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César Osta
Pablo Blanchard
Rodrigo Ceni

FACULTAD DE CIENCIAS ECONÓMICAS Y DE ADMINISTRACIÓN
IECON INSTITUTO DE ECONOMÍA
UNIVERSIDAD DE LA REPÚBLICA URUGUAY

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Thermal Capacity as Reliability Insurance: Welfare Redistribution in Electricity Market

César Osta, Pablo Blanchard y Rodrigo Ceni*

Resumen

¿Por qué los sistemas eléctricos mantienen una costosa capacidad térmica que parece difícil de justificar bajo criterios de mercado convencionales, y cuáles son las consecuencias en términos de bienestar de hacerlo? Abordamos esta pregunta interpretando la capacidad térmica de respaldo como una forma de seguro de confiabilidad frente a eventos de escasez de baja probabilidad pero alto impacto. Sobre la base del modelo de Joskow y Tirole (2007), incorporamos la aversión social al riesgo en el problema de planificación de capacidad, permitiendo que las decisiones de inversión reflejen no solo las pérdidas esperadas de bienestar, sino también la preocupación de la sociedad por eventos extremos de escasez. Utilizando datos detallados del sistema eléctrico uruguayo, estimamos el grado de aversión social al riesgo implícito en las decisiones observadas de capacidad y evaluamos la distribución resultante del bienestar entre consumidores con diferentes sensibilidades a los precios en tiempo real. Encontramos que un marco de planificación neutral al riesgo puede explicar la mayor parte de la capacidad de generación, pero no logra justificar más del 60% de la capacidad térmica fósil del sistema. En cambio, el plan de capacidad observado es consistente con un criterio de planificación que asigna un peso sustancial a las pérdidas de bienestar asociadas con eventos extremos de escasez. La capacidad térmica adicional incrementa el bienestar de ambos grupos de consumidores. Los consumidores insensibles al precio se benefician principalmente a través de una menor exposición a interrupciones del suministro eléctrico, mientras que los consumidores sensibles al precio se benefician mediante menores costos esperados de electricidad y una menor dependencia de la autogeneración. Sin embargo, los costos y beneficios de este seguro de confiabilidad se distribuyen de manera desigual. Aunque la ganancia de bienestar de los consumidores insensibles al precio es sustancialmente mayor, ellos financian la mayor parte de la inversión adicional a través de precios más altos de la electricidad, generando transferencias significativas de bienestar hacia los consumidores sensibles al precio.

Palabras clave

sensibilidad a los precios en tiempo real; pérdida de bienestar por racionamiento; confiabilidad; eventos de alto impacto y baja probabilidad.

Clasificación JEL

L11, L52, L94

* César Osta: MIEM, andres.osta@gmail.com. Pablo Blanchard: FCEA-UDELAR, pablo.blanchard@fcea.edu.uy. Rodrigo Ceni: FCEA-UDELAR, rodrigo.ceni@fcea.edu.uy.

Abstract

Why do electricity systems maintain costly thermal capacity that appears difficult to justify under stan- dard market criteria, and what are the welfare consequences of doing so? We address this question by interpreting thermal backup capacity as a form of reliability insurance against high-impact, low-probability scarcity events. Building on the model of Joskow and Tirole (2007), we incorporate social risk aversion into the capacity-planning problem, allowing investment decisions to reflect not only expected welfare losses but also society's concern about extreme scarcity events. Using detailed data from the Uruguayan electricity system, we estimate the degree of social risk aversion implicit in observed capacity choices and evaluate the resulting welfare distribution across consumers with different sensitivities to real-time prices. We find that a risk-neutral framework can explain most generation capacity but fails to account for more than 60% of the system's fossil thermal capacity. The observed capacity plan is instead consistent with a planning criterion that places substantial weight on welfare losses associated with extreme scarcity events. Additional thermal capacity increases welfare for both consumer groups. Price-insensitive consumers benefit primarily through reduced exposure to electricity shortages, while price-sensitive consumers benefit through lower expected electricity costs and reduced reliance on self-generation. However, the costs and benefits of this reliability insurance are unevenly distributed. Although the welfare gain for price-insensitive consumers is substantially larger, they finance most of the additional investment through higher electricity prices, generating significant welfare transfers toward price-sensitive consumers.

Keywords

real-time price sensitivity, rationing welfare loss, reliableness, high-impact low-probability events.

JEL Classification

L11, L52, L94

1 Introduction

Electricity systems with high renewable penetration increasingly rely on dispatchable thermal capacity to guarantee reliability during periods of scarcity (Wolak, 2022). Yet these plants often operate only a few hours per year and appear difficult to justify under standard market criteria. Despite their low utilization rates, regulators and system planners continue to maintain or expand thermal backup capacity (Holmberg and Ritz, 2021). This raises the question: Why is this capacity maintained, and who benefits from these investments?

One possible explanation is that dispatchable capacity provides insurance against rare but severe scarcity events. As renewable penetration increases, the risk of supply shortages associated with intermittency becomes more important, while most consumers continue to face retail tariffs that do not reflect short-term scarcity conditions. Consequently, consumers differ in their exposure to scarcity risk and in their ability to respond to it. Understanding how capacity investments protect consumers with different degrees of price sensitivity, and how the costs and benefits of these investments are distributed across consumers, is therefore central to evaluating the welfare consequences of electricity market design (Borenstein and Bushnell, 2022; Ambec and Crampes, 2019; Pollitt and Anaya, 2016).

The value of this insurance is unlikely to be the same across consumers. Some consumers can respond to scarcity prices or rely on alternative energy sources, while others remain highly exposed to interruptions (Joskow and Tirole, 2007; Wolak, 2011; Joskow and Wolfram, 2012). Consequently, reliability investments may generate substantial welfare transfers across consumer groups, making the incidence of capacity planning decisions a central consideration in electricity market design (Fabra et al., 2022; Borenstein and Bushnell, 2022).

We study whether observed capacity choices can be interpreted as reliability insurance and examine their distributional consequences (Billimoria et al., 2022). We extend the model of Joskow and Tirole (2007) by incorporating a planner who places value on avoiding large welfare losses associated with high-impact, low-probability (HILP) scarcity events. The model allows us to infer the degree of social risk aversion embedded in observed capacity decisions and to quantify how the resulting investments affect different consumer groups (Bussiere and Fratzscher, 2008; Mancarella, 2022). We apply the model to the Uruguayan electricity system, a middle-income country with near-universal access, high renewable penetration, and a regulated market structure. This setting provides a unique opportunity to examine how scarcity risk influences investment decisions and welfare outcomes.

Consumers differ in their ability to respond to scarcity prices. A large literature shows that dynamic pricing can reduce peak demand and improve welfare by encouraging consumers to adjust consumption in response to real-time costs (Wolak, 2011; Joskow and Wolfram, 2012; Ito, 2014). However, adoption of real-time pricing remains limited, and many consumers continue to face flat tariffs that provide weak incentives to respond during scarcity events (Borenstein and Bushnell, 2022; Wolak and Hardman, 2021).

At the same time, increasing renewable penetration introduces additional supply-side uncertainty due to the intermittency of wind and solar generation (Ambec and Crampes, 2012, 2019). These developments have renewed interest in resource adequacy, capacity mechanisms, and security-of-supply policies designed to maintain reliability under high renewable penetration (Newbery, 2016; Holmberg and Ritz, 2021; Wolak, 2022; Keppler et al., 2022). While these mechanisms are often justified as responses to reliability concerns, less attention has been devoted to understanding how their costs and benefits are distributed across consumers with different abilities to respond to scarcity.

Our results suggest that thermal backup capacity behaves as a form of reliability insurance. While a risk-neutral framework can explain most generation capacity observed in Uruguay, it fails to account for a large share of thermal backup capacity. We show that the observed investment plan can be rationalized only if society places substantial value on avoiding extreme scarcity events. The resulting capacity expansion protects consumers who are highly exposed to interruptions while simultaneously lowering electricity costs for consumers with access to self-generation, generating substantial welfare transfers across consumer groups.

Quantitatively, the observed capacity plan is consistent with a planning criterion that assigns a weight of 0.60 to welfare losses associated with the most severe 0.9% of scarcity events, implying a 136% increase in thermal capacity relative to the risk-neutral benchmark. Although this additional capacity is primarily motivated by concerns about welfare losses during extreme scarcity events, its benefits extend beyond the consumers most exposed to reliability risk. Price-sensitive consumers also gain through lower expected electricity costs, while price-insensitive consumers bear most of the costs associated with the expansion. In fact, price-insensitive consumers pay nearly ten times more per MWh for electricity than price-sensitive consumers, financing most of the additional investment. As a result, reliability-oriented capacity expansion not only improves system reliability but also generates substantial redistribution across consumer groups.

This paper contributes to the literature in three ways. First, it provides a framework for interpreting dispatchable generation capacity as a form of reliability insurance against high-impact, low-probability scarcity events and for quantifying how the costs and benefits of that insurance are distributed across consumer groups. Second, we extend the model of Joskow and Tirole (2007) by introducing social risk aversion into the planner's objective function. This extension allows us to analyze capacity expansion decisions when society places value not only on expected welfare outcomes but also on reducing welfare losses associated with extreme scarcity events. In doing so, we offer a potential explanation for why observed levels of thermal capacity may exceed those predicted by standard risk-neutral frameworks. Third, we use detailed data from the Uruguayan electricity system to recover the degree of social risk aversion implicit in observed capacity choices and quantify the incidence of reliability-oriented investment policies.

2 Institutional Background and Capacity Planning

Uruguay has a highly regulated electricity market. The legal framework establishes that the wholesale market operates competitively in both generation and consumption phases, with shared use of the transmission system under an open access regime. The state-owned company, UTE, holds a legal monopoly on transmission and distribution, which are considered public services by law and are therefore regulated. The regulator, URSEA, calculates access charges for transmission and distribution and submits them for approval to the central government. The system operator, ADME, is responsible for managing the wholesale electricity market, coordinating its participants to balance supply and demand.

Generation is centrally dispatched by the system operator based on an economic merit order, from the lowest to the highest short-term marginal cost, except for small plants, which can be self-dispatched. This dispatch process determines both the operation and the hourly marginal cost of the system's generation. This cost is equal to the hourly price in the spot market when it is not higher than a cap price set by the central government. There are five types of generation sources during the studied period: hydroelectric, fossil fuel thermal, wind, biomass, and photovoltaic solar. Wind, solar, and most biomass generation sources are dispatched at zero variable cost, as regulated. Hydroelectric generation is dispatched according to the opportunity cost of stored water, calculated by the operator, while fossil fuel thermal generation is dispatched based on its variable cost, which reflects fuel and operational expenses.

Hydroelectric and fossil fuel thermal plants are wholly owned, either directly or indirectly, through UTE, by the state. For wind, biomass, and photovoltaic solar generation, most of the capacity is privately owned, with a smaller portion belonging to UTE. The majority of private generation was encouraged by the government through public auctions organized by UTE, where firms submitted bids pairing power capacity with a price. UTE commits to purchasing all electricity produced by the best offers at the bidding price (D'Agosti, 2022).

This policy transformed Uruguay into one of the world's most renewable-intensive electricity systems, with wind generation accounting for approximately 35% of electricity production in 2023 (Brown and Jones, 2024). While the expansion of renewable generation substantially reduced dependence on fossil fuels, it also increased the importance of maintaining dispatchable resources capable of ensuring reliability during periods of low renewable output. This combination of high renewable penetration and continued reliance on thermal backup capacity makes Uruguay a particularly suitable setting for studying the reliability value and distributional consequences of capacity investments.

Afterward, UTE distributes the electricity to the vast majority of final consumers throughout the country. Retail tariffs do not vary according to consumers' exposure to reliability risk or their willingness to pay for additional reliability.

The indicative generation expansion plans developed by the Ministry of Industry, Energy and Mining (MIEM) place strong emphasis on security-of-supply objectives and include additional thermal capacity to reduce the risk of electricity shortages (MIEM, 2025). These planning decisions provide a useful benchmark for evaluating whether observed capacity choices can be interpreted as reflecting preferences for reliability and protection against extreme scarcity events.

3 Model

3.1 General framework

In our model, and following Joskow and Tirole (2007), there is a single wholesale electricity market operating under perfect competition with two types of homogeneous consumers: one sensitive to the wholesale real-time price and another insensitive, whose demands are $\hat{D}(.)$ and $D(.)$, respectively. The only source of uncertainty in this model, the state of nature ν, comes from the energy supply and is determined by the availability of renewable resources and generation plants. The model defines the demands depending on prices for sensitive and insensitive consumers, $\hat{p}(\nu)$ and $\overline{p}$, respectively. Sensitive consumers buy electricity on the wholesale market, while insensitive consumers are served by retail suppliers who buy electricity on the wholesale market and sell it to them at $\overline{p}$. Generators, owners of power plants, pay their costs, variable (c) and fixed ($I(c)$), by selling the electricity they generate on the wholesale market. The social planner decides the marginal price for the real-time price sensitive consumers, $\hat{p}(\nu)$; the marginal price $\bar{p}$ for the real-time price insensitive consumers, the energy consumption for both consumers (no energy rationing), $\hat{\alpha}(\nu)$ and $\alpha(\nu)$; the rate of utilization of the power plants $u(c, \nu)$, and the investment plan K.

The model first determines the level of investment the planner would make without social preferences for reliability. Then, we incorporate the potential impact of reliability risk, specifically high impact low probability (HILP) events, on the loss of welfare of insensitive consumers using a Conditional Value-at-Risk (CVaR) framework. We assume that the planner internalizes the preferences of price-insensitive consumers regarding exposure to extreme scarcity events. When the planner internalizes these preferences, the investment plan includes additional capacity from dispatchable power plants that would not be viable in the risk-neutral wholesale market. This extra capacity acts as a strategic reserve overlaid on this market, serving as insurance for insensitive consumers against energy scarcity events, similar to the insurance mechanism approach described by Billimoria et al. (2022).

The additional capacity—remunerated almost entirely through the price paid by insensitive consumers—creates a positive externality for sensitive consumers by reducing their expected electricity costs, resulting in a welfare redistribution between the two groups.

3.2 Risk neutral framework ($\beta = 0$)

Under the risk-neutral framework, the planner maximizes expected social welfare, defined as the difference between consumer surplus and the total cost of generation capacity. Consumer surplus consists of the surplus of price-sensitive consumers, $\hat{S}(\hat{p}(\nu), \hat{\alpha}(\nu))$ and $S(\bar{p}, \alpha(\nu))$; and the total cost of the generation plants in the market, given c and $I(c)$. We define the insensitive consumers' surplus as $S(\bar{p}, \alpha(\nu)) = \tilde{S}(\bar{p}) - W_{\text{loss}}(\nu)$, where $\tilde{S}(\bar{p})$ is the surplus without energy rationing and $W_{\text{loss}}(\nu)$ is the welfare loss due to energy rationing in ν.[1] In the Equation 1 the only term that depend on $\alpha(\nu)$ is $\mathbb{E}[W_{\text{loss}}(\nu)]$. Consequently, under risk neutrality, the planner evaluates capacity decisions exclusively through their effect on expected welfare losses, without assigning additional weight to extreme scarcity events. The optimization problem must satisfy the feasibility condition that generation capacity is sufficient to meet consumption in every state of nature

$$\begin{aligned} \max_{\hat{p}(\nu),\bar{p},\hat{\alpha}(\nu),\alpha(\nu),u(c,\nu),K} \; & \tilde{S}(\bar{p}) - \mathbb{E}[W_{\text{loss}}(\nu)] + \mathbb{E}\left[\hat{S}(\hat{p}(\nu), \hat{\alpha}(\nu))\right] - \mathbb{E}\left[\int_0^\infty c\, u(c,\nu)\, dK(c)\right] - \int_0^\infty I(c)\, dK(c) \\ \text{s.t.} \quad & \int_0^\infty u(c,\nu)\, dK(c) \geq \alpha(\nu) D(\bar{p}) + \hat{\alpha}(\nu)\hat{D}(\hat{p}(\nu)) \quad \forall \nu \end{aligned} \tag{1}$$

In the equilibrium only plants with a marginal cost lower than the price of the wholesale market dispatching in each state (Equation 2). In our framework $u(c, \nu)$ takes only values $\{0, 1\}$ whether the plant is producing energy and $\int_0^\infty u(c,\nu)\, dK(c)$ is the energy that is produced in the market in the state ν. Sensitive consumers never face rationing, and their consumption decisions follow the equilibrium price of the wholesale market (Equation 3). In scenarios involving rationing, the price that generators and suppliers to insensitive consumers receive matches the Value of lost load ($Voll$), as is seen in Equation 4 and 5.[2] The model ensures free entry for generation investments that implies all generation plants in the market cover their costs, both variable and fixed, at the real-time equilibrium price of the wholesale market (Equation 6).

$$u(c,\nu) = \begin{cases} 1 & \text{when } c < p(\nu) \\ 0 & \text{when } c > p(\nu) \end{cases} \tag{2}$$

$$\hat{D} = \hat{D}(p(\nu)) \quad \rightarrow \quad \hat{\alpha}(\nu) = 1 \tag{3}$$

$$\mathbb{E}\left[\frac{\partial S}{\partial \bar{p}} - p(\nu)\frac{\partial D}{\partial \bar{p}}\right] = 0 \tag{4}$$

$$\text{Voll} = p(\nu) \quad \forall \alpha(\nu) \in (0,1) \tag{5}$$

$$I(c) = E[\max\{(p(\nu) - c), 0\}] \quad \rightarrow \quad dK(c) = 0 \tag{6}$$

In sum, the model of Joskow and Tirole (2007) obtains a *second-best optimum* with an expected optimal

[1] The sensitive consumers clear the market, then there is no energy rationing.

[2] As the source of uncertainty comes from the supply, the Value of lost load (Voll) does not depend on the state of nature ν. Since it is assumed that the opportunity losses from consumption do not generate utility, and that rationing is perfectly anticipated and rotational by geographic area in a proportional manner, $Voll = \frac{\tilde{S}(\bar{p})}{D(\bar{p})}$.

percentage of rationing for insensitive consumers' demand ($\mathbb{E}[(1-\alpha(\nu))]$), and an expected optimal welfare loss for insensitive consumers ($\mathbb{E}[W_{\text{loss}}(\nu)] = \mathbb{E}[(1-\alpha(\nu))D(\overline{p})Voll]$).

3.3 Social risk aversion ($\beta > 0$)

A limitation of the risk-neutral framework is that it evaluates welfare losses solely according to their expected value and does not distinguish between frequent small losses and rare but severe scarcity events. To capture society's aversion to large welfare losses associated with high-impact, low-probability (HILP) events, we extend the planner's objective function following Mancarella (2022). The increasing penetration of low-carbon generation technologies has renewed interest in reliability assessment beyond expected outcomes alone. In this context, capacity planning may reflect not only the expected welfare consequences of scarcity, but also a societal desire to reduce exposure to extreme welfare losses. Accordingly, we augment the objective function to account for both expected welfare losses and the tail risk associated with HILP events. The parameter β determines the weight assigned to welfare losses occurring in the tail of the distribution relative to expected welfare losses, thereby capturing the degree of social risk aversion embedded in the planning criterion. The parameter γ identifies the portion of the distribution considered extreme and therefore determines the level of protection against HILP events incorporated into the planning processThe planner now solves Equation 7.

$$\begin{aligned}
\max_{\hat{p}(\nu),\overline{p},\hat{\alpha}(\nu),\alpha(\nu),u(c,\nu),K} \tilde{\tilde{S}}(\overline{p}) - \mathbb{E}\left[W_{\text{loss}}(\nu)\right] - \beta\Bigg[\text{CVaR}_{\gamma}(W_{\text{loss}}(\nu)) - \mathbb{E}\left[W_{\text{loss}}(\nu)\right]\Bigg] \\
+ \mathbb{E}\left[\hat{S}(\hat{p}(\nu),\hat{\alpha}(\nu))\right] - \mathbb{E}\left[\int_0^{\infty} c\, u(c,\nu)\, dK(c)\right] - \int_0^{\infty} I(c)\, dK(c) \qquad (7) \\
\text{s.t.} \quad \int_0^{\infty} u(c,\nu)\, dK(c) \geq \alpha(\nu)D(\overline{p}) + \hat{\alpha}(\nu)\hat{D}(\hat{p}(\nu)) \quad \forall \nu
\end{aligned}$$

$\tilde{\tilde{S}}(\overline{p})$ represents the surplus without energy rationing under the social risk-aversion framework. The term $\text{CVaR}\gamma(W\text{loss}(\nu))$ captures the expected welfare loss associated with the worst scarcity events, corresponding to the upper $(1-\gamma)$ tail of the welfare-loss distribution. Thus, it measures the average welfare loss conditional on the occurrence of high-impact, low-probability (HILP) events affecting system reliability, as in Equation 8.

$$\text{CVaR}_{\gamma}(W_{\text{loss}}(\nu)) = \frac{1}{1-\gamma}\int_{W_{\text{loss}}(\nu)_{\gamma}}^{\max(W_{\text{loss}}(\nu))} W_{\text{loss}}(\nu) f(W_{\text{loss}}(\nu))\, dW_{\text{loss}}(\nu) \qquad (8)$$

The difference between the expected welfare loss during HILP events and the expected welfare loss across all events, $\text{CVaR}\gamma(W\text{loss}(\nu)) - \mathbb{E}[W_{\text{loss}}(\nu)]$, captures the additional welfare risk associated with extreme scarcity events. This risk measure is weighted by the parameter β, which reflects the degree of social risk aversion embedded in the planning criterion. The resulting term is added to the expected welfare loss to construct the objective function under social risk aversion, as shown in Equation 9.

$$\text{W}_{\text{HILP}} = \mathbb{E}[W_{\text{loss}}(\nu)] + \beta\left[\text{CVaR}_{\gamma}(W_{\text{loss}}(\nu)) - \mathbb{E}(W_{\text{loss}}(\nu))\right], \quad \beta \in [0,1] \quad \text{and} \quad \gamma \in [0,1) \qquad (9)$$

Higher values of β increase the weight assigned to welfare losses associated with extreme scarcity events relative to expected welfare losses, reflecting a greater degree of social risk aversion. Higher values of γ place greater emphasis on rarer and more severe events, thereby increasing the level of protection against high-impact, low-probability (HILP) scarcity events embedded in the planning criterion.

The optimal solution under social risk aversion continues to satisfy Equations 2, 3, and 5, but no longer satisfies Equation 6, which is replaced by Equation 10 for the marginal unit of K.[3]

$$\begin{aligned}\frac{\partial}{\partial K}\left(\tilde{\tilde{S}}(\bar{p})\right) - \frac{\partial}{\partial K}\left(\mathrm{W_{HILP}}\right) + \frac{\partial}{\partial K}\left(\mathbb{E}\left[\hat{S}(p(\nu))\right]\right) \\ -\frac{\partial}{\partial K}\left(\mathbb{E}\left[\int_0^\infty c\, u(c,\nu)\, dK(c)\right]\right) - \frac{\partial}{\partial K}\left(\int_0^\infty I(c)\, dK(c)\right) = 0\end{aligned} \tag{10}$$

Due to how we are going to operationalize the model, Equation 4 continues to be fulfilled, otherwise it would not be fulfilled. We next describe how to operationalize this model.

4 Methodology and Data

4.1 Model implementation

The total internal demand is divided into sensitive and insensitive consumers. The total demand of each group is treated as exogenous. Under this assumption, Equation 4 is satisfied. Sensitive consumers represent large electricity users with access to self-generation technologies, whereas insensitive consumers comprise the remaining consumers in the system.

In our implementation, price sensitivity does not arise from a downward-sloping demand response, as in the original formulation of Joskow and Tirole (2007). Instead, sensitive consumers can substitute between self-generation and electricity purchases from the market while maintaining a fixed total electricity demand. Consequently, the welfare gains experienced by sensitive consumers reflect reductions in self-generation costs rather than conventional demand-response efficiency gains.

To operationalize wholesale-market price sensitivity, we assume that sensitive consumers generate their own electricity at a variable cost of c_{sg} whenever the market price is greater than or equal to this value. Self-generation is assumed to be always available. Thus, the demand of sensitive consumers can be met either through market purchases ($\hat{D} * m$) or through self-generation ($\hat{D} * sg$), as shown in Equation 11. Under this specification, Equation 3 continues to hold.

$$\hat{D} = \hat{D}_m(\hat{p}(\nu), c_{sg}) + \hat{D}_{sg}(\hat{p}(\nu), c_{sg}) \tag{11}$$

Self-generation supplies a fraction $(1 - \hat{\lambda}(\nu))$ of sensitive consumers' total demand, while the remaining fraction, $\hat{\lambda}(\nu)$, is purchased from the market in each state of nature.

In the original model, the entire demand of sensitive consumers is supplied through the market. Therefore, representing self-generation as in Equation 11 requires incorporating the self-generated component into the model while preserving the assumption that total electricity demand remains fixed.

Because the total demand of sensitive consumers is exogenous, an increase in market-supplied electricity must be matched by an equivalent reduction in self-generation. Consequently, the response of market demand to an increase in generation capacity satisfies ($\frac{\partial}{\partial K}\left(\hat{D}_{\mathrm{m}}\right) = -\frac{\partial}{\partial K}\left(\hat{D}_{\mathrm{sg}}\right)$). Under the assumption that consumers derive the same utility from electricity regardless of its source, the welfare effects of additional generation capacity arise exclusively from replacing more expensive self-generated electricity with cheaper market purchases. Therefore, once the investment cost of the marginal unit of capacity is accounted for in Equation 10, the variation in

[3] Equation 10 assumes that ($\mathbb{E}\left[\hat{S}(\hat{p}(\nu), \hat{\alpha}(\nu))\right] = \mathbb{E}\left[\hat{S}(p(\nu))\right]$) due to the fulfillment of Equation 3.

the expected surplus of sensitive consumers, $\frac{\partial}{\partial K}\left(\mathbb{E}[\hat{S}(p(\nu))]\right)$, can be represented by Equation 12, given the self-generation cost c_{sg}.

$$\frac{\partial}{\partial K}\left(\mathbb{E}\left[\hat{S}(p(\nu))\right]\right) = -\frac{\partial}{\partial K}\left(\mathbb{E}\left[c_{\mathrm{sg}}\hat{D}_{\mathrm{sg}}(p(\nu))\right]\right) \tag{12}$$

In the case of insensitive consumers, it is assumed that they do not have an alternative energy source other than the electricity market. Therefore, when the market cannot provide electricity, they are rationed, as represented in the model.

To determine the efficient dispatch of the wholesale electricity market that meets Equation 2, the Electric Power Systems Simulator (SimSEE) platform is used.[4] This platform determines the optimal operational policy by minimizing the system's expected future operating costs over a defined period, considering total demand, as well as the capacities, technical characteristics, and variable costs of the plants. Fixed costs associated with the plants are not included in the optimization. The electrical systems modeled by this platform involve stochastic processes, resulting in simulation outcomes that are also stochastic. The randomness analyzed includes hydraulic contributions to dams, plant breakdown and repair states, and the availability of wind and solar resources.

The platform meets the energy balance in each simulated time interval. A sink for surplus electrical energy is modeled in SimSEE to provide an outlet for potential excess wind, solar, or hydraulic energy that the system might encounter. The platform also represents unsupplied electricity through the generation of fictitious units called lost load units. These units account for unsupplied energy so that the system's demand always equals the sum of the system's electricity generation, imports, minus exports, plus unsupplied energy, in each simulated time interval. Adhering to this energy balance ensures compliance with the constraint of the optimization problem in Joskow and Tirole (2007). In summary, the optimal operation policy of SimSEE satisfies Equations 2 and 5.

Each lost load unit is modeled with a variable cost and a maximum lost load relative to total demand. Lost load units are dispatched by the platform in ascending order of their variable costs. Since we use the platform to determine the efficient dispatch of the market, lost load units can be represented as rationing for insensitive consumers and as self-generation for sensitive consumers. In the former case, the variable cost of the lost load unit is $Voll$, and the maximum lost load represents energy rationing relative to total demand. In the latter case, the variable cost of the lost load unit is c_{sg} of a small-scale fossil thermal generating unit, and the maximum lost load represents the demand of sensitive consumers relative to total demand.

The notation $I(c)$ is maintained throughout the paper. In the theoretical model, $I(c)$ represents the fixed-cost schedule associated with generation capacity indexed by variable cost c. In the empirical implementation, capacity additions are modeled as discrete generation blocks. Therefore, Equation 13 is used to compute the annual fixed cost of each generation block included in the simulations.

The annual fixed cost function $(I(c))$ is defined in Equation 13.

$$I(c) = \frac{(FOM + Ins)}{1000}K + \frac{K_0^{1-sf} \cdot Cov_0 \cdot (1 + fund) \cdot crf}{1000}K^{sf} \tag{13}$$

$I(c)$ is expressed in million \$ per year, and K is in MW. FOM represents the annual fixed operation and maintenance costs, while Ins refers to the annual insurance payment, both expressed in \$ per kW per year. K_0 and Cov_0 correspond to the capacity and overnight investment cost of the reference plant, expressed in MW and \$ per kW, respectively. sf is a scale factor related to the investment cost of power plants. $fund$ is the

[4] SimSEE is a set of tools and models that create a simulator for each case study using stochastic dynamic programming algorithms. It was developed at the Institute of Electrical Engineering of the Faculty of Engineering at the University of the Republic (Chaer et al., 2019).

percentage of funding costs over Cov_0, calculated as, $fund = \sum_{n=1}^{y} \rho \times (y - n + 1) \times \%Cov_{0,n}$, where n is the year of capital expenditure, y is the total construction period in years, ρ is the real annual social discount rate, and $\%Cov_{0,n}$ is the expenditure percentage for year n. This formula follows Theis (2021) assuming no real capital escalation during construction. crf is the capital recovery factor, calculated as, $crf = \frac{\rho(1+\rho)^N}{(1+\rho)^N - 1}$, where N is the plant's economic life in years.

Given the values of c, c_{sg}, $Voll$, $I(c)$, $\hat{D}(.)$, and $D(.)$, for both a risk-neutral and a reliability-risk-averse planner, we estimate the optimal values of $E[u(c,\nu)]$, $E[\alpha(\nu)]$, $E[\hat{\lambda}(\nu)]$, $\overline{p}$, $E[\hat{p}(\nu)]$, K, and the variability of the optimal $E[p(\nu)]$ paid by both sensitive consumers and suppliers of insensitive consumers.

The calculated electricity prices do not take into account the environmental effects of the generation sources, and reflect the generation cost without considering transmission and distribution losses.

4.1.1 Risk-neutral framework ($\beta = 0$)

We first establish as a benchmark the investment plan $K(c)$ when the planner does not internalize any risk ($\beta = 0$). The marginal plant of this plan and its capacity $K^*_{\beta=0}$, with a variable cost $c^*_{\beta=0}$, is the one that verify Equations 1 to 6 given the capacity of the plants with lower variable cost, $\bar{K}$. The solution is in Equation 14.

$$K(c) = \begin{cases} \bar{K} & \text{if } c < c^*_{\beta=0} \\ K^*_{\beta=0} & \text{if } c = c^*_{\beta=0} \\ 0 & \text{if } c > c^*_{\beta=0} \end{cases} \tag{14}$$

$K^*_{\beta=0}$ is calculated by varying the capacity of the candidate marginal plant by 1 MW. We assume that the expected wholesale electricity price from Equation 6 for $K^*_{\beta=0}$ covers all costs of $\bar{K}$.

4.1.2 Social risk aversion ($\beta > 0$)

Starting from the benchmark investment plan, we analyze capacity expansion decisions under social risk aversion ($\beta > 0$). In this framework, the planner assigns additional weight to welfare losses associated with high-impact, low-probability (HILP) scarcity events. The investment decision is determined by Equation 10, where the marginal benefit of additional capacity equals its marginal cost for ($0 < \beta \leq 1$).

The assumption of exogenous total demand quantities for each type of consumer simplifies Equation 10. For insensitive consumers, the variation in surplus without energy rationing, due to the addition of a marginal unit of K, is zero ($\frac{\partial}{\partial K}\left(\tilde{\tilde{S}}(\overline{p})\right) = 0$). For sensitive consumers, the variation in surplus is defined by Equation 12. Therefore, Equation 10, in discrete terms of the marginal unit of K ($\Delta K_{\beta>0}$) is expressed in Equation 15.

$$\underbrace{-\Delta W_{HILP} - \Delta\mathbb{E}[c_{\text{sg}}\hat{D}_{\text{sg}}(p(\nu))]}_{\text{Benefits of } \Delta K_{\beta>0}} - \underbrace{\Delta\mathbb{E}\left[\int_0^\infty c\, u(c,\nu) dK(c)\right] - \Delta\int_0^\infty I(c) dK(c)}_{\text{Costs of } \Delta K_{\beta>0}} = 0 \tag{15}$$

The sign of each term of Equation 15 when K varies is: $\Delta W_{HILP} < 0$, $\Delta E[c_{\text{sg}}\hat{D}_{\text{sg}}(p(\nu))] < 0$, $\Delta E\left[\int_0^\infty cu(c,\nu)dK(c)\right] > 0$, and $\Delta\int_0^\infty I(c)dK(c) > 0$. As $-\Delta W_{HILP} \geq -\Delta E[W_{\text{loss}}(\nu)]$, there are higher benefits for each investment rise from the benchmark investment plan. The level of investment when $\beta > 0$ is higher than in Joskow and Tirole (2007) framework, so $K^*_{\beta>0} > \bar{K} + K^*_{\beta=0}$.[5] Thus $K^*_{\beta>0} = \bar{K} + K^*_{\beta=0} + \sum^* \Delta K_{\beta>0}$, the latter being the optimal sum of $\Delta K_{\beta>0}$. Greater β and γ values result in a greater $\sum^* \Delta K_{\beta>0}$, which in turn leads to a greater $K^*_{\beta>0}$.

From Equations 9 and 15 we can solve for β value compatible with the equality of benefits and costs of the marginal unit $\Delta K_{\beta>0}$, given γ, in the Equation 16.

[5] γ has to be greater than zero as well, but since we are analyzing HILP events, it is implied than γ is large enough.

$$\beta = \frac{\Delta E\left[\int_0^\infty c\, u(c,\nu)dK(c)\right] + \Delta\int_0^\infty I(c)dK(c) + \Delta E[c_{\text{sg}}\hat{D}_{\text{sg}}(p(\nu))] + \Delta E[W_{\text{loss}}(\nu)]}{-\Delta[\text{CVaR}_\gamma(W_{\text{loss}}(\nu)) - E(W_{\text{loss}}(\nu))]} \tag{16}$$

In our framework, the risk-neutral solution leads to substantial welfare losses for insensitive consumers during HILP events. Under social risk aversion, additional investment is undertaken to reduce exposure to these losses. This investment acts as insurance for insensitive consumers against the reliability issues associated with HILP events. Additionally, this investment lowers the total electricity cost for sensitive consumers, as self-generation is replaced by cheaper electricity purchased from the market.

The value of $\sum^* \Delta K_{\beta>0}$ is calculated from $\bar{K} + K^*_{\beta=0}$ by incorporating homogeneous thermal plants $\Delta K_{\beta>0}$ with c $> c^*_{\beta=0}$. This value depends on the social planner's aversion to reliability risk and preferred degree of resilience, represented by the values of β and γ, respectively. Therefore, $\sum^* \Delta K_{\beta>0}$ according to the reliability risk and resilience preferences implicit in the system data satisfies the conditions of Equation 17.

$$\begin{cases} \text{minimize}\left\{\frac{(\text{CVaR}_\gamma(W_{\text{loss}}(\nu))-\mathbb{E}(W_{\text{loss}}(\nu)))_{\text{model}} - (\text{CVaR}_\gamma(W_{\text{loss}}(\nu))-\mathbb{E}(W_{\text{loss}}(\nu)))_{\text{data}}}{(\text{CVaR}_\gamma(W_{\text{loss}}(\nu))-\mathbb{E}(W_{\text{loss}}(\nu)))_{\text{data}}}\right\} \\ \beta \in (0,1] \\ \beta < \beta_{\max} \\ 0.9 \leq \gamma \leq 0.995 \end{cases} \tag{17}$$

Since the risk-neutral benchmark produces a higher reliability-risk measure than the observed system, and additional capacity monotonically reduces this measure, the relative deviation in Equation 17 is non-negative over the feasible set. Therefore, minimizing the signed deviation is equivalent to minimizing the relative distance.

We compute $\beta_{\max}$ as the value that satisfies Equation 16 for $\Delta K_{\beta>0}$, using the actual investment plan observed in the data (K_{data}) (MIEM indicative plan). Following Billimoria et al. (2022), we set $\gamma = 0.9$ to represent a low confidence level, as commonly employed in tail risk analyses, and $\gamma = 0.995$ to reflect the higher confidence level consistent with international insurance solvency standards. Data from the Uruguayan power system are used to estimate the degree of social risk aversion (β) and the level of protection against extreme scarcity events (γ) implicit in observed capacity choices.

4.2 Data

Our estimates are based on the Uruguayan power generation system expected for 2024-2028, simulating daily periods divided into sets of 1 hour, 4 hours, 13 hours, and 6 hours, ordered from highest to lowest net demand, as in Alvarez et al. (2023). Net demand is the difference between total demand and non-dispatchable renewable energy generation. We simulate 1000 equiprobable realizations of the vector ν.

Monetary values are calculated in 2023 US dollars ($), and these values per unit of energy are computed in levelized terms for 2024-2028, using a 7.5% real annual social discount rate in US dollars (ρ), as in OPP (2014).[6]

Table 1 shows amounts of internal demand in 2023. The expected average annual cumulative growth rate of internal demand for the period 2024-2028 is 2.3%.

The total internal demand structure between sensitive and insensitive consumers is based on the 2022 UTE consumption data, separating large consumers (sensitive) from the rest (insensitive). This structure remains the same for all simulated days. For the aforementioned sets of hours, the consumption structure for large

[6] OPP estimates the real annual social discount rate in Uruguayan currency. We assume the interest rate parity and the theory of relative purchasing power parity to ensure equal real rates in both US and Uruguayan currencies. The levelized value per unit of energy formula is: $LV = (\sum_{d=1}^{366}\sum_{t=1}^{5} V_{d_t}.En_{d_t}/(1+\rho)^t)/(\sum_{d=1}^{366}\sum_{t=1}^{5} En_{d_t}/(1+\rho)^t)$, where LV is the levelized value per unit of energy, V is the value per unit of energy, En is the energy quantity, d is the day, and t is the year.

consumers is based on their average hourly consumption curve, while for the rest, it is calculated by difference.[7] These consumption patterns are assumed to remain constant throughout the analyzed period.

Table 2 lists the generation capacity by source for 2023 and 2028.

The plants included in $\bar{K}$ from Equation 14 have the capacity values reported in Table 2.[8] Neutral initial hydrological conditions were modeled, without climatic biases, to focus on investment decisions. For simplicity, only energy surplus exports were considered.

Table 3 lists the values of the parameters of the lost load units that are modeled on the platform.

Three types of rationing are represented for insensitive consumers. Voluntary rationing (type 1), previously notified involuntary rationing of less than 5 hours per day (type 2), and previously notified involuntary rationing of 5 hours or more per day (type 3). The lost load values related to these types of rationing are calculated for consumers in the residential and service sectors. Based on Osta (2023), the value related to type 1 rationing ($Voll_1$) is estimated using the consumer surplus method, assessing the willingness to pay to avoid rationing, and the values related to the other types of rationing ($Voll_2$ and $Voll_3$) are estimated using the production function method, considering electricity as an input for both residential well-being and the added gross value in the service sector.

The average daily economic impact of involuntary power supply interruptions for both types of consumers, with and without prior notification, is \$7,691/MWh and \$8,894/MWh, respectively. To account for prior notification, a positive factor less than 1 is applied to the economic impact without prior notification, depending on the duration of the interruption and, therefore, on the percentage of involuntary rationing relative to total demand. $Voll_2$ and $Voll_3$ are derived from a nonlinear function that relates the average economic impact with prior notification and the percentage of involuntary rationing relative to total demand.

It is assumed that the self-generation by sensitive consumers comes from generating units that are owned or leased on the market. The analysis does not consider rental costs of these generating units, so the cost of self-generation is independent of the generating unit's source. This simplification is based on the fact that self-generation is more relevant in a theoretical context with non-negligible anticipated rationing than in the current context.[9] Load shifting is not studied because estimating the productive cost of shifting consumption from peak hours to off-peak hours is beyond the scope of this analysis.

In the Uruguayan wholesale power market, candidate marginal plants are the combined cycle and the combustion turbines due to their higher variable costs. Using Equation 13 and the values of the parameters in Table 4, $I(c)$ functions for both types of plants are calculated. For combined cycle, $I(c_{cc}) = 0.01432K + 0.33745K^{0.82}$, and for combustion turbine, $I(c_{ct}) = 0.00915K + 0.26001K^{0.82}$.[10]

$\Delta K_{\beta>0}$ is assumed to be a 50 MW combustion turbine, with c = \$261.7/MWh, representing the most frequent high variable cost fossil thermal power plant in the Uruguayan system. It is modeled as a new power plant with an annual fixed cost, calculated based on $I(c_{ct})$ function, equal to \$6.89 million per year.

The estimated value of $I(c_{sg})$ for total self-generation is \$29.16 million per year, based on 481 small-scale generating units and the parameter values in Table 4.

[7] The structures were calculated from the net annual demands of 2019–2023, and the average structure was then used.

[8] Small plants from renewable sources were grouped, by source, into a single plant with zero variable cost for simplification.

[9] In a context with nearly zero anticipated rationing, approximately 25% of large industrial electricity consumers possess their own private generating units.

[10] For the combined cycle, its capacity is significant for the system, so it is modeled with minimum technical requirements for both combustion and steam turbines. The relationship between the minimum and full capacity of these turbines is maintained at 33% and 27%, respectively, as the combined cycle capacity varies. This plant is also modeled to turn on and off on a daily basis. Smaller thermal plants are modeled without these requirements.

5 Results

In this section, we begin by presenting the benchmark results derived from the model proposed by Joskow and Tirole (2007), focusing on a risk-neutral planner's decision-making process regarding the optimal investment plan to ensure sufficient generation capacity to meet expected demand. Next, we extend the model to include a reliability risk-averse planner who also considers high-impact low-probability (HILP) events, thus requiring additional investment to cover these unlikely scenarios. Finally, we perform a welfare analysis to determine the distribution of the generation investment costs and their impact on overall welfare. All our estimations take into account the parameters estimated for the period 2024-2028.

5.1 Risk-neutral framework ($\beta = 0$)

The structure of the installed capacity in equilibrium, as estimated in a risk-neutral framework based on Equation 14, is presented in columns 3 and 4 of Table 5, following the framework proposed by Joskow and Tirole (2007). We estimate the value of $K^*_{\beta=0}$ to be 371 MW, representing the combined cycle capacity. The expected variable cost that consumers face for its use ($c^*_{\beta=0}$) is \$208.5/MWh, with an expected utilization rate, $E[u(c,\nu)]$, of 7%.[11] The investment plan represents the capacity at which the lower-cost option ($\bar{K}$) and the marginal plant $K^*_{\beta=0}$ operate. Taking the existing low-variable-cost capacity ($\bar{K}$) as given, the model endogenously determines the optimal combined-cycle capacity $K^*_{\beta=0}$. Conditional on $\bar{K}$, the resulting plan accounts for 85% of the expected Uruguayan investment plan. It should be noted that the expected utilization rate of the main renewable sources is below 50%, reaching 21% in the case of solar energy. This is our main source of uncertainty, and the incorporation of fossil thermal plants is a strategy to address it. This risk-neutral investment plan accounts for only 37% of the expected fossil thermal capacity of Uruguay.

The market consumption under this investment plan is shown in column 4 of Table 8. Insensitive consumers experience expected rationing, which represents 0.32% of their demand. This rationing consists of 85% voluntary and 15% involuntary measures, respectively. Sensitive consumers do not experience rationing by definition; however, they need to self-generate an expected 1.39% of their demand at a cost of \$345/MWh, which results in an expected unit cost of \$56.2/MWh for the total electricity consumed. The average expected marginal price for both types of consumers is \$70/MWh.[12]

The average expected marginal price hides a heterogeneous behavior throughout the year. Therefore, we next estimate the price dynamics for different types of consumers in a typical calendar year, shown in Figure 1. To explain these dynamics, we also illustrate the net demand for the same year in Figure 1. Net demand is the difference between total demand and generation from wind and solar sources and must be met by hydroelectric and thermal plants. This explains why higher net demand leads to higher market prices and vice versa. Under rationing, when the price is set by $Voll$, the market is likely to face a shortage of renewable resources, as well as insufficient water and thermal capacity to meet demand. This is more probable during summer (days 1-60) and autumn-winter (days 100-250). We highlight the linear correlation between the expected daily price paid by insensitive consumers' suppliers and the expected daily net demand, shown in Figure 1, with a correlation coefficient of 0.78 (0.57 if the total demand is considered). For sensitive consumers, the correlation is also positive but lower (0.62), as they self-generate electricity when the market price reaches or exceeds their self-generation cost of \$345/MWh. Thus, higher prices, such as those during involuntary rationing, do not affect the prices paid by these consumers.

In addition to seasonal variations, the hours of the day are also relevant periods to determine different

[11] Since the variable cost of the combined cycle depends on the utilized capacity, its value is influenced by ν.

[12] Due to surplus exports and curtailments, this price accounts for 82% of the generators' average expected price, \$58.1/MWh.

expected prices because net demand varies significantly during these times. We estimate the expected price dynamics for both types of consumers on a typical day, as shown in Table 6, with hours grouped into four categories based on net demand, from highest to lowest. The comparison of expected prices paid by sensitive consumers and by suppliers of insensitive consumers, taking into account the hourly consumption pattern of the former, allows us to estimate the impact of insensitivity on expected prices. If insensitive consumers had the same hourly consumption pattern as sensitive consumers, the expected price would be $71.8/MWh, which is $19.7/MWh higher than the expected price for sensitive consumers. Therefore, demand insensitivity implies paying a 38% higher expected price.

5.2 Social risk aversion ($\beta > 0$)

We formalize an extension of the model that incorporates supply uncertainty and social risk aversion. The main components of the framework are presented in Equations 15 through 17. Figure 2 illustrates the effects of successively adding homogeneous 50 MW fossil thermal plants to the system. The lower panel compares the welfare risk associated with high-impact, low-probability (HILP) scarcity events obtained under the model with the corresponding risk implied by the observed Uruguayan capacity plan, for different values of γ. We focus on the capacity levels at which the welfare risk predicted by the model most closely matches the welfare risk associated with the observed system. The upper panel presents the combinations of β and γ that satisfy the conditions in Equation 17 for each successive 50 MW capacity addition. The relevant values for the social risk-aversion solution are those associated with the maximum feasible values of these parameters. The upper bound for γ is set at 0.995, corresponding to confidence levels commonly used in international insurer solvency standards (Billimoria et al., 2022). The upper bound for β is determined by the condition that the marginal cost and marginal benefit of adding an additional 50 MW of fossil thermal capacity, relative to the observed Uruguayan capacity plan, are equal. As a result, the maximum feasible value of β depends on the value of γ.[13] Based on this calibration, the socially risk-averse planning criterion implies an additional 600 MW of fossil thermal capacity relative to the risk-neutral solution.

The result that we estimate in Figure 2 is shown in Table 7, that implies an optimal increase of 600 MW in fossil thermal capacity.[14]The observed capacity plan is consistent with a planning criterion that assigns a weight of 0.60 to welfare losses associated with extreme scarcity events. While the inverse estimation procedure could in principle map to multiple (β, γ) combinations, the restrictions imposed in Equation 17 ($\beta \in (0, 1]$, $\beta < \beta_{max}$, $0.9 \leq \gamma \leq 0.995$) yield a unique solution within the feasible parameter space, as shown in Figure 2. In our model, the HILP events are those with an occurrence of 0.009. These parameters governing social risk aversion and protection against extreme scarcity events balance the benefits and costs of incorporating the last 50 MW fossil thermal plant with $c >$ \$208.5/MWh into the market, bringing the model's reliability risk of HILP events closer to that of the expected Uruguayan capacity. See the purple line in Figure 2.

The addition of 600 MW of investment capacity does not change the expected utilization rate of $\bar{K}$ and barely affects the expected utilization rate of the marginal risk neutral plant, as shown in columns 5 and 6 of Table 5.[15] Consequently, the value of the additional investment does not arise from higher average utilization, but from

[13] This threshold is estimated relative to the observed Uruguayan capacity plan rather than the theoretical sequence of homogeneous 50 MW fossil thermal plants used in the model.

[14] Uruguay's expected additional fossil thermal capacity, according to the neutral-risk solution, is 741 MW. The lower capacity increase in the model can be attributed to two technical factors, which make the result expected. First, the Uruguayan combined cycle plant (550 MW) is much larger than the one in the model (371 MW), requiring more backup capacity when unavailable. Second, the model assumes newer fossil thermal plants, with higher availability, compared to older plants in Uruguay.

[15] Although the 50 MW fossil thermal plants have higher variable costs than the combined cycle, their smaller size allows the system operator to dispatch them with fewer technical restrictions, which in turn leads to lower operating costs, making it advantageous to substitute the combined cycle under certain circumstances.

reducing welfare losses during scarcity events. Specifically, the new capacity decreases involuntary rationing among price-insensitive consumers and reduces the need for self-generation among price-sensitive consumers.

The capacity expansion implied by the social risk-aversion framework substantially reduces the exposure of price-insensitive consumers to involuntary rationing. As shown in Column 5 of Table 8, expected rationing falls by 0.06% of demand in absolute terms, corresponding to an 18.8% reduction relative to the risk-neutral benchmark. Under the new investment plan, 99.7% of expected rationing is voluntary and only 0.3% is involuntary. Thus, the additional thermal capacity effectively eliminates most involuntary shortages and substantially reduces the welfare losses associated with extreme scarcity events.

For price-sensitive consumers, the main effect of the additional capacity is not improved reliability but a reduction in self-generation. Self-generated electricity falls to only 0.06% of total demand, as market purchases increasingly replace more expensive self-supplied energy. Consequently, the expected unit cost of electricity consumed by these consumers ($52.4/MWh) becomes almost identical to the expected market price of purchased electricity ($52.2/MWh). Since the expected market price changes only marginally relative to the risk-neutral benchmark ($52.1/MWh), price-sensitive consumers bear little of the cost associated with the additional capacity expansion.

The distributional consequences of the investment are reflected in the pricing structure. The expected market price faced by suppliers serving price-insensitive consumers is $54.7/MWh, compared with an average market price of $54.2/MWh across all consumers. However, to recover the fixed costs of the expanded generation fleet, suppliers serving price-insensitive consumers must charge an expected retail price of $84.3/MWh. As a result, generators recover their costs primarily through the tariff paid by price-insensitive consumers[16], while price-sensitive consumers benefit from lower self-generation costs without bearing a proportional share of the investment burden. All these results suggest that the additional thermal capacity functions as a form of reliability insurance. The investment is motivated by the desire to reduce welfare losses associated with extreme scarcity events, yet its benefits extend beyond the consumers most exposed to reliability risk. While price-insensitive consumers finance most of the capacity expansion, price-sensitive consumers also benefit through lower electricity costs, generating substantial welfare redistribution across consumer groups.

The dynamic of expected daily prices is shown in Figure 3. If we compare this figure with Figure 1, we can observe that the increase in capacity brings the expected prices paid by the suppliers of insensitive consumers in the market closer to those paid by sensitive consumers. This is because involuntary rationing, which explains most of the difference between these prices, is less likely with increasing capacity. Therefore, the prices determined by $Voll_2$ and $Voll_3$ are also less likely.

5.3 Consumers' welfare analysis

Under the social risk-aversion framework, additional thermal capacity affects consumers through two distinct channels. For price-sensitive consumers, welfare increases because additional capacity reduces reliance on costly self-generation. For price-insensitive consumers, welfare increases because the probability and severity of electricity shortages decline, particularly during high-impact, low-probability (HILP) events. In both cases, the welfare gains exceed the additional generation costs associated with the 600 MW expansion, resulting in positive net welfare effects for both consumer groups.

Table 9 reports the welfare estimates. For price-sensitive consumers, ΔW captures the savings associated with substituting self-generated electricity with electricity supplied by new market plants, while ΔC reflects the

[16] Cost recovery is not part of the optimization. Under social risk aversion the free-entry condition (Equation 6) is replaced by the planner's marginal-benefit condition (Equation 10), which determines the optimal capacity but not its financing. Cost recovery is computed ex post: fixed costs not covered by spot revenues are allocated to the retail tariff of price-insensitive consumers, and the $84.3/MWh price is the value that closes this condition.

additional generation costs incurred by the system. The resulting net welfare gain is approximately \$3.7/MWh. Given total consumption of roughly 11 million MWh over the five-year period, this corresponds to a welfare gain of approximately \$40 million in present value.

For price-insensitive consumers, welfare gains arise primarily through improved reliability. Specifically, they obtain \$2.7/MWh from a reduction in expected rationing and an additional \$66.2/MWh from lower welfare losses during HILP events. Although their expected electricity cost increases by \$9.5/MWh, this additional payment can be interpreted as the cost of obtaining protection against extreme scarcity events. Table 9 disaggregates these effects to make their source transparent. Considering only expected outcomes—the reduction in expected rationing net of the higher tariff—price-insensitive consumers are in fact worse off, with a net expected loss of \$6.8/MWh. Their positive net welfare gain of \$59.4/MWh arises entirely from the valuation of the reduction in HILP-event risk, captured by the CVaR component of Equation 9, which accounts for the overwhelming majority of their total welfare gain. The welfare improvement for price-insensitive consumers is therefore driven by reduced exposure to extreme scarcity events rather than by improvements in expected outcomes. With total consumption approaching 40 million MWh over the five-year period, the resulting welfare gain amounts to approximately \$2.3 billion in present value.

These results suggest that the additional thermal capacity functions as a form of reliability insurance. Price-insensitive consumers finance most of the investment through higher electricity prices because they place value on avoiding severe scarcity events. At the same time, price-sensitive consumers benefit from lower self-generation costs while bearing only a small share of the additional investment burden. Consequently, reliability-oriented capacity expansion generates substantial welfare redistribution across consumer groups. In this sense, the willingness of price-insensitive consumers to pay for greater protection against scarcity creates a positive externality for price-sensitive consumers.

Moreover, as expected self-generation falls from 1.39% to 0.06% following the expansion, price-sensitive consumers can avoid part of the capital and operating costs associated with self-generation technologies. If these costs are fully avoided, the welfare gain for sensitive consumers increases by an additional \$10.9/MWh, raising the total welfare gain to \$14.6/MWh. Under this upper-bound scenario, the total welfare improvement for sensitive consumers reaches approximately \$158 million in present value over five years.

6 Conclusions

This paper studies why electricity systems maintain thermal capacity that appears difficult to justify under standard market criteria and examines the welfare consequences of doing so. We show that a risk-neutral framework can explain most generation capacity observed in Uruguay but fails to account for a large share of thermal backup capacity. Conditional on the existing low-variable-cost capacity ($\bar{K}$), the model of Joskow and Tirole (2007) explains 85% of the generation capacity observed in the Uruguayan system, but only 37% of its fossil thermal capacity. Interpreting thermal capacity as reliability insurance against high-impact, low-probability (HILP) scarcity events helps reconcile this gap and provides a rationale for the additional capacity observed in practice. The model also highlights the role of demand heterogeneity: because insensitive consumers are less responsive to scarcity signals, they face expected electricity prices that are 38% higher than those faced by sensitive consumers.

To account for the observed level of thermal capacity, we extend the framework of Joskow and Tirole (2007) by incorporating social risk aversion toward welfare losses associated with extreme scarcity events. We estimate that the observed capacity plan is consistent with a planner who assigns a weight of 0.60 to welfare losses associated with the most severe 0.9% of scarcity events. Under these preferences, the optimal investment plan requires increasing fossil thermal capacity by approximately 136% relative to the risk-neutral benchmark. Despite its low expected utilization rate of only 4%, this additional thermal capacity plays an important role in reducing exposure to extreme scarcity events and therefore acts as a form of reliability insurance.

The welfare implications of this insurance are highly uneven across consumers. Although the additional thermal capacity is primarily motivated by the reliability concerns of price-insensitive consumers, it also benefits price-sensitive consumers by reducing their reliance on self-generation and lowering their expected electricity costs. Price-insensitive consumers bear almost all of the fixed costs associated with the capacity expansion through higher electricity prices, while price-sensitive consumers receive part of the benefits without paying a proportional share of the costs. As a result, reliability-oriented capacity investments generate substantial welfare redistribution across consumer groups.

More broadly, our results suggest that capacity planning decisions should be viewed not only as instruments for ensuring reliability, but also as mechanisms that determine how the costs and benefits of reliability are allocated across consumers. In this sense, thermal capacity serves not only as backup generation, but also as a form of insurance whose incidence has important welfare consequences.

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7 Tables and figures

Table 1: Internal demand of the Uruguayan power system in 2023

Description	Unit	Value
Annual average hourly demand	MWh	1,310
Maximum capacity demand	MW	2,213
Minimum capacity demand	MW	760

Source. ADME (2023)

Table 2: Capacity (K) of the Uruguayan power system in MW

Generation source	2023	2028
Hydroelectric	1,541	1,541
Wind	1,477	1,477
Biomass	320	360
Photovoltaic solar	239	339
Fossil thermal - reciprocating engines	70	70
Fossil thermal - combined cycle	550	550
Fossil thermal - combustion turbines	562	562

Note. Based on the information obtained from Alvarez et al. (2023) and data from MIEM. Electricity from biomass is mainly generated by cogeneration plants with varying availability. Biomass capacity is based on the largest plant's gross capacity, and for others, it is calculated by applying an availability factor of 0.87 over available capacity.

Table 3: Lost load units modeled

Parameter	Description	Unit	Value
$Voll_1$	Value of lost load related to rationing type 1	\$/MWh	242
$Voll_2$	Value of lost load related to rationing type 2	\$/MWh	4,565
$Voll_3$	Value of lost load related to rationing type 3	\$/MWh	8,315
x_1	Maximum rationing type 1 relative to total demand		2%
x_2	Maximum rationing type 2 relative to total demand		12.7%
x_3	Maximum rationing type 3 relative to total demand		63.7%
c_{sg}	Variable cost of sensitive consumers self-generation	\$/MWh	345
$\frac{\hat{D}(.)}{\hat{D}(.)+D(.)}$	Sensitive consumers demand relative to total demand		21.6%

Note. x_1 is defined by Decree N° 105/013, x_2 corresponds to the inflection point of the non-linear function from which $Voll_2$ and $Voll_3$ are calculated, and x_3 is calculated by default. The expression $\frac{\hat{D}(.)}{\hat{D}(.)+D(.)}$ is based on 2022 MIEM consumption data for large and general consumers. Finally, c_{sg} is calculated using a specific consumption of 0.27 m^3/MWh, a non-fuel variable cost of \$6.75/MWh, as reported by CNE (2023), and the average price of 50S gas oil (excluding taxes) in October 2023, as reported by MIEM.

Table 4: VALUES OF THE PARAMETERS OF ANNUAL FIXED COST ($I(c)$) FOR EACH FOSSIL THERMAL PLANT

Parameter	Unit	Combined cycle	Combustion turbine	Small-scale generator
FOM	\$ per KW per year	11.96	6.87	5.98
Ins	\$ per KW per year	2.36	2.28	0
K_0	MW	1,243	419	0.5
Cov_0	\$ per kW	943	913	947
sf		0.82	0.82	1
$fund$		17.18%	13.50%	7.5%
crf		8.47%	8.47%	11.33%

Note. The values of FOM, K_0, and Cov_0 for combined cycle and combustion turbine plants come from cost data in EIA (2024). To adjust for higher unit investment costs in a small economy like Uruguay, Cov_0 for each plant was calculated by averaging project costs from locations with higher-than-base costs. Since the EIA data uses net capacity, the combined cycle plant value was adjusted for a 1.29% internal loss to reflect gross capacity. In the case of the combustion turbine, due to its considered reduced capacity, this adjustment was not made. For the small-scale generating unit, FOM, K_0, and Cov_0 are based on cost data from CNE (2021), updated to 2023, for a 0.5 MW motor generator set. The Ins value is not relevant for the small-scale generating unit, but for combined cycle and combustion turbine, Ins is 0.25% of Cov_0 as per KPMG and SEG INGENIERIA (2015). The sf value for combined cycle and combustion turbine reflects economies of scale, as described by Baumann (2014). For the small-scale generating unit, it is assumed that $sf = 1$, as its Cov_0 corresponds directly to the considered capacity. The construction period is assumed to be 4 years for combined cycle, 3 years for combustion turbine, and 1 year for the small-scale generating unit, based on Uruguayan experience and CNE (2023). According to Theis (2021), the Cov_0 breakdown is: for the combined cycle, $\%Cov_{0,1}$=10%, $\%Cov_{0,2}$=25%, $\%Cov_{0,3}$=49%, and $\%Cov_{0,4}$=16%; for the combustion turbine, $\%Cov_{0,1}$=10%, $\%Cov_{0,2}$=60%, and $\%Cov_{0,3}$=30%. For combined cycle and combustion turbine, N is 30 years, based on Theis (2021), while for the small-scale generating unit, N is 15 years, based on Uruguayan experience. For simplification, the plant's retirement cost is assumed to be equal to its salvage value in all cases.

Table 5: INSTALLED CAPACITY IN EQUILIBRIUM

		Risk neutral		Risk averse	
K(c)	Generation source	K (MW)	$E[u(c,\nu)]$	K (MW)	$E[u(c,\nu)]$
$\bar{K}$	Hydroelectric	1,541	48%	1,541	48%
$\bar{K}$	Wind	1,477	42%	1,477	42%
$\bar{K}$	Biomass	360	78%	360	78%
$\bar{K}$	Photovoltaic solar	339	21%	339	21%
$\bar{K}$	Fossil thermal	70	12%	70	12%
$K^*_{\beta=0}$	Fossil thermal	371	7%	371	6%
$\sum^* \Delta K_{\beta>0}$	Fossil thermal	0	0	600	2%

Note. K is from 2028. $E[u(c,\nu)]$ is the 2024-2028 average, excluding the 2028 photovoltaic solar value due to distortion from new capacity added that year. The expected variable cost of $K^*_{\beta=0}$ in the risk neutral equilibrium is \$208,5/MWh and \$200,2/MWh in the risk averse equilibrium.

Table 6: EXPECTED PRICES BY HOURLY NET DEMAND WITH A RISK NEUTRAL PLANNER

Net demand category	Number of hours	Expected market consumption sensitive	$E[p(v)]$ paid by sensitive (\$/MWh)	Expected market consumption insensitive	$E[p(v)]$ paid by suppliers of insensitive (\$/MWh)
Highest	1	3.7%	90.2	5%	120
High	4	15.6%	75.1	19.2%	104
Moderate	13	56.4%	54.5	54.6%	77.6
Lowest	6	24.4%	26.1	21.2%	30.5

Note. The hours of the typical day are ordered from highest to lowest net demand. The demand structure of sensitive consumers according to the net demand categories is 3.8%, 15.8%, 56.3%, and 24.1%, while for insensitive consumers it is 5.1%, 19.2%, 54.6%, and 21.1%.

Table 7: Model solution with a reliability risk averse planner

Notation	Description	Unit	Value
$\sum^* \Delta K_{\beta>0}$	Capacity added when the planner internalizes reliability risk	MW	600
β	Weight assigned to welfare losses in HILP events		0.60
γ	Confidence level defining HILP events		0.991

Table 8: Market consumption and prices

Notation	Description	Unit	Value	
			Risk neutral	Risk averse
$E[\alpha(\nu)]$	Expected market consumption relative to demand of insensitive		99.68%	99.74%
$E[\hat{\lambda}(\nu)]$	Expected market consumption relative to demand of sensitive		98.61%	99.94%
$\overline{p}$	Expected marginal price for insensitive	\$/MWh	74.8	84.3
$E[\hat{p}(\nu)]$	Expected marginal price for sensitive	\$/MWh	52.1	52.2

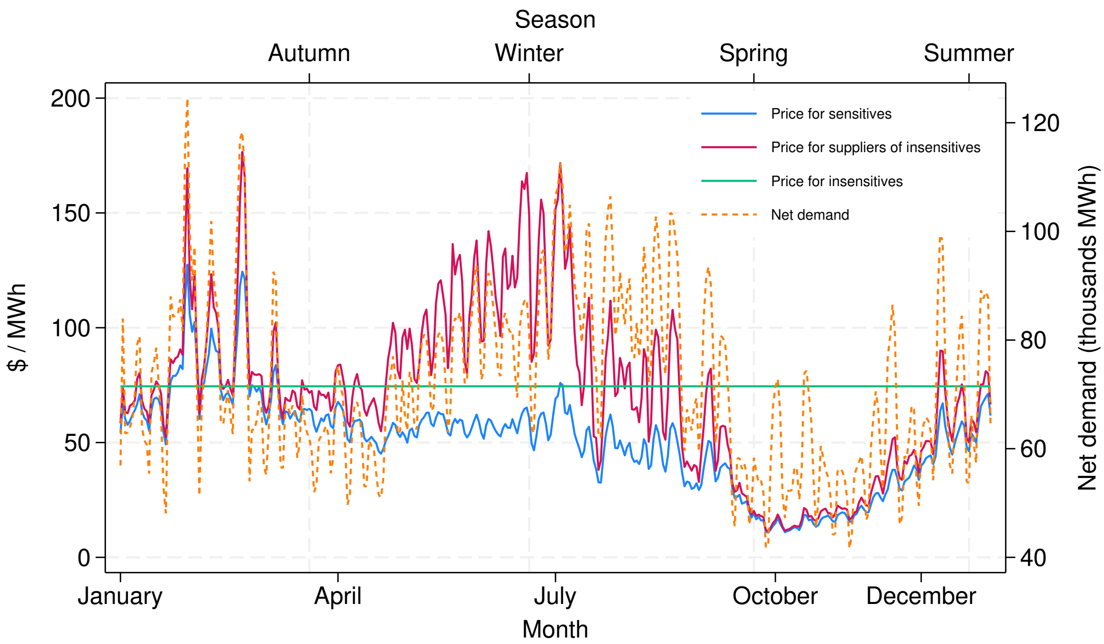
Note. Since the combined cycle operates with technical minimums, its marginal cost decreases as capacity increases, affecting the market's marginal cost. As a result, the portion of its variable cost not covered by the market's marginal cost must be added to the price for each consumer type. In the risk neutral case, for the expected marginal price, this added value is \$0.36/MWh for sensitive consumers and \$0.32/MWh for insensitive consumers. In the risk averse case, for the expected marginal price, the added value is \$0.32/MWh for sensitive consumers and \$0.28/MWh for insensitive consumers.

Table 9: Decomposition of consumers' welfare

Consumer type	Expected component			Risk valuation	Total
	ΔW_{exp} (\$/MWh)	ΔC (\$/MWh)	$\Delta(W_{\text{exp}}-C)$ (\$/MWh)	ΔW_{HILP} (\$/MWh)	$\Delta(W-C)$ (\$/MWh)
Sensitive	4.6	0.9	3.7	0.0	3.7
Insensitive	2.7	9.5	−6.8	66.2	59.4

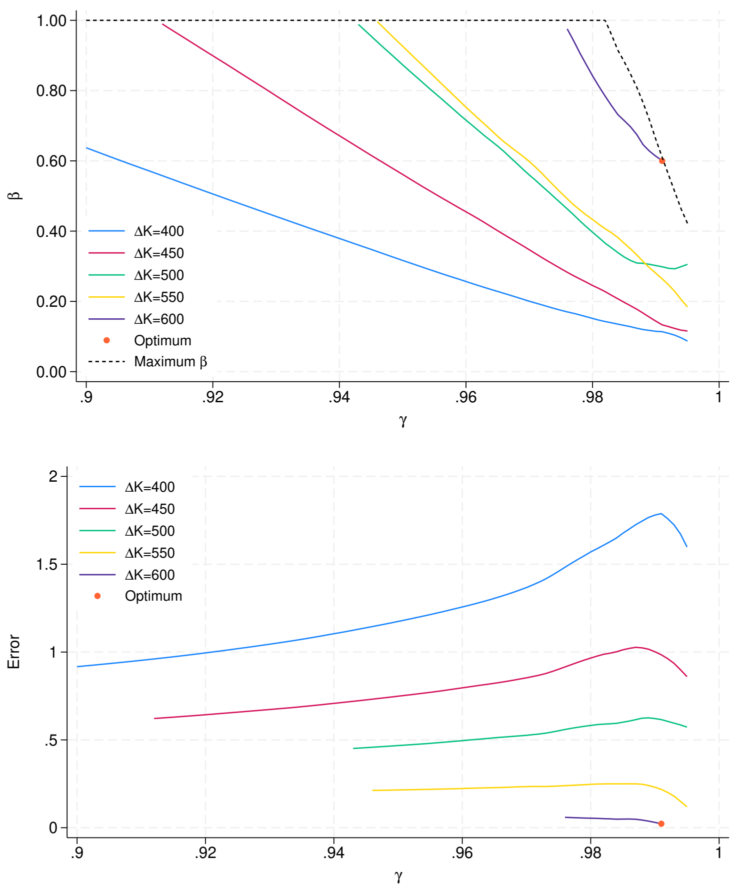
Note. ΔW_{exp} is the expected welfare gain: reduced self-generation cost for sensitive consumers and reduced expected rationing for insensitive consumers. ΔC is the expected cost increase. $\Delta(W_{\text{exp}} - C)$ is the net welfare change considering only expected outcomes. ΔW_{HILP} is the welfare gain from the reduction in the tail-risk (CVaR) component of Equation 9, evaluated at $\beta = 0.60$ and $\gamma = 0.991$; it is zero for sensitive consumers, who never face rationing. $\Delta(W - C)$ is the total net welfare change. Values in \$/MWh are computed on each group's total consumption after the capacity increase.

Figure 1: Expected daily prices and net demand with a risk neutral planner



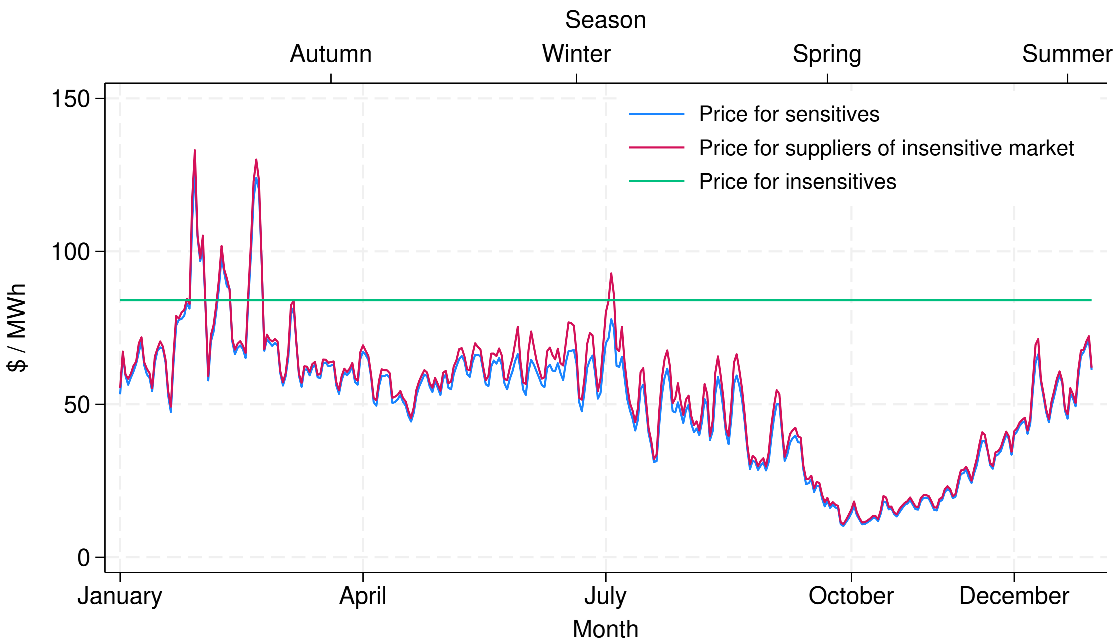
Note. February 29, 2024 and 2028 are not considered.

Figure 2: Model solution with a reliability risk averse planner



Note. The error is: $\frac{\left(\text{CVaR}_\gamma(W_{\text{loss}}(\nu))-\mathbb{E}(W_{\text{loss}}(\nu))\right)_{\text{model}}-\left(\text{CVaR}_\gamma(W_{\text{loss}}(\nu))-\mathbb{E}(W_{\text{loss}}(\nu))\right)_{\text{data}}}{\left(\text{CVaR}_\gamma(W_{\text{loss}}(\nu))-\mathbb{E}(W_{\text{loss}}(\nu))\right)_{\text{data}}}$. The minimum value of the error is 2.3%. The upper bound of β at the optimum ($\gamma = 0.991$) is 0.61.

Figure 3: Expected daily prices with a reliability risk averse planner



Note. February 29, 2024 and 2028 are not considered.