), Sauma and Oren (2009), Pozo et al. (2013) and Munoz et al. (2013).[8]

The rest of this paper is organized as follows. In Section 2, we discuss the dispatch problem and describe the Colombian electricity market. Section 3 introduces the economic model adopted and explain our construction of marginal costs for thermal plants and opportunity costs for hydro plants. Section 4 presents the results. Section 5 is a brief conclusion.

2. The problem

In this section we briefly explain the Colombian spot market design before and after the regulation of 2009 and the most important features of resolution 051 of that year.[9] 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 the most important (see Appendix 1.D). For the period under study, the average proportion of electricity exports plus imports as a proportion of generation was 1.75%. For this study we use residual demand of exports and imports.

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).

2.1. Economic dispatch

The main features of the, pre 2009, economic dispatch were:

a) Plants submit two-part offers: a minimum price at which they are willing to generate during the next 24 h along with their maximum generating capacity for every hour of the next 24 h.[10]
b) Plants inform the system operator about the fuel and plant configuration that should be used for solving the unit commitment problem.

[3] A well designed centralized unit commitment requires a rich set of technological parameters to calculate the efficient dispatch but due to the way plants report their bids, efficiency losses may persist even under truthful bidding. For example a single price bid for all 24 h can be interpreted as the average marginal cost, but this would result in an inefficient dispatch. Allowing for multipart price bids that can vary hourly may improve efficiency, provided that generators use the multipart format to reflect their true cost structure.

[4] See Sionashi and Nicholson (2011).

[5] 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.

[6] Document CREG – 011 (2009), Resolución 051 (2009) and subsequent modifications.

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

[8] During El Niño in 2016, it was observed that opportunity costs were the result of penalties imposed by CREG due to reservoir water levels.

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

[10] In the economic dispatch, maximum generating capacity is taken as the declared capacity of generators, subject to verifiability and, if different to real maximum capacity, subject to penalties. In the ideal dispatch, maximum generating capacity is the verified expost capacity. Since the focus of the paper is on the ideal dispatch, we are using real observed maximum capacities the day after.

c) The system operator estimates the hourly demand for the following 24 h.
d) Generators submit basic technical characteristics of plants (ramp model for thermal plants, minimum energy operating restrictions $Q_{i,\bar{t}}$ 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.

The economic dispatch solves the following problem:

$$min_{q_{i,t}} \sum_{t=0,\ldots,23} \sum_i b_i \times q_{i,t} \tag{1}$$

where b_i is the price bid offer of plant i for the next 24 h and $q_{i,\ t}$ is the production of plant i in hour t. The optimization problem is 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 in the next 24 h. However, the prices are determined ex post to account for deviations, based on a separate run referred to as "ideal dispatch", discussed below.

2.2. Real time dispatch

Real-time production schedules deviate from the day-ahead economic dispatch schedule for various reasons: forecast errors of real-time demand relative to its day-ahead forecast, energy losses, overloaded lines, etc. Therefore, the system operator is required to fine-tune the actual dispatch in real time. Once the real-time generation in the 24 h has occurred the system operator calculates the ideal dispatch.

2.3. Ideal dispatch (under self-unit commitment)

The ideal dispatch is an ex-post calculation which ignores transmission constraints and is used for settlement purposes. The optimization problem that is solved in the ideal dispatch calculation is the following:

$$min_{q_{i,t}} \sum_i b_i \times q_{i,t} \tag{2}$$

where b_i is the price bid of plant i for the next 24 h, $q_{i,\ t}$ is the production of plant i in hour t and the optimization problem is subject to the same restrictions as the economic dispatch except for transmission constraints that are ignored in this problem. 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 of the marginal plant that is "flexible".[14] We denote this price by p_t^m. The hourly spot price, p, is defined as this equilibrium price, $p_t = p_t^m$ (after 2009, the spot price has been modified with an uplift as explained below).

2.4. Ideal dispatch (under centralized unit commitment)

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

Once the optimization problem of the ideal dispatch is solved for the 24 h, the marginal price p_t^m, is calculated as the price bid of the marginal plant that is flexible. The hourly spot price, p_t, is defined as p_t^m plus an uplift ΔI, which is defined in the following way.

Let

$$I_i = \sum_{t=1}^{24} q_{i,t} \times p_t^m \tag{3}$$

be the income of plant i according to the ideal dispatch and let

$$C_i = \sum_{t=1}^{24} q_{i,t} \times b_i + \sum_{t=1}^{24} c_i^s s_{i,t} \tag{4}$$

be the generating cost of plant i, where c_i^s are startup costs and $s_{i,\ t}$ is a binary variable indicating if the plant is started up at time t.

Then the uplift is defined as:

$$\Delta I = \frac{\sum_i \max\{0, C_i - I_i\}}{\sum_{t=1}^{24} D_t} \tag{5}$$

and the hourly spot price is defined as[15]:

$$p_t = p_t^m + \Delta I \tag{6}$$

Therefore, the spot price guarantees that demand will pay for startup of dispatched 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 flexible 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, and (3) thermal plants for which $C_{N,\ i} > I_{N,\ i}$ make no reimbursement.

3. Model

The dispatch model we used is explained in the Appendix. A key feature of our methodology is the construction of marginal costs for thermal plants and opportunity costs for hydro plants.

3.1. Marginal and opportunity costs

The Colombian electricity sector is a hydro dominated but diversified system. Fig. 1 shows a time series of the composition between hydro and thermal generation (as a proportion of total generation) since 2001. The graph also shows the spot price (right axis measured in Colombian pesos (COP) per kWh).

One of the key variables that we will need to estimate is the marginal costs and opportunity costs of water. We take a pragmatic and standard approach, which is common in the economic literature Borenstein et al. (2002), Mansur (2008). The methodology for estimating the marginal costs of plants that use coal and natural gas as their principal fuel is based on: (1) the heat rate of each plant, (2) fuel caloric value, (3) fuel price (P), (4) variable operating and maintenance costs (VOM), and (5) taxes. Then the marginal cost of a thermal plant c_T^m is:

$$c_T^m = \frac{\text{Heat Rate}}{\text{Calorific Value}} * \text{P} + \text{VOM} + \text{TAXES} \tag{7}$$

[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 down time).

[12] Power grids require closely balanced real time generation and load. This is achieved through AGC, which automatically adjusts the power output of generators.

[13] More precisely this is a settlement price since technically speaking there is no spot market.

[14] An inflexible plant is one that cannot change its output without violating technical restrictions (i.e., a thermal plant in the middle of a startup profile is an inflexible plant).

[15] We have abstracted from other institutional details to focus in the economic consequences of the dispatch. For example, additional side payments are made to compensate the energy produced by plants operating under inflexible conditions.

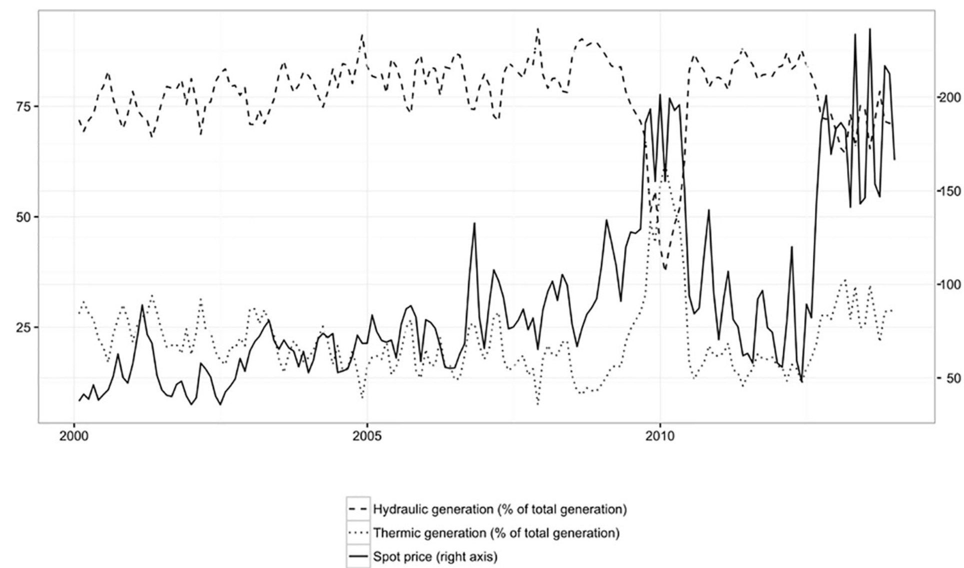

Fig. 1. Mix of hydro and thermal generation (left axis in proportions) and market prices in Colombian pesos (right axis).

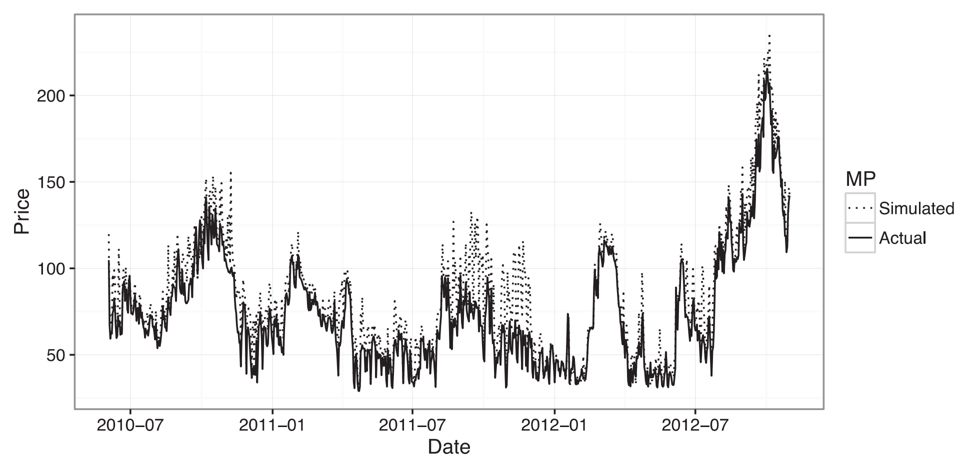

Fig. 2. Actual vs. simulated average daily market prices.

We use a fuel price time series adjusted by caloric value and transport costs from UPME[16] and heat rates are obtained from the power exchange web page for all thermal plants. We used different VOM costs for different technologies, specifically US$5/MWh for gas plants and US $6.9/MWh for coal power plants.[17]

We use the daily official exchange rate (TRM) obtained from *Banco de la República*[18] to express marginal costs in Colombian pesos.

The opportunity cost of water is one of the most difficult variables to estimate. Hydro plants face a tradeoff between producing now and storing water to produce in the future. In a static one shot game between generators in an organized energy market, the opportunity cost of a hydro generator H producing at time t can be estimated by the maximum price offered by thermal generators that were dispatched at that time (which we denote by b_t^*), thus as a pragmatic estimation of opportunity costs c_H^m, that only accounts for the present, we use:

$$c_{H,t}^m = \min\{b_t^*, b_{H,t}\}, \tag{8}$$

where $b_{H,\ t}$ is the hydro plant H bid at time t.

We recognize that there are other ways to estimate the opportunity cost of water, as in Pereira and Pinto [1985], which better characterize the dynamics of hydro-thermal systems.

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

3.2. Validation

To test the validity of our model, we simulate the period from June 2010 to October 2012 using real startup costs and bids. Then we compare the resulting market price (MP) with the real market price, as reported by the power exchange. Figs. 2 and 3 show the daily and weekly averages of the real versus the simulated market price.

As the plots show, there is a good match between the simulated and the real market price. Table 1 reports a series of measurements on the

[16] UPME refers to the Colombian energy and mining planning department (Unidad de Planeación Minero Energética): http://www.sipg.gov.co/sipg/documentos/precios_combustibles

[17] VOM are taken from Resolution No. 034, March 13 de 2001, article No. 1: http://apolo.creg.gov.co/Publicac.nsf/Indice01/Resoluci%C3%B3n-2001-CREG034-2001

[18] Central Bank of Colombia.

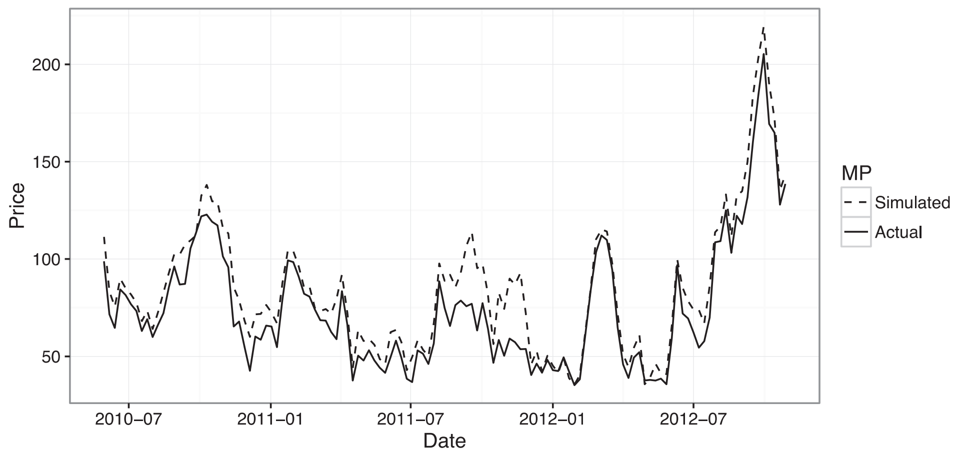

Fig. 3. Actual vs. simulated average weekly market prices.

Table 1
Goodness of fit measure for simulated market prices. MAPE, MPE, MAE and RMSE are all measure of goodness of fit of the model.[a]

Measure of error	Daily	Weekly
MAPE	15.43%	14.89%
MPE	−14.69%	−14.63%
MAE	10.42 COP	10.10 COP
RMSE	14.73 COP	12.76 COP

[a] Let $(y_t)_{t=1,\ldots,N}$ be a time series and $(\hat{y}_t)_{t=1,\ldots,N}$ an estimation of y_t.
The mean absolute predictive error in percentage terms MAPE is defined as: MAPE $= \sum_{t=1}^{N} |\frac{\hat{y}_t - y_t}{y_t}|$.
The mean predictive error in percentage terms MPE is defined as: MPE $= \sum_{t=1}^{N} \frac{\hat{y}_t - y_t}{y_t}$.
The mean absolute error MAE is defined as: MAE $= \sum_{t=1}^{N} |\hat{y}_t - y_t|$
The root mean square error in percentage terms RMSE is defined as: RMSE $= \sqrt{\sum_{t=1}^{N} (\hat{y}_t - y_t)^2}$.

Table 2
Goodness of fit measures for simulated production cost.

Measure of error	Daily	Weekly
MAPE	14.23%	9.49%
MPE	14.23%%	9.49%
MAE	1.00e + 9 COP	5.34e + 9 COP
RMSE	1.04e + 9 COP	6.26e + 9 COP

goodness of fit of the market price generated by our model, relative to the real market price.

Fig. 4 and Table 2 show the fit of our model in terms of total costs. MAPE, MPE, MAE and RMSE are all measure of goodness of fit of the model (for their definition, see footnote a in Table 1). COP means Colombian Pesos (Colombian official currency).

It is interesting to note that our model overestimates actual market prices and underestimates total costs. One of the reasons for this discrepancy could be that in the actual dispatch performed by the exchange there are a number of complex rules which exclude generators deemed inflexible from participation in the price setting.

In the next section we will simulate a benchmark competitive market based on estimated true costs (rather than bids) and compare it with the real market. We have two options when analyzing the real market: use the actual dispatch based on historical data, or use simulated dispatch after feeding our model with the real bids and start-up costs. We select the second option, since as noted before, there is a small bias in our model with respect to the realized outcomes and in absence of detailed information regarding the causes of that distortion, we believe that the estimate of relative efficiency will be more reliable using a consistent model for the competitive benchmark simulation and the bid based simulation.

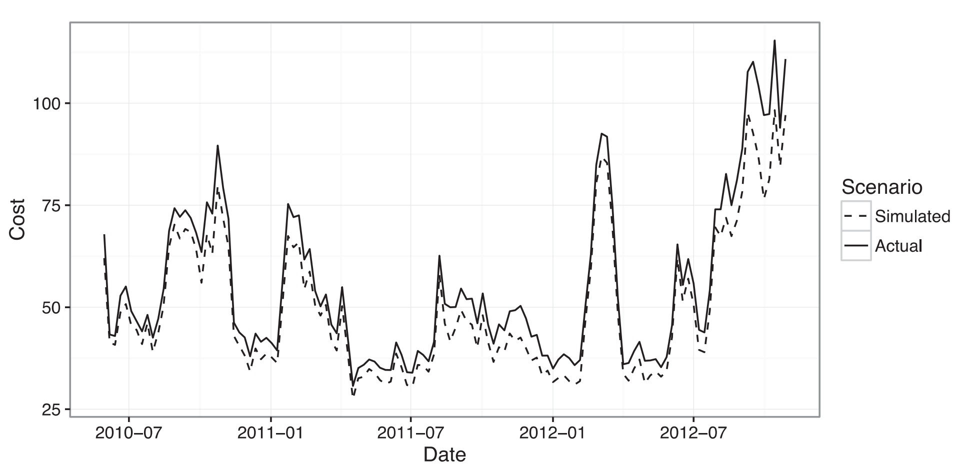

Fig. 4. Actual vs. simulated average weekly production cost.

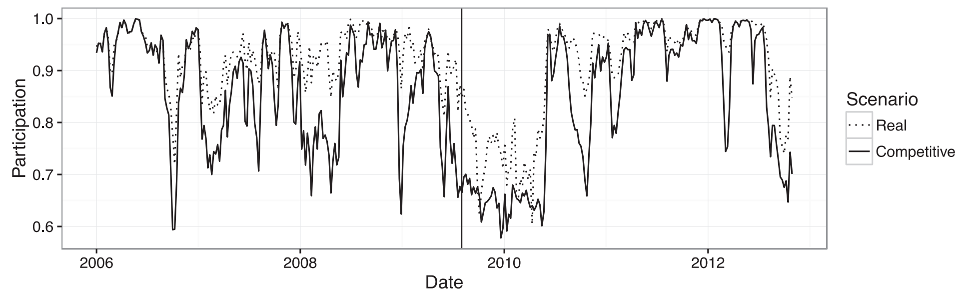

Fig. 5. Share of hydro energy in total weekly generation.

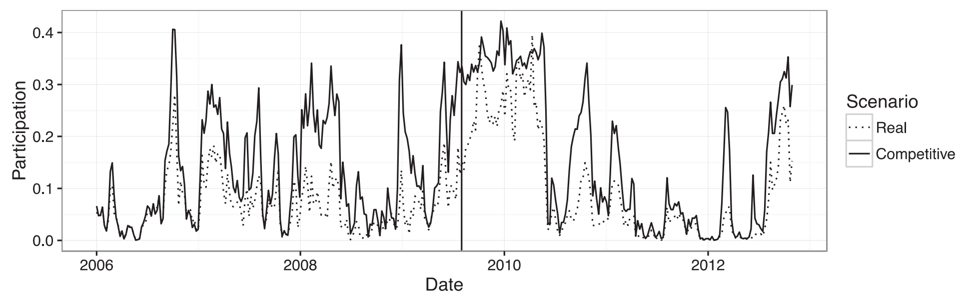

Fig. 6. Share of thermal energy in total weekly generation.

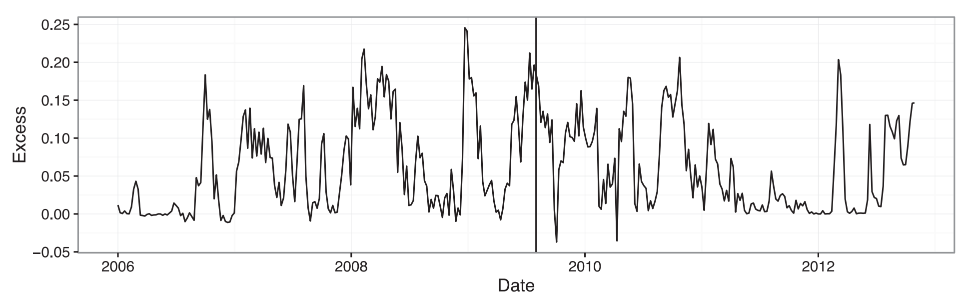

Fig. 7. Weekly excess hydro generation relative to the competitive benchmark.

4. Results: competitive benchmark vs bid-based simulation

We perform three simulations: (1) The competitive benchmark for the whole period of study. (2) The simulated real scenario before 2009, result of using our structural model of the dispatch under self-unit commitment and (3). The simulated real scenario after 2009, result of using our structural model of the dispatch under centralized-unit commitment. To be more precise:

- The competitive benchmark for the whole period of study is constructed in the following way. We first construct marginal costs for thermal plants and opportunity costs for hydro plants for the entire period of study using the methodology explained in Section 3.1. Next, we estimate startup costs for the entire period.[19] For the period after 2009, under centralized unit commitment, we have reported startup costs.[20] For the period before 2009 we estimated startup costs using the methodology presented in the Appendix 1.B. Now, using marginal costs, opportunity costs and startup costs for the entire period of study, assuming the latter are good estimates of real startup costs, we plug in these values in our dispatch model for centralized unit commitment (optimization problem of Appendix 1.A). The marginal price p^* is then determined as the price of the cheapest flexible dispatched plant.[21] We take the output of the model as our competitive benchmark.

Table 3
Annual shares of Hydro vs. Thermal energy production.

Year	Thermal participation		Hydro participation	
	Real	Competitive	Real	Competitive
2006	6.29%	8.16%	93.71%	91.84%
2007	8.43%	14.74%	91.57%	85.26%
2008	5.09%	13.96%	94.91%	86.04%
2009 BR	8.00%	17.35%	92.00%	82.65%
2009 AR	23.93%	34.41%	76.07%	65.59%
2010	14.48%	22.73%	85.52%	77.27%
2011	3.28%	5.78%	96.72%	94.22%
2012	5.96%	11.72%	94.04%	88.28%

19 These startup costs will be used for all three scenarios.

20 Startup costs are reported every three months. We think this mitigates considerably any incentives to misreport.

21 In our model, an inflexible plant is one such that: (1) It is voluntarily being tested. (2) A hydro plant that is operating at its technical minimum. (3) A thermal plant which is generating at it technical minimum. (4) A thermal plant that is in soak or desynchronization phase. A thermal plant that is generating at its technical maximum *is not* considered an inflexible plant.

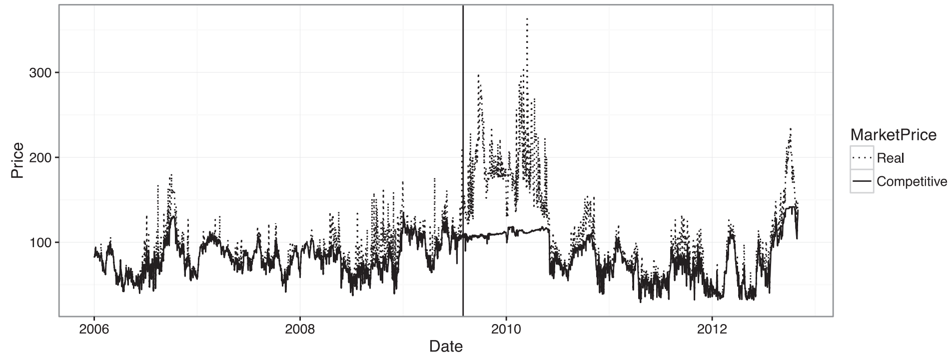

Fig. 8. Real vs. competitive daily average market price.

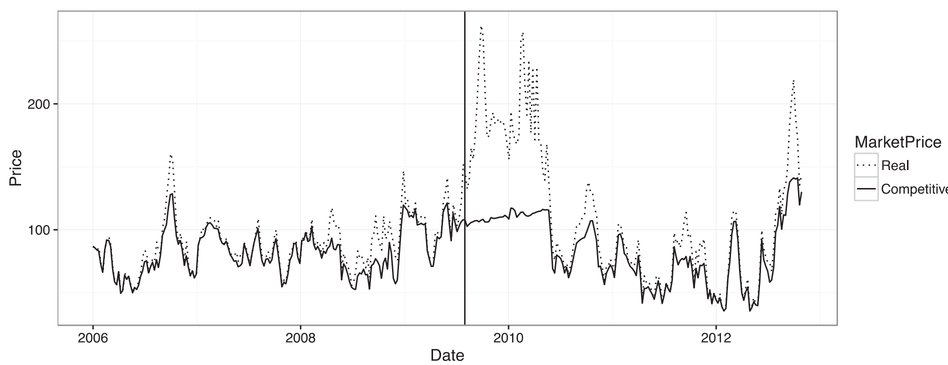

Fig. 9. Real vs. competitive weekly average market price.

- The simulated real scenario before 2009 is constructed as follows. We first simulate an hourly uniform auction using the reported energy bids (i.e., solve problem in Eqs. 1 and 2 form Section 2). Then we determine which of the dispatched plants are inflexible. This is done by calculating the dispatch using the reported energy bids and startup costs with the full centralized unit commitment model (by solving the optimization problem in Appendix 1.A). The marginal price p^* is then determined as the price of the cheapest flexible dispatched plant (according to the uniform auction). This is our model for self-unit commitment and hourly optimization for the period before 2009.
- The simulated real scenario after 2009 uses the reported energy bids and startup costs with the full centralized unit commitment model (optimization problem in Appendix 1.A). The marginal price p^* is then determined as the price of the cheapest flexible dispatched plant.

Finally, to calculate the spot price p_t we add an uplift to the marginal price p_t^m that compensates the losses of generators that could not fully cover their start-up costs. This is done for the competitive benchmark and the simulated real scenario after 2009.

Table 4
Annual shares of Hydro vs. Thermal energy production excluding the period of very high prices.

Reform	Thermal participation		Hydro participation		Hydro excess
	Real	Competitive	Real	Competitive	
Before	6.84%	13.17%	93.16%	86.83%	6.84%
After	4.73%	9.69%	95.27%	90.31%	4.73%

4.1. Hydro and thermal generation

We calculate the participation of hydro and thermal generation in the production of energy, both for the competitive and real scenarios. Figs. 5 and 6 present the weekly participation across time in percentages.

Note that with respect to the perfect-competition scenario, thermal generators have been under-producing, and hydro generators have been over-producing. The reason is that, historically, thermal generators have over-bid, and so the optimization algorithm has allocated less power production to thermal units than what is optimal. Fig. 7 clarifies the previous claim by presenting the weekly excess hydro supply with respect to perfect competition.

Table 3 presents the average participation over years, before and after the 2009 reform. It is always the case that hydro participation in the Real Scenario is greater than in the Competitive Scenario. The reform seems to have had an effect in diminishing this excess of production.

The sharp increase in thermal generation for the competitive benchmark just after the reform (from 17% to 34.41%) is due to water shortage during that period because of El Niño phenomena (see Appendix 1.C). Note that there is also a sharp increase in observed (real) thermal generation during this period.

The next plot shows the daily average and weekly average market prices for the real and competitive scenarios. The vertical line shows the point when the reform took place (see also Fig. 8). (See Fig. 9.)

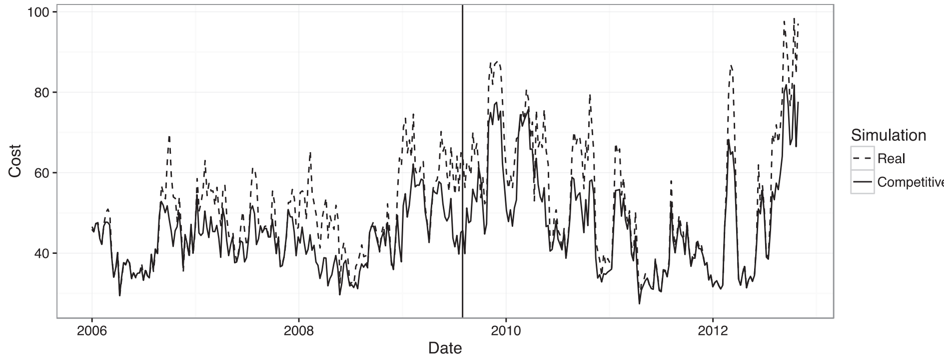

Fig. 10. Total weekly costs for the actual dispatch vs. competitive benchmark in thousands of Colombian pesos.

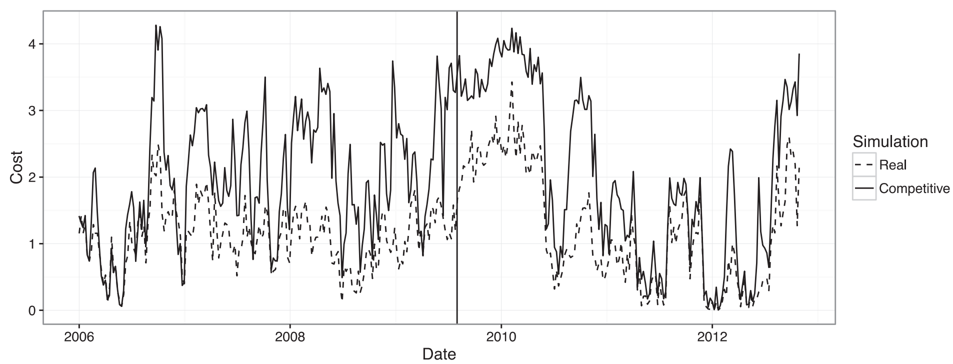

Fig. 11. Total weekly costs for thermal generation in the actual dispatch vs. competitive benchmark in thousands of Colombian pesos.

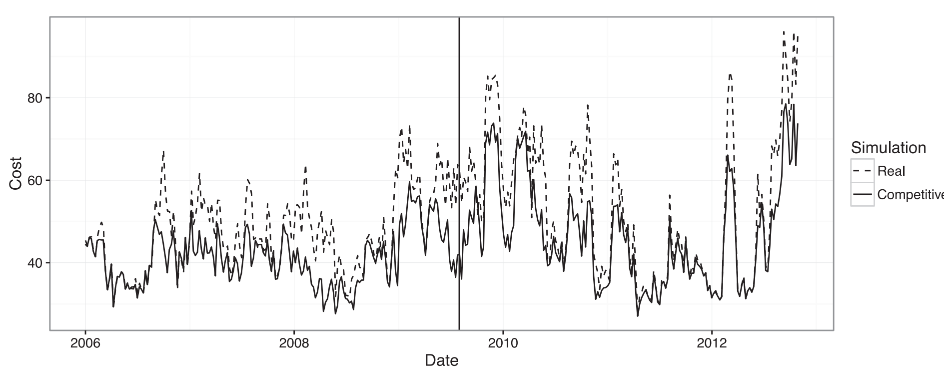

Fig. 12. Total weekly costs for hydro generation in the actual dispatch vs. competitive benchmark in thousands of Colombian pesos.

In previous versions of this study, industry participants suggested that our results were driven mainly by the unusual period of high spot prices due to el Niño phenomena (see paragraph 1.C of the Appendix) that corresponds to the period in which we find the sharpest difference between the real and competitive spot price.[22] Therefore, we excluded

Table 5
Total generation costs.

Year	Hydro costs		Thermal costs		Total costs	
	Real	Competitive	Real	Competitive	Real	Competitive
2006	2611.63	2238.48	65.46	114.25	2677.09	2352.72
2007	2702.40	2356.39	60.79	101.48	2763.19	2457.87
2008	2753.11	2405.24	56.64	102.70	2809.75	2507.94
2009 BR	1607.79	1399.93	34.07	59.31	1641.86	1459.24
2009 AR	1173.60	1009.73	24.97	45.41	1198.57	1055.15
2010	2647.67	2292.25	61.99	108.23	2709.66	2400.48
2011	2485.44	2158.17	60.67	106.26	2546.11	2264.43
2012	2127.43	1867.51	53.11	91.10	2180.55	1958.61

[22] In fact, the argument raised was that our marginal costs for thermal plants did not reflect the real situation during that period of gas shortage because the cost during that period was not reflected by the price of gas since thermal plants had to substitute gas with more expensive liquid fuels that our model does not account for.

Table 6
Average weekly deadweight loss ratios.

Year	2006	2007	2008	2009BR	2009AR	2010	2011	2012
Deadweight	3.87%	10.90%	17.95%	18.70%	19.04%	14.69%	4.23%	10.26%

Table 7
Average weekly deadweight loss ratios with exclusion of a period of very high fuel prices.

Reform	Before	After
Deadweight Ratio (DWR)	12.12%	8.80%

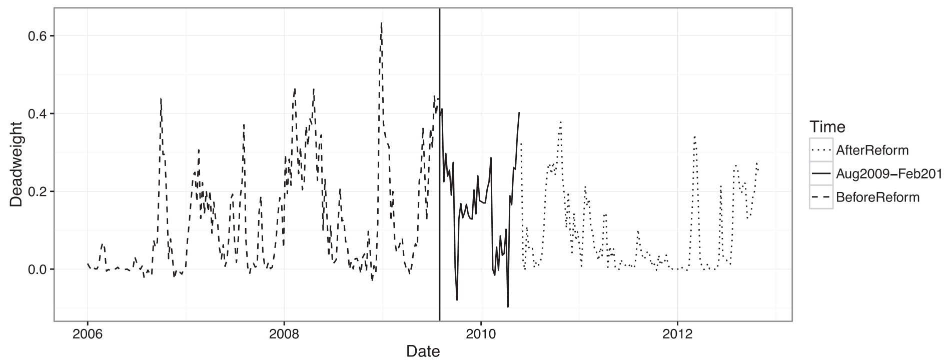

Fig. 13. Deadweight loss ratio for different periods.

this period from the analysis, August 2009–February 2010, when the difference between the real and competitive price is greatest. Table 4 below presents the corresponding results if we exclude this period.

4.2. Economic efficiency

In order to determine the efficiency of the energy market we first calculate the total costs of production in both the competitive and the real world scenario. The competitive and real total costs of any given day are:

$$C^C = \sum_{t=1}^{24}\sum_i q_{it}^C c_{it}^m + \sum_{t=1}^{24}\sum_i s_{it}^C c_i^s \quad (9)$$

$$C^R = \sum_{t=1}^{24}\sum_i q_{it}^R c_{it}^m + \sum_{t=1}^{24}\sum_i s_{it}^R c_i^s \quad (10)$$

where q_{it}^C and q_{it}^R denote the quantity produced at time t by generator i in the competitive and real scenario, respectively; s_{gt}^C and s_{gt}^R are binary variables that indicate whether generator g was started at time t; finally, c_{it}^m indicate marginal costs for thermal plants or opportunity costs for hydro plants and c_i^s indicate start-up costs. Note that c_{it}^m are the estimated marginal costs or opportunity costs, the costs that were used in the competitive scenario simulation, and not the costs that were actually bid by generators.

Figs. 10, 11 and 12 present the weekly total costs corresponding to the actual dispatch and competitive benchmark. We also include separate plots for the thermal and hydro generation.

As can be noted, total costs are greater in the simulated real scenario than in the competitive benchmark. The reason is that the competitive total costs are optimal, that is, demand cannot be satisfied at a lower cost. The real scenario, on the other hand, is optimal given the bids of the generators, which differ from marginal costs.

Tables 5 and 6 below present the total generation costs (in billions of COP) for different time periods, decomposed into hydro and thermal energy.

To measure the efficiency of the market we calculate the deadweight loss due to bids that differ from marginal costs. For any given period, this deadweight loss DW is calculated as

$$DW = C^R - C^C \quad (11)$$

A bigger deadweight loss means a less efficient market. Because we do not want our efficiency measure to depend on the energy produced on a given period, we calculate the deadweight loss ratio, *DWR*:

$$DWR = \frac{C^R - C^C}{C^C} \quad (12)$$

Fig. 13 below presents the weekly deadweight loss ratio across the period that we are considering.

Table 6 below presents the average weekly deadweight loss ratio for different time periods.

Table 7 presents the average results across the periods in each regime excluding the period of very high fuel prices (August 2009–February 2010). We observe that the weekly deadweight loss ratio decreases after the reform.

To validate the significance of the above result we perform a mean difference t-test between the weekly deadweights before and after the reform with

$$H_0: \overline{DW}_{Before} = \overline{DW}_{After} \quad (13)$$

$$H_a: \overline{DW}_{Before} > \overline{DW}_{After} \quad (14)$$

which results in: T statistics = −2.4668 and P-value = 0.007087.

With a confidence of 1%, we conclude that the weekly deadweight loss of the market decreased after the reform, which is evidence of more efficient energy production.

Finally, before closing this section, we would like to discuss the potential qualitative impact of our estimation of the opportunity costs of water in our results.[23] Recall that we have estimated the opportunity cost of water to be the minimum between the bid of the hydro generator and the maximum price offered by thermal generators that were dispatched; see eq. (8). Since that real world conditions allow hydro generators to store water and produce it later when the electricity price is higher, our estimation of opportunity costs of hydro's necessarily

[23] We are thankful to an anonymous referee for raising this point and asking to clarify these issues.

underestimates these costs relative to the true real-world opportunity costs of hydro's (even more if we consider that we are also ignoring potential penalties due to water shortages). Notice that this has no effect on the real-world dispatch since the dispatch depends only on the observed bids. It follows that we are underestimating the real-world production costs of hydro's.

Also, relative to a competitive benchmark the opportunity costs the hydro's that we have estimated from the real world overestimates the opportunity costs of water of the competitive benchmark. Hence, if we use lower opportunity costs for hydro's in the competitive benchmark two things might happen in this benchmark: (1) we should expect less thermal generation in the competitive benchmark that what we are estimating; and (2) we are overestimating hydro's true opportunity costs in the competitive benchmark relative to hydro's costs in our competitive benchmark. Both effects suggest that hydro's generating costs in our competitive benchmark have bene overestimated relative to the true hydro's generating costs under competitive conditions.

Putting together both arguments this means we have underestimated the difference (gap) between the real world and the competitive benchmark dispatch costs.

5. Conclusions

The economic and engineering literature has extensively discussed the fact that in the presence of non-convexities, self-committed uniform price auctions with energy only offer prices can lead to productive inefficiencies. 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 market clearing price would need to be sufficiently high to compensate for startup costs. This paper capitalizes on the recent transition in Colombia from self-commitment to centralized unit-commitment (a transition that took place in October 2009) to empirically evaluate the relative economic efficiency under the two regimes. For doing so we introduce a structural model of the dispatch to estimate the benefits (if any) of the 2009 regulatory intervention in Colombia. Our results, which compare the relative deadweight loss due to the misrepresentation of costs by bidders and dispatch inefficiency, suggest that centralized unit commitment has improved economic efficiency. The observed relative deadweight loss reduction of at least 3.32% can be explained in part by the fact that, before 2009, there was an underproduction of thermal energy relative to the competitive benchmark and that this inefficiency was corrected after 2009.

This paper is a follow up paper to Riascos et al. (2016) in which we use econometric techniques to address the problem of economic efficiency and provide evidence of increased exercise of market power after the transition to centralized unit commitment. Taken together these results suggest that, although centralized unit commitment may have improved economic efficiency, the mechanism used to elicit information from generators, upon which the market prices and settlements are based, may compel generators to act strategically so that the efficiency gains are not passed on to the end users of electricity.

Acknowledgements

For excellent research assistance we thank Julián Rojas. Colombia's ISO, XM and Regulatory Agency CREG were very helpful in providing data and clarifying many issues concerning the Colombian dispatch. In particular, we are thankful to Jorge Arias and Jaime Castillo from XM and Javier Diaz and Camilo Torres from CREG. For helpful discussions we also thank Juan Esteban Carranza, Jose Javier Moran and Natalia Serna. We also benefited from discussions at the two workshops held with industry agents (November 25 and December 4, 2013), where preliminary results of this work were presented, and from written comments by ACOLGEN, ANDEG, EPM, ISAGEN, GECELCA, EPSA, David Harbor and Nils-Henrik von der Fehr. This research project complements the paper: Transition to Centralized Unit Commitment: An Econometric Analysis of Colombia's Experience by Riascos, Bernal, Oren and de Castro and improves the structural analysis in the final report commissioned to CREG: An Evaluation of CREG 051–2009 Regulatory Intervention in Colombian Electricity Market Final Report, December 19, 2013. Financial support is greatly acknowledged. A. Riascos would like to thank the Centro de Estudios de Economía Industrial e Internacional, Banco de la República for financial support. All errors are our own responsibility.

Appendix 1

In this Appendix, we provide a detailed description of our model of the ideal dispatch. The dispatch model is cast as a mixed integer linear program. We also highlight the main differences with the independent system operator ideal dispatch model.

A. Dispatch model

We use the following notation:

- $t = 0, 1, \ldots, 23$; denotes one of the 24 h of the day.
- i denotes a plant.
- $p_{i,t}$ is the power provided by plant t during hour t.
- $p_{i,t}^{soak}$ is the power provided by plant t during hour t and start-up phase.
- $p_{i,t}^{des}$ is the power provided by plant t during hour t and desynchronization phase.
- $u_{i,t}$ is a binary variable indicating if unit i is up in period t.
- $s_{i,t}$ is a binary variable indicating if unit i is started in period t.
- $h_{i,t}$ is a binary variable indicating if unit i is stopped in period t.
- $u_{i,t}^{soak}$ is a binary variable indicating if unit i is in the start-up phase.
- $u_{i,t}^{disp}$ is a binary variable indicating if unit i is in the dispatch phase.
- $u_{i,t}^{des}$ is a binary variable indicating if unit i is in the shut-down phase.
- n_i^{soak} represents the number of hours during the start-up phase (since start-up until output is at the technical minimum).
- n_i^{des} represents the number of hours during shut-down phase (from a technical minimum to shut-down).
- n_i is the minimum up-time of unit i.
- f_i is the minimum down-time of unit i.
- $b_{i,t}$ is the the price bid of plant i for hour.
- c_i^s is the startup costs.
- D_t is the estimated total domestic demand for hour t.
- $P_{i,t}^{min}$ and $P_{i,t}^{max}$ are the minimum and maximum generating capacity respectively.[24]

The ramp model is similar to Simoglou et al. (2010). We assume that thermal units follow three consecutive phases of operation: (1) soak or start-up phase (from zero to technical minimum), (2) dispatchable (when output is between the technical minimum and maximum feasible power output) and (3) de-synchronization phase (when output is below the technical minimum and just before shut-down).

In the soak phase, the power output follows a block model. In the dispatchable phase we assume an affine model for power. In the desynchronization phase we assume a block model.

[24] For thermal plants the minimum and maximum is independent of t. For hydro it is zero for most plants except for those that are constrained by environmental requirements that may depend on t.

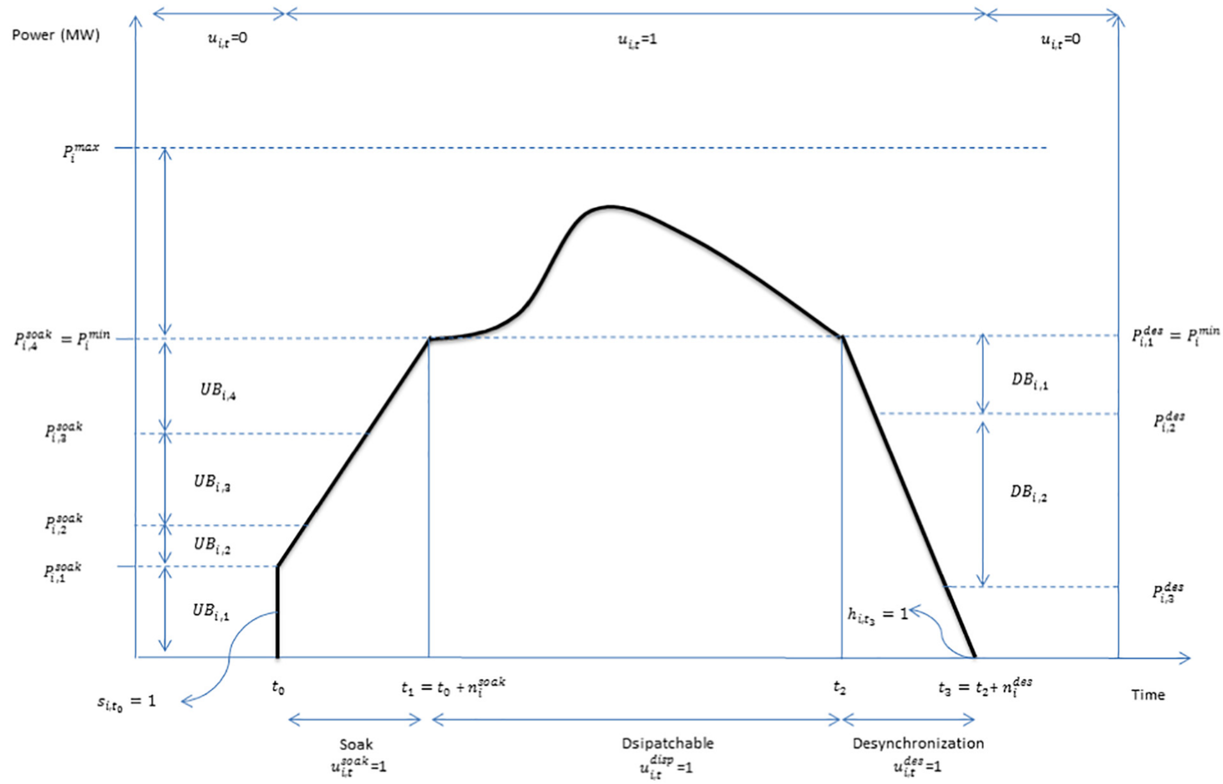

Fig. A-1. Ramp model of a thermal plant.

Optimization problem

The ideal dispatch is the solution to the following optimization problem. It is a mixed integer linear program.

Objective function

$$\min_{p_{i,t},p^{soak}_{i,t},p^{disp}_{i,t},p^{des}_{i,t},s_{i,t},h_{i,t},u_{i,t},u^{soak}_{i,t},u^{disp}_{i,t},u^{des}_{i,t}} \sum_{t=0,\dots,23} \sum_i b_i \times p_{i,t} + c_i^s\, s_{i,t}$$

s.t.

Output feasibility

Feasible output:

$$D_t \le \sum_i p_{i,t}$$

Soak phase

Soak phase starts immediately following start-up:

$$\sum_{\tau=t-n_i^{soak}+1}^{t} s_{i,\tau} = u^{soak}_{i,t}$$

Let $\{UB_{i,\,s}\}_{s=1,\dots,n_i^{UB}}$ be the ramp up blocks during soak phase, then:

$$P^{soak}_{i,s} = \sum_{j=1}^{s} UB_{i,s}$$

is the power provided by plant i, and period s following start-up. Then, during soak phase, the power output of the unit is constrained by:

$$\sum_{\tau=t-n_i^{soak}+1}^{t} s_{i,\tau} P^{soak}_{i,t-\tau+1} = p^{soak}_{i,t}$$

Dispatch phase

We simplify the current model by assuming linear up and down ramp constraints:

$$p_{i,t} \le \frac{UR + b \times p_{i,t-1}}{a} + N\left(u^{soak}_{i,t} + u^{des}_{i,t}\right)$$

$$p_{i,t} \ge \frac{-DR + c \times p_{i,t-1}}{d} - N\left(u^{soak}_{i,t} + u^{des}_{i,t}\right) - Nh_{i,t}$$

here N is a sufficiently large parameter.

De-synchronization phase

The de-synchronization phase starts before shut-down:

$$\sum_{\tau=t+1}^{t+n_i^{des}} h_{i,\tau} = u^{des}_{i,t}$$

Let $\{DB_{i,\,s}\}_{s=1,\dots,n_i^{DB}}$ be the ramp down blocks during the de-synchronization phase and

$$P^{des}_{i,DesynchHours(g)-s+1} = \sum_{j=1}^{s} DB_{i,j}$$

be the power provided by plant *i* s periods after desynchronization is started. Then, during the de-synchronization phase the power output of a unit is constrained by[25]:

$$\sum_{\tau=t+1}^{t+n_i^{des}} h_{i,\tau} P^{des}_{i,t+1-\tau+n_i^{des}} = p^{des}_{i,t}$$

[25] This is a simplification of the current Colombian dispatch model. We do not consider an alternative shut down ramp whenever output is not at the technical minimum.

Minimum up time

Plants are constrained to be up for n_i periods after they are started up:

$$\sum_{\tau=t-n_i+1}^{t} s_{i,\tau} \le u_{i,t}$$

Minimum down time

Plants are constrained to be down for f_i periods after they are shut down:

$$\sum_{\tau=t-f_i+1}^{t} h_{i,\tau} \le 1-u_{i,t}$$

Power output constraints

$$p_{i,t} \ge p_{i,t}^{soak} + p_{i,t}^{des} + P_i^{min} u_{i,t}^{disp}$$

$$p_{i,t} \le p_{i,t}^{soak} + p_{i,t}^{des} + P_i^{max} u_{i,t}^{disp}$$

$$p_{i,t} \le p_{i,t}^{soak} + p_{i,t}^{des} + P_i^{max} u_{i,t}^{disp} + \left(P_i^{min} - P_i^{max}\right) z_{i,t+n_i^{des}}$$

Logical status of commitment

The following are restrictions required for the transition of the binary variables:

$$u_{i,t} = u_{i,t}^{soak} + u_{i,t}^{disp} + u_{i,t}^{des}$$

$$s_{i,t} - h_{i,t} = u_{i,t} - u_{i,t-1}$$

$$h_{i,t} + s_{i,t} \le 1$$

Boundary conditions

$$s_{i,-n_i+1}, s_{i,-n_i+2,\ldots}, s_{i,0} \text{ given}$$

$$h_{i,-f_i+1}, h_{i,-f_i+2,\ldots}, h_{i,0} \text{ given}$$

where all variables represent observed variables of the real dispatch of the previous 24 h.

B. Construction of startup costs

Before 2009, startup costs were not reported by generators. In order 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 (as shown in Table B-1).

Table B-1
Fuel types for different units.

Generator	Startup fuel
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. GUAJIRA 1 and 2 are the only plants that can use both types of fuel.

Fuel prices are reported in 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 2009–2012 period. Since fuel costs have a six month frequency we used a local regression model to construct daily fuel cost data. For an appropriate fit of the LOESS model we use a smoothness parameter of $\alpha = 0.3$. With the LOESS fit we construct a new database with the price of fuel for each plant, with 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:

$$c_{it}^s = \beta_{i0} + \beta_i^T c_{it}^f + \varepsilon_{it}.$$

where c_{it}^s are start-up costs depending on the generator, c_{it}^f represents gas or coal fuel cost. In the case of GUAJIRA 1 and 2, c_{it}^f is a vector with gas and coal fuel costs as its components.

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

Table B-2 presents these results.[26] For 12 generators the restriction on the coefficients β_i^T were binding.

Fig. B-2
Goodness of fit for startup cost estimation.

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

(continued on next page)

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

Fig. B-2 (*continued*)

Generator	R2	Generator	R2
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

C. El Niño events

An event of El Niño is declared by the Climate Prediction Center (CPC) of the National Oceanic and Atmospheric Administration (NOAA) as a period in which the 3-month average sea-surface temperature of the Pacific Ocean, also known as the Oceanic Niño Index (ONI), exceeds 0.5 °C in the east-central equatorial Pacific. Table 1 shows the date ranges for the latest events of El Niño since 2000 as reported by the CPC.[27]

Table C-1
Latest events of El Niño since 2000.

Start	End	Highest ONI
Jum-2002	Feb-2003	1.2
Jul-2004	Apr-2005	0.7
Aug-2006	Jan-2007	0.9
Jul-2009	Apr-2010	1.3
Nov-2015	May-2016	2.3

Source: NOAA's Climate Prediction Center.

D. Electricity exports and imports

The next figure shows electricity exports plus imports as a proportion of generation. International transactions of electricity are subordinated to the domestic market. That is, they do not determine prices in the domestic market. For this study we have residual demand from exports and imports.

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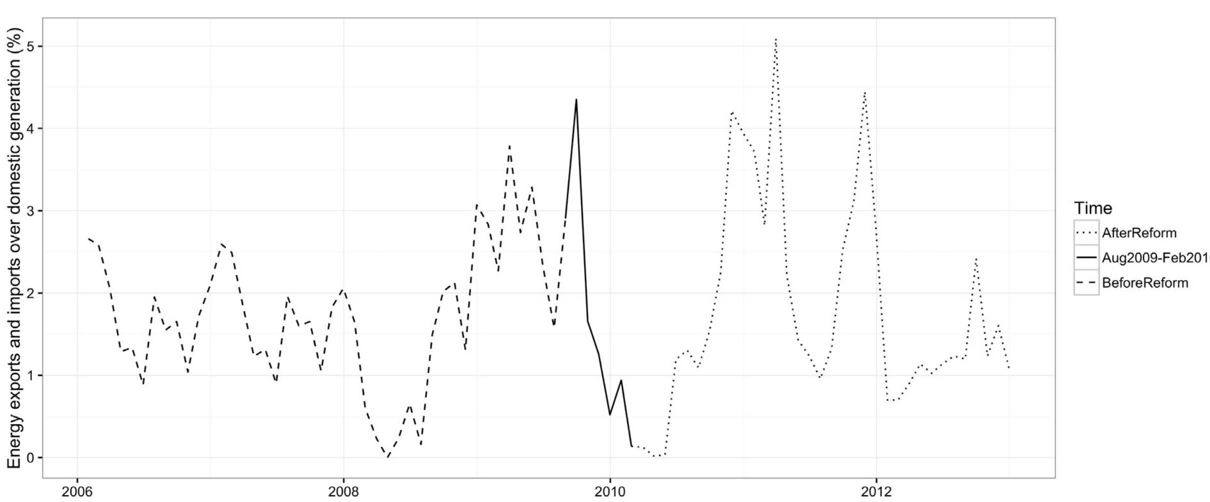

Fig. D-1. Exported plus imported energy as a proportion of domestic generation.

[27] The historical data of El Niño is available in http://www.cpc.noaa.gov/products/analysis_monitoring/ensostuff/ensoyears.shtml