Reliability Options in Renewable-Dominated Electricity Markets*

Shaun D. McRae† and Frank A. Wolak‡

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Abstract

Recent rolling blackouts in industrialized economies have highlighted the need for a capacity mechanism to ensure a reliable electricity supply. We demonstrate severe shortcomings of a popular capacity mechanism—reliability options—caused by their interaction with fixed-price forward contracts for energy. Large generators can trigger the reliability option exercise, reducing the incentive that forward contracts provide for firms to not exercise market power. Hydroelectric generators sell more forward contracts and store less water, reducing system reliability. We empirically demonstrate that Colombian generators respond to these incentives in the short and long run. The objectives of reliability options could be achieved at lower cost by reforming the forward contract market.

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†Centro de Investigación Económica and Department of Economics, ITAM. Email: shaun.mcrae@itam.mx.

‡Program on Energy and Sustainable Development and Department of Economics, Stanford University, Stanford, CA 94305-6072. Email: wolak@stanford.edu.

1 Introduction

A reliable electricity supply has long been a hallmark of industrialized economies. However, recent rolling blackouts in places such as California (Meyer and Waters, 2020), Texas (Jacobs, 2021), and Australia (Murphy and Knaus, 2017) have challenged this expectation. Electricity system operators implement rolling blackouts when there is insufficient generation to meet demand. The proximate cause in each of these cases was an extreme weather event that simultaneously increased electricity demand and reduced generation availability from renewable and non-renewable sources. Such extreme temperature events are "very likely" to occur more frequently with increased global warming (IPCC, 2023). Furthermore, 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. These trends necessitate a critical evaluation of mechanisms to ensure electricity reliability.

While the exact timing of extreme weather events may be unpredictable, they are not unexpected. Under the traditional vertically integrated monopoly model, electricity systems were designed to have sufficient generation capacity to cope with all foreseeable contingencies. However, in restructured electricity markets, no single entity is responsible for ensuring demand is met under every possible system condition. Electricity retailers lack an incentive to acquire sufficient energy in the forward market because the cost of insufficient procurement is spread across all customers through random curtailment during rolling blackouts.[1] Conversely, electricity generators lack an incentive to keep infrequently used capacity available because price caps in the wholesale market prevent the price from rising high enough to clear the market. Given these shortcomings, there is widespread agreement that restructured electricity markets require a long-term capacity mechanism to ensure sufficient supply is always available to meet demand.

Historically, the design of capacity mechanisms provided weak incentives for plants to be available during critical system conditions (Bushnell et al., 2017). To address this limitation, many electricity markets are reforming their capacity mechanisms to provide stronger incentives for generators to be available when most required. One popular mechanism uses "reliability options". These are a financial instrument that provides market-based incentives through call option contracts purchased by the system operator

1. System operators cannot target rolling blackouts at the individual customer level, meaning all customers in a specific region are at risk regardless of their retailer's forward energy procurement, creating a "reliability externality" (Wolak, 2013).

from electricity generators.[2] The quantity of these options that generators can sell, known as their "firm energy," is fixed by regulators and differs by generation technology. Like traditional capacity payment mechanisms, 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," evolves through time and is indexed to the marginal cost of the highest-cost generation technology in the system. During "scarcity periods" when the wholesale spot price exceeds the scarcity price, generation firms that produce less than their firm energy must refund the difference between the spot and scarcity prices for their generation shortfall.

The financial structure of the reliability options can be represented by the following simplified expression for the hourly wholesale market revenue of a generation firm i.

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

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 q_i^f is the firm energy of generator i. The reliability option effectively imposes a financial penalty on generation firms for producing less than their firm energy ($q_i < q_i^f$) during scarcity periods ($P_s < P$).

In this paper, we demonstrate severe flaws with this type of reliability option design. First, we show that generation firms with the ability to exercise market power can affect whether a scarcity period is triggered. Even if the short-term wholesale market is typically competitive, market power problems are greatest during critical demand conditions. We show that a generator's incentive to trigger a scarcity period depends on their quantities of firm energy and fixed-price forward contracts for energy.[3] This is because the scarcity price sets a cap on the settlement price for all wholesale market transactions, including the price used to settle fixed-price forward contracts. The effect of this cap is that forward

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) within a specific timeframe. In the reliability option setting, the system operator (the buyer) has the right to buy the specified quantity of electricity from the generator (the seller) at the strike price. This option would only be exercised if the wholesale spot price for electricity (the price of the underlying asset) exceeds the strike price.

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, regardless of the market price at that time. In the context of electricity markets, generators typically sell fixed-price forward contracts to retailers, locking in the price for a specified electricity quantity at a future date. Importantly, these contracts are purely financial arrangements between generators and retailers, and are settled based on the difference between the spot and contract prices on the delivery date. They 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.

contracts no longer reduce the incentive of generators to exercise unilateral market power in scarcity periods.[4]

The short-run effects of the interaction between reliability options and fixed-price forward contracts are compounded in the long run. Because of the cap on the settlement price for forward contracts, generators selling forward contracts face a reduced financial penalty for having insufficient generation capacity to meet their contract obligations. This reduces their incentive to take costly actions to insure against generation capacity shortfalls. For example, hydroelectric generators have less incentive to store additional water in their reservoirs to supply at least their forward contract quantity during a drought. In the long run, hydroelectric firms will be willing to take on more risk by selling greater quantities of fixed-price forward contracts.

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 introduce 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]

We use hourly information 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 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

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 the ability to do so. Section 3.1 provides further detail on the incentive effects of fixed-price forward contracts.

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 and so has access to complete data on the forward contract positions of each market participant. XM publishes the hourly quantities of forward contracts bought and sold by each participant. This level of transparency is uncommon in electricity markets, where fixed-price forward contract quantities are typically unobserved. 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 forward contract data (McRae and Wolak, 2014; Wolak, 2000, 2007).

hydro inflows, storage levels, fossil fuel usage, and fossil fuel prices.

We first demonstrate that firms have the ability to choose whether the reliability option is exercised. We calculate the hour-by-hour inverse 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. 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 optimal hourly generation as the best response to its ex-post 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 demands when submitting offers in the short-term market. Analysis of plant-level offers provides further evidence that generators 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 forward contract quantities before and after their introduction in December 2006. As predicted by our theoretical discussion, the net forward contract quantities were higher for hydroelectric firms after December 2006, rising from 65 to 71 percent of total generation. This increase meant hydroelectric firms sold more forward contracts than firm energy, expanding the range over which firms can profitably exploit the mechanisms that we identify. 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 forward contract sales after the introduction of the reliability options, increasing their opportunities to profitably exercise short-run market power.

The Colombian example is relevant for other electricity markets that are increasing their share of intermittent renewable generation as part of the transition away from fossil fuels. Our results demonstrate that capacity payment mechanisms may have unexpected consequences in settings where generators have the ability to exercise unilateral market power. 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 reliability. Although our analysis focuses on intermittent hydro inflows, similar problems could arise in other markets with a high share of intermittent renewable generation from wind and solar, especially during periods when these resources are unavailable. This is an urgent issue to study because many countries are adopting capacity 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 necessary to serve future demand. This approach extends and standardizes the current bilateral market of bespoke fixed-price forward contracts. While regulation will be required to build liquidity in the long-term market for forward energy, eventually other types of forward contracting might develop and augment the standardized market. Developing such a system of forward markets would obviate the need for a separate capacity payment mechanism.

Related Literature

Holmberg and Tangerås (2023) and Bublitz et al. (2019) review the capacity mechanisms implemented in different electricity markets. 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. According to Holmberg and Tangerås (2023), strategic reserves are likely to be more efficient than market-wide capacity mechanisms in markets with a significant share of intermittent renewable energy. Capacity mechanisms also differ based on their procurement approach, which can be either centralized by the system operator or decentralized by 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 mitigate 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 generator market power and encouraging generation investment. His model does not consider the case of reliability options. 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 exercise of market power by the large incumbent generator in Ireland could increase electricity procurement costs by 40 to 100 percent relative to a competitive counterfactual.[7]

In contrast to the existing literature, our analysis focuses on the interaction between three markets: the short-term wholesale market, the fixed-price forward contract market, and the capacity market (reliability options). Our stylized model shows 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 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 by the system operator and ultimately paid for by consumers—can lead to lower reliability of the electricity system.

Our paper provides a detailed empirical analysis of the short-term and long-term performance of a capacity mechanism using market data. A unique feature of the Colombian wholesale market is the quality of the data provided by the system operator about the wholesale market, including the plant-level offers and generation, the hourly forward contract positions of every firm, and the reliability option payments. The richness of the data allows us to test the predictions of our stylized model about the interaction between the short-term wholesale market and the forward contract market. We show that generators

7. 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 and strike prices as stochastic processes and varying the correlation between them.

recognize and respond to the incentives provided by the reliability options.

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 potential short-run and long-run distortions from reliability options. Section 4 presents a series of descriptive and analytical results for 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 outlines our alternative approach for ensuring long-term resource adequacy based on standardized forward contracts. Section 7 concludes.

2 Background

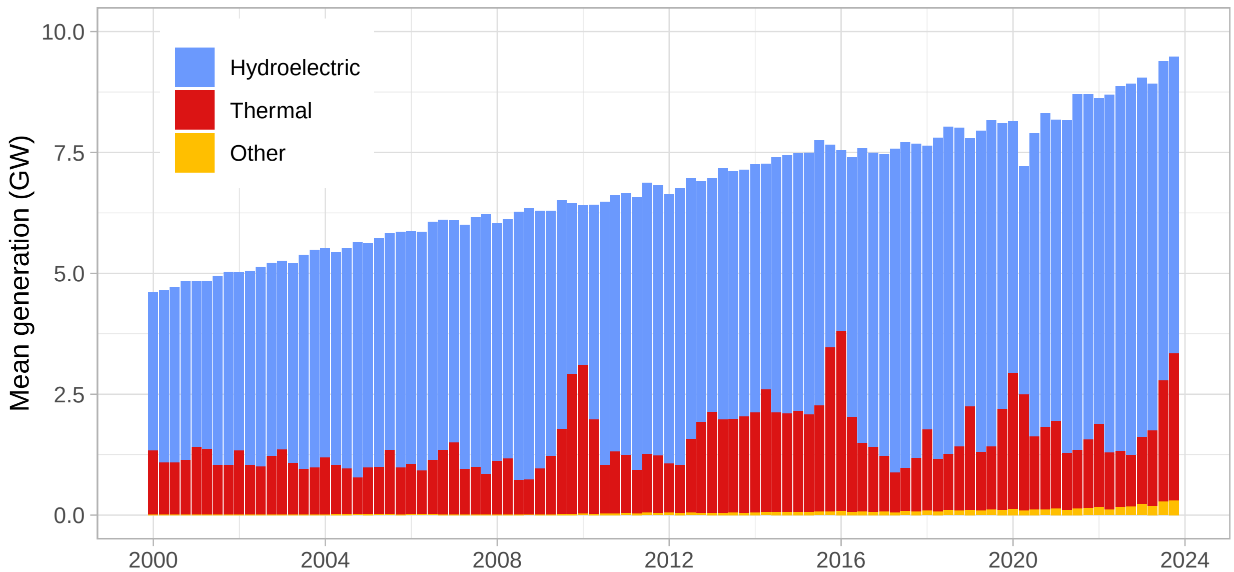
Colombia's electricity generation remains predominantly hydroelectric, similar to other South American countries. From 2000 to 2023, the annual mean generation grew from 4.7 gigawatts (GW) to 9.2 GW, reflecting an average growth rate of 3.0 percent.[8] Between 2000 and 2009, hydro generation met most 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 of the composition of electricity generation in Colombia is the periodic reduction in hydroelectric energy 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

8. 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.

Figure 1: Hydroelectricity remains the dominant form 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 8 for an example showing the calculation of mean generation in GW.

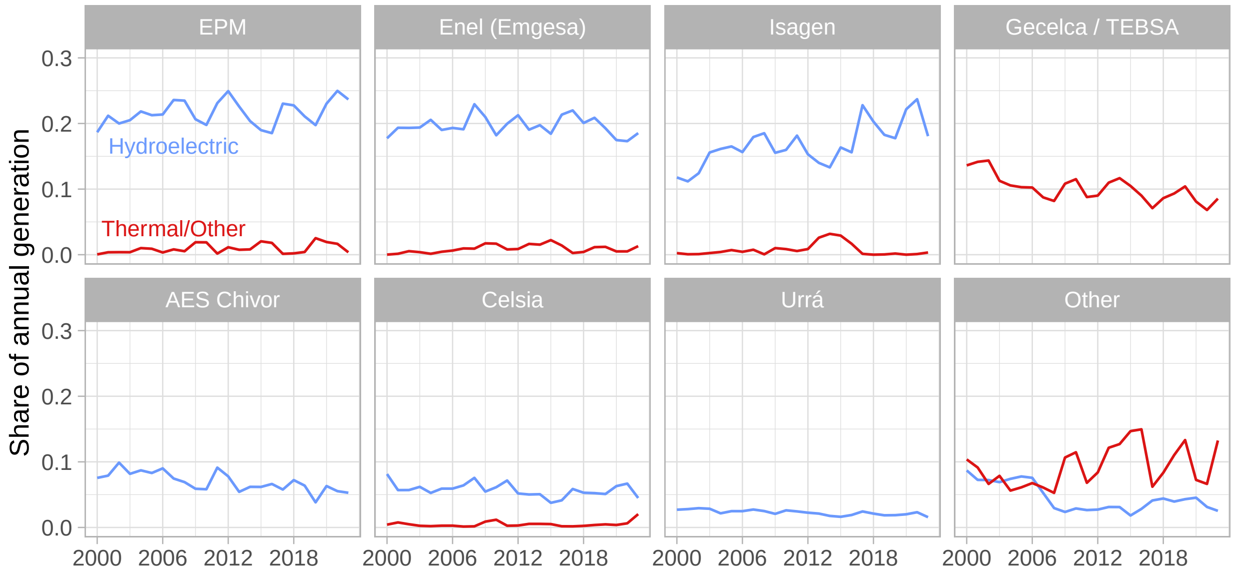
combined generation market share of about 60 percent (Figure 2).[9] These three firms are predominantly hydroelectric, each with a small thermal generation capacity. The largest thermal plant is Termobaranquilla (TEBSA), partially owned by the thermal generator Gecelca. Three smaller firms have significant 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-price forward contracts for energy, and the sale of reliability options. In the wholesale market, generators submit daily price and hourly quantity offers for their units to a central pool run by XM, the system operator.[10] XM uses these offers to calculate the operational dispatch

9. 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.

10. The wholesale market design in Colombia is different from the cost-based short-term markets used elsewhere in Latin America (Galetovic et al., 2015; Rudnick and Montero, 2002). In a cost-based market, the price component of offers is restricted to be close to marginal cost.

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).

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. The "spot" price used for financial settlement is based on the price offer of the marginal generation plant each hour in the ideal dispatch (Mastropietro et al., 2020).[11] This is the wholesale price that we use throughout our analysis.

Market participants can reduce their financial exposure to the spot market by signing long-term, fixed-price forward contracts for energy. Electricity generators sell forward contracts 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

11. Since 2009, thermal generators have submitted the startup costs 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 the offers in the Colombian market. They found that the market reform reduced production costs, although this reduction was not passed through to lower wholesale prices. Reguant (2014) and Jha and Leslie (2021) show how startup costs can change generator behavior in wholesale electricity markets.

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 forward contracts that retailers have to 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 for these options (in $ per MW) is determined by auctions for long-term investment in new generation capacity, first held in May 2008 and December 2011.[12] The quantity of reliability options that each plant 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.[13] Both existing and new generation plants receive these payments from selling reliability options.

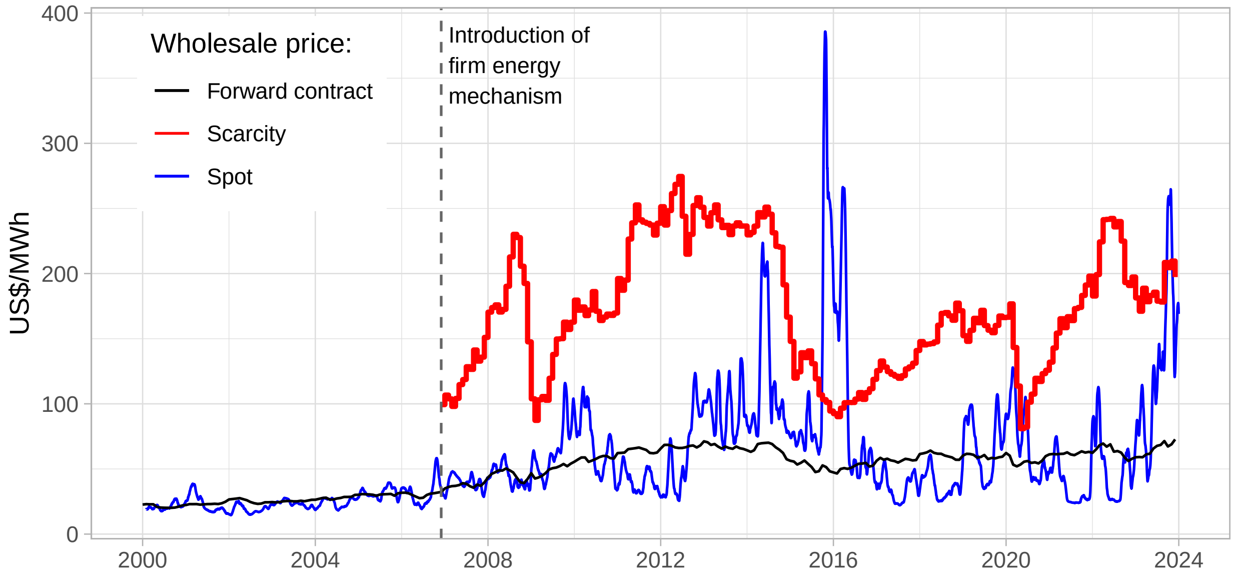
Compared to other capacity mechanisms, the novel feature of reliability options is that they are a financial instrument that provides market-based incentives for generators. In Colombia, the strike price for the options, known as the "scarcity price," is recalculated each month based on changes in an international fuel oil benchmark. During periods when the spot price exceeds the scarcity price, the generators selling reliability options are expected to produce at least their firm energy quantity. All wholesale market transactions, including settling the fixed-price forward contracts, occur at the scarcity price. If generators produce less or more than their firm energy quantity during scarcity periods, they pay or receive the difference between the wholesale price and the scarcity price, multiplied by their deviation from the firm energy quantity. This creates a financial incentive for generation firms to produce at least their firm energy quantity during periods of system scarcity.

For most hours during the first nine years after introducing reliability options, the 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 market price exceeded the scarcity price. During this period,

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

13. 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.

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



Notes: The figure shows the monthly mean wholesale market 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.

the generation firms that did not produce their firm energy quantity were required to pay back the shortfall, multiplied by the difference between the spot and scarcity prices.

3 Illustrative model

In this section, we provide a model to illustrate the interaction of reliability options with the market for fixed-price forward contracts for energy. Under certain conditions, suppliers have an incentive to withhold output to cause scarcity conditions. In turn, these incentives may lead generators to sell more or fewer fixed-price forward contracts for energy.

3.1 Incentive effects of forward contracts

Unilateral market power is the ability of a firm to raise (or lower) market prices. 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 market power. Because all firms submit their offers into the short-term market simultaneously and the realized demand is unknown at that time, the precise form of the residual demand curve is unknown when a firm submits its offers. However, because firms repeatedly interact in this market and the offers submitted by competitors are observed with some delay, generators can predict the residual demand curve that they are likely to face.

When the firm chooses the offer curve to submit to the market operator, it effectively chooses the point along its realized residual demand curve where it will operate. The firm will produce the generation quantity and receive the wholesale price set by the price and quantity pair where its offer curve crosses its realized residual demand curve. As discussed in Wolak (2000) and Wolak (2003), the firm chooses the offer price and quantity increment combinations that make up its aggregate willingness-to-supply curve given the distribution of possible residual demand curves that it faces to maximize its expected profits given the variable cost of operating its generation units.

We now consider a simple theoretical model of fixed-price forward contracts. Suppose a generator faces a downward-sloping inverse residual demand curve:

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

The variable q in this expression is the generation quantity of 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.[14] 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 forward contracts, the generator will act as a monopolist off its residual demand curve and produce where marginal revenue equals marginal cost. Assume the marginal cost for the generator is zero. In this case, $MR = 400 - 200q = 0$, implying the firm will maximize profits by choosing $q = 2$. The market price corresponding to this

14. 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 step-function residual demand curves.

generation quantity is \$200.

Fixed-price forward contracts reduce the incentive for electricity generators to restrict their output and increase the 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:

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

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[15];
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 $c(q)$.

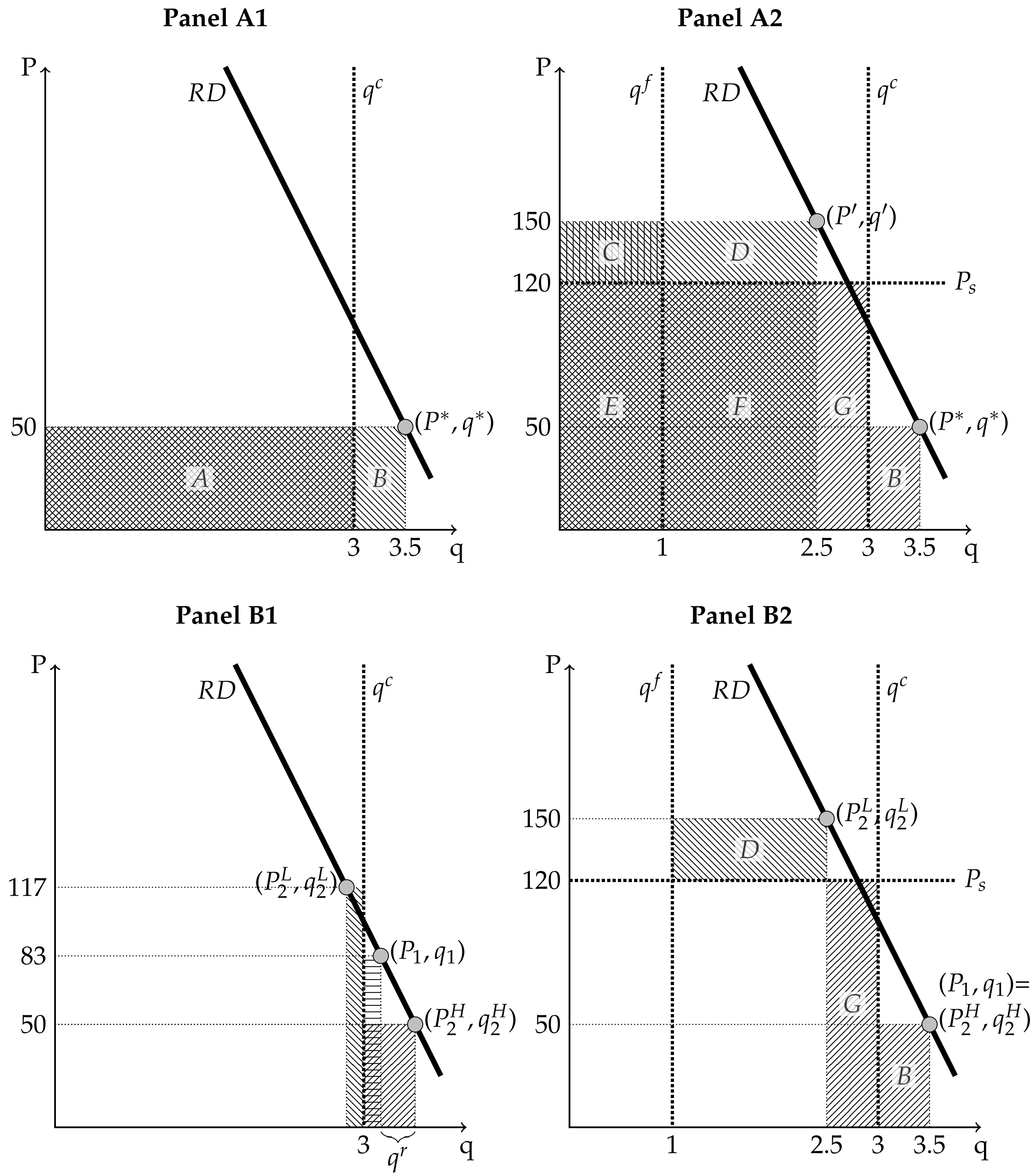
Equation (3) can be rewritten in the form of a Contract for Differences, which represents the typical way in which the forward contracts are settled by XM:

$$\Pi = P(q)q - (P(q) - P^c)q^c - c(q) \tag{4}$$

The forward contract obligation motivates the firm to increase its output above $q = 2$, because of the additional term $-P'(q)q^c$ in the first-order condition for profit maximization. This incentive is shown graphically in Panel A1 of Figure 4. Given its residual demand, the firm can still increase the market price to \$200 by restricting its generation to 2. However, the firm can maximize its profits by increasing its generation to 3.5 (Panel A1). The wholesale price falls to \$50 and reduces the wholesale market revenue to the area $A + B$. The forward contract obligation is the area A, leaving the firm with a positive net revenue of the area B, plus its forward contract revenue. 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 produce at any point along its residual demand curve.

15. 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).

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



Notes: Panels A1 and B1 show the calculation of net revenue with only 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 interaction of forward contracts and reliability options

Suppose we introduce reliability options to the setting where generation firms have fixed-price forward contracts (Panel A2 of Figure 4). 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 profit for the firm is given by Equation (5).

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

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 also predetermined when the firm chooses its generation offer[16];
3. the revenue from selling the generation quantity q at the spot price $P(q)$;
4. the cost of fulfilling the supplier's 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 generation $c(q)$.

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 wholesale market transactions at the scarcity price (Section 2). Equation (5) is written so that generation revenue is uncapped (component 3) and, if the spot price exceeds the scarcity price, the generator must pay the difference between the spot and scarcity price for its full firm energy obligation (component 5). However, this is exactly equivalent to capping the generation revenue at the scarcity price and the generator

16. 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.

paying (or receiving) the difference between the spot and scarcity price for the difference between the generation and firm energy quantities:

$$
\begin{aligned}
&P(q)q - \max(P(q) - P_s, 0)q^f && (6)\\
&\quad = \min(P(q), P_s)q + \max(P(q) - P_s, 0)Q - \max(P(q) - P_s, 0)q^f && (7)\\
&\quad = \min(P(q), P_s)q + \max(P(q) - P_s, 0)(q - q^f) && (8)
\end{aligned}
$$

Suppose the spot price $P(q)$ is below the scarcity price P_s. In that case, Equation (5) simplifies to Equation (3), with the addition of the firm energy revenue $P^f q^f$ (Panel A2 of 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 net 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 (5) 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 $(P(q) - P_s)q^f$, equal to the area C on Panel A2.[17]

The generation revenue, net of 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

17. 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 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.

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 for 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 a 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 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 curves it submits and 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 production over multiple periods. The context is the choice by hydroelectric generators on how much to produce each period and how much to store in their reservoirs to produce in a future period. We assume there is uncertainty in the future hydroelectric 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 residual demand curve stays constant for both 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 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 optimal 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 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 storage.

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 it would be 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 optimal 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, the optimal 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 of 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 $P^f q^f$ to the generator. The implicit promise of the reliability option instrument is that it provides incentives for the generator to ensure sufficient generation is available during dry periods when it is most required. 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, while q^c is fixed in the short term when generation firms submit their offers to the wholesale market, q^c is a choice variable in the long term.[18] In the bilateral forward contract market, generation firms choose the quantity and price of forward contracts they offer to sell. There are no regulatory minima or maxima for the quantity of 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 the high spot price. Moreover, to reduce the risk associated with a large quantity of forward contracts, the hydroelectric generators will hold more water in storage. The hydroelectric firms will require a high forward contract price P^c to compensate them for the additional risk.

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. They are no longer required to insure themselves against 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.

18. 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.

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 little 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 higher value (as a share of nameplate capacity) for thermal 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 no 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 reliability options will shift out the forward contract offer curve of hydroelectric generators but do 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.

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 their offer behavior.

The reliability options will also affect long-term 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 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

In this section, we analyze the offer and operating behavior of the generators in the Colombian wholesale electricity market to demonstrate the real-world relevance of the predictions from the model in Section 3.

The Colombian market operator XM provided the data for our analysis. In this section, we use hourly information on the market's operation from December 2006 to June 2016. The 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 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 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.[19]

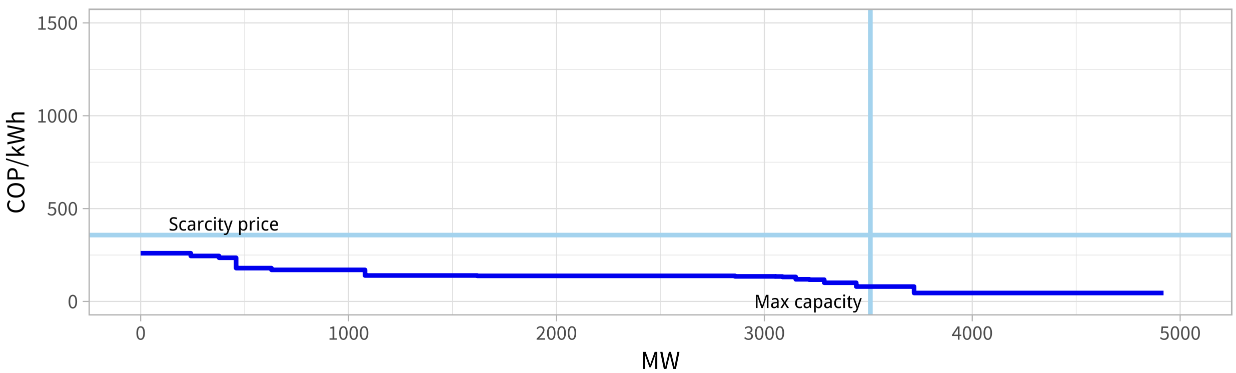
Figure 5 shows the three possible configurations for the realized residual demand curve. The first case is when the firm's inverse residual demand curve lies below the scarcity price for all feasible generation quantities. The nameplate capacity of the generation units determines the maximum generation 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 inverse residual demand curve lying below the scarcity price, there will not be a scarcity period for any choice of generation quantity.

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

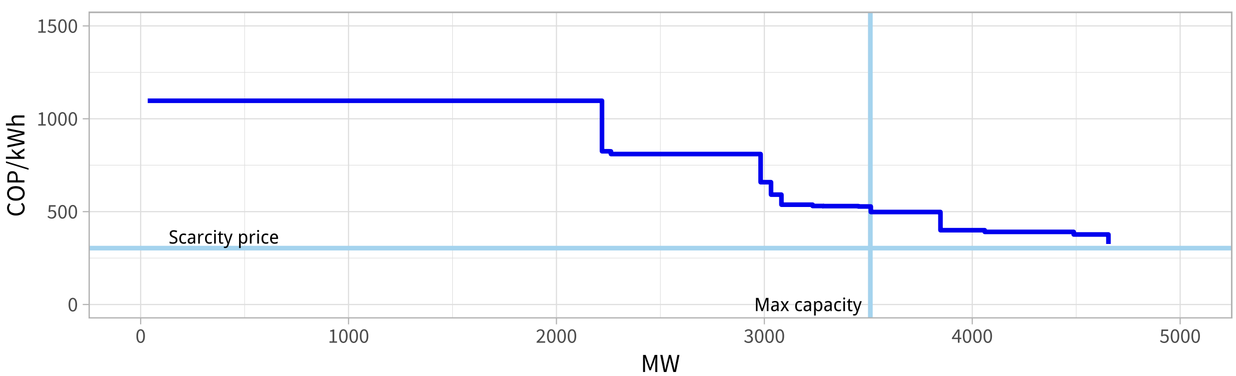
19. As noted earlier, because the offers of other suppliers and the realized value of system demand are unknown when the generation firm submits its offer curve, it is unlikely that the offer curve will intersect the realized residual demand curve at exactly the *ex-post* profit-maximizing price and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

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

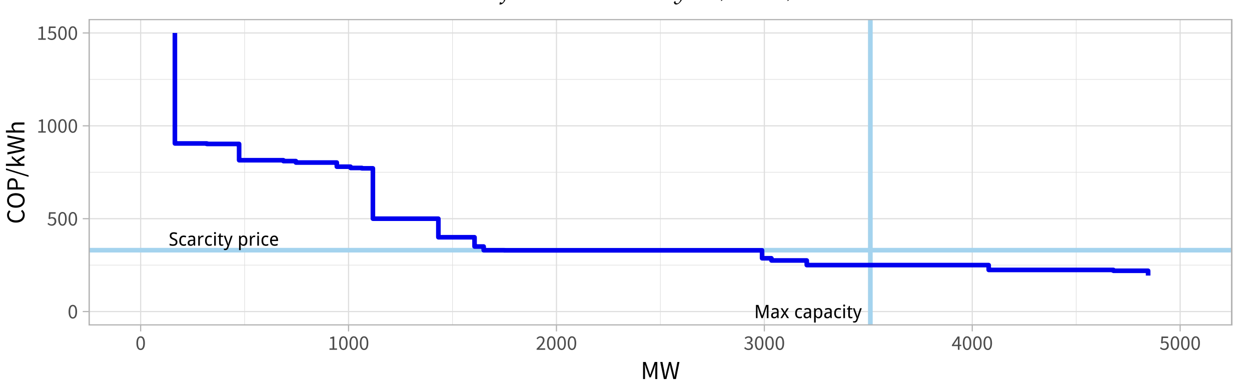
Case 1: Scarcity period cannot be induced by EPM
Residual demand for EPM on July 25, 2015, at 6:00 PM.



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.



occur regardless of the firm's generation quantity.

The final case is the one in which the inverse 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 at the time 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 producing less than 1600 MW or could have avoided a scarcity period by producing more than that quantity.

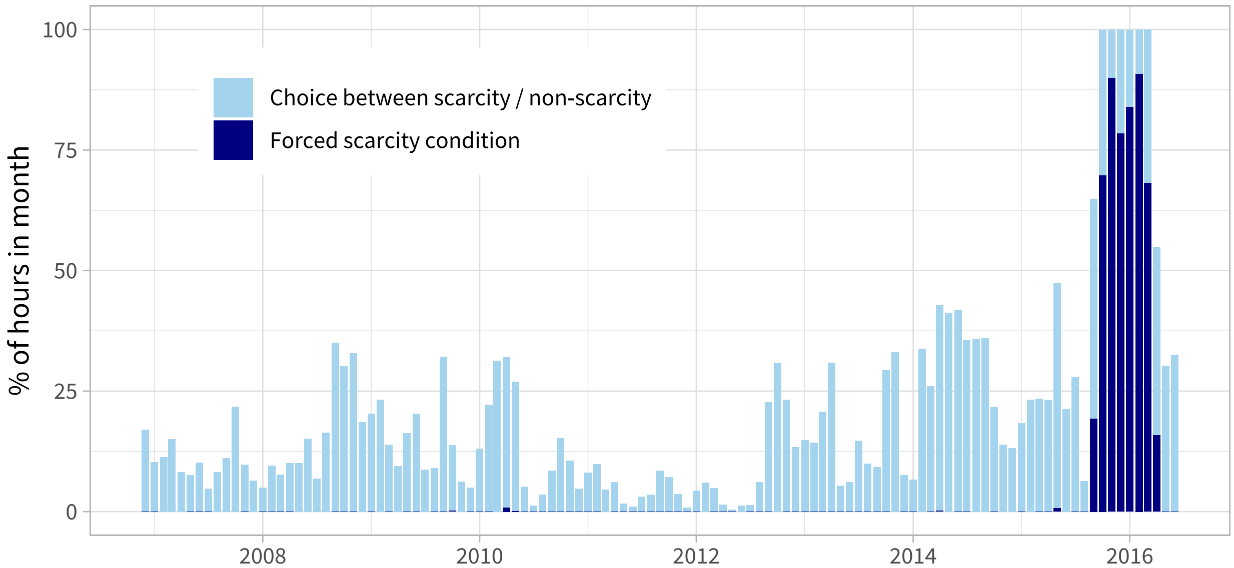
Throughout most of the sample period, EPM could cause a scarcity period during at least a few hours of each month (Figure 6). For most of the six months at the end of 2015 and the beginning of 2016, scarcity periods would have occurred regardless of the price and quantity offers by EPM. However, even 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, 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 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 (5) shows how the short-run

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.

profits for the firm depend on whether or not the wholesale spot price exceeds the 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 forward contract and reliability option obligations. Even when a 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 costs. We ignore revenue from forward contracts and the reliability option sales because the prices and quantities of these contracts are fixed and do not depend on short-term market decisions.

The calculation of the best response 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 penalties 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 (9) provides the daily profit for the generation firm i.

$$\Pi_i = \sum_{t=0}^{23} \left(P(q_{it})q_{it} - \min(P(q_{it}), P_s)q_{it}^c - c_i(q_{it})\right) + RO(q_i, q_{-i}, q_i^f, q_{-i}^f) \tag{9}$$

Compared to the expression for hourly profits in Equation (5), we ignore the revenue from 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 8 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 the 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 for which it would have been optimal for Emgesa.

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 (9), as shown in Figure 8. Because we do not have a closed-form expression 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.

Using the optimal generation costs, we recovered an estimate of the monthly opportunity cost of water implied by the observed thermal and hydroelectric generation during the month for each of the three firms. 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):

$$SSD(c_w) = \sum_{k=H,F} \sum_{t=0}^{T} (q_{kt}^{opt}(c_w) - q_{kt}^{act})^2 \tag{10}$$

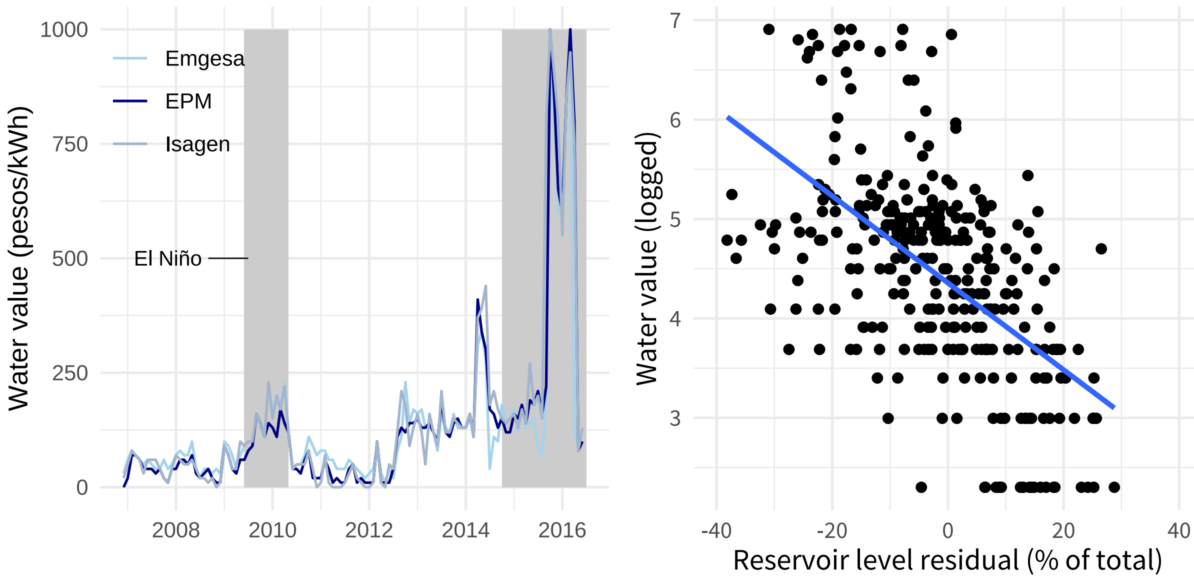
The opportunity cost for each firm and month is the c_w that minimizes Equation (10).

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 7 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 residual demand in 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, 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

Figure 7: Estimated opportunity cost of water is highest during El Niño periods and when reservoir levels are low



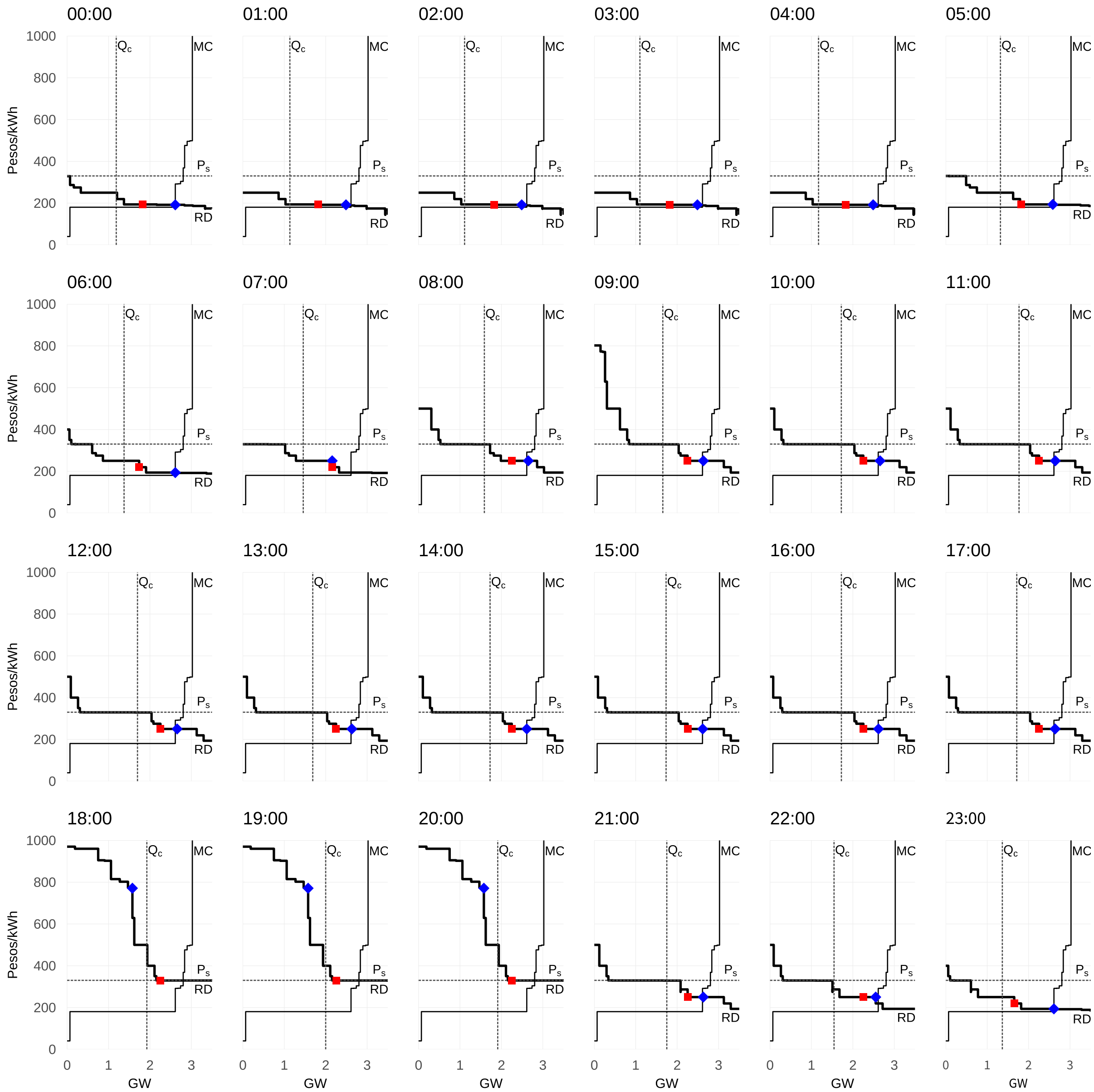
Notes: The left figure shows the monthly opportunity cost of water for each firm, calculated as the c_w that minimizes Equation (10). The shaded dates are the El Niño periods when hydro inflows are reduced. The right figure shows the correlation between the logged opportunity cost and the reservoir levels 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.

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 scarcity periods 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. 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

Figure 8: 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 the marginal cost curve MC. Noise has been added to the marginal cost curve to mask confidential information. The diamond points show the best-response quantities and prices that would maximize profits for the day. The 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.

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. These hours are classified based on the profit-maximizing choice for the firm between scarcity and non-scarcity periods. For each choice, the percentage of hours in the two categories is shown.

scarcity period did not occur in 96 percent of the hours in which it had the ability but not the incentive to induce scarcity.

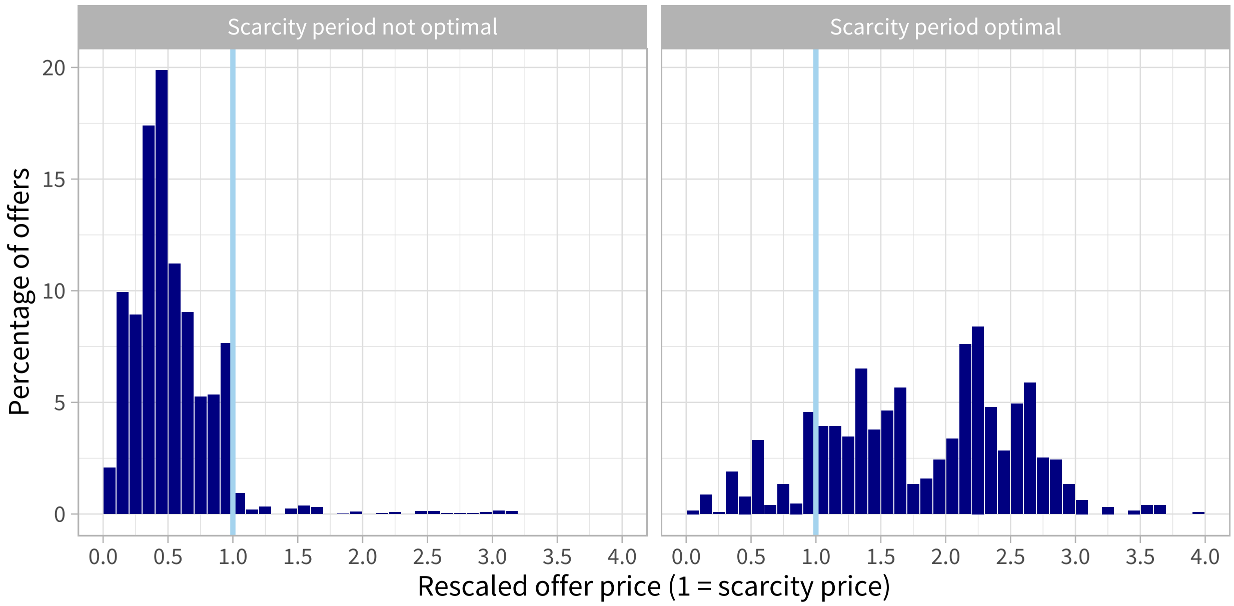
Overall, these results provide strong evidence that the largest generation firms recognize the incentives created by the reliability options and respond to them in their offer behavior. Most of the time, profits would be higher without a scarcity period, and in these hours, the firms submit offers to 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 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' responses to these incentives in their offer behavior.

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

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



the hours when the firm did and did not have the incentive to induce scarcity, as defined above. In each hour, we calculate the highest accepted offer price (that is, the highest offer with positive dispatched generation). 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 offer. A scaled price greater than 1 would be an offer 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 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 scarcity and submitting generation offers that would do so. 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.

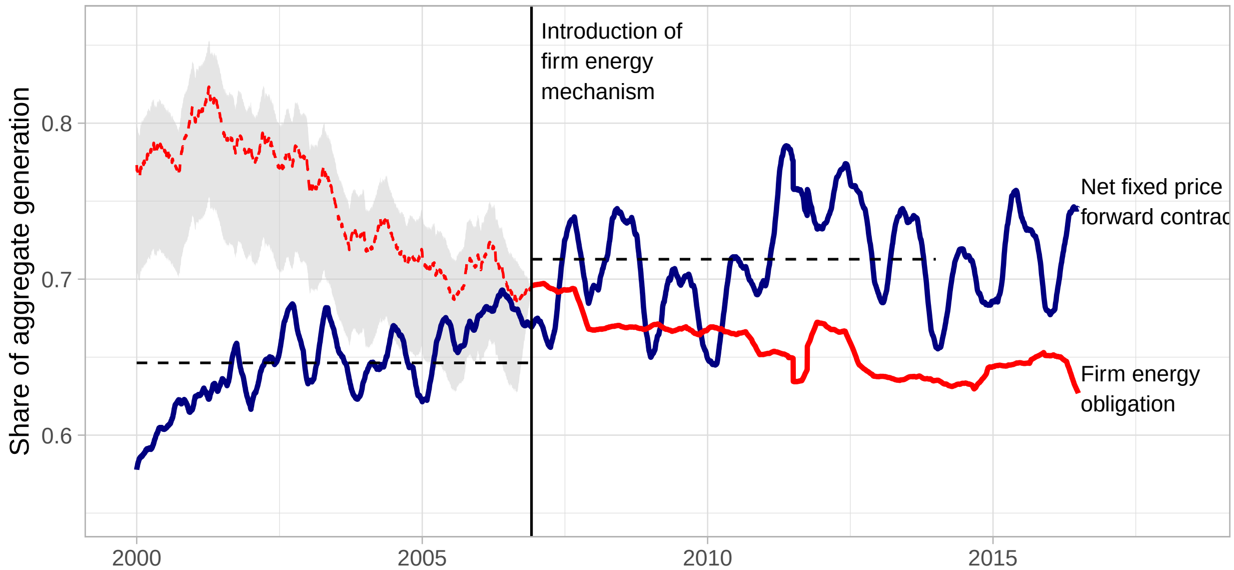
5 Long-run responses to reliability options

The previous section demonstrated how the three largest generation firms responded to the short-term incentives provided by the reliability options. We held the forward contract and firm energy quantities constant in that analysis. This assumption is appropriate in the short term since these quantities remain fixed from the perspective of the generation firms submitting offers in 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 discussed how the reliability options might alter generators' incentive to sell fixed-price forward contracts. Conversely, the firm energy quantities are set by a regulatory formula, although, as we will show below, there may be scope for thermal generators to adjust their assigned quantities.

In this section, we examine the long-run effects of the reliability options by comparing forward contract quantities before and after their introduction in December 2006. Because forward contracts are typically signed months or even years in advance, 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. We conduct the analysis separately for generation firms that are predominantly hydroelectric and those that are predominantly thermal. Given that the market size has increased over time (Figure 1), we present all quantities as shares of aggregate generation.

As illustrated in Section 3, the short-term strategic incentives for generation firms depend on the relative magnitude of the firm energy and 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. Without data on these quantities, 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. Assuming a fixed value for this ratio, and given that we observe the nameplate capacity throughout our sample period, we can predict the firm energy quantity before there were reliability options. 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.

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

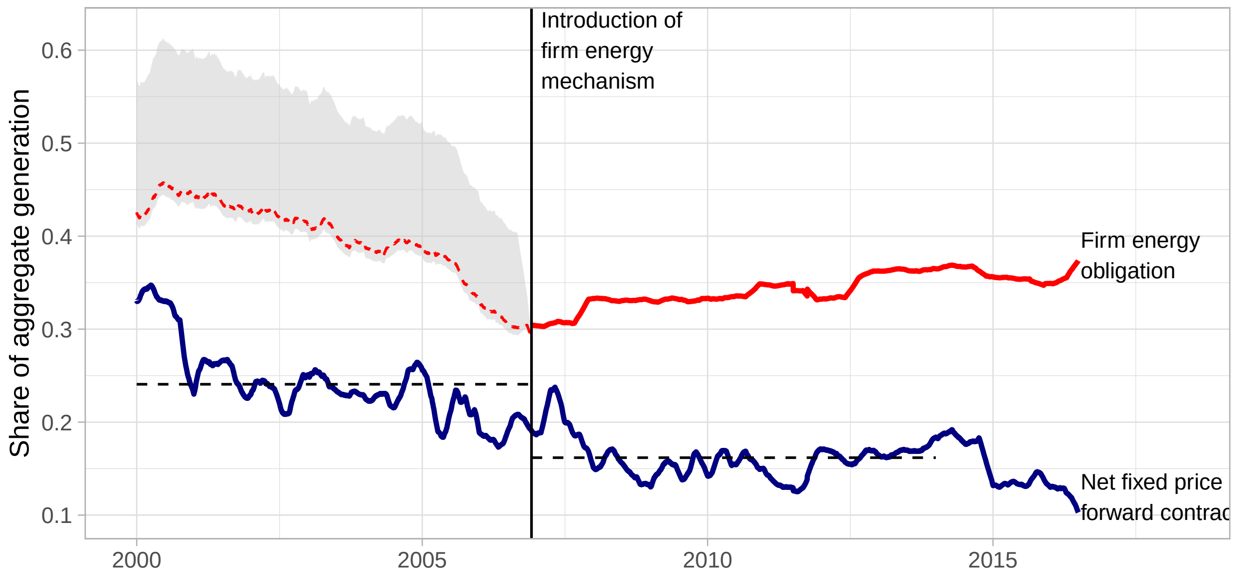


Notes: The graph shows (in blue) the net fixed price forward contract position of the electricity generation firms in Colombia that are predominantly hydro, expressed as a share of the system generation. The red line shows the firm energy obligations of the same firms. The red dashed line shows the backcasted firm energy obligation 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 forward contract position for the seven years before and after the introduction of the reliability options in December 2006.

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 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 forward contract sales by hydroelectric firms is even more 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

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

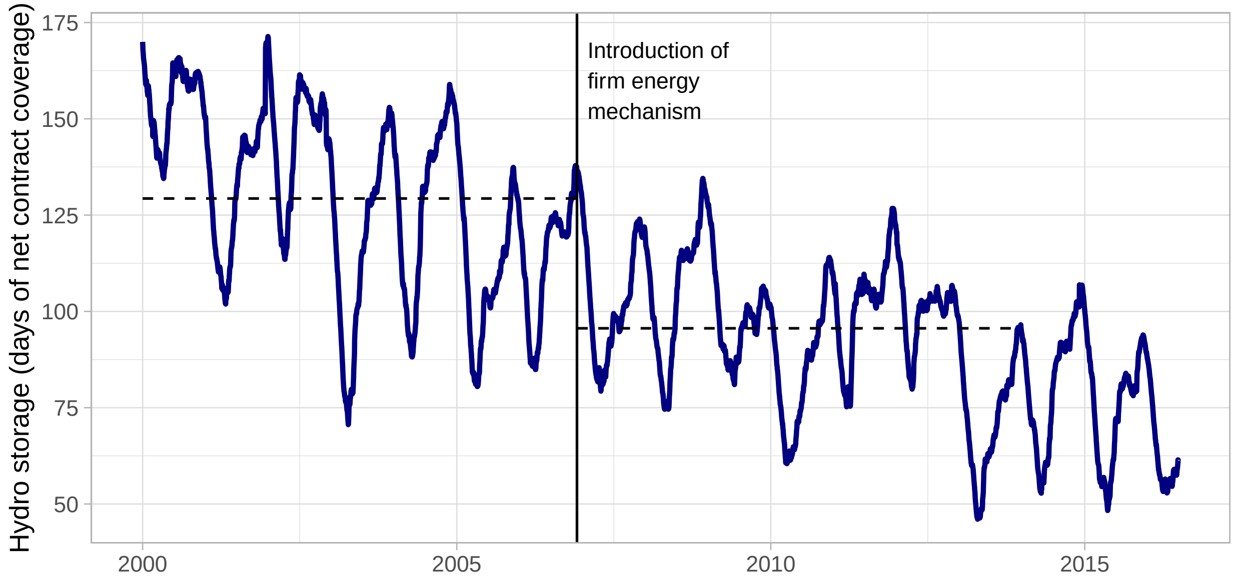


Notes: The graph shows the net fixed price forward contract position and the firm energy obligations of the electricity generation firms in Colombia that are predominantly thermal, expressed as a share of the system generation. See also notes to Figure 10.

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 forward contracts by hydro firms exceeded their firm energy obligations after 2006. The case analyzed in Section 3, in which the forward contract 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. 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

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

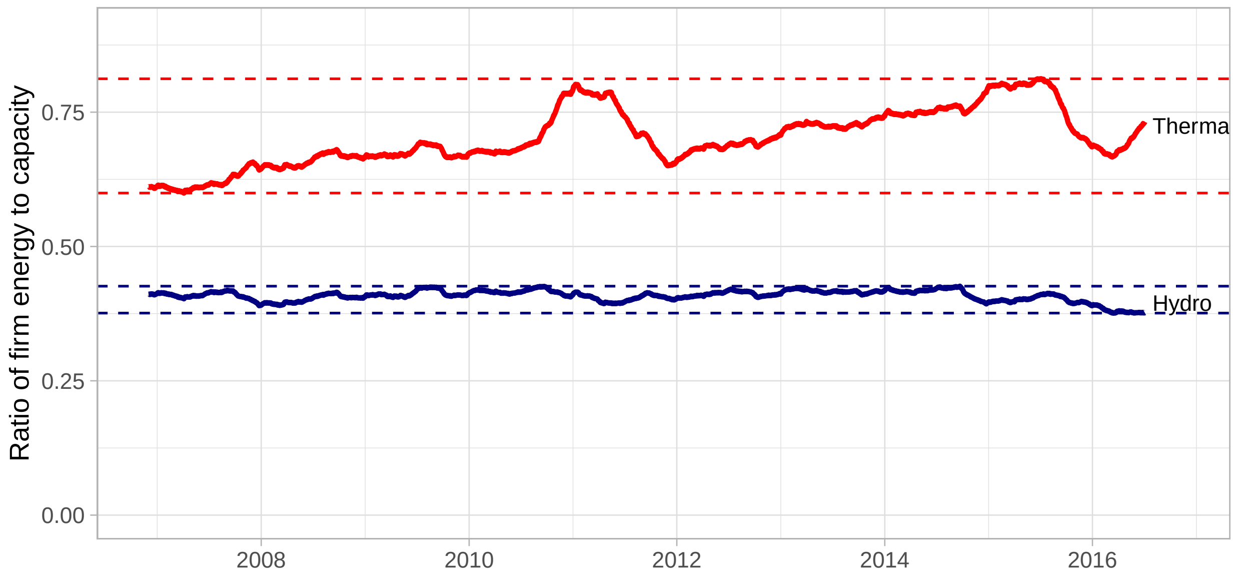


Notes: The graph shows the aggregate reservoir storage levels in Colombia, expressed as the number of days of the net fixed price forward contract position that could be covered by the stored volumes.

(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 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 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 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. They may have contributed to the more volatile spot prices after

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.

the introduction of the reliability options (Figure 3) and worsened 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 estimation method for firm energy in Figure 12 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. Thermal plants were able to change operational and fuel supply arrangements to increase their regulated firm energy quantities.

Our long-run analysis in this section reveals that the introduction of reliability options induced significant changes in the 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 a profit-maximizing response to the reliability options, it likely contributed to greater spot price volatility and increased the market's vulnerability to adverse hydrological conditions. Although both 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 that focuses on improving the forward contract market directly.

6 Alternatives to a capacity-based mechanism

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 wholesale market price. Moreover, fixed-price forward contracts encourage generators to make their generation capacity available to supply their contracted quantity. In the case of hydroelectric generators, fixed-price forward contracts may provide incentives to hold additional water in storage as insurance against future periods of low inflows.

In this paper, we show that the combination of the reliability options with fixed-price forward contracts has the perverse effect of undoing the above positive 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 contract quantity. In turn, this encourages firms to sell a higher quantity of forward contracts than the generation quantity they can produce under adverse supply conditions. As a result, the combination of forward contracts and reliability performs worse at guaranteeing the availability of generation in adverse conditions than either does 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 has been disappointing. Several new thermal generation plants that were assigned firm energy were never built or were completed far behind schedule (McRae and Wolak, 2016). Some existing thermal plants failed to procure sufficient 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.

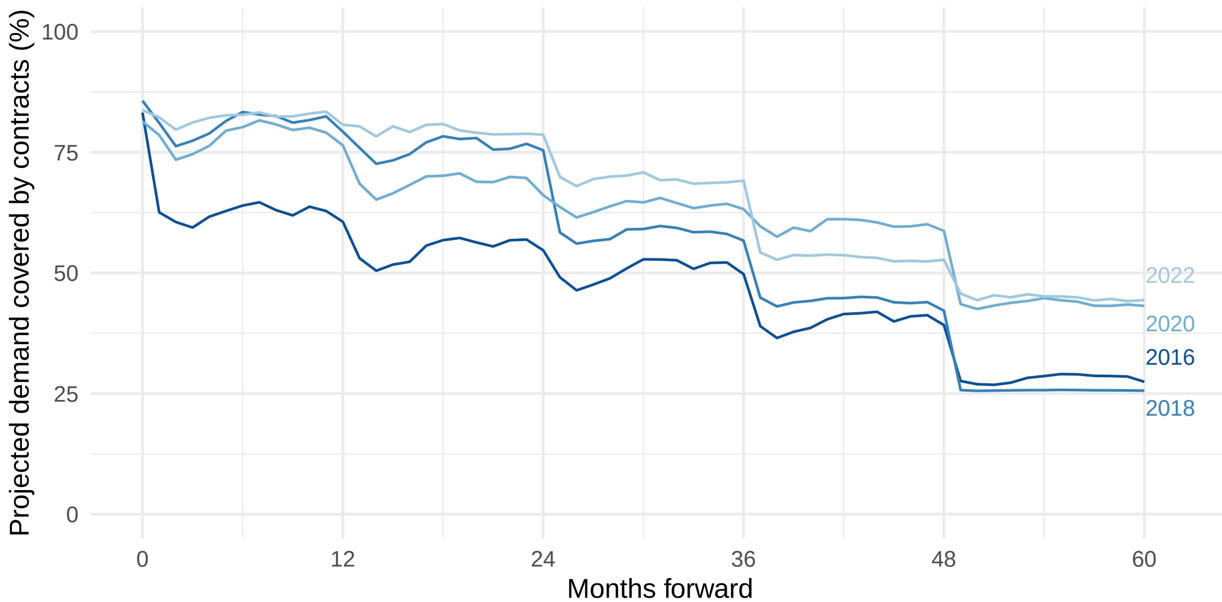
While the reliability options failed to guarantee the construction of sufficient generation capacity, the existing design of fixed-price forward contracts in Colombia cannot satisfy this objective either. The main problem is that few electricity retailers in Colombia buy forward contracts with a time horizon until delivery greater than three years. Figure 14 shows the forward contract coverage of project 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 market size for 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 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 several modifications to the forward contract market that could help address the above issues in Colombia. To ensure an adequate level of forward contracting and improve liquidity in the market, regulation should be implemented requiring electricity retailers to cover a fixed share of their projected demand with standardized forward contracts purchased through a centralized auction.[20] This required share should

20. Rather than each retailer procuring customized contracts to match their particular load profile, a set of standardized futures contracts should be created, with quantities and hourly shapes based on the aggregate system load profile. Retailers and generators could then transact in these fungible "system-shaped" contracts, with quantities for each hour based on the system load shape. For example, if 15 percent of total demand

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).

start relatively high for contracts close to delivery, for example, 97 percent coverage for contracts one year out. The mandated share would decline gradually for delivery dates further out, for instance, stepping down to 90 percent four years in advance. These fixed quantities ensure retailers hedge a significant portion of demand while encouraging the development of a more active market for contracts with a long delivery time. Such a market would encourage the entry of new generators to compete to supply these contracts.

These reforms would significantly improve the efficiency and competitiveness of the forward electricity market in Colombia. A liquid forward market with high levels of participation would provide transparent price signals, reduce risks for market participants, and provide a revenue stream to generators far enough in advance of delivery to allow them to bring online sufficient resources to meet demand. The overall result will be that forward contracts alone could satisfy the three objectives of reliability options at the start of this section without the need for a separate mechanism to ensure long-term resource

occurs between 6:00 and 7:00 p.m., then 15 percent of the contract quantity would be delivered in that hour. Standardized contracts matching the system profile would facilitate the development of a more liquid futures market, allowing participants to easily buy and sell contracts as needed to manage their positions. This would reduce the risk for retailers and generators of holding a suboptimal quantity of contracts relative to their actual demand or supply.

adequacy.

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 theoretical model 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 forward contracts while holding less water in storage, increasing the system's vulnerability to low inflows.

We verify these predictions empirically using a rich dataset from the Colombian market. We find that generators respond to the incentives of reliability options in both the short and long run. For many days of our sample, the largest generators have the ability to trigger a scarcity period. In their short-term offer behavior, they respond as predicted to the incentives created by the reliability options. 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.

We propose an alternative approach to long-term resource adequacy based on enhancing the existing forward contract market. Mandating that retailers purchase a minimum share of their projected demand through standardized forward contracts could provide generators with the long-term revenue certainty needed to invest in new capacity. The forward contract market, on its own, could achieve the stated objectives of the reliability options: mitigating market power, ensuring generation availability, and encouraging investment in new generation. Employing a single forward market would avoid the current problems caused by the perverse interaction between the forward contract market and the reliability options, achieving the same objectives at a lower cost for electricity consumers.

These results have important implications for the design of 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.[21] Both quantities are summed across the plants i belonging to generator j (I_j).

$$q_{jd}(deviation) = \sum_{i \in I_j} \sum_{h=1}^{24} q_{ijhd}(ideal) - \sum_{i \in I_j} q_{ijd}(firm) \tag{11}$$

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 hourly firm energy for this calculation, $q_{jhd}(firm)$, is determined by a pro rata assignment of the daily firm energy using the share of ideal generation in each hour.

$$q_{jhd}(firm) = q_{jd}(firm) \frac{q_{jhd}(ideal)}{\sum_{h=1}^{24} q_{jhd}(ideal)} \tag{12}$$

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.[22] 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.

$$R_{jhd}(firm) = \max(0, P_{hd} - P_d(scarcity))(q_{jhd}(ideal) - q_{jhd}(firm)) \tag{13}$$

21. The system operator in Colombia solves two generation dispatch problems, with and without accounting for transmission constraints. The ideal generation is the generation calculated under an assumption of no transmission constraints.

22. Note that the terminology in the regulation is inconsistent. The daily firm energy deviations (*DDOEF*) are measured in kWh. The hourly firm energy refunds are measured in pesos but are labelled as "hourly deviations" (*DHOEF*).

The total daily firm energy refunds are the sum of the hourly firm energy refunds for the generators with positive firm energy deviations (J_+).

$$R_d(firm) = \sum_{j \in J_+} \sum_{h=1}^{24} R_{jhd}(firm) \tag{14}$$

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.

$$S_{jd}(firm) = R_d(firm) \frac{q_{jd}(deviation)}{\sum_{j \in J_-} q_{jd}(deviation)} \tag{15}$$

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

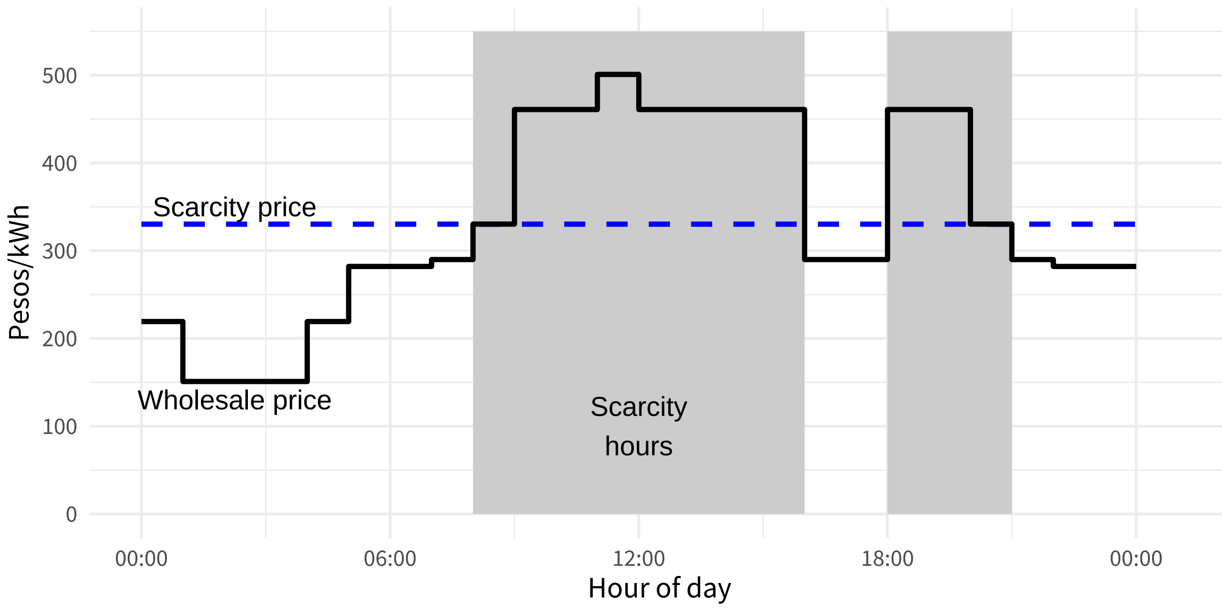
We illustrate the calculation in Section A using data for one day: May 28, 2015.

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.[23] The unadjusted firm energy on May 28 was 197.8 GWh, divided between 187.4 GWh of dispatched generation and 10.4

23. 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

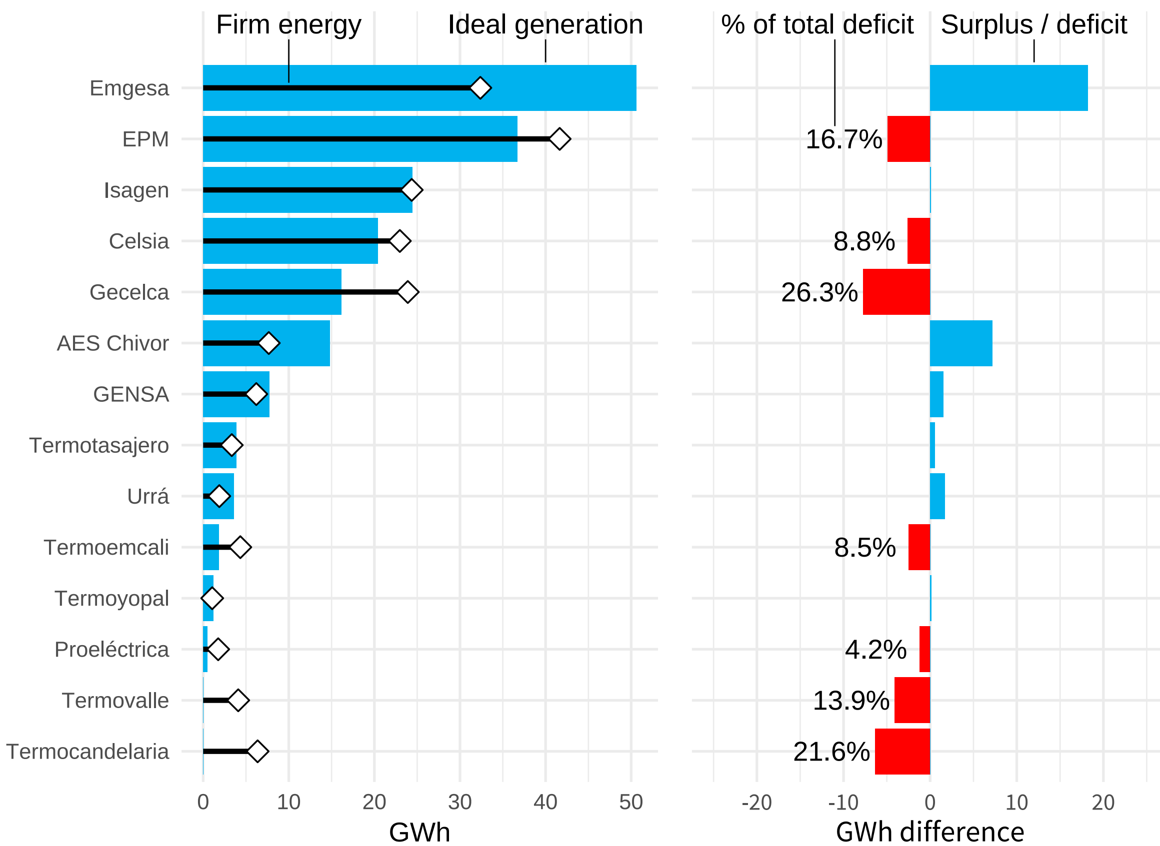


GWh of non-dispatched generation. The ideal generation on May 28 was 175.9 GWh for the dispatched plants and 10.4 GWh for the non-dispatched plants. The adjustment factor to scale the firm energy of the dispatched plants was $175.9/187.4 = 0.939$.

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

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



A3 shows the hourly refund. The hourly refund was almost zero at 8:00AM and 8:00PM, because the 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

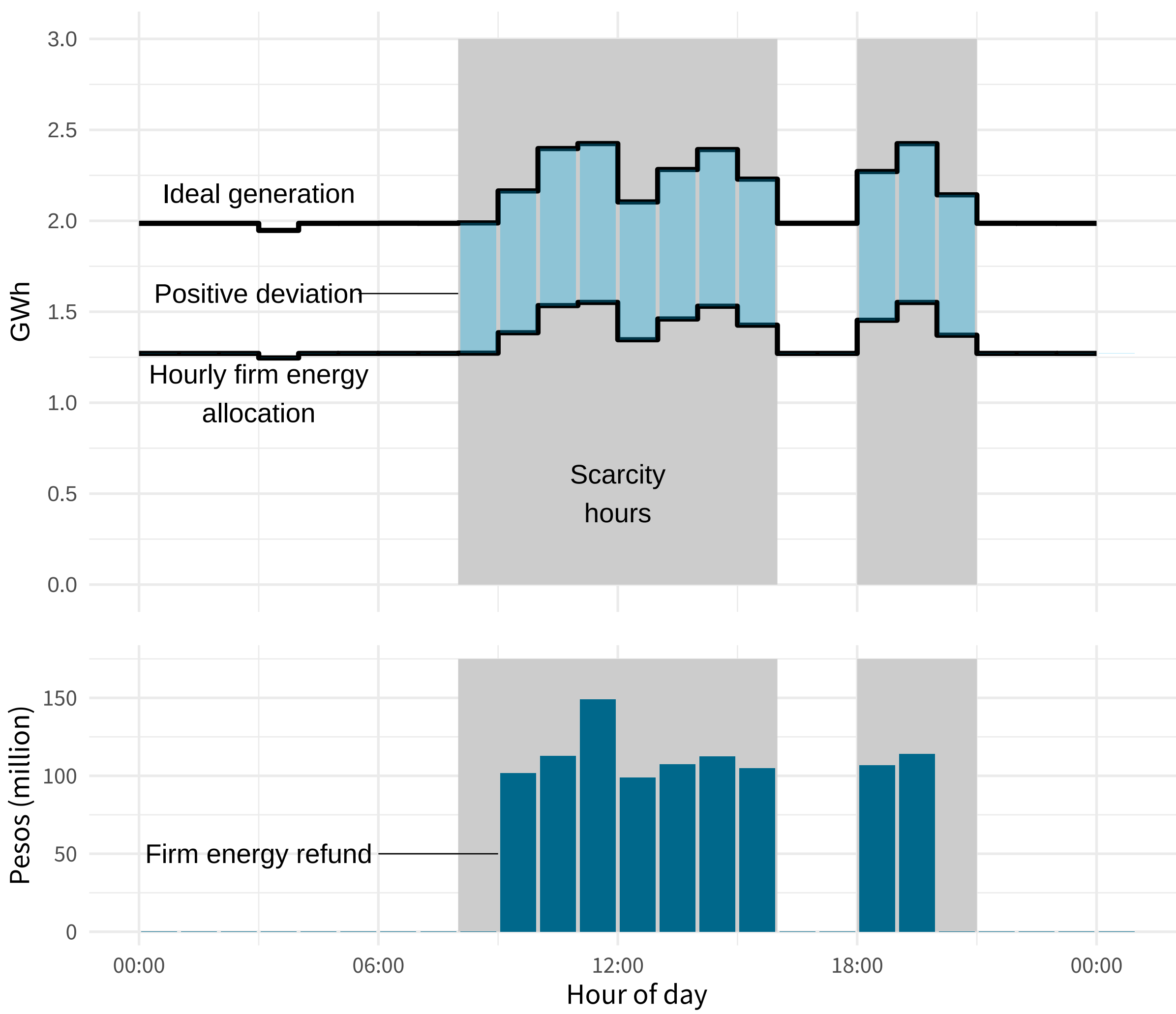


Figure A4: Firm energy obligations and payments on May 28, 2015