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ABSTRACT

Recent energy shortfalls in renewables-dominated electricity markets call for a mechanism to ensure demand is met under all system conditions. We demonstrate severe shortcomings of an increasingly popular mechanism—reliability options—caused by its interaction with fixed-price forward contracts for energy. Large generators can trigger the option exercise, weakening the short-term incentive to sell output provided by forward contracts alone. In the longer term, hydro generators sell more forward contracts and store less water, reducing system reliability. We empirically show that Colombian generators respond to these incentives. We analyze a standardized energy contracting approach to long-term resource adequacy that does not create these economic incentives.

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1 Introduction

Energy supply shortfalls in renewables-dominated electricity markets such as California (Meyer and Waters, 2020), Texas (Jacobs, 2021), and Australia (Murphy and Knaus, 2017) have challenged the view that a reliable electricity supply can be maintained in regions with large shares of renewable energy. Electricity system operators in these regions have had to implement rolling blackouts because of insufficient energy to meet system demand. The proximate cause in each of these cases was an extreme weather event that simultaneously increased electricity demand and reduced energy availability from renewable and non-renewable sources. The ongoing energy transition heightens the vulnerability to such events through greater reliance on intermittent renewable generation and the switch from fossil fuels to electricity for many energy uses such as transportation and space heating. These trends necessitate a critical evaluation of mechanisms to ensure system demand is met in all hours of the year in renewables-dominated markets.

While the exact timing of extreme weather events may be unpredictable, they are not unexpected. Under the traditional vertically integrated geographic monopoly regime, a single entity—the geographic monopoly utility—was responsible for ensuring sufficient resources to serve demand in its service territory under all foreseeable demand and supply conditions. Particularly in industrialized countries, this regime created strong incentives for the monopoly utility to serve demand during extreme weather events with a high level of reliability.

In contrast, in the wholesale market regime, no single entity is responsible for ensuring there is sufficient energy to meet demands at all locations in the grid under all possible system conditions. System operators can only manage the grid with generation resources offered into the market. Generation unit owners can only supply energy from the units under their control. Retailers can only withdraw the energy that generation unit owners inject into the transmission grid. With the current distribution network infrastructure, system operators cannot target curtailment actions at the individual customer level, meaning that all customers in a specific region of the grid are at risk of being curtailed regardless of their retailer's forward energy procurement strategy.[1] This creates what Wolak (2013) calls a "reliability externality" because no single customer bears the full cost of failing to procure sufficient energy in advance to meet its real-time demand. For this reason, Wolak

1. As Von Meier (2006) emphasizes, the physics of electricity network operation implies that all customers in one portion of a local distribution grid receive electricity at the specified voltage and frequency or none of those customers receive electricity.

(2021) argues that all wholesale electricity markets, particularly those with significant intermittent renewables, require a long-term resource adequacy mechanism to ensure sufficient energy is available to meet demand at all locations in the grid under all system conditions.

Historically, the design of long-term resource adequacy mechanisms provided weak incentives for generation units to provide sufficient energy to meet demand during critical system conditions (Bushnell et al., 2017). To address this limitation, many electricity markets are reforming their long-term resource adequacy mechanisms to provide stronger incentives for generators to provide energy when it is most needed. One increasingly popular mechanism uses "reliability options". These financial instruments provide market-based incentives through call option contracts purchased by the system operator from electricity generators.[2] The maximum quantity of these options that generators are allowed to sell, known as their "firm energy," is fixed by regulators and differs by generation technology. The guaranteed payment that generators receive for selling their firm energy provides a revenue stream even if they do not produce electricity. The option strike price, known as the "scarcity price," changes over time and is typically indexed to the system operator's estimate of the marginal cost of the highest-cost generation technology in the region. During "scarcity periods," when the wholesale spot price exceeds the scarcity price, generation firms are required to pay the difference between the spot price and the scarcity price, multiplied by their quantity of reliability options. Correspondingly, electricity purchasers receive a refund of the difference between the spot price and the scarcity price, multiplied by their purchase quantity, effectively capping their purchase price at the scarcity price.

The hourly short-term market revenue of generation firm i that has sold q_i^f units of a reliability option at an hourly price of P^f takes the following form:

$$Revenue_i = Pq_i - \max(P - P_s, 0)q_i^f + P^f q_i^f \tag{1}$$

In Equation (1), P is the hourly wholesale spot price, q_i is the hourly generation output of firm i, P_s is the scarcity price, and $\max(x, 0)$ is equal to x if x is positive and zero otherwise. The reliability option provides an incentive for generators to produce at least their firm

2. A call option is a financial contract that gives the buyer the right, but not the obligation, to purchase an underlying asset at a predetermined price (the strike price) at a specific time. In the reliability option setting, the buyer has the right to purchase the specified quantity of electricity from the seller at the strike price during the specified time interval. This option would only be exercised during the settlement period if the spot price of wholesale electricity on that date (the price of the underlying asset) exceeds the strike price.

energy quantity q_i^f during scarcity periods when $P > P_s$.

In this paper, we demonstrate severe shortcomings with the incentives for generation unit owner behavior created by this reliability option design, particularly in regions with significant renewable generation resources. First, we show that generation firms with the ability to exercise unilateral market power in the short-term energy market can affect whether a scarcity period is triggered. A generator's incentive to trigger a scarcity period depends on its quantities of firm energy and fixed-price forward contracts for energy.[3] This is because the scarcity price caps the price paid for all short-term wholesale market energy purchases, including the spot price used to settle fixed-price forward contracts. The effect of this cap is that forward contracts no longer limit the incentive of generators to exercise unilateral market power during scarcity periods.[4]

The short-run consequences of the interaction between reliability options and fixed-price forward contracts are compounded in the long run. Because of the cap on the short-term market price used to settle fixed-price forward contracts, generators selling forward contracts face a lower expected cost for having insufficient generation to meet their forward contract obligations. This reduces their incentive to take costly actions to insure against generation capacity shortfalls. As shown in Section 3.3, hydroelectric generators have less incentive to store additional water in their reservoirs to supply at least their fixed-price forward contract position during periods with low water inflows. In the long run, hydroelectric firms will be willing to take on more risk by selling greater quantities of fixed-price forward contracts for the same expected quantity of future water inflows.

We demonstrate the empirical importance of the interaction between reliability options and fixed-price forward contracts using more than ten years of data from the Colombian wholesale electricity market. In December 2006, Colombia became the first country to in-

3. A fixed-price forward contract is an agreement between two parties to buy or sell an asset at a predetermined price on a future date. In the context of electricity markets, generators typically sell fixed-price forward contracts to retailers, locking in the price, P^c, for a pre-specified quantity, q^c, of electricity at a future date. These contracts are purely financial arrangements between generators and retailers and are settled based on the difference between the hourly spot price, P, and the contract price on the delivery date. The seller of the contract receives from or pays to the buyer of the contract the "difference payment" $(P^c - P)q^c$ during the settlement period. These financial contracts have no direct implications for the physical operation of the electricity system, except through their effect on the offer behavior of generators in the short-term market, as shown in Wolak (2000).

4. McRae and Wolak (2014) use data from the New Zealand wholesale electricity market to demonstrate how fixed-price forward contracts for energy can reduce the *incentive* for generation firms to exercise unilateral market power, even when they have a significant *ability* to do so. The authors derive half-hourly measures of the *ability* and *incentive* of the four largest suppliers in the New Zealand wholesale electricity market to exercise unilateral market power.

troduce reliability options. Four other electricity markets have subsequently implemented reliability options based on the Colombian model: the New England ISO in the United States and the national electricity markets in Ireland, Italy, and Belgium.[5]

Our empirical analysis uses hourly market input and output data provided by the Colombian market operator XM from January 2000 to December 2023. This hourly information includes the price and quantity offers for each generation unit, the system demand, the generation output of each unit, and the short-term wholesale price. An unusual and important component of our data is that we observe both the hourly fixed-price forward contract positions of each firm and the reliability option quantities and prices.[6] We supplement this hourly data with daily information on hydro inflows, storage levels, input fossil fuel usage, and input fossil fuel prices.

We first demonstrate that the three large hydro firms in Colombia have the ability to choose whether the reliability option is exercised through their offers into the short-term energy market. We calculate the hour-by-hour residual demand curve faced by each firm. When this curve intersects the scarcity price at a quantity between the firm's minimum and maximum generation output, the firm's choice of generation quantity will determine if there is a scarcity period. We find that Empresas Públicas de Medellín (EPM), the largest Colombian generator, can choose to create a scarcity period in 16 percent of the sample hours between 2006 and 2016.

To assess the profitability of triggering a scarcity period, we calculate each firm's ex-post profit-maximizing hourly output level as the best response to its realized hourly residual demand curves over each 24-hour period. We find that EPM's best-response output predicts the occurrence of a scarcity period in more than 90 percent of hours. Similar results are observed for other large firms. Remarkably, these results hold despite suppliers not knowing their hourly realized residual demand curves (which depend on realized system demands and the offer curves submitted by other suppliers) when submitting

5. Vazquez et al. (2002) and Cramton and Stoft (2008) describe the theory behind reliability options and some practical issues in their implementation. Mastropietro et al. (2018) review the reliability option design in the Italian electricity market, while Bhagwat and Meeus (2019) compare the design in the Irish and Italian electricity markets. Mastropietro et al. (2024) compare the design of reliability options across the five electricity markets where they have been implemented.

6. In the Colombian electricity market, XM clears all forward contracts. Consequently, it has complete data on the hourly forward contract quantities and prices of each market participant and publishes the hourly quantities of forward contracts bought and sold by each market participant. This level of transparency is uncommon in electricity markets, where the fixed-price forward contract quantities for individual market participants are confidential. Researchers studying these markets have had to estimate or infer the forward contract positions from offer data (Reguant, 2014; Hortaçsu et al., 2019), unless they have access to confidential fixed-price forward contract data (McRae and Wolak, 2014; Wolak, 2000, 2003, 2007).

their hourly offer curves into the short-term market. Analysis of plant-level offer prices of the hydro suppliers provides further evidence that they recognize and respond to the incentives provided by the interaction of the reliability options with their fixed-price forward contracts.

Finally, we examine the long-run effects of the reliability options by comparing the fixed-price forward contract obligations of hydro and thermal generators before and after the introduction of reliability options in December 2006. As predicted by our simple theoretical analysis, the net fixed-price forward contract quantities were higher for hydroelectric firms after December 2006, rising from 65 to 71 percent of total generation.[7] This increase meant hydroelectric firms sold more forward contracts than firm energy, expanding the range over which firms can profitably exploit the mechanisms we identify. After December 2006, hydroelectric firms also reduced their reservoir storage levels by more than one month of forward contract quantities, contributing to an increased vulnerability of the system to low water inflows. Conversely, thermal generation firms reduced their fixed-price forward contract sales after the introduction of the reliability options, increasing their opportunities to profit from the exercise of unilateral market power in the short-term market.

The Colombian reliability options experience is increasingly relevant for other electricity markets that have ambitious intermittent renewable energy goals that are typically part of a policy to transition away from fossil fuels. Our results demonstrate that reliability options may have unexpected consequences in settings where generators have the ability to exercise unilateral market power in the short-term market. Specifically, the reliability options in Colombia crowd out other forms of insurance against generation shortfalls, potentially reducing system reliability—an ironic outcome given that electricity consumers must pay generation firms for these options with the goal of enhancing electricity supply reliability. Although our analysis focuses on intermittent hydro inflows, similar problems could arise in other markets with a large share of intermittent renewable generation from wind and solar resources, especially during periods when these resources are unavailable. We believe this is an urgent issue to study because many countries are adopting similar mechanisms, with an increasing share of generation revenue provided through these mechanisms instead of the spot or forward contract markets for energy.

As an alternative to reliability options, Wolak (2022) describes an approach to long-term resource adequacy that provides strong incentives for the least-cost supply of the energy

7. The term "net forward contract quantities" refers to the fact that generators can both buy and sell these financial instruments, although in practice they hold positive net positions.

necessary to serve demand under all possible system conditions. This approach creates a standardized fixed-price forward contract for energy that is shaped to the realized hourly system load shape throughout the year. These standardized fixed-price forward contracts for energy would be sold through periodic centralized auctions run by the system operator. This mechanism is designed to ensure system demand is met in all hours of the year. It does not restrict how individual generators and retailers might hedge their short-term price and quantity risk relative to their position in standardized fixed-price forward contracts.

Related Literature

Holmberg and Tangerås (2023) and Bublitz et al. (2019) review the long-term resource adequacy mechanisms implemented in different electricity markets around the world. These mechanisms can be categorized into two main types: market-wide capacity mechanisms and strategic reserves. Market-wide capacity mechanisms provide capacity payments to almost all generation units in the market, whereas strategic reserves target capacity payments to a select few plants. These mechanisms also differ based on their procurement approach, which can be either centralized by the system operator or decentralized through obligations applied to individual retailers.

There is a small theoretical literature on the strategic behavior of generation firms in the presence of capacity mechanisms. Fabra (2018) develops an analytical framework incorporating generation investment and short-run pricing decisions, showing that a combination of a price cap and capacity payment is required to encourage efficient levels of investment when generators have market power. She studies the case of reliability options and their potential to limit the exercise of unilateral market power but acknowledges the crucial role of regulators in setting the scarcity price. Brown (2018) also develops a theoretical model of generation investment as a multi-stage game in which firms first choose their capacity, then participate in a capacity auction, and finally in an electricity auction. He shows that regulators, in choosing the parameters of the capacity demand curve for the auction, face a tradeoff between limiting the exercise of unilateral market power in the capacity market and encouraging generation investment. Léautier (2016) develops an analytical model to compare reliability options with physical capacity certificates and develops conditions under which these are equivalent. Finally, Teirilä and Ritz (2019) construct a simulation model of the Irish electricity market to study the potential exercise of market power under a system of reliability options. They model the capacity market, generator entry and exit, and the short-run wholesale market. Although the capacity market leads to new generation entry, the authors argue that the exercise of unilateral market power in the capacity market by the large incumbent generator in Ireland could increase electricity procurement costs by 40 to 100 percent relative to a competitive counterfactual.[8]

Our analysis focuses on the interaction between three markets: the short-term wholesale energy market, the fixed-price forward contract for energy market, and the capacity market (reliability options). Our simple model demonstrates that the interaction between reliability options and fixed-price forward contracts changes the incentive for generators to exercise unilateral market power in the short-term energy market. Moreover, we also show how reliability options change the long-run incentives of generators to sell fixed-price forward contracts and (in the case of hydro generators) store water. An implication of these long-run effects is that reliability options—bought from generators and ultimately paid for by consumers—can lead to lower reliability of the electricity system.

A detailed empirical analysis of the short-term and long-term performance of a capacity mechanism using market outcome data from the Colombian electricity market is possible because of the hourly data provided by the Colombian system operator about the wholesale market—the plant-level offers and generation, the hourly forward contract positions of every firm, and the reliability option payments—which allows us to examine the validity of the predictions of our stylized model about the interaction between the short-term wholesale market and the fixed-price forward contract market. We find that generators recognize and respond in economically significant ways to the incentives provided by the reliability options in both the short-term energy market and the long-term energy contract market.

The remainder of the paper is organized as follows. Section 2 provides details on the structure of the Colombian electricity market. Section 3 uses a simple theoretical model to illustrate the short-run and long-run distortions from reliability options. Section 4 presents a series of descriptive and analytical results on the performance of the reliability options in the short run, while Section 5 shows the long-run effects of the options on forward contracting behavior. Section 6 describes the key features our alternative approach for ensuring long-term resource adequacy based on standardized fixed-price forward contracts. Section 7 concludes.

8. There have been few papers that focus on non-strategic aspects of reliability options. Fontini et al. (2021) use a real options framework to model the generation investment decision in the presence of reliability options, showing that under certain conditions, reliability options may delay investment in new capacity. Andreis et al. (2020) derives closed-form pricing formulas for reliability options, treating the electricity price and strike price as stochastic processes and varying the correlation between them.

2 Background

Colombia's electricity generation remains predominantly hydroelectric, similar to other South American countries. From 2000 to 2023, the annual mean generation grew from 4.7 gigawatts (GW) to 9.2 GW, reflecting an average annual growth rate of three percent.[9] Between 2000 and 2009, hydro generation met most of this demand growth (Figure 1). However, thermal generation played a more significant role from 2012 to 2016. Recently, hydro generation has regained its share due to the construction of several large-scale hydroelectric projects. It accounted for 78 percent of the total generation between 2000 and 2004 and maintained the same share between 2020 and 2023. In contrast, wind and solar generation have developed slowly, with a combined share of less than 1 percent between 2020 and 2023.

The most striking pattern in the composition of electricity generation in Colombia is the periodic reduction in hydroelectric energy availability associated with the climatic phenomenon known as *El Niño*. This event is characterized by increased water temperatures in the central Pacific Ocean. One effect of this for Colombia is a reduction in rainfall (and hence inflows into hydro reservoirs) in the major hydro-producing regions of the country. This reduction in inflows associated with El Niño occurred in 2009–10, 2015–16, 2019–20, and 2023. As seen in Figure 1, these periods were associated with a substantial drop in hydroelectric generation and a corresponding increase in thermal generation.

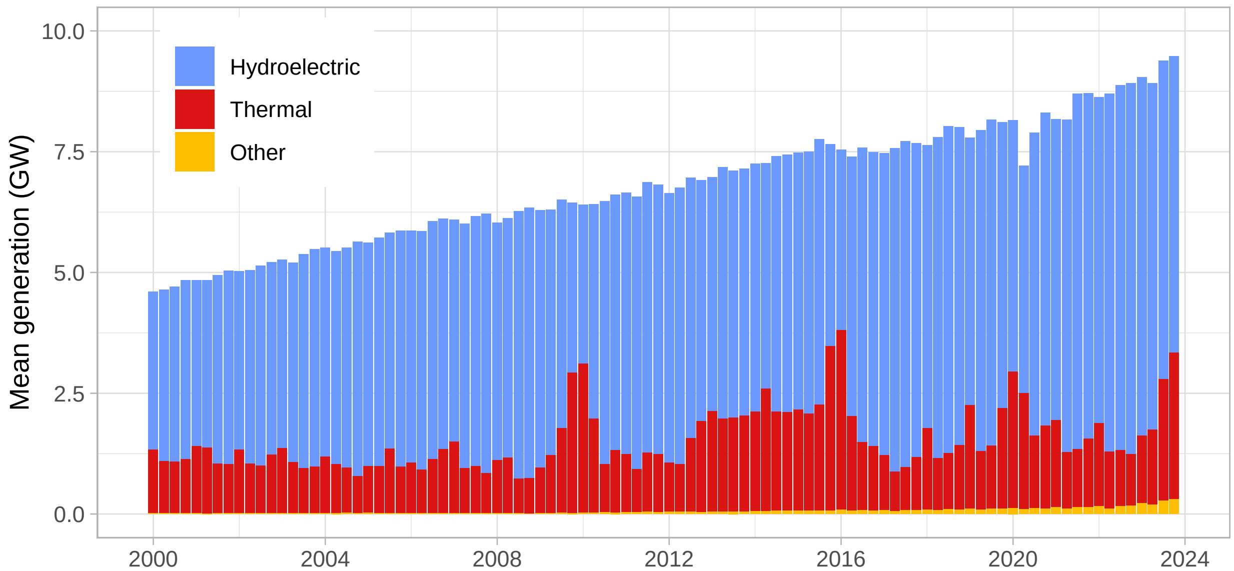
The structure of the generation market has remained stable for the past quarter-century. The three largest generation firms are EPM, Enel (formerly Emgesa), and Isagen, with a combined generation market share of about 60 percent (Figure 2).[10] These three firms are predominantly hydroelectric, each with a small thermal generation capacity. The largest thermal plant is Termobaranquilla (TEBSA), partially owned by the thermal generator Gecelca. Three smaller firms have significant hydroelectric generation capacity: AES Chivor, Celsia, and the state-owned Urrá. The remaining generation capacity, predominantly thermal, is split between many small firms, the largest comprising less than 2 percent of total generation between 2000 and 2023.

There are three sources of revenue for the generation firms: the sale of electricity and operating reserves in the short-term wholesale market, the sale of long-term fixed-

9. The annual mean generation in GW is calculated as the total generation in GWh divided by the number of hours in the year. For example, in 2023, the annual mean generation was $\frac{80687 \text{ GWh}}{24\times 365 \text{ hours}} = 9.2$ GW.

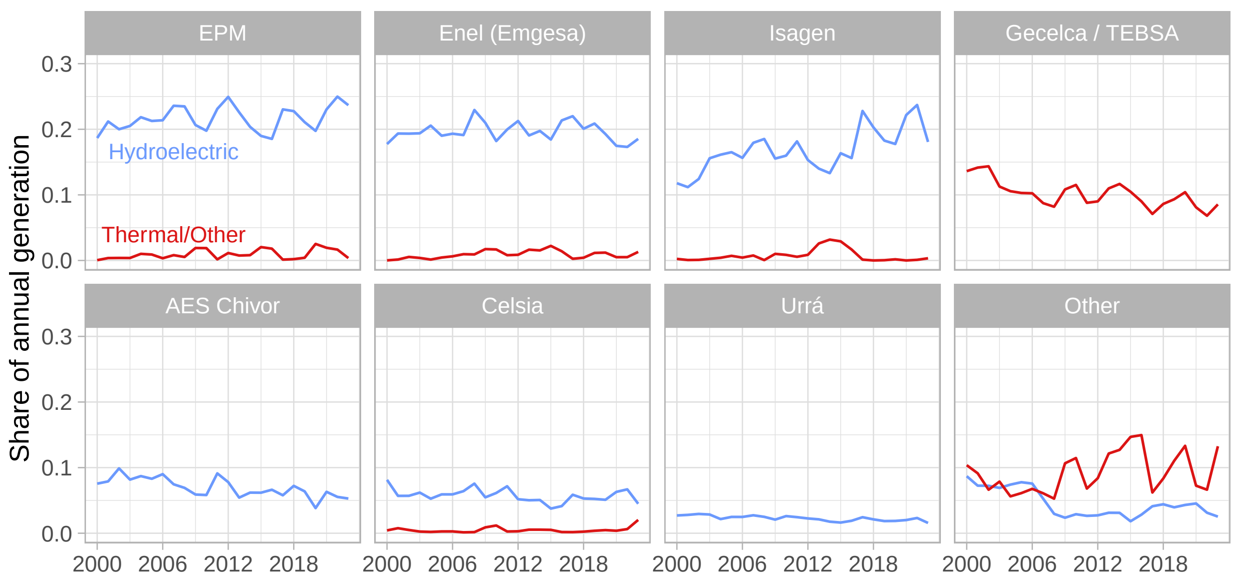
10. One of these companies is publicly owned, and two are private: EPM is a public utility owned by the municipality of Medellín, Enel is an Italian multinational that entered the Colombian market in 1997, and Isagen was a former state-owned company privatized in 2016.

Figure 1: Hydroelectricity remains the dominant mode of generation in Colombia despite 3% average annual demand growth since 2000



Notes: Calculation based on plant-level hourly generation data from XM Compañía de Expertos en Mercados (2019). See Footnote 9 for an example showing the calculation of mean generation in GW.

Figure 2: Stable market structure over past quarter-century with three large hydroelectric firms comprising 60 percent of the market



Notes: Calculation based on plant-level hourly generation data from XM Compañía de Expertos en Mercados (2019).

price forward contracts for energy, and the sale of reliability options. In the short-term wholesale market for energy, generators submit daily price and hourly quantity offers for their generation units to XM, the system operator.[11] XM uses these offers to calculate the operational dispatch of the system accounting for physical conditions such as plant operating constraints and transmission constraints. However, all commercial outcomes are determined *ex post* based on an hour-by-hour calculation of the "ideal dispatch". The ideal dispatch uses the generation offers, the realized demand, and realized plant availability, but ignores transmission constraints.[12] The "spot" price used for financial settlement, typically referred to as the Bolsa price, is based on the price offer of the marginal generation plant each hour in the ideal dispatch (Mastropietro et al., 2020).[13] The Bolsa price is the hourly wholesale price we use throughout our analysis.

Market participants can reduce their financial exposure to spot market prices by signing long-term, fixed-price forward contracts for energy. Electricity generators in Colombia typically sell fixed-price forward contracts for energy to reduce their exposure to low spot prices for their generation output in the short-term market; electricity retailers buy forward contracts to reduce their exposure to high spot prices for serving their customers on fixed-price retail contracts. Electricity retailers must hold a public tender for the forward contracts they buy to serve their regulated customers, with the forward contract price being one component of the regulated electricity price for each retailer. There are no restrictions on the contracting process for serving unregulated customers. An important feature of the forward contract market is that there is no regulation of the quantity of fixed-price forward contracts that retailers must buy. On average, retailers cover about 80 percent of their retail load obligation through forward contract purchases, but there is substantial heterogeneity across retailers.

The final revenue source for generators is the sale of reliability options. The system operator purchases reliability option contracts from electricity generators. The price paid

11. The wholesale market design in Colombia is different from the administrative cost-based short-term markets used elsewhere in Latin America (Galetovic et al., 2015; Rudnick and Montero, 2002).

12. Because Colombia sets a single spot price for the entire country each hour of the day, individual generation units can also receive positive reconciliation payments to supply additional energy relative to their ideal dispatch or negative reconciliation payments to supply less energy than their ideal dispatch because of transmission and other operating constraints (McRae and Wolak, 2014).

13. Since 2009, thermal generators have submitted startup cost offers associated with each unit. An uplift payment added to the spot price compensates the thermal generators who do not recover their as-bid costs, including the startup costs. Riascos et al. (2016) and Camelo et al. (2018) study the effect of including startup costs in generation unit offers in the Colombian market and found that this reform reduced total production costs to meet demand, although this reduction was not passed through into lower wholesale prices.

for these options (in $ per MW) is determined by auctions for long-term investment in new generation capacity, first held in May 2008 and subsequently in December 2011, February 2019, and February 2024.[14] The quantity of reliability options that each generation unit can supply (its "firm energy") is determined by a regulatory formula. For hydroelectric generators, the calculation is based on the minimum historical inflows, while for thermal generators, the calculation is based on generation capacity and fuel availability guarantees.[15] Both existing and new generation plants receive these payments from selling reliability options.

Compared to other capacity mechanisms, the novel feature of reliability options is that they are a financial instrument that provides market-based incentives for generators to supply energy when it is most needed. In Colombia, the strike price for the options, known as the "scarcity price," is recalculated each month based on changes in an international fuel oil price benchmark. During periods when the spot price exceeds the scarcity price, generators receive the spot price for their output, but are required to pay to XM the amount $(P - P_s)q_i^f$, the difference between the spot price and the scarcity price times that generator's firm energy quantity. This creates a financial incentive for generation firms to produce at least their firm energy quantity during scarcity periods. During these scarcity periods, XM refunds the amount $(P - P_s)q_i$ to each electricity purchaser for their purchase quantity q_i, effectively capping the price paid by electricity purchasers at P_s.[16] Moreover, because XM settles all forward contracts, the settlement price for all fixed-price forward contracts is equal to P_s during scarcity periods.

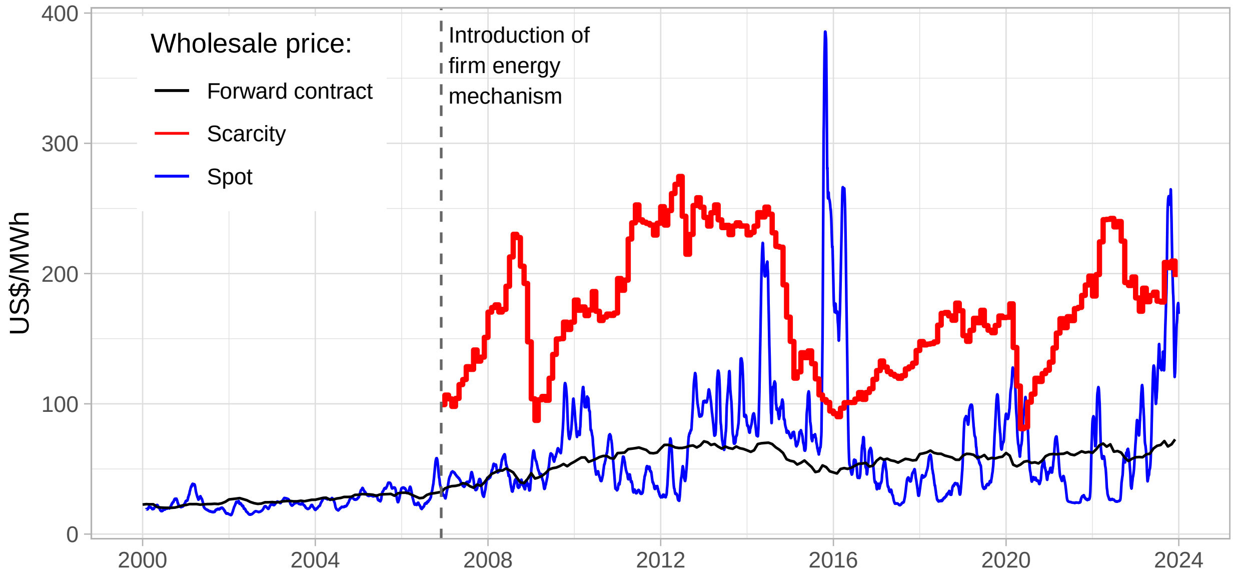
For most hours during the first nine years after introducing reliability options, the hourly spot price was below the scarcity price, meaning that the scarcity condition was not triggered (Figure 3). This changed during the El Niño event at the end of 2015 and the start of 2016. For six months, the hourly short-term market price exceeded the scarcity price in most hours.

14. Harbord and Pagnozzi (2012) review the design, outcome, and performance of these auctions.

15. Brito-Pereira et al. (2022) review the approaches used to calculate the firm energy contribution of renewable generators, including in the Colombian market, and suggest improvements to the methodology. Wolak (2022) describes the challenges facing regulators and market operators in California and Texas in setting firm energy values for wind and solar resources.

16. As described in Appendix A, the firm energy quantities q_i^f are rescaled each day so that the sum of the q_i^f across all generators is equal to the total generation. Because total generation is equal to total demand (including losses), this rescaling ensures that the total firm energy payments by generators during scarcity periods are exactly equal to the total refunds to electricity purchasers.

Figure 3: Spot prices below the scarcity price most of the time, except for a sustained period of high prices in 2015–16



Notes: The figure shows the monthly mean wholesale market price, the monthly mean forward contract price, and the monthly scarcity price for each month from January 2000 to December 2023. For those hours in which the market price exceeds the scarcity price, generation firms have an incentive to produce at least their firm energy quantity. This condition occurred in almost every hour between October 2015 and March 2016.

3 Illustrative model

This section presents an illustrative model of the incentives for supplier behavior in the short-term market created by the interaction of reliability options with the market for fixed-price forward contracts for energy. Under certain conditions, hydro suppliers have an incentive to cause scarcity conditions. In the longer term, these incentives may lead hydroelectric generators to sell more fixed-price forward contracts for energy.

3.1 Incentive effects of fixed-price forward contracts

Unilateral market power is the ability of a firm to raise (or lower) the market price and profit from it. The residual demand curve of a generation firm, defined as the market demand less the quantity supplied by its competitors at each possible market price, measures its *ability* to exercise unilateral market power. Because all firms submit their offers into the short-term market simultaneously and the realized system demand is unknown at that time, the precise form of the residual demand curve facing any firm is unknown when submitting its offer curve. However, because firms repeatedly interact in this market and the offers submitted by competitors are observed with some delay, generators are likely to be able to predict the key features of the realized residual demand curves they will face each hour of the day.

A supplier chooses the offer price and quantity increments that make up its aggregate offer curve to maximize its expected profits in the short-term market given the variable cost of operating its generation units (Wolak, 2000, 2003). In so doing, it effectively chooses the point along its realized residual demand curve where it will operate. The firm sells the generation quantity and receives the wholesale price set by the price and quantity pair where its offer curve crosses its realized residual demand curve.

Consider a simple model of supplier output choice with fixed-price forward contracts. Suppose a generator faces the downward-sloping inverse residual demand curve:

$$P(q) = 400 - 100q \tag{2}$$

The variable q in this expression is the generation sold by the firm, and $P(q)$ is the corresponding short-term market price for this quantity q. This inverse residual demand curve is shown in each graph of Figure 4.[17] For our simple theoretical model, we assume that the firm can observe its residual demand curve and that it has sufficient capacity to operate at any point on the curve. In our empirical analysis we use the firm's actual residual demand curve and only allow it to produce energy up to the amount of capacity it owns.

Without any fixed-price forward contract obligations, the generator will act as a monopolist off its residual demand curve and sell output where the marginal revenue of selling an additional MWh equals the marginal cost of producing that MWh.[18] Assume for simplicity the marginal cost of selling an additional unit of energy for the generator is zero. In this case, $MR = 400 - 200q = 0$, implying the firm maximizes its variable profits by choosing $q = 2$. The market price corresponding to this generation quantity is $200.

Fixed-price forward contract obligations reduce the incentive for electricity generators

17. In most electricity markets, including the Colombian wholesale market, the hourly offer curves submitted by generators are non-decreasing step functions. Each step is a price and quantity pair representing the additional generation quantity the firm is willing to supply at that price. Because the offer curves are step functions, so too are the residual demand curves. However, for analytical simplicity, we assume that residual demands are linear functions for our illustrative model. In our empirical analysis, we use the actual step-function residual demand curves faced by each supplier.

18. As noted in Wolak (2003), this result relies on the assumption that the supplier's residual demand curve is continuously differential. The case of step-function residual demands is discussed in Wolak (2003) and Wolak (2007).

to increase their offer price or restrict their output to increase the short-term market price. Suppose the generator in the example has sold $q^c = 3$ of forward contracts at a price P^c. With these forward contracts in place, the profit for the firm is now:

$$\Pi(q) = \underbrace{P^c q^c}_{1} + \underbrace{P(q)q}_{2} - \underbrace{P(q)q^c}_{3} - \underbrace{c(q)}_{4} \tag{3}$$

There are four components in the profit equation:

1. the forward contract revenue $P^c q^c$, which is predetermined when the firm chooses its generation offer[19];

2. the revenue from selling the quantity q at the wholesale market price $P(q)$;

3. the cost of fulfilling the supplier's forward contract obligation, q^c, at the short-term market price; and

4. the variable cost of generation $c(q)$, which we assume is zero in this analysis.

The forward contract obligation motivates the firm to increase its output above q^c. This incentive is shown graphically in Panel A1 of Figure 4. With $q^c = 3$, the firm maximizes its profits by increasing its short-term market sales to 3.5 (Panel A1), regardless of the value of P^c, which drops out of the firm's first-order condition for q. The wholesale price falls to \$50.[20]

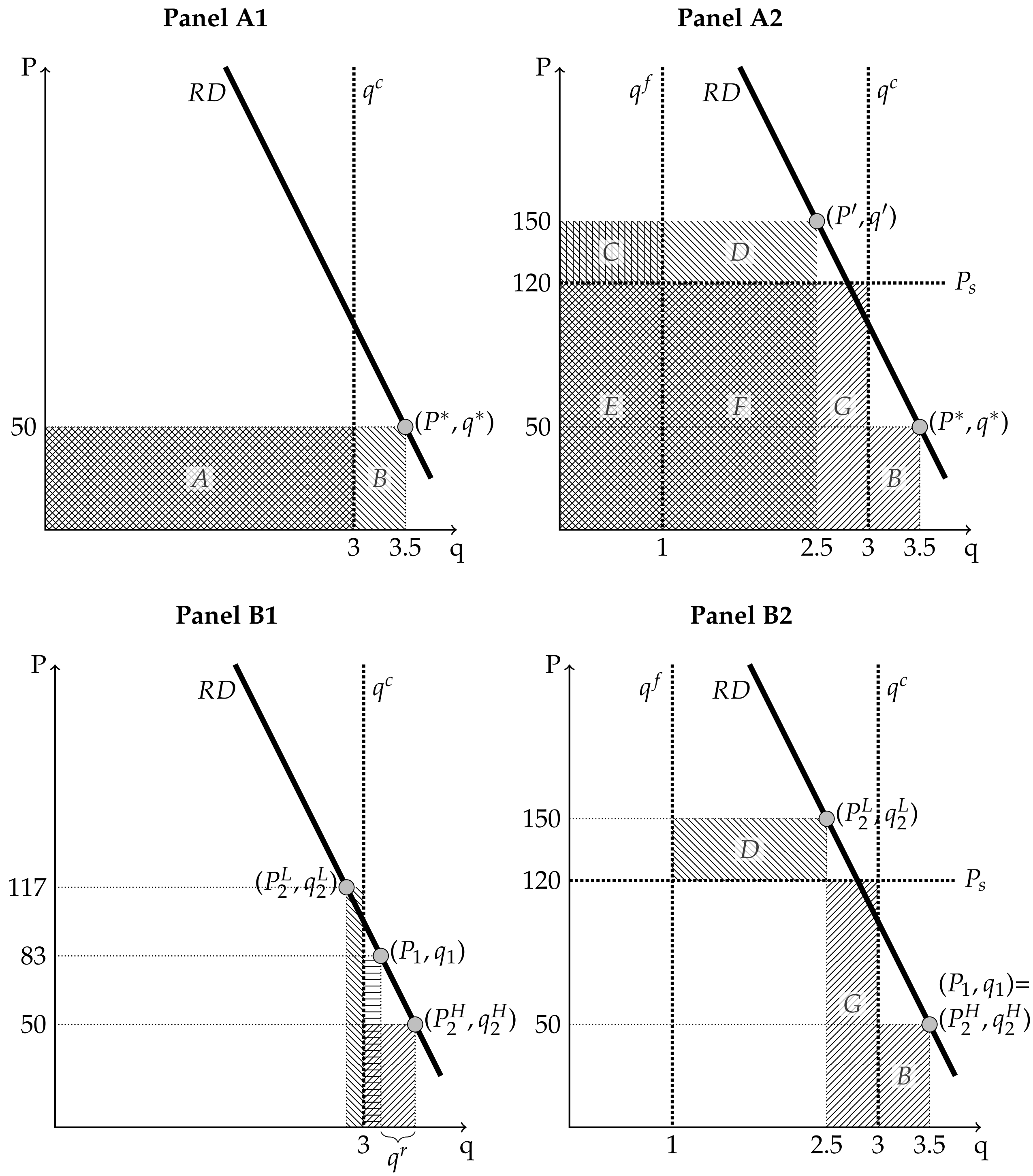
In panel A1, the wholesale market revenue earned by the firm is equal to the area $A + B$. The revenue earned from the firm's forward contract obligation, $P^c q^c$, can be larger or smaller than the area A, depending on the value of P^c relative to \$50. Because the firm has more energy in the short-term market than q^c, it also earns a positive net revenue of the area B. With the forward contracts in place, the firm has less *incentive* to withhold generation to push up the wholesale market price, even though it still has the *ability* to sell energy at any point along its residual demand curve.[21]

19. We assume that the forward contract price P^c and forward contract quantity q^c are predetermined because they depend on agreements made months or even years in advance of the short-term market (Wolak, 2007; McRae and Wolak, 2014).

20. The firm would like to raise the short-term price only if its short-term market sales exceed q^c. If $q = q^c$, then the value of the short-term price, P, has no impact on the firm's variable profits.

21. McRae and Wolak (2014) derive measures of the unilateral *ability* and *incentive* to exercise unilateral market power based on the shape of a firm's residual demand function and fixed-price forward obligations and compute them on a half-hourly basis for the four largest suppliers in the New Zealand electricity market.

Figure 4: Reliability options interact with fixed-price forward contract for energy obligations



Notes: Panels A1 and B1 show the calculation of the short-term wholesale market revenue including the fixed-price forward contracts for energy obligations. Panels A2 and B2 show the calculation adding the reliability options. Panels B1 and B2 consider two periods with uncertain inflows in the second period.

3.2 Short-term market interaction of forward contracts and reliability options

We introduce reliability options to the setting where generation firms have fixed-price forward contracts (Panel A2 of Figure 4). Suppose the generation firm sells a quantity $q^f = 1$ of reliability options for a price P^f. There is an administratively set scarcity price $P_s = \$120$. The variable profit for the firm is given by Equation (4).

$$\Pi = \underbrace{P^c q^c}_{1} + \underbrace{P^f q^f}_{2} + \underbrace{P(q)q}_{3} - \underbrace{\min(P(q), P_s)q^c}_{4} - \underbrace{\max(P(q) - P_s, 0)q^f}_{5} - \underbrace{c(q)}_{6} \tag{4}$$

Compared to Equation (3), one component has changed, and there are two new components in the profit equation:

1. the forward contract revenue $P^c q^c$, which is predetermined when the firm chooses its generation offer;
2. the reliability option revenue $P^f q^f$, which is predetermined when the firm chooses its generation offer into the spot market[22];
3. the revenue from selling the generation quantity q at the spot price $P(q)$;
4. the cost of fulfilling the supplier's fixed-price forward contract obligation, q^c, at the minimum of the spot and scarcity prices;
5. the cost of fulfilling the reliability option obligation, q^f, if the spot price exceeds the scarcity price; and
6. the variable cost of production, $c(q)$.

Compared to Equation (3), the cost of fulfilling the fixed-price forward contract obligation q^c (component 4) is capped at P_s. This is because the reliability options cap the settlement price for all spot market transactions at the scarcity price, as discussed in Section 2.

Suppose the spot price $P(q)$ is below the scarcity price P_s. In that case, Equation (4) simplifies to Equation (3), with the addition of the firm energy revenue $P^f q^f$ (Panel A2 of

22. We assume that P^f, the price of the reliability option, is predetermined because it is set in periodic auctions for investment in new generation capacity. The quantity of reliability options, q^f, is predetermined because it is based on a regulatory formula and is updated at most once per year.

Figure 4). At a price of \$50, the wholesale market revenue and forward contract obligation are identical to Panel A1. The firm will have a short-term wholesale market revenue of the area B, plus its forward contract and firm energy revenue. In this example, the area B is equal to \$25.

Now suppose the generator produces a quantity $q = 2.5$, giving a spot price $P(q) = 150$, which is above the scarcity price P_s. Consider the three components of the profit function in Equation (4) that depend on $P(q)$. First, the wholesale market revenue $P(q)q$ is the area $C + D + E + F$. Second, the cost of fulfilling the supplier's fixed-price forward contract obligations simplifies to $P_s q^c$. This cost corresponds to the area $E + F + G$ on Panel A2 of Figure 4. As long as $P(q)$ exceeds P_s, the forward contract obligation is fixed and does not depend on $P(q)$. Finally, the reliability options obligate generators to pay the difference between the spot and scarcity prices for their firm energy quantity when this difference is positive. With $P(q)$ greater than P_s, this obligation simplifies to $(P(q) - P_s)q^f$, which is equal to the area C on Panel A2.[23]

The short-term wholesale market revenue, including the fixed-price forward contract and reliability option obligations, is the sum of these three components, corresponding to the area $(C + D + E + F) - C - (E + F + G) = D - G$. Note that the reliability option obligation motivates the generator to produce at least their firm energy quantity q^f during periods with high prices. However, because the cost of meeting the forward contract obligation is a fixed amount, there is no longer an incentive for the firm to produce at least its forward contract quantity q^c. This contrasts with Panel A1, where the firm had an incentive to produce at least q^c. In other words, the reliability options changed the incentive of the firm to restrict its generation and increase the market price.

With reliability options, generators with the ability to exercise unilateral market power can often choose whether or not there is a scarcity period by their output choice. In Panel A2, the profit-maximizing quantity q^* that avoids a scarcity period is 3.5, with net revenue of 25 (the area B). The profit-maximizing quantity q' that triggers a scarcity period is 2.5, with a net revenue of $1.5 \times 30 - 0.5 \times 120 = -15$ (the area $D - G$). Given the choice

23. The example presented in Figure 4 uses a simplification of the reliability option calculation to highlight the strategic incentives. In practice, the settlement of the reliability options occurs at a daily, not hourly, level. The net position for the firm is calculated as the difference between its total generation for the day and its daily firm energy quantity. Firms with excess generation (as in Panel B2) will have their hourly firm energy quantities (area E in Panel B2) determined based on an allocation of their firm energy across hours, proportional to their hourly generation. Firms with a generation shortfall will have their daily firm energy obligation determined based on their share of the total shortfall for all generators. Appendix A provides a detailed example of the daily clearing mechanism for the reliability options we use in our empirical analysis in Section 4.

between these alternatives, it will be optimal in this example for the firm to produce an output of 3.5. However, depending on the values of P_s, q^f, and q^c, there will be periods in which it is optimal for the firm to restrict its output through the offer curve it submits to the spot market to create a scarcity condition.

3.3 Effects of uncertainty in generation availability

In the bottom two panels of Figure 4, we extend our example of the incentive effects of reliability options to incorporate dynamic considerations, where firms choose how to allocate their hydro production over multiple periods. The choice of hydroelectric generators is how much to produce each period and how much to store in their reservoirs to produce in a future period, assuming there is uncertainty in future hydro inflows.

Suppose there are two periods. In the first period, a quantity $q = 3.5$ is available. In the second period, with 50 percent probability, there is a quantity $q = 3.5$ available (high-water scenario H), and with 50 percent probability, there is a quantity $q = 2.5$ available (low-water scenario L). For simplicity, we assume that the supplier's residual demand curve is the same for the two periods and scenarios.

First, consider the case of forward contracts only (Panel B1). In the first period, the firm has sufficient water to produce its profit-maximizing quantity of 3.5 and earn profits of 25. In the second period, there is a 50 percent probability that the firm receives a further 3.5 and can produce 3.5 for a profit of 25. However, if the firm receives 2.5 in the second period, its quantity will be 2.5, and the spot price will be \$150. This creates a loss for the firm because of its forward contract obligation $q^c = 3$. The loss will be $-0.5 \times 150 = -75$. So the expected profit for the firm is $25 + 0.5 \times 25 + 0.5 \times (-75) = 0$.

Instead of producing the single-period profit-maximizing quantity of 3.5 in the first period, it is expected profit-maximizing across the two periods and scenarios for the firm to withhold generation in the first period, storing water in its reservoir to insure against the low-water scenario in the second period. The expected profit-maximizing quantity in the first period is 3.167. This means that the firm will store $q^r = 0.333$ in the first period. If the high-water scenario occurs in the second period, this stored water will not be used: the firm will receive 3.5 and produce 3.5, discarding the stored water. However, if the low-water scenario occurs in the second period, the output will be $2.5 + 0.333 = 2.833$. The firm will still make a loss due to its forward contract obligations of $q^c = 3$, but this loss will be much smaller than the case without stored water: $-0.167 \times 117 = -19.44$. The expected profit for the firm is $0.167 \times 83.33 + 0.5 \times 25 + 0.5 \times -19.44 = 16.67$. This is larger than the expected profits of 0 without storing water in the first period.

Now consider the case of combining forward contracts with the reliability options (Panel B2). Suppose the firm produces 3.5 in the first period and then 2.5 or 3.5 in the second period, depending on whether inflows are high or low. Because of the reliability options, the loss from producing $q = 2.5$ in the second period is much lower than in the absence of the mechanism. The loss is the area $D - G$, equal to -15, compared to the loss of -75 with only forward contracts.

As a result, it is no longer expected profit maximizing for the firm to store water in the first period as insurance against the low-water scenario in the second period. The reliability options provide insurance against a low-water outcome because they cap the firm's losses from being unable to fulfill its forward contract obligations. The expected profit from producing 3.5 in the first period is $25 + 0.5 \times 25 + 0.5 \times -15 = 30$. If the firm avoids scarcity in the second period, storage and output will be the same as in Panel B1, with an expected profit of 16.67. So expected profits are higher from using all the water in the first period and not storing any water.

Comparing Panel B1 and B2, we see that the reliability options lead to greater hydro generation and reduced storage during Period 1 when inflows are high. The quantity stored during Period 1 is 0.33 in Panel B1 but 0 in Panel B2. As a result, during subsequent periods with low inflows, the increase in the wholesale market price is greater (150 rather than 117), and variation in the hydro output is greater. With less water stored in Panel B2, it is more likely that a period of low inflows will lead to periods in which total available capacity cannot meet system demand.

This is a striking result. The sale of reliability options provides an additional revenue stream of $P^f q^f$ to the generator. The implicit promise of the reliability option instrument is that it provides incentives for the plant owner to ensure sufficient energy is available during dry periods when energy is most needed. Instead, as shown in Panel A2, there may be situations when the generator is motivated to withhold generation relative to what it would have produced without the reliability options but with its fixed-price forward contract for energy obligations in place. Moreover, as shown in Panel B2, the reliability options reduce the incentive for a hydroelectric generator to store water as insurance against future low inflows.

3.4 Long-run effect of firm energy on forward contracting

The discussion in the previous section treated the forward contract quantity q^c and the firm energy quantity q^f as fixed. This is a realistic assumption for q^f, which is set for each generation plant based on a regulatory formula. However, although q^c is fixed when generation firms submit their offer curves for energy to the spot market, q^c is a choice variable in the long term.[24] In the bilateral forward contract market, generation firms choose the quantities and prices of forward contracts they sell or buy. There are no regulatory minima or maxima for the quantity of fixed-price forward contracts that generators can sell.

Without reliability options, hydroelectric generators will be reluctant to sell long-term fixed-price forward contracts above their minimum output under a worst-case inflow scenario. As shown in Panel B1 of Figure 4, selling a quantity q^c of forward contracts that exceeds minimum inflows is extremely costly if the low inflow scenario occurs and the firm has to buy the shortfall at a high spot price. Moreover, to reduce the risk associated with a large quantity of fixed-price forward contract obligations, hydro generators will hold more water in storage and likely require a higher forward contract price P^c to compensate them for the additional risk they face.

Given the interaction of forward contracts with the reliability options described above, hydro generators will be more willing to sell fixed-price forward contracts together with the reliability options. As shown in Panel B2 of Figure 4, the reliability options insure hydro generators against the risk of low inflows and buying electricity at a high spot price to meet their forward contract obligations. The hydro suppliers are no longer required to insure themselves against extreme spot prices associated with low inflows by holding more water in storage. As a result, given the reduction in low-water risk provided by the reliability options, hydroelectric firms will offer to sell more fixed-price forward contracts at a lower contract price P^c.

The reliability options have an asymmetric effect on thermal generator firms. Barring unanticipated outage events, and provided they have signed long-term fuel supply agreements, there is a limited risk of thermal generators being unable to generate their full nameplate capacity. Therefore, the regulatory formula that determines the firm energy q^f typically sets a significantly higher value (as a share of nameplate capacity) for thermal

24. We assume that "long term" is the horizon over which the forward contract quantity can be varied and "short term" is the horizon over which this quantity is fixed. Throughout this section, we assume the generation capacity of firms is fixed.

generators compared to hydro generators. Because of the lower risk of supply shortfalls for thermal generators, they do not benefit from the implicit insurance provided by the reliability options. Therefore, after introducing reliability options, there is unlikely to be a change in the willingness of thermal generators to sell fixed-price forward contracts at any given price P^c.

Accounting for its effect on the two types of generators, the existence of reliability options is likely to shift out the fixed-price forward contract offer curve of hydroelectric generators but not affect the forward contract offer curve of thermal generators. This change will increase the quantity of fixed-price forward contracts sold by hydroelectric generators and reduce the quantity sold by thermal generators. Section 5 finds considerable empirical support for these theoretical predictions.

3.5 Empirical predictions

The previous discussion in this section provides several predictions about the effect of reliability options on wholesale market outcomes. First, the reliability options will affect the offer behavior of generation firms in the short-term wholesale market. Large generators will have the unilateral *ability* to withhold their generation and create a scarcity event in which the spot price exceeds the scarcity price. It may be profitable for generators to do this, depending on the quantities of their firm energy and fixed-price forward contract obligations. The response of generators to these short-term incentives will be apparent in the offer prices they submit to the short-term market.

The reliability options will also affect forward market outcomes. Hydroelectric generators will sell more fixed-price forward contracts by offering them at a lower forward price than before the introduction of the reliability options. Thermal generators will sell fewer contracts. Moreover, hydroelectric generators will have less incentive to store water as insurance against future low inflows, so hydro storage levels (relative to fixed-price forward contract obligations) will drop.

In Section 4, we empirically study the effect of the reliability options on short-term market outcomes. In Section 5, we then study the effect of introducing the reliability options on long-term market outcomes.

4 Short-run responses to reliability options

This section analyzes the offer and operating behavior of the generators in the Colombian wholesale electricity market to demonstrate the empirical relevance of the predictions from the analysis in Section 3.

We use hourly market input and output data provided by XM from December 2006 to June 2016. This hourly information includes the price and quantity offers for each generation unit, the system demand, the dispatched and actual generation output of each unit, and the market (Bolsa) price. We supplement the hourly data with information on hydrological inflows and storage levels, as well as information on fossil fuel usage and prices.

4.1 Large generators can create scarcity periods

In some hours, the largest generators in the Colombian electricity market can effectively determine whether or not there is a scarcity period. The realized residual demand of a generator—that is, the realized market demand less the aggregate offer curve of all competing generators—describes the possible combinations of market price and generation quantity pairs that the firm can choose. Assuming the generation unit owner observes the residual demand curve it will face, it can choose any price and quantity combination along the curve, up to its generation capacity, by submitting an offer curve that intersects the residual demand curve at the desired point.[25]

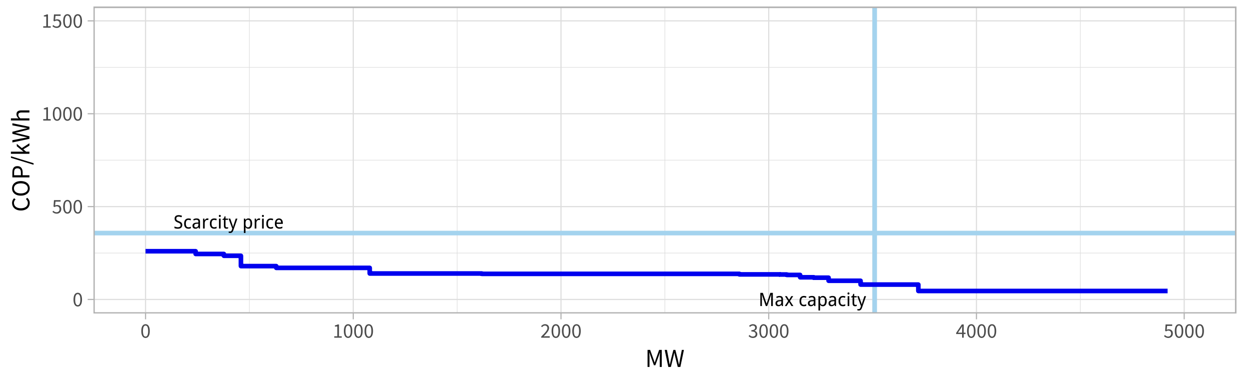
Figure 5 shows the three possible configurations for the realized residual demand curve for EPM. The first case is when the EPM's residual demand curve lies below the scarcity price for all feasible generation quantities. The nameplate capacity of the generation units determines the maximum generation quantity. The minimum generation quantity for thermal plants is assumed to be zero, but for hydroelectric generators, the minimum generation quantity may be greater than zero due to environmental regulations on downstream water flows. With the residual demand curve lying below the scarcity price, there will not be a scarcity period for any choice of generation quantity by the firm.

The second case is when the residual demand curve lies above the scarcity price over the entire range of feasible generation quantities. In that case, a scarcity period will occur

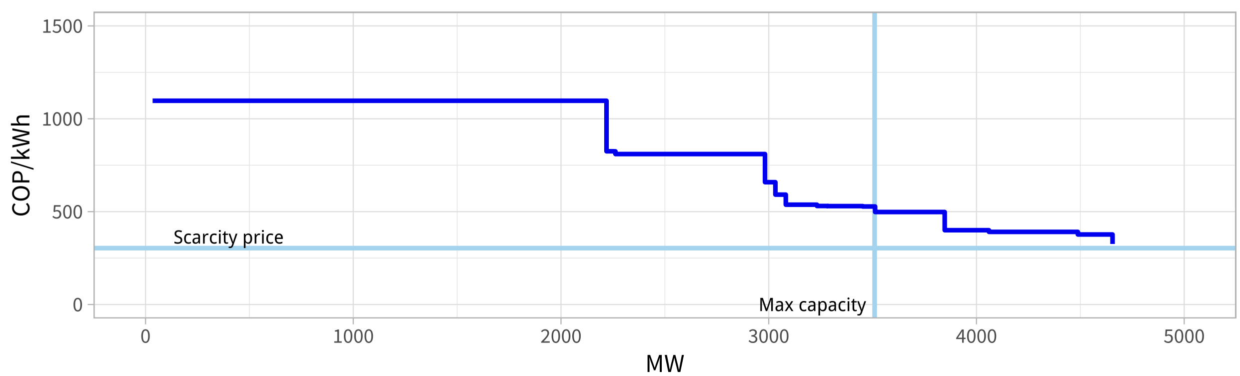
25. As noted earlier, because the offers of other suppliers and the realized value of system demand are unknown when the generation firm submits its offer curve, it is unlikely that the offer curve will intersect the realized residual demand curve at exactly the ex-post profit-maximizing price and quantity pair.

Figure 5: In certain system conditions, generation firms can choose whether or not a scarcity period occurs

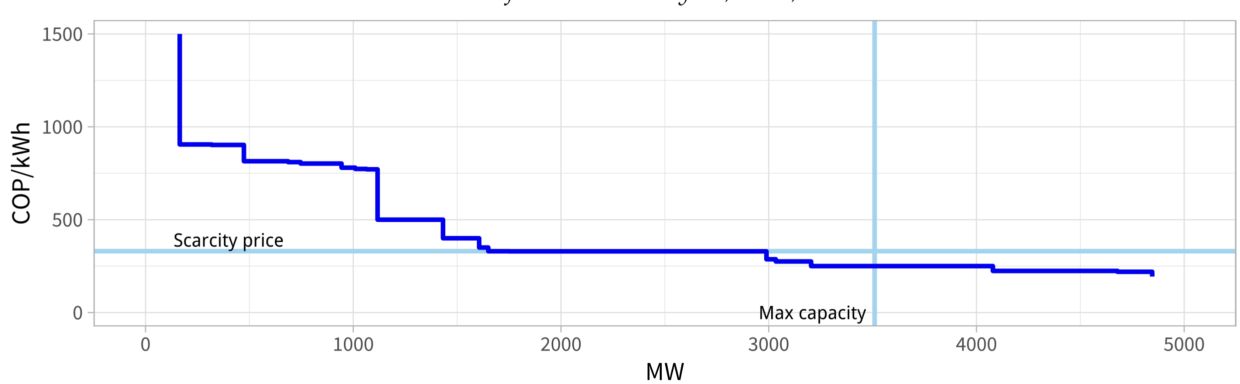
Case 1: Scarcity period cannot be induced by EPM
Residual demand for EPM on July 25, 2015, at 6:00 PM.



Case 2: Scarcity period will occur regardless of EPM's generation quantity
Residual demand for EPM on November 25, 2015, at 6:00 PM.



Case 3: Scarcity period is determined by EPM's generation quantity
Residual demand for EPM on May 25, 2015, at 6:00 PM.



regardless of the firm's generation quantity.

The final case is when the residual demand curve intersects the scarcity price at a quantity that lies within the range of feasible generation quantities. In that case, if the generator chooses a quantity that is less than the intersection quantity, there will be a scarcity period. If the generator chooses a quantity that is more than the intersection quantity, then there will not be a scarcity period. For this case, because it is feasible to generate quantities that are either greater than or less than the intersection quantity, the generator can choose whether or not a scarcity period occurs. Nonetheless, because the residual demand curve a supplier faces is unknown when it submits its offer curve, there is no guarantee that its desire to create or avoid a scarcity period will be successful.

Changes over time in the residual demand and scarcity price mean that the ability of a generator to determine the occurrence of a scarcity period will vary across days and hours (Figure 5). At 6:00 p.m. on July 25, 2015, EPM could not have caused a scarcity period for any quantity choice. At 6:00 p.m. on November 25, 2015, a scarcity period would have occurred regardless of the quantity EPM chose. Finally, at 6:00 p.m. on May 25, 2015, EPM could have caused a scarcity period by selling less than 1600 MW or avoided a scarcity period by selling more than that quantity.

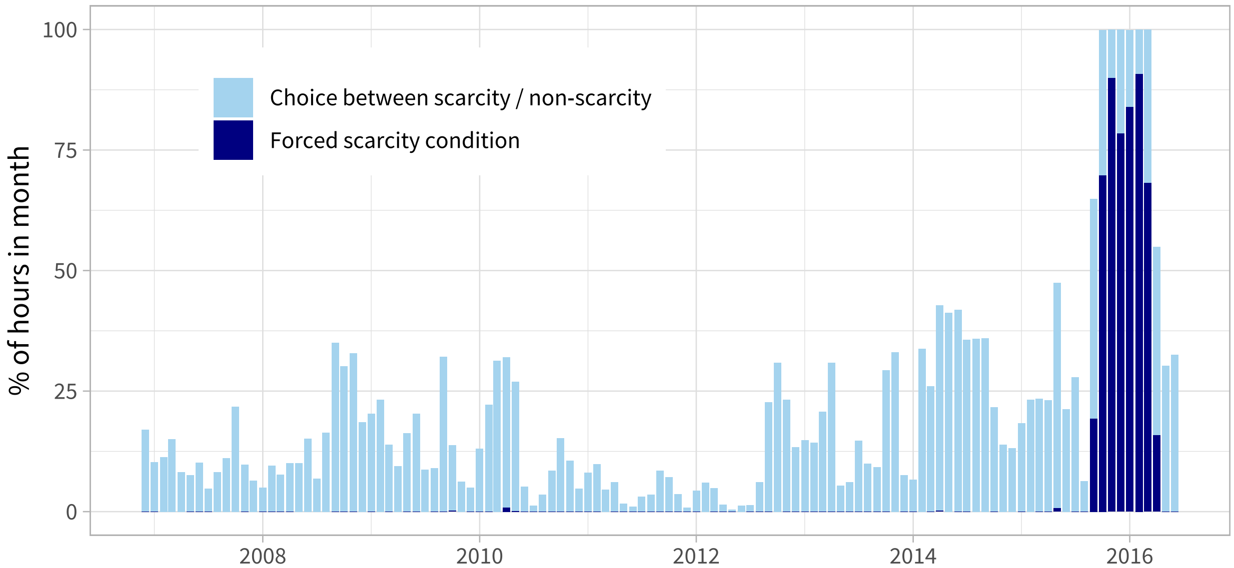
Throughout most of the sample period, EPM could cause a scarcity period during at least a few hours of each month (Figure 6). For most of the six months at the end of 2015 and the beginning of 2016, scarcity periods would have occurred regardless of the price and quantity offers by EPM. However, even in this extreme period, EPM could determine the scarcity outcome in a few hours.

Over the entire sample period, EPM could choose between scarcity and non-scarcity periods in 16 percent of hours (top block of Table 1). In 4.5 percent of hours, naerly all during 2015 and 2016, a scarcity period was forced to occur for any choice of offers by EPM. The other two large firms also had a substantial ability to induce scarcity periods, though in fewer hours than EPM. Emgesa could induce a scarcity period in 11 percent of hours, and Isagen could do the same in 6 percent of hours. The remaining smaller generation firms in the Colombian market had limited ability to create scarcity periods.

4.2 Generation firms respond to incentives to create scarcity periods

Although the three largest generation firms frequently have the ability to cause scarcity periods, they may not have the incentive to do so. Equation (4) shows how the short-run profits for the firm depend on whether or not the wholesale spot price exceeds the

Figure 6: EPM could choose to induce a scarcity period in 16 percent of hours between 2006 and 2016



Notes: The graph classifies the inverse residual demand of EPM for each hour of the sample period. Light bars show the hours where the inverse residual demand crossed the scarcity price within the range of feasible generation quantities for EPM. Dark bars show the hours where the inverse residual demand lay above the scarcity price. In the remaining hours, the inverse residual demand lay below the scarcity price.

scarcity price. The higher revenue in the short-term market from restricting output to cause a scarcity period ($P > P_s$) might not cover the higher cost of fulfilling the firm's fixed-price forward contract and reliability option obligations. Even when an expected profit-maximizing firm can cause a scarcity period, it will only do so if the profits with a scarcity period are greater than those without a scarcity period.

We empirically analyze the choices made by the largest generation firms during the days and hours in which they could create a scarcity period. For this analysis, we calculate the firm's best response to the generation offers of the other firms on that day. This best response will depend on the firm's hourly forward contract position, its daily firm energy obligation from the reliability options, and its generation variable costs. We ignore revenue from forward contracts and the reliability option sales because the prices and quantities of these contracts are fixed when suppliers submit their offer curves into the spot market.

The calculation of the best response quantity for a given hour is complicated by the non-separability of the reliability option obligations across hours of the day. When there is at least one scarcity period in a day, the calculation of payments or refunds for the reliability options depends on the generation in every hour of the day, not just the scarcity periods (Appendix A). It also depends on the net reliability option positions of every other firm in the market—which will depend on firm i's hourly quantities q_{it}. Equation (5) provides the daily profit for the generation firm i.

$$\Pi_i = \sum_{t=0}^{23} \left(P(q_{it})q_{it} - \min(P(q_{it}), P_s)q_{it}^c - c_i(q_{it})\right) + RO(q_i, q_{-i}, q_i^f, q_{-i}^f) \quad (5)$$

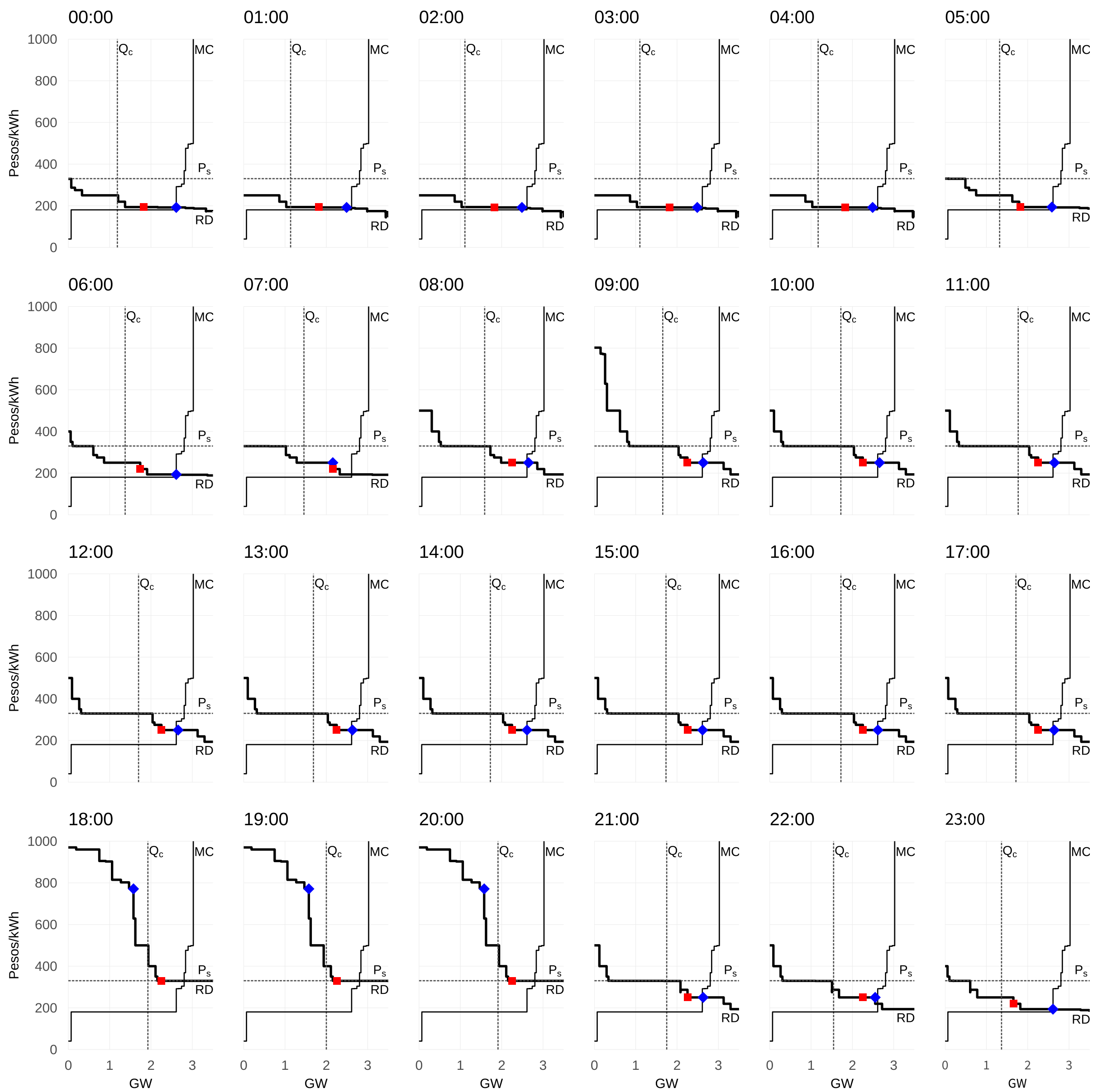
Compared to the expression for hourly profits in Equation (4), we ignore the revenue from fixed-price forward contract and reliability option sales. We also replace the hourly cost of fulfilling the reliability option obligation with the daily calculation of $RO()$ using the algorithm described in Appendix A, consistent with the actual algorithm used to clear each firm's reliability options, rather than our stylized model.

Figure 7 illustrates the profit-maximization problem for one day for Emgesa. There were three hours in which it would have been optimal for Emgesa to withhold generation and create a scarcity period. In these hours, the optimal generation was less than the forward contract quantity—however, this did not matter because its fixed-price forward contract obligation was capped at the scarcity price. Emgesa could have further increased its profits by increasing its generation in the non-scarcity hours and reducing its reliability option obligation in the scarcity hours. The actual market outcomes on this day showed that a scarcity period occurred in precisely the three hours when it would have been profit-maximizing for Emgesa for scarcity conditions to occur.

The profit-maximizing choice of quantities depends on the marginal generation costs in the nonlinear term $c_i(q_{it})$. Most of the generation capacity of the three largest firms in the Colombian market is hydroelectric. Although there is no direct monetary cost of using water, the firms' production decisions are determined by the opportunity cost of water usage. An extra megawatt-hour of water released from a reservoir will not be available to produce electricity later, potentially when the price is higher. The challenge for our analysis of profit-maximizing behavior is that the opportunity cost of water used by the firms is unobserved.

For an assumed value of the opportunity cost of water c_w, we calculated the marginal cost curve based on the plant-level capacities, the heat rates of the thermal plants, and confidential data on the thermal fuel costs. Given this marginal cost curve, we solved a non-linear optimization problem to find the combination of hourly quantities that maximized Equation (5), as shown in Figure 7. Because we do not have a closed-form expression

Figure 7: Incentives for choosing between scarcity and non-scarcity conditions vary across the day as the residual demand changes



Notes: The figure shows the residual demand *RD* faced by Emgesa for each hour on May 25, 2015, plus the hourly contract position q^c, the scarcity price P_s, and its marginal cost curve *MC*. Noise has been added to the marginal cost curve shown in the figure to avoid disclosure of confidential fuel cost information. The blue diamond points show the best-response quantities and prices that would maximize profits for the day given the realized residual demand curves that Emgesa faced on May 25, 2015. The red square points show the actual quantities and prices in each hour. There are three hours for which it would be profit-maximizing for Emgesa to withhold generation and create a scarcity period: 18:00, 19:00, and 20:00. The realized prices in these hours were above the scarcity price.

for profits, our optimization used the Subplex optimization algorithm, a variant of the derivative-free Nelder-Mead algorithm (Ypma, 2014). We repeated this optimization procedure using a grid of opportunity cost values. Each opportunity cost gave a vector of the optimal hourly thermal and hydro generation quantities for that day.

We recovered an estimate of the monthly opportunity cost of water by comparing the profit-maximizing thermal and hydro generation quantities (as a function of c_w) to the observed thermal and hydroelectric generation during the month for each of the three firms. Specifically, for each firm, month, and opportunity cost c_w, we calculated the sum of squared deviations between the hourly optimal (opt) and actual (act) generation quantities, both hydro (H) and thermal (F):

$$SSD(c_w) = \sum_{k=H,F} \sum_{t=0}^{T} (q_{kt}^{opt}(c_w) - q_{kt}^{act})^2 \tag{6}$$

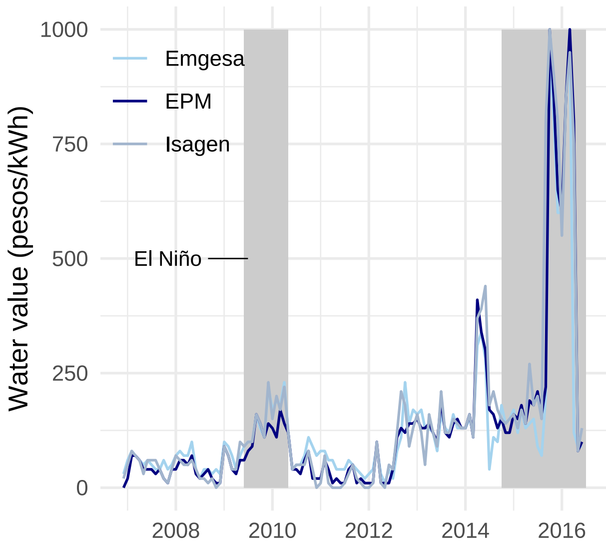
The opportunity cost for each firm and month is the value of c_w that minimizes Equation (6).

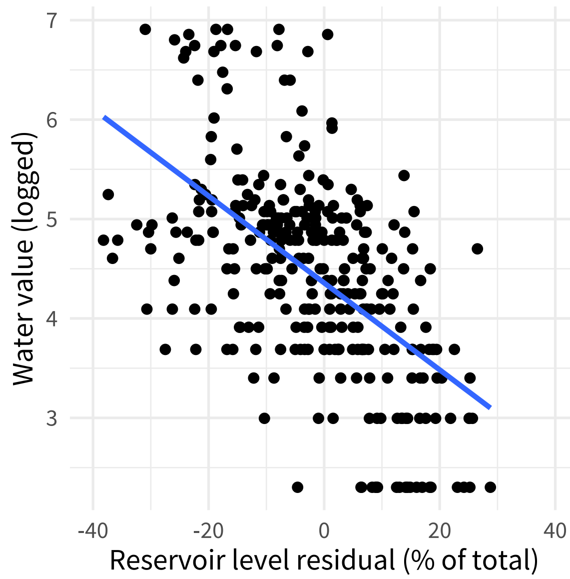
We solved the optimization problem to find the monthly opportunity cost of water and hourly profit-maximizing generation quantity, for each day from December 1, 2006 to June 30, 2016, for the three firms EPM, Emgesa, and Isagen. Figure 8 shows the implied monthly water values. These are correlated across the three firms, reflecting the commonalities in their hydrological and market conditions. The opportunity cost is highest during the two El Niño periods when water was scarcest (left panel). We find a negative correlation between the opportunity cost for a firm and its seasonally adjusted reservoir levels (right panel), even though the reservoir levels were not used in the calculation.

The optimization procedure gives the best-response prices and quantities for each hour for the three firms, accounting for the short-run incentives of the fixed-price forward contracts and the reliability options. We can compare these profit-maximizing outcomes to the observed prices and quantities. In particular, we focus on the triggering of a scarcity period by withholding sufficient generation so that the market-clearing price exceeds the scarcity price. Whether this is optimal will depend on the quantities of reliability options and fixed-price forward contracts and the shape of the firm's residual demand curve each hour.

During the 115 months in the data, there were 13,575 hours when EPM could choose between scarcity and non-scarcity periods. Most of the time, profits would be higher if the scarcity period were avoided. For EPM, in 1,274 of the hours in which it had a choice,

Figure 8: Estimated opportunity cost of water is highest during El Niño periods and when reservoir levels are low





Notes: The left figure shows the monthly opportunity cost of water for each firm, calculated as the c_w that minimizes Equation (6). The shaded dates are the El Niño periods when hydro inflows are reduced. The right figure shows the correlation between the logged opportunity cost and the reservoir levels for each firm as a percentage of total capacity. The reservoir levels are seasonally adjusted using a regression of the reservoir levels on firm-by-month dummies from 2000 to 2018.

profits would be higher if a scarcity period occurred (second block of Table 1). In 90 percent of these hours, a scarcity period did occur. This result confirms that EPM usually created a scarcity period when it had the ability and incentive to do so.

For the other 12,301 hours (90.6 percent) in which EPM had a choice, profits would be higher if the scarcity periods were avoided. In 98 percent of these hours, the scarcity period did *not* occur. That is, in most of the hours in which EPM had the *ability* but not the *incentive* to create a scarcity period, EPM ensured that a scarcity period did not occur. These two sets of results are remarkable because EPM did not know the exact residual demand curve realization it would face during each of these hours. Nevertheless, it made the ex-post profit-maximizing choice between inducing or avoiding a scarcity period with at least 90 percent accuracy.

The results are similar for Emgesa and Isagen. There were 447 hours in which Emgesa had the ability and incentive to create a scarcity period, and in 89 percent of these hours, a scarcity period occurred. For Isagen, there were 871 hours when it had the ability and incentive to create a scarcity period, which occurred in 75 percent of these hours.

Table 1: In the hours when they could choose, the three largest firms responded to the incentives to create or avoid a scarcity period

	Emgesa	EPM	Isagen
Non-scarcity hours	70018	66639	74548
Forced scarcity hours	4564	3786	4386
Scarcity/non-scarcity choice hours	9418	13575	5066
Total hours	84000	84000	84000
Hours when scarcity period was optimal	447	1274	871
% which were scarcity	88.8	90.1	75.4
% which were non-scarcity	11.2	9.9	24.6
Hours when scarcity period was not optimal	8971	12301	4195
% which were scarcity	3.0	2.4	4.4
% which were non-scarcity	97.0	97.6	95.6

Notes: The top section of the table shows the classification of hourly residual demand into the three categories shown in Figure 5, for the three strategic firms. The bottom section of the table focuses on the hours in which the firm could choose between scarcity and non-scarcity conditions. These hours are classified based on the profit-maximizing choice for the firm between scarcity and non-scarcity conditions. For each choice, the percentage of hours in the two categories is shown.

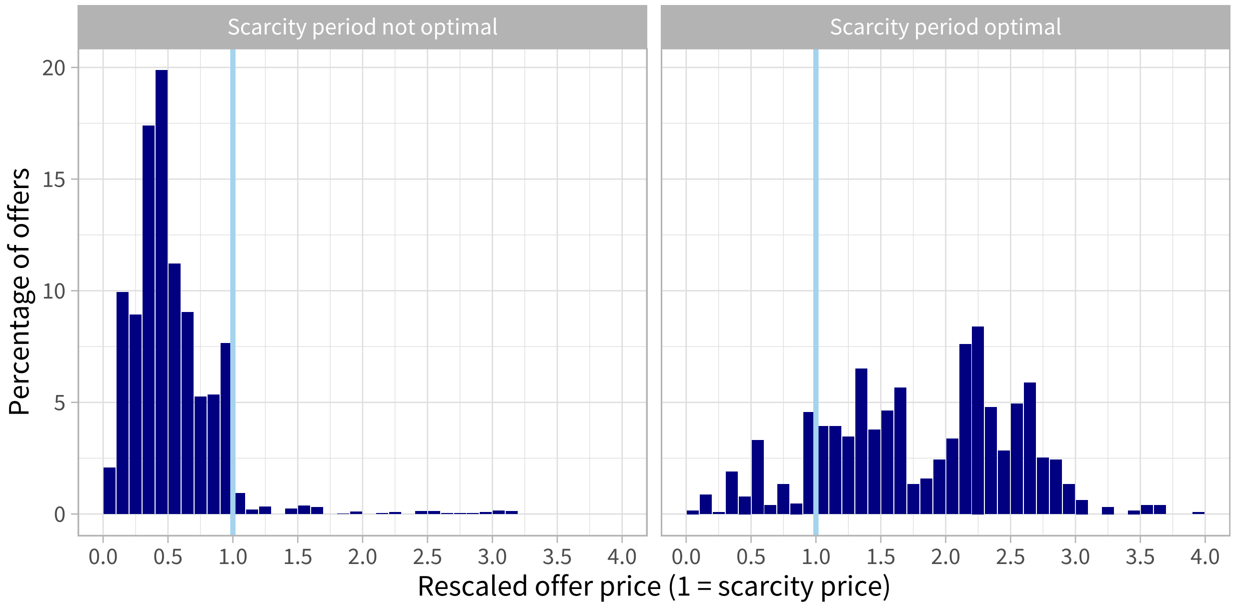
Conversely, there were 8,971 hours in which Emgesa had the ability but not the incentive to create a scarcity period, which was avoided in 97 percent of these. For Isagen, the scarcity period did not occur in 96 percent of the hours in which it had the ability but not the incentive to induce scarcity.

Overall, these results provide strong evidence that the largest generation firms recognize the incentives created by the reliability options and respond to them in their offer behavior. Most of the time, profits would be higher without a scarcity period, and in these hours, the firms submit offers to avoid crossing the scarcity price threshold. In a small proportion of hours, profits would be higher with a scarcity period, and in these cases, the firms submit offers in a manner that creates a scarcity period.

4.3 Offer price behavior reflects the incentives of the reliability options

In the previous subsection, we showed that the market outcomes—whether or not a scarcity period occurred—were strongly associated with the profit-maximizing incentives for the generation firms. In this section, we show direct evidence of the firms' response to these incentives in the offer prices they submit to the spot market.

Figure 9: Generation price offers for EPM respond to incentives to induce or avoid scarcity periods



For each firm, we focus again on the hours in which it could choose whether or not a scarcity period occurred. We then compare the distributions of generation offer prices for the hours when the firm did and did not have the ex-post incentive to induce scarcity, as defined above. In each hour, we calculate the highest accepted offer price (that is, the highest offer with positive generation sales quantity). To compare the offers across months with different scarcity prices, we scale all of the offer prices by the scarcity price. A price of 1 would be an offer price that exactly equals the scarcity price in effect at the time of the price offer. A scaled offer price greater than 1 would be an offer price above the scarcity price, potentially inducing a scarcity period. A scaled price of less than 1 corresponds to an offer below the scarcity price.

For the 12,301 hours in which EPM had the ex-post incentive to avoid creating a scarcity period, there is a high degree of bunching of the accepted offers just below the scarcity price (Figure 9). This offer distribution is consistent with EPM recognizing its incentive to avoid creating a scarcity period and submitting generation offers to accomplish that. Conversely, for the 1,274 hours in which EPM had the incentive to create a scarcity period, nearly all of its offer prices were above the scarcity price. We observe similar results for Emgesa and Isagen.

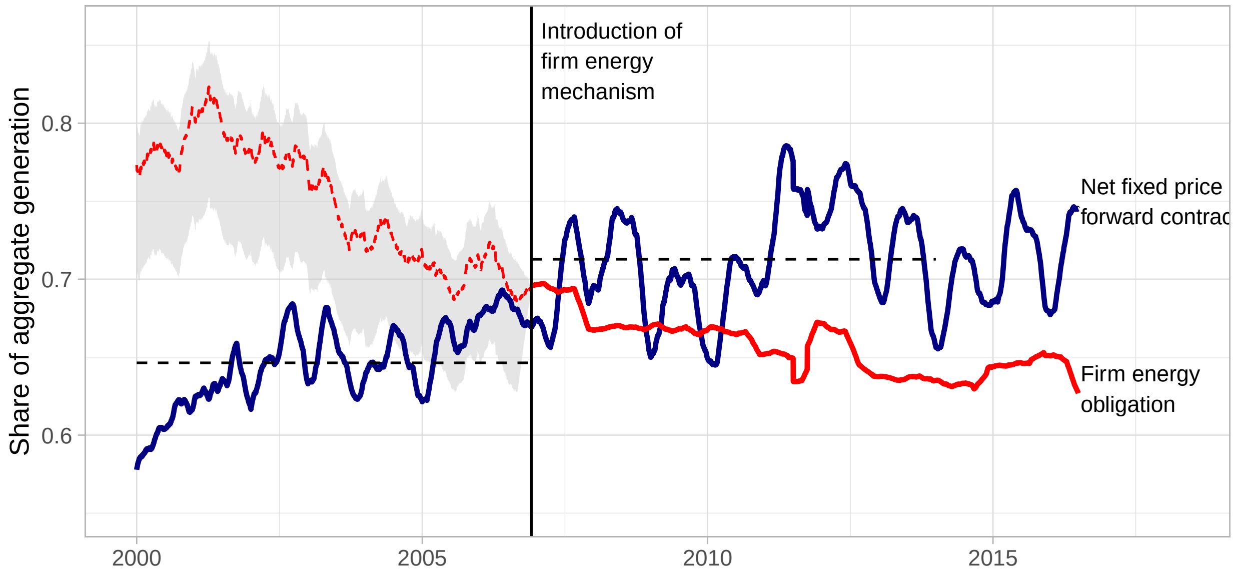
5 Long-run responses to reliability options

The previous section demonstrated how the three largest generation firms responded to the short-term incentives provided by the reliability options. We held the fixed-price forward contract and firm energy quantities constant in that analysis. This assumption is appropriate in the short term because these quantities are fixed from the perspective of the generation firms submitting offers into the short-term market. However, these quantities are not fixed in the long term, as generators can adjust the quantities of fixed-price forward contracts they sell in the bilateral contract market. Section 3 discusses how the reliability options might alter generators' incentive to sell fixed-price forward contracts. We demonstrate below that the administrative formula used to set firm energy quantities can allow thermal generators to alter their assigned firm energy quantities if it is in their financial interest to do so.

In this section, we examine the long-run effects of the reliability options by comparing fixed-price forward contract quantities before and after their introduction in December 2006. Because fixed-price forward contracts are typically signed months or even years in advance of the financial clearing date, and the introduction of the reliability options had been planned for a long time before their implementation, we do not attempt to estimate an immediate effect (e.g., between November 30 and December 1, 2006). Instead, we focus on the long-term change in forward contract positions, comparing the seven years before and after the introduction of reliability options. We conduct the analysis separately for generation firms that are predominantly hydroelectric and those that are predominantly thermal. Given that the size of the Colombia market has increased over time (Figure 1), we present all quantities as shares of system-wide generation.

As illustrated in Section 3, the short-term incentives for the offer behavior of generation firms depend on the relative magnitude of the firm energy and fixed-price forward contract positions: whether the forward contract quantity is less than or greater than the firm energy quantity. We can observe the forward contract quantities both before and after the introduction of the reliability options, as well as the firm energy quantities after their introduction. However, the firm energy quantities were not calculated before the reliability options existed. For this reason, we "backcast" the firm energy quantities in these earlier years. Specifically, we calculate the ratio of the firm energy to the nameplate capacity of the generation plants by technology. Assuming a fixed value for this ratio, and given that we observe the nameplate capacity throughout our sample period, we can construct a prediction of the firm energy quantity of each supplier before there were reliability options.

Figure 10: Hydroelectric generators increased their sales of fixed-price forward contracts after the introduction of the reliability options



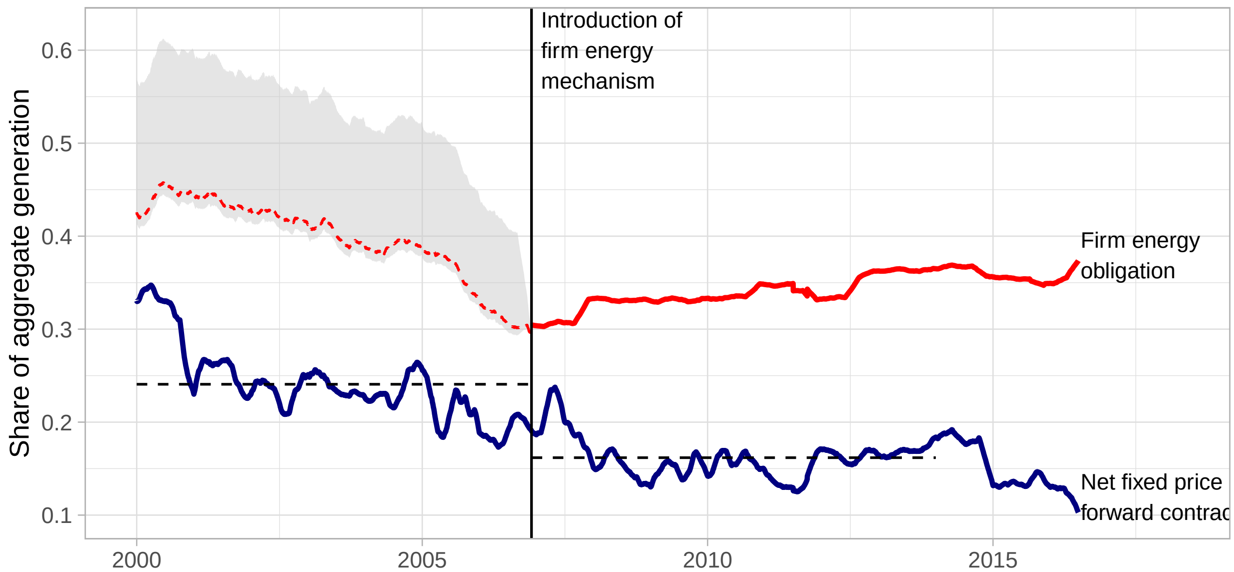
Notes: The graph shows (in blue) the net fixed price forward contract position of the electricity generation firms in Colombia that are predominantly hydro, expressed as a share of the system generation. The red line shows the firm energy obligations of the same firms. The red dashed line shows the backcasted firm energy quantities based on the aggregate nameplate capacity and the average ratio of the firm energy to the nameplate capacity during the first twelve months of the reliability options. The grey-shaded region shows high and low values for the firm energy obligation based on the minimum and maximum ratios over the sample period. All lines are shown as 90-day-forward moving averages. The dashed horizontal lines show the mean net fixed-price forward contract obligations for the seven years before and after the introduction of the reliability options in December 2006.

For our base case results, we use the ratio of firm energy to nameplate capacity during the first twelve months after the introduction of reliability options.

We first consider the effect of the reliability options on hydroelectric firms (Figure 10). Net forward contract quantities were higher for hydroelectric firms after introducing the reliability options in December 2006. In the seven years before December 2006, hydro firms' mean forward contract position was 64.6 percent of total generation, compared to a mean of 71.3 percent in the following seven years, an increase of 6.7 percentage points or more than 10 percent of the baseline level. As shown in Figure 10, the seasonal variation in the fixed-price forward contract positions increased after introducing the reliability options. In some years, the low-to-high variation within the year reached 10 percent of total generation, compared to a variation of 5 percent or less in earlier years.

The increase in fixed-price forward contract sales by hydroelectric firms is even more

Figure 11: Thermal generators decreased their sales of fixed-price forward contracts after the introduction of the reliability options

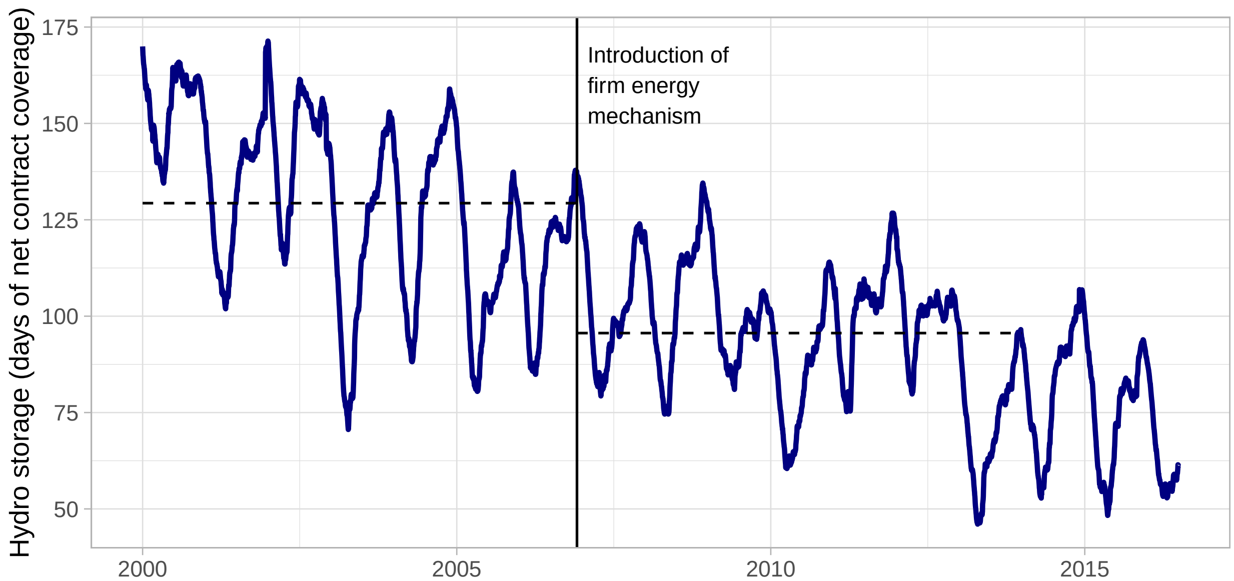


Notes: The graph shows the net fixed price forward contract position and the firm energy obligations of the electricity generation firms in Colombia that are predominantly thermal, expressed as a share of the system generation. See also the notes to Figure 10.

striking when compared to the firm energy quantities. Based on nameplate capacity, we estimate that the firm energy of hydroelectric generators would have been about 80 percent of system generation in 2000, declining to about 70 percent by 2006. Forward contract quantities would have been much lower than firm energy quantities during this period, with a gap of nearly 20 percent of system generation in 2000, converging to just a few percent by 2006. After introducing the reliability options, the higher forward contract quantities and lower firm energy quantities led to a reversal in their positions. With a few limited exceptions, sales of fixed-price forward contracts by hydro firms exceeded their firm energy obligations after 2006. The case analyzed in Section 3, in which the forward contract quantity is higher than the firm energy quantity, would not have been expected based on observed contract quantities before the reliability options were introduced. Instead, it represents an endogenous response by hydro generators to sell more forward contracts after 2006.

We observe the opposite pattern for forward contract sales by thermal generators (Figure 11). In the seven years before the introduction of the reliability options, the net forward contract position of thermal generators represented 24.1 percent of total generation.

Figure 12: Reservoir levels as a share of forward contract obligations fell after the introduction of the reliability options

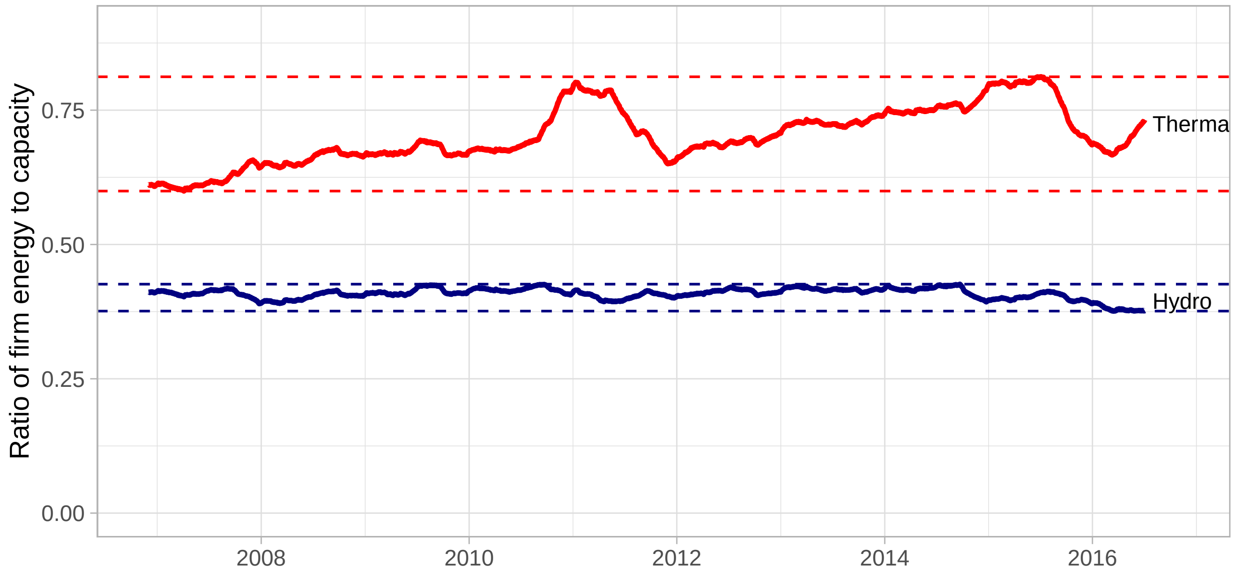


Notes: The graph shows the aggregate reservoir storage levels in Colombia, expressed as the number of days of the net fixed price forward contract position that could be covered by the stored volumes.

This fell to 16.2 percent of total generation in the first seven years with reliability options—a decline of 7.9 percentage points or nearly 33 percent. Thermal generators have always sold a lower quantity of forward contracts than what their firm energy obligations are (or would have been). However, this gap has increased, from about 10 percent of total generation in 2007 to more than 20 percent by 2015.

As discussed in Section 3, the reliability options provide insurance for hydroelectric generators against being unable to meet their fixed-price forward contract obligations because of a reduction in reservoir inflows. This creates the incentive to offer forward contracts at more attractive prices relative to the forward contract offers of the thermal units (Figure 10). In addition, the mechanism may also crowd out a form of self-insurance employed by hydroelectric generators: storing more water in their reservoirs as a buffer against potential future supply shortfalls. Figure 12 shows the hydroelectric reservoir levels before and after introducing the reliability options, expressed as the number of days of forward contract quantities. Reservoir levels vary over the year because of the pattern of dry and rainy seasons. However, the average storage level fell after introducing the reliability options in December 2006. The average storage level in the seven years before represented 129 days of the forward contract quantities. The average level fell to 96 days

Figure 13: Thermal generators received a higher allocation of firm energy relative to their nameplate capacity



Notes: The graph shows the ratio of the 90-day-forward moving average of total firm energy to the 90-day-forward moving average of total nameplate capacity by the type of generation firm (predominantly hydro or predominantly thermal). The dashed lines show the minimum and maximum values of the ratio for each type of firm.

of the forward contract quantities in the seven years after—a drop of more than one month of reserves. The lower average storage levels increased the susceptibility of the system to adverse hydrological conditions and may have contributed to the more volatile spot prices after the introduction of the reliability options (Figure 3) as well as the severity of the electricity crises during the El Niño events of 2009–10, 2015–16, and 2023–24.

Figures 10 and 11 show the backcasted firm energy quantity before introducing the reliability options. The red dashed line uses the mean ratio of nameplate capacity to firm energy quantity for the year after the reliability options were introduced. The grey shaded area shows the estimated firm energy based on the full range of this ratio, from its minimum to maximum value, in the ten years after 2006. Figure 13 shows the trend in this ratio over the ten years. This ratio was close to 40 percent for hydroelectric firms throughout the entire period. The lack of volatility in the ratio provides reassurance that our method for estimating the firm energy of hydro units in Figure 10 was appropriate. Conversely, thermal firms had a large increase in the ratio of firm energy to nameplate capacity, increasing from about 60 percent to over 80 percent during the ten years after 2006.

The firm energy calculation for thermal plants is based on historical plant availability and the quantities of contracted fuel supply. Figure 13 demonstrates that the thermal plants were able to change operational and fuel supply arrangements to increase significantly their regulated firm energy quantities.

Our long-run analysis in this section reveals that the introduction of reliability options induced significant changes in the fixed-price forward-contracting behavior of both hydroelectric and thermal generators. Hydroelectric generators increased their sales of forward contracts and reduced their reservoir levels relative to their contract quantities. While this may have been an expected profit-maximizing response to the reliability options, it likely contributed to greater spot price volatility and increased the Colombian market's vulnerability to adverse hydrological conditions. Although both fixed-price forward contracts and reliability options might independently improve system reliability, it is the interaction between the two instruments that leads to these unintended consequences. Given these findings, the next section explores an alternative approach to long-term resource adequacy.

6 Alternatives to capacity-based mechanisms

The design of the reliability options had three objectives: mitigating market power, providing incentives for firms to make their generation capacity available, and providing incentives for firms to invest in new generation (Fabra, 2018). As shown in Section 3, fixed-price forward contracts satisfy at least the first two objectives. If generators sell fixed-price forward contracts, they have less incentive to exercise market power by restricting their output to increase the spot wholesale market price. Moreover, fixed-price forward contract obligations provide a strong financial incentive to generators to supply at least their contracted quantity of energy. In the case of hydroelectric generators, fixed-price forward contracts are likely to provide incentives to hold additional water in storage as insurance against future periods of low inflows.

This paper demonstrates for the case of the Colombian electricity market that the combination of the reliability options with fixed-price forward contracts can undo the market-efficiency-enhancing effects of fixed-price forward contracts. During the endogenously chosen scarcity periods, fixed-price forward contracts no longer motivate firms to produce at least their fixed-price forward contract quantity of energy, which encourages hydro firms to sell a higher quantity of forward contracts than the generation quantity they can produce under stressed supply conditions. As a result, the combination of fixed-price forward contracts and reliability options performs worse at guaranteeing generation availability during adverse conditions than either is likely to do in isolation.

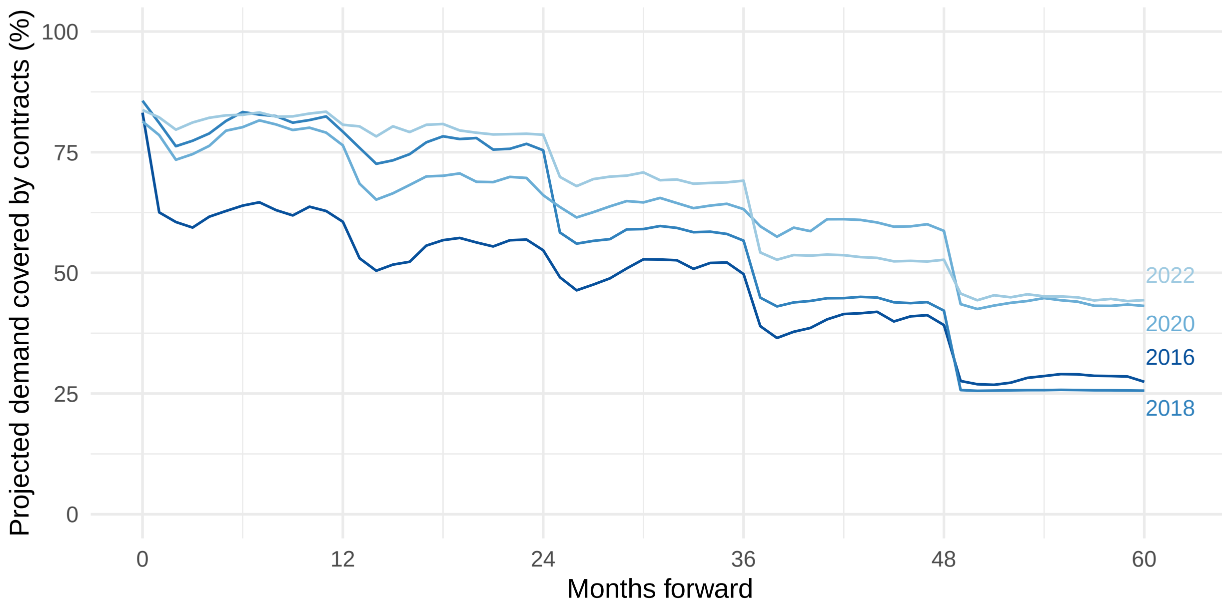
Thus far, we have not discussed the third objective of the reliability options: providing an incentive to invest in new plants. In theory, the guaranteed stream of future payments to new generation plants from selling reliability options will induce the entry of generation plants that would not otherwise be built. However, the performance of reliability options in maintaining sufficient thermal generation capacity as backup during dry years in Colombia has been disappointing. Several new thermal generation plants that sold firm energy were never built or were completed far behind schedule (McRae and Wolak, 2016). Some existing thermal plants failed to procure sufficient input fossil fuel to operate at capacity during the 2015–16 scarcity period. In one case, a thermal plant walked away from its firm energy obligations and refused to produce electricity despite receiving reliability option payments during the previous nine years.

While the reliability options failed to guarantee that sufficient generation was available during low hydro conditions, the existing design of fixed-price forward contracts in Colombia cannot satisfy this objective either. The main problem is that few electricity retailers in Colombia buy forward contracts with a time horizon until delivery greater than three years. Figure 14 shows the forward contract coverage of projected demand over the subsequent five years as of the year-end of 2016, 2018, 2020, and 2022. Approximately 80 percent of retail demand is covered by forward contracts, with the remaining 20 percent purchased on the spot market. These shares have changed little over time. While the share of demand covered by forward contracts more than two years before delivery has increased, this share still remains relatively low. Less than 50 percent of projected demand more than four years before delivery is covered by forward contracts.

The small size of the market for fixed-price forward contracts with a long lead time to delivery makes it difficult for potential new generators to participate in this market. The process of siting, permitting, and building a new generation plant takes many years in Colombia, and there is potential for unanticipated and lengthy delays. This makes it risky for new generators to sell fixed-price forward contracts with a fixed start date just two or three years later. As a result, the participants in the long-term forward contracts market are overwhelmingly the existing large generators.

Wolak (2022) proposes a standardized fixed-price forward contract approach to long-term resource adequacy that addresses these shortcomings. The product that all retailers must purchase in these standardized forward contracts is an annual energy quantity that

Figure 14: Less than half of the projected regulated demand in four years is covered by forward contracts between retailers and generators



Notes: The figure shows forward contract coverage at the end of each calendar year for the following five years (XM Compañía de Expertos en Mercados, 2021).

"delivers" on an hourly basis according to the hourly system load shape within the year. This product would be sold through periodic centralized auctions to ensure that retailers and large consumers receive a competitive price for this long-term resource adequacy product. These contracts would be sold sufficiently far in advance and with sufficient duration to provide the revenue stream necessary to support needed investment in new generation capacity.

A key feature of this mechanism is that it assigns all system-wide risk associated with meeting hourly system demands throughout the year to sellers of long-term resource adequacy energy. Because the annual energy "delivers" according to the hourly share of total energy consumed in that hour, if there is a substantial increase in demand during some hour of the year, sellers of this long-term resource adequacy energy know that more of their annual energy will be used to meet the realized fixed-price forward contract obligations assigned to this period under this mechanism.[26] Thurber et al. (2022) present a game-based comparison of the performance of a traditional capacity-based long-term resource adequacy mechanism to this standardized fixed-price forward contract (SFPFC)

26. Wolak (2021) presents several examples of how this feature of the mechanism operates.

approach.

A key feature of the SFPFC resource adequacy mechanism is that 100 percent of realized system demand in every hour is covered by a standardized fixed-price forward contract. This feature addresses the reliability externality discussed earlier. However, it does not mean that 100 percent of the hourly output of any generation unit owner or the hourly consumption of any retailer or large customer is covered by a fixed-price forward contract. The mechanism allows significant scope for producers and consumers to realize financial benefits from hedging the difference between their standardized fixed-price forward contract obligations and their short-term market sales and purchases.

7 Conclusion

In this paper, we demonstrate how reliability options in the Colombian electricity market create perverse incentives for generators through their interaction with the fixed-price forward contract market. Our simple theoretical analysis shows that reliability options can provide incentives for generators with market power to withhold capacity to trigger a scarcity period—or sell excess generation to avoid a scarcity period. In the long term, reliability options may lead hydroelectric generators to sell more fixed-price forward contracts while holding less water in storage, increasing the system's vulnerability to low inflows and electricity supply shortfalls.

We provide a wide range of empirical evidence consistent with these predictions using a rich dataset from the Colombian market. We find that generators respond to the incentives of reliability options in the short and long run. For many days of our sample, the largest generators have the ability to trigger a scarcity period with their short-term offer behavior, and when it is in their ex-post interest, they do so with a high frequency. In the long run, after the introduction of the options in 2006, hydroelectric firms sold more fixed-price forward contracts and reduced their reservoir levels relative to their contract positions. Thermal generators took actions to continuously increase their administratively determined firm energy quantities as a percent of the nameplate capacity of their generation units after the introduction of the reliability mechanism.

We believe these results have important implications for the design of long-term resource adequacy policies in electricity markets worldwide. Reliability options do not appear to be the most cost-effective approach to ensure generation availability during scarcity conditions. As the transition to electricity systems with a high share of intermittent renewable generation makes such scarcity conditions increasingly common, a critical reassessment of current market designs is essential to ensure a reliable and affordable electricity supply.

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A Additional details of firm energy calculation

A.1 Daily firm energy calculation

Let $q_{jd}(deviation)$ be the daily firm energy deviation (*Desviación Diaria de la Obligación de Energía Firme* or *DDOEF* in Spanish) for generator j on day d. This is the difference between the daily *ideal* generation for generator j and the daily firm energy for generator j.[27] Both quantities are summed across the plants i belonging to generator j (I_j).

$$q_{jd}(deviation) = \sum_{i \in I_j} \sum_{h=1}^{24} q_{ijhd}(ideal) - \sum_{i \in I_j} q_{ijd}(firm) \tag{7}$$

If $q_{jd}(deviation)$ is positive, meaning that generator j has an *ideal* generation exceeding its firm energy obligation, then during scarcity hours the generator will be paid for the excess generation. The hour h firm energy for this calculation, $q_{jhd}(firm)$, is determined by a pro rata assignment of the daily firm energy using firm $j's$ the share of *ideal* generation in each hour.

$$q_{jhd}(firm) = q_{jd}(firm) \frac{q_{jhd}(ideal)}{\sum_{h=1}^{24} q_{jhd}(ideal)} \tag{8}$$

In this expression, $q_{jd}(firm)$ is the daily firm energy for generator j and $q_{jhd}(ideal)$ is the hourly *ideal* generation for generator j, in both cases summing across all of the plants $i \in I_j$. The hourly firm energy is only calculated for the generators with a positive firm energy deviation.

The generators with positive $q_{jd}(deviation)$ receive an hourly firm energy refund (*Desviación Horaria de la Obligación de Energía Firme* or *DHOEF* in Spanish) during scarcity hours. This refund is the difference between the wholesale price and the scarcity price, multiplied by the difference between the *ideal* generation and the hourly firm energy.

$$R_{jhd}(firm) = \max(0, P_{hd} - P_d(scarcity))(q_{jhd}(ideal) - q_{jhd}(firm)) \tag{9}$$

The total daily firm energy refunds are the sum of the hourly firm energy refunds for

27. The system operator in Colombia solves two generation dispatch problems, with and without accounting for transmission constraints. The *ideal* generation of a plant is the generation sold under the assumption of infinite transmission capacity.

the generators with positive firm energy deviations (J_+).

$$R_d(firm) = \sum_{j \in J_+} \sum_{h=1}^{24} R_{jhd}(firm) \tag{10}$$

The firm energy refunds $R_d(firm)$ are assigned to the generators with negative firm energy deviations (J_-). They need to make firm energy payments ($S_{jd}(firm)$). The assignment is based on the share of the daily firm energy deviation out of the total of the negative firm energy deviations.

$$S_{jd}(firm) = R_d(firm) \frac{q_{jd}(deviation)}{\sum_{j \in J_-} q_{jd}(deviation)} \tag{11}$$

By construction, the total payments by the generators with negative firm energy deviations will equal the total refunds to the generators with positive firm energy deviations.

We note that the obligations for the generators with *ideal* generation below their firm energy obligation depend only on their total *ideal* generation for the day. The intraday pattern of generation is irrelevant. In particular, for days when the wholesale price exceeds the scarcity price in only some hours, it does not matter whether the generator produced more or less of its output during the scarcity hours.

A.2 Example of firm energy calculation

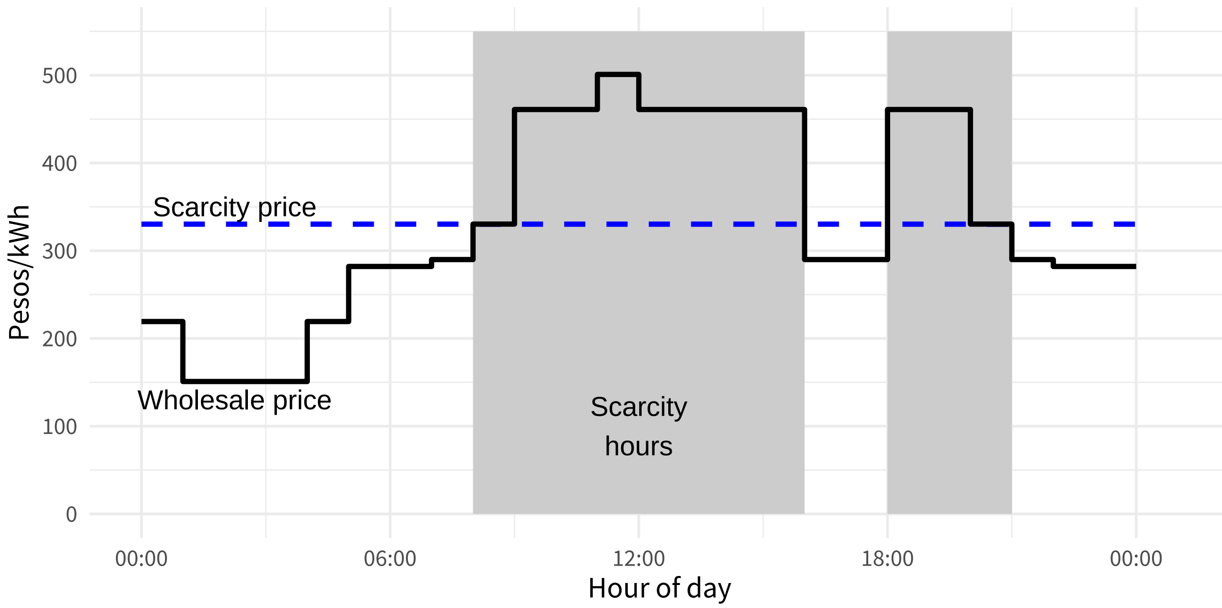
We illustrate the calculation in Section A using data for one day: May 28, 2015.

The wholesale price exceeded the scarcity price on 11 hours of the example day (Figure A1). The scarcity price of 330.27 pesos/kWh was constant for all hours in May 2015. The wholesale price reached a daily maximum of 500.94 pesos/kWh at 11:00AM on May 28. There were two hours (8:00AM and 8:00PM) with a wholesale price of 330.34 pesos/kWh, a fraction of a peso above the scarcity price.

The daily firm energy obligation of each generator was scaled so that the aggregate firm energy was exactly equal to the aggregate *ideal* generation.[28] The unadjusted firm energy on May 28 was 197.8 GWh, divided between 187.4 GWh of dispatched generation and 10.4 GWh of non-dispatched generation. The *ideal* generation on May 28 was 175.9 GWh for

28. More specifically, the aggregate firm energy is scaled to equal the total domestic demand, including both self-consumption by generators and allocated transmission losses. Electricity exports to Venezuela and Ecuador are excluded from domestic demand. These exports comprised 0.4 percent of total electricity demand on May 28, 2015. We ignore this additional adjustment for the purpose of this example.

Figure A1: Hourly wholesale prices and scarcity price on May 28, 2015

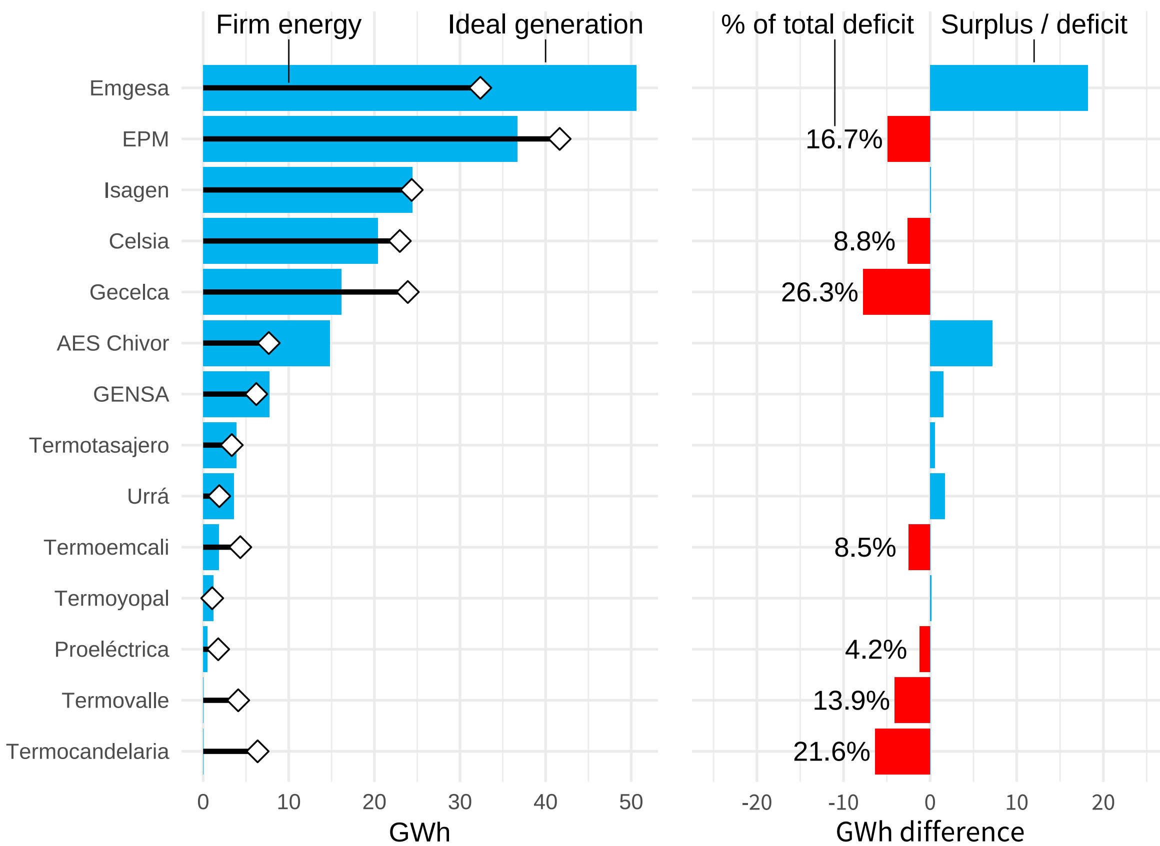


the dispatched plants and 10.4 GWh for the non-dispatched plants. The adjustment factor to scale the firm energy of the dispatched plants was $175.9/187.4 = 0.939$.

Because there was a scarcity period for at least one hour on May 28, the scaled firm energy of each generator was compared with its *ideal* generation (left panel of Figure A2). Emgesa had a positive daily firm energy deviation: its *ideal* generation of 50.6 GWh exceeded its firm energy obligation of 32.4 GWh. In contrast, EPM had a negative daily firm energy deviation, with its *ideal* generation of 36.7 GWh below its firm energy obligation of 41.6 GWh. There were seven generators with positive deviations and seven with negative deviations (right panel of Figure A2). By construction, the sum of the positive and negative deviations equals zero.

The hourly firm energy obligation is calculated only for the generators with positive deviations. The top panel of Figure A3 shows the calculation of the hourly positive deviations for Emgesa on May 28. The top line shows the hourly *ideal* generation for Emgesa. The bottom line shows the proportional allocation of the daily firm energy, based on the share of *ideal* generation each hour out of the total *ideal* generation. Emgesa received a firm energy refund for the 11 scarcity hours. This refund was calculated as the difference between its *ideal* generation and the allocated firm energy, multiplied by the difference between the scarcity price and the wholesale price. The bottom panel of Figure A3 shows the hourly refund. The hourly refund was almost zero at 8:00AM and 8:00PM, because the

Figure A2: Daily generation and firm energy by firm for May 28, 2015



difference between the wholesale price and the scarcity price in those hours at only 0.08 pesos/kWh.

We repeated this calculation for the six other generators with positive firm energy deviations (left panel of Figure A4). Emgesa had the largest daily refund of 1009 million pesos. Isagen had a very small refund (6 million pesos) because its daily *ideal* generation was very similar to its daily firm energy obligation. The sum of the positive firm energy refunds was 1726 million pesos.

The positive refunds were allocated to the seven generators with negative firm energy deviations (right panel of Figure A4). This allocation was based on the share of each generator's negative firm energy deviation of the total negative firm energy deviations. This share is shown on the right panel of Figure A2. For example, EPM had a generation shortfall of 4.9 GWh, which was 16.7 percent of the total negative firm energy deviations of 29.4 GWh. As a result, EPM had to make a firm energy payment of 289 million pesos, equal to a 16.7 percent share of 1726 million pesos. By construction, the total payments for negative firm energy deviations were equal to the total refunds for positive firm energy deviations.

Figure A3: Hourly generation, firm energy allocation, and firm energy refund for Emgesa on May 28, 2015

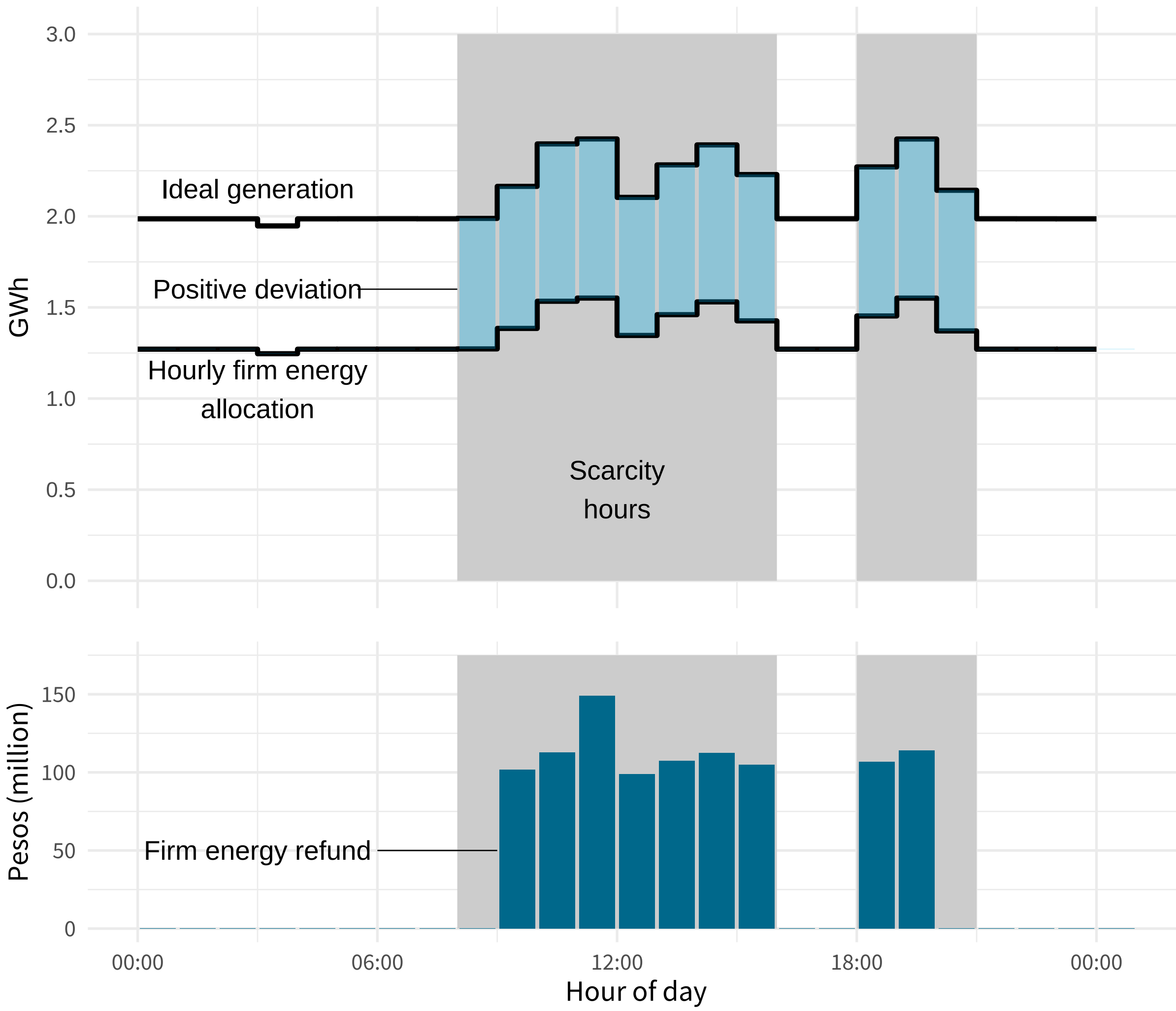


Figure A4: Firm energy obligations and payments on May 28, 2015